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On the variability of CO_2 feed flows into CCS transportation and storage networks

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ABSTRACT

The flexible operation of CO_2 injection wells presents significant challenges. To avoid premature degradation of wells or loss of integrity it is imperative to understand the feed flow patterns that future CO_2 transportation and storage networks will face. We use a unit commitment economic dispatch (UCED) model to study CCS operating regimes in low carbon energy systems scenarios that are characterised by high shares of weather dependent renewable power generation. Using the case study of Great Britain, we determine the extent to which flexible operation of CCS plants is required, resulting in variable CO_2 flows that need to be accommodated by future CO_2 transportation and storage networks. We find that around 21% and 12% of the net flow rate changes over 6h-periods in the core scenario have greater amplitudes than 30% and 50% of nominal flow, respectively. When changes are averaged over two consecutive blocks of 6 h, representing the smoothing effect achievable via line-packing over a pipeline of reasonable length and diameter, around 9% of the net changes have greater amplitudes than 40% of nominal flow. Given the high and frequent fluctuations in feed flows across all considered scenarios, further research is urgently required on the capability of transportation and storage networks to accommodate variable CO_2 flow rates.

1. Introduction

With the entry into force of the Paris Agreement (United Nations, 2015) in November 2016, most countries worldwide committed to climate change mitigation consistent with keeping the increase in global average temperature well below 2 °C, which implies a need to decarbonise the energy system. CO_2 capture and storage (CCS), power generation from renewable sources (wind, solar, etc.) and nuclear power have gained widespread attention as low carbon technologies that can be used to deliver the required reductions of greenhouse gas (GHG) emissions. The very different operational characteristics and roles these technologies play in electricity systems are, however, often disregarded.

While power from weather dependent renewable sources is predominantly intermittent and variable, nuclear plants provide firm base load power at low operational, however, high capital costs. CO_2 capture and storage fitted on fossil (or biomass) fired power stations is able to provide firm and flexibly dispatchable power at comparatively low capital cost and low (or potentially negative) GHG emissions. This makes the technology ideally suited for balancing low carbon energy systems dominated by high penetrations of variable renewable energy.

This characteristic as a firm capacity provider with good load following capability contrasts with the majority of the literature that focuses on exploring different CCS technologies as individual components of the process chain (e.g. either capture, transportation or storage) at steady-state and design conditions rather than as parts of an integrated system that needs to operate in a flexible manner.

As of yet, only a relatively small amount of literature has investigated the flexible capabilities and operating patterns of CCS plants in future low carbon energy systems, and the consequences these may have on the operating behaviour of these plants (Brouwer et al., 2015; Van der Wijk et al., 2014; MacDowell and Staffell, 2016; Oates et al., 2014; Bruce et al., 2014; Bruce, 2015; Mechleri et al., 2017a). MacDowell and Staffell (2016) classify studies, modelling the interaction between CCS plants and the electricity market, into three levels of complexity:

1. Operation of a CCS power station(s) can be evaluated under a predefined pattern of prices (e.g. historical prices of electricity, fuel or carbon);

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2. An electricity system scenario ('snapshot') can be modelled by choosing a profile for electricity demand and a power generation portfolio (incl. CCS plants), that will meet demand according to a dispatch procedure; or
3. A dynamic scenario for the future can be created, that is driven by underlying policy and investor behaviour. A coupled power system investment and dispatch model first determines the optimal power generation portfolio, and subsequently the detailed operational dispatch of the power plants.

Several studies model CCS power plants, in particular the value of flexible capture operation ('solvent storage' and capture plant 'bypass'), under predefined (mostly historical) price patterns (Oates et al., 2014; Cohen et al., 2011; Chalmers, 2010; Husebye et al., 2011; Mechleri et al., 2017b; Van Peteghem and Delarue 2014). 'Bypass' describes the operational mode of the CCS plant when the capture unit is switched off, resembling operation of a fossil fuelled power station without CO_2 capture capability. 'Solvent storage' refers to the technique at post-combustion CCS power plants of delaying the energy-intensive step of solvent regeneration to later points in time in order to boost electrical output when electricity prices are high. However, given that these studies are typically based on historical price patterns they are not necessarily able to predict operating patterns under the significantly different conditions expected in future low carbon energy systems.

Other studies taking the second and third approaches focus on examining the operating profiles and role of CCS power stations in future energy systems (Brouwer et al., 2015; Van der Wijk et al., 2014; MacDowell and Staffell, 2016; Bruce, 2015; Bruce et al., 2014; Bruce et al., 2016). They generally conclude that CCS plants will need to operate in a flexible, load following (i.e. responding to changing demand levels by adjusting power output) manner in future energy systems in order to balance the large penetrations of renewable power generation.

However, very little consideration is given in any of the above studies to whether the future CO_2 transportation and storage (T&S) systems can cope with the large and potentially frequent and irregular fluctuations in CO_2 feed flow rates that the projected operating profiles of CCS power plants imply. The studies generally assume no downstream constraints to flexible operation of CO_2 T&S networks. Concerns have been raised about whether this assumption is justified. Spitz et al. (2017), IEAGHG (2016) and Jensen et al. (2014) present reviews of the issues associated with variable CO_2 flow-rates for T&S systems. The injection wells in particular have been identified as a potential constraint to flexible operation of the CCS system (Spitz et al., 2017; Sacconi et al., 2016, Aursand et al., 2017; Lund et al., 2017; Roy et al., 2016).

Potentially the most important issue associated with varying flow rates through injection wells is related to the repeated thermal expansion and contraction of well materials. Over time this can degrade the well, impacting its integrity (e.g. through debonding of well materials due to different thermal expansion coefficients). The effect can be magnified if two-phase flow develops at the wellhead (i.e. strong Joule-Thomson cooling), as a consequence of the wellhead pressure reducing at low relative flow rates due to a decreased backpressure from injection. Additional well related issues that can arise and are exaggerated by two-phase flow include repeated harmful oscillations and vibrations at conditions close to the critical point, hydrogen induced embrittlement of well materials (only when hydrogen is present in the flow), and hydrate formation.

Some authors have assessed the integrity risk induced by repeated cyclic thermal stresses at lab-scale or via modelling (Albawi et al., 2014; De Andrade et al., 2014; Lund et al., 2017; Roy et al., 2016; Aursand et al., 2017). Lund et al. (2017) conclude, consistent with other authors, that "large temperature variations may be expected during CO_2 injection, and this may lead to significant stresses and possible damage to the annual seal […of the well…]" (p.164). The risks and effects of cyclic thermal stresses over projected infrastructure lifetimes of 25–30 years are, however, still to be understood; therefore injection well operating limits in terms of the frequency or magnitude of flow variations are also as of yet undefined. Although there are no clear 'show stoppers' regarding flexible operation of wells, it is clear that some of the risks and uncertainty surrounding operating limits would be reduced if the requirements for flexible operation, as induced by operating characteristics of the energy system, are better understood.

Appropriate design and operation of the network may be able to mitigate CO_2 flow variability. Spitz et al. (2017) review mitigation options that could be implemented at the power plant, within the transportation system or through changing the well design. For example, at the power plant level, solvent storage can be used at post-combustion capture power plants to decouple electricity production from production of compressed and liquefied CO_2 (to an extent determined by the size of the solvent storage tanks and the energy intensity of the solvent regeneration process). This can allow balancing (i.e. smoothing out the fluctuations) of CO_2 flows feeding into the T&S system. Similarly, liquid oxygen storage and hydrogen storage can be used at oxy-fuel and pre-combustion capture power plants, respectively (Spitz et al., 2017; ETI, 2015; IEAGHG, 2016).

At the transportation level, Sanchez Fernandez et al. (2016) explore different pressure regimes that could permit maintenance of single phase CO_2 flow across the transport, injection and storage systems. Maintenance of single phase flow is important to reduce various risks associated with two phase flow (e.g. booster station compressor integrity, pooling of liquid/vapour phase at low/high pipeline bends, corrosion, low temperatures at the wellhead, etc. − Sanchez Fernandez et al., 2016; Jensen et al., 2014; IEAGHG, 2016). Aghajani et al. (2017) investigate the possibility of balancing CO_2 flow fluctuations by line-packing pipelines. Line-packing refers to the technique of changing the pressure level in the transportation system in order to pack either more or less fluid into the pipeline. By managing the pressure and velocity of CO_2 in this way, transportation pipelines can be used as an interim store for CO_2 to balance flows through the network.

Finally, Kaufmann et al. (2016) investigates the option of using geological saline aquifers as an interim store for balancing CO_2 flows in the transportation network. Alternatively, pressure vessels installed along the transportation system can be used as interim stores (IEAGHG, 2016). However, although technically feasible any such solution is likely to come at increased cost and/or decreased efficiency.

In order for future CO_2 T&S networks to be designed efficiently, it is therefore imperative to rigorously analyse and understand the operating conditions the networks are likely to face.

Our study addresses this gap in the literature by characterising CO_2 flow regimes feeding into CO_2 T&S systems across a range of future low carbon energy system scenarios for the case study example of Great Britain (GB) with varying penetrations of renewable energy. The paper is structured as follows: Section 2 describes the underlying model and the considered energy system scenarios. Section 3 presents and discusses the results, characterising the CO_2 flows that are expected to be produced by CCS power stations under the different scenarios. Section 4 summarises the findings of this study and concludes.

2. Methodology

2.1. Model

The study utilises a unit commitment and economic dispatch (UCED) model based on Bruce et al. (2016) and Stanojevic (2011). For specified power plant portfolios and wind regime inputs, the model optimizes for each time-step (hourly discretisation) the dispatch of available thermal plants according to a least cost merit order approach (operating costs). The approach considers technical generator as well as system constraints to identify feasible future operating scenarios. After identifying feasible operating scenarios it chooses the available least cost option by deploying a priority based dynamic programming enumeration method. Operating profiles, realised operating costs and CO_2 emissions are calculated on an hourly basis for all thermal plants over the simulated time period (one year in this study). The model was realised in MATLAB. For a detailed description of the model the reader is referred to Bruce et al. (2016).

Although capable of considering any number of different plant types, the model has been specified for the purpose of this study to consider only nuclear, NGCC (Natural Gas Combined Cycle) and OCGT (Open Cycle Gas Turbine) power stations as thermal generators. No unabated coal fired power plants were considered, in line with UK government predictions for the year 2024 and later (BEIS, 2016). NGCC plants can be specified in the model to simulate NGCC plants equipped with CO_2 capture capability (NGCC-CCS plants). Post-combustion CO_2 capture (PCC) technology with a constant capture rate of 90% was assumed for these plants for whenever the PCC unit is operated. The possibility of temporarily switching off the PCC unit for recovering the energy penalty associated with CO_2 capture is discussed only within a sensitivity case in Subsection 3.6.3. The capture rate of 90% was chosen to be consistent with the majority of the literature, although it is realised that capture rates beyond 90% can be as or more cost-effective, particularly for monoethanolamine (MEA) based capture technologies. It was assumed that only those NGCC plants with highest baseline power plant efficiency (LHV) were fitted with CCS capability, to reflect CCS becoming a standard component in future new-build NGCC power plants. A minimum stable generation load of 40% has been assumed for all conventional power stations.

2.2. Scenario selection and input data

A set of high resolution (3 × 3 km) wind speed data for GB was available for the years 2002–2010 from Hawkins (2012). Based on locations of existing wind farm sites, sites under construction, sites under planning, and accounting for wake losses, electrical losses and technical availability, the available wind power generation profiles were calculated. Power curves were assumed according to Bruce (2015). After assessing the data, wind data from the years 2008, 2004 and 2010 was selected for illustrative high, medium and low wind speed scenarios. In the following these scenarios will be referred to as the 'high', 'medium', and 'low' wind speed scenario, respectively. Wind data and historical demand data remained coupled for all respective years due to the strong correlation and complex interdependencies between weather patterns and electricity demand. Historical demand data was taken from National Grid (2015) and has been normalised and weather corrected according to the methodology presented in Bruce (2015), for better inter-yearly comparison of dispatch profiles.

A wind power generation capacity of 15GW, 30GW and 45GW was assumed in the low, medium and high wind deployment scenarios, respectively. These levels reflect the current amount of installed wind capacity in the UK (15.6GW, RenewableUK, 2017), and the medium and high wind deployment scenarios forecasted by the GB transmission system operator (National Grid) for 2035, respectively (National Grid, 2016a). In line with government predictions for 2035, nuclear capacity was assumed at 17.1GW (BEIS, 2016). The minimum level of synchronised generation was set to 15GW to ensure sufficient system inertia for maintaining the rate of change of frequency within acceptable limits (National Grid, 2011, 2013).

A grid average annual CO_2 emission intensity of 60 g/kWh and 100 g/kWh was selected in the reference scenarios, in line with UK Government targets (BEIS, 2016) for 2028 and approximately 2050, respectively. This represents a significant reduction in the average emission intensity level of 420 g/kWh in 2015 (DECC, 2015). A higher emission intensity of 140 g/kWh was chosen as an illustrative sensitivity case. CCS capacity was adjusted between the different scenarios in order to reach the required CO_2 emission intensity, on average over the year, after taking into account the available wind power generation for each scenario. This was implemented by assuming CO_2 capture capability on as many NGCC plants as needed to reach the targeted emission intensity.

NGCC and OCGT capacity was adjusted in every scenario to reach a de-rated generation capacity of at least 65.8GW. This capacity constraint was set to allow for a de-rated capacity margin of 6.5% over the average annual peak demand over the evaluated years of 60GW, as well as for covering a largest credible in-feed loss of 1.8GW (Ofgem, 2013, 2014). This is to maintain a comparable yet realistic generation fleet across all wind scenarios for satisfying historical demand levels. The technology-specific availability factors are based on (National Grid, 2016b) and are provided in Appendix A. A flat availability curve was assumed for thermal generators across the year.

A cost-optimal split between NGCC and OCGT gas-fired capacity was calculated, based on BEIS (2016) assumptions for capital, operational, and CO_2 costs as well as operational lifetime data, and a discount rate of 7.5%. This leads to an NGCC load factor threshold of 11%, below which it is more cost effective to build and operate an OCGT instead of an NGCC plant to satisfy power demand. It is assumed that the capacity market and the provision of balancing services deliver sufficient incentives to operate at the assumed load factors. Any residual demand and reserve requirement that could not be met with the respective power generation fleet, due to low wind resource availability during peak demand times, was assumed to be met by Demand Side Response (DSR) procured by the system operator for this purpose (National Grid, 2016c).

Technical, techno-economic and economic parameters were selected consistently to represent a 2035 scenario, although it is recognised that some sensitivity scenarios (e.g. 60 g/kWh emission intensity and 45GW wind power capacity) might be more realistic for later years in the century. The scenario with 30GW wind power generation capacity, 100 g/kWh emission intensity and wind and electricity demand data from 2004 will be referred to as the base case. A summary of the core scenarios considered in this study is provided in Table 3 in Subsection 3.1.

Fossil power plant full load efficiencies on a LHV basis were interpolated between lower and upper limits based on Gas Turbine World (2013) and Brouwer et al. (2015), to reflect gradual advances in technology over time (see Table 1). Part-load efficiency penalties for fossil power plants are according to Brouwer et al. (2015).

Upward and downward reserve requirements were set to cover unexpected changes in wind output and electricity demand resulting from forecasting uncertainties within 3.5 standard deviations (3.5σ) or 99.95% of events. This is consistent with a reliability standard of security of supply of 3 h per year used by the GB system operator National Grid (Loss of Load Expectation Risk metric, National Grid, 2014). Reserve was further scheduled according to the largest credible in-feed loss of 1.8GW (Ofgem, 2013, 2014). System reserve requirements can

Table 1
Base power plant full load efficiency data (LHV).

Capacity type	Full load LHV efficiency	Reference
Nuclear Plant	36.7%	Bruce (2015)
NGCC	62.1–59.5%	Brouwer et al. (2015), Gas Turbine World (2013)
OCGT	41.8–37.5%	Brouwer et al. (2015), Gas Turbine World (2013)

be met through a combination of synchronous spinning and non-synchronous standing reserve (Wood et al., 2014). An allocation of 1.5σ as spinning reserve and 2σ as standing reserve is assumed based on Silva (2010).

Further technical, techno- economic and economic input data is summarised in Tables 1 and 2 as well as in Appendix B.

2.3. Limitations

Before presenting the results in Section 3, several limitations to this study should be noted. Firstly, although it is widely recognised that a significant decarbonisation of the economy requires decarbonisation of industrial processes, including through CCS, no CCS from industrial sources has been considered within this study. Depending on the operating regimes of the industrial facilities, this could either smooth out or amplify CO_2 flows feeding into T&S networks. Secondly, onshore and offshore wind power are considered here to take into account the specific availability patterns and intermittency of this power generation technology. Other variable generation sources, e.g. solar power, are not included in this work. It is worth noting that the effect on variability of CO_2 flows caused by changes in solar power output is likely to be more predictable than those caused by wind power. Further research is recommended to explore this effect. Thirdly, neither the electrification of transport nor the effect of smart grids on electricity demand levels and patterns have been considered. These technologies have the potential to change demand patterns significantly and, again, either increase or decrease the flexibility in output required from CCS power stations. Fourthly, no energy storage has been considered. The effect of energy storage on CO_2 flow patterns is uncertain. Although energy storage has the potential to smooth out operating profiles of fossil power plant at times, it might equally amplify these at other times. Finally, the study assumes that wind and demand patterns will remain similar over the coming decades.

With large uncertainty about the deployment levels of the mentioned technologies, and considering these caveats, the present study provides a useful baseline estimate of the operating flexibility likely to be required by future CO_2 T&S systems. It is only when the requirement for operating flexibility is better understood, that the additional costs associated with managing the operational issues that flexible operation imply can be minimised.

Table 2
Fuel and CO_2 prices.

Resource	Price	Reference(s)
Natural Gas	£21.2/MWh_{th}	BEIS (2016)
Uranium	£3.5/MWh_{th}	Based on Bruce (2015), Brouwer et al. (2016)
CO_2	£101.1/tCO_2	BEIS (2016)

Table 3
CCS capacity required to reach emission intensity for different wind scenarios for base year ('medium' wind speeds; Realised CO_2 emission intensity in brackets when intended intensity cannot be reached due to constraints).

Installed Wind Capacity Scenario	CO_2 Emission Intensity Scenario		
	60 g/kWh	100 g/kWh	140 g/kWh
15GW	20.2GW	12.3GW	7.0GW
30GW	14.0GW	7.0GW	0.9GW
45GW	8.8GW	0.9GW	0.0GW (*107.2 g/kWh)

3. Results

3.1. CCS capacity required for given scenarios

Table 3 summarises all modelled core scenarios of this paper (excluding sensitivity cases). It serves as a reference table throughout this study as it shows the amount of CCS capacity that is required and installed in the respective core scenarios for reaching CO_2 emission intensity targets of 60 g/kWh, 100 g/kWh and 140 g/kWh, under the assumption of different amounts of installed wind capacity and 'medium' wind speeds. An emission intensity of 140 g/kWh could not be reached with 45GW of installed wind capacity, as the CO_2 emission intensity reaches a maximum of 107.2 g/kWh without CCS plants being considered, as indicated in the corresponding field.

Table 3 indicates that 7.0GW of CCS capacity is required in the base case (30GW wind, 100 g/kWh CO_2 emission intensity). This compares to 14.0GW and 0.9GW of CCS capacity for the low and high emission intensity scenarios respectively, with 30GW of wind capacity being available. At 45GW of installed wind capacity the required amount of CCS capacity decreases, while it increases with less installed wind capacity. This compares to a total thermal capacity of around 61–69GW throughout the respective scenarios.

3.2. Time profiles (power and CO_2 output)

Fig. 1a displays the aggregate power output curves of CCS-equipped power stations over the month with the lowest (February) and highest (June) required power generation variability in the base case. It is notable that even in the month with the lowest variations, CCS power stations need to load follow substantially to compensate for imbalances between net electricity demand (total demand minus power supplied and dispatched from wind farms) and supply. This load following operation manifests in cyclic operation of CCS power plants, including the shifting between production of high levels of electricity (typically during daytime) and low levels of electricity (typically at night).

Fig. 1b shows the aggregate amount of CO_2 produced by the PCC facilities based on the operating profiles of Fig. 1a. The time profiles of CO_2 production resemble the profiles of electricity generation; however, they also reflect the part-load efficiency losses of the thermal generation fleet. Again, variations in CO_2 production can be observed, often on a daily basis, although the amplitudes of the variations are somewhat less pronounced than for the electricity production profiles.

Similarly to the previous figure, Figs. 2 and 3 show the aggregate CO_2 production profiles over a representative ('average') month of the base year (October) for a range of emission intensity and installed wind power scenarios. Fig. 2c shows the same data line on two different scales (y-axes) to facilitate comparison with Fig. 3b.

The following core observations can be made when comparing the profiles of captured CO_2:

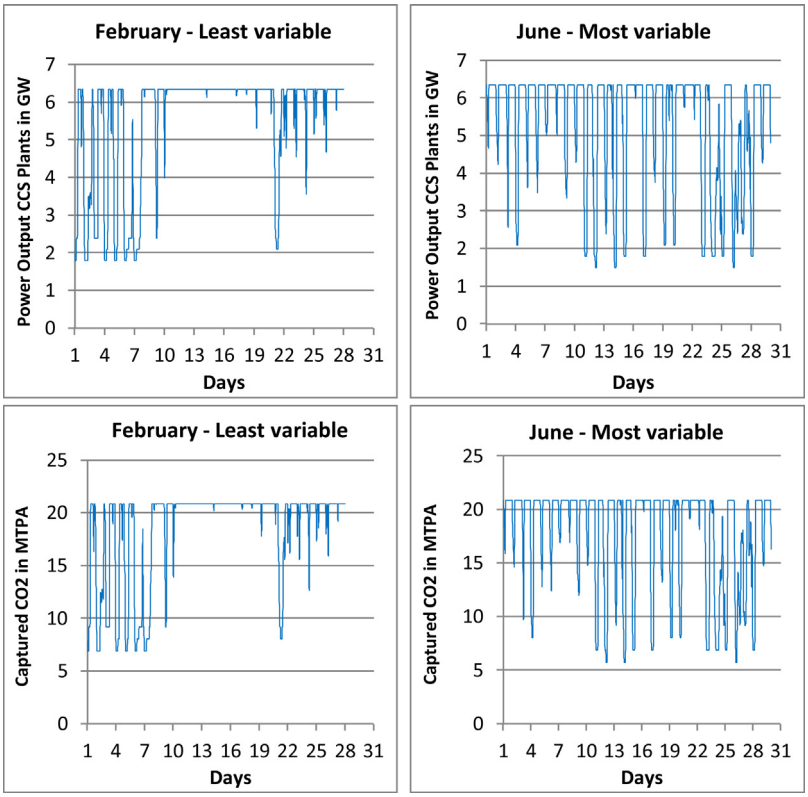

Fig. 1. a: Collective power output of CCS power stations in month with highest and lowest fluctuations in base case ('medium' wind speeds, 30GW wind, 7.0GW CCS, 100 g/kWh). (above)*. b: Time profile of collectively captured CO_2 in month with highest and lowest fluctuation in base case ('medium' wind speeds, 30GW wind, 7.0GW CCS, 100 g/kWh). (below).

*The discrepancybetween installed CCS capacity and the maximum delivered power in Fig. 1a is an effect of the assumed availability of 90% for NGCC-CCS plant over the year (see Section 2.2 and Appendix A).

- The absolute levels of CO_2 captured in the scenarios are very different. This is due to the different amounts of CCS capacity installed in the scenarios (see Table 3 for installed CCS capacities).
- In some scenarios, the amount of CO_2 captured oscillates predominantly between two levels (Figs. 2c and 3b), while in others changes in flow rates are more 'variable in size' (Figs. 2a and 3a). Oscillating flow profiles occur when the CCS fleet is comprised of only a few plants (e.g. < 4) that tend to collectively adapt their output between full and minimum load to respond to changes in the relatively narrow net demand band that they cover (i.e. in which they need to load follow) based on their merit order position. 'Variable in size' load changes (Figs. 2c and 3b) occur when the CCS fleet is larger, and automatically covers a greater net demand range in which the plants need to load follow, producing more variable output. CO_2 T&S networks for large CCS power station clusters therefore need to be designed for a more continuous infeed flow range than networks for only a few CCS power stations.
- The relative and absolute spread (difference) between the maximum and minimum CO_2 flow rates in the respective scenarios grows with increasing deployment of CCS capacity, magnifying the amplitude of the largest flow rate fluctuations. Whilst a factor of 2.3 between minimum and maximum CO_2 flow rates characterises this spread in scenarios with small CCS fleets (Figs. 2c and 3b), this ratio indicating the size of the largest flow fluctuations rises to 3.6 and 5.9 in scenarios with large CCS fleets (Figs. 3a and 2a). Larger flow rate fluctuations are generally more difficult for T&S networks/injection wells to handle (in particular when two-phase flow develops across the wellhead at low relative flow rates as a consequence of the reduced backpressure from injection − see section 1).
- The variability of CO_2 flows feeding into the T&S networks is substantial regardless of wind capacity and emission intensity scenario, even though the CO_2 flow profiles in the respective scenarios have individual characteristics.

3.3. CO_2 flow duration curves

To explore the behaviour of CO_2 flows over an entire year, Fig. 4 illustrates the 'flow duration curves' for all nine core scenarios. The curves can be thought of as captured CO_2 duration profiles, similar to Figs. 2 and 3, however, over the entire base year and stacked along the x-axis from high levels of CO_2 captured (left) to low levels of CO_2 captured (right). In this work, they will be referred to as CO_2 flow duration curves (FDC), as they indicate the amount of CO_2 that will need to be accommodated as feed-flows by future downstream CO_2 T&S systems, for the given amounts of time of the year. This comes with the assumption that no balancing of CO_2 flows will be performed within the boundary of the power plants.

In all modelled scenarios the nominal (maximum) amount of CO_2 is captured over a significant proportion of time of the year (Fig. 3). While in the high emission intensity scenario (c), this is the case for 292–311 days of the year, dependent on wind deployment scenario, this number drops to 220–262 days in the medium (b), and 148–161 days in

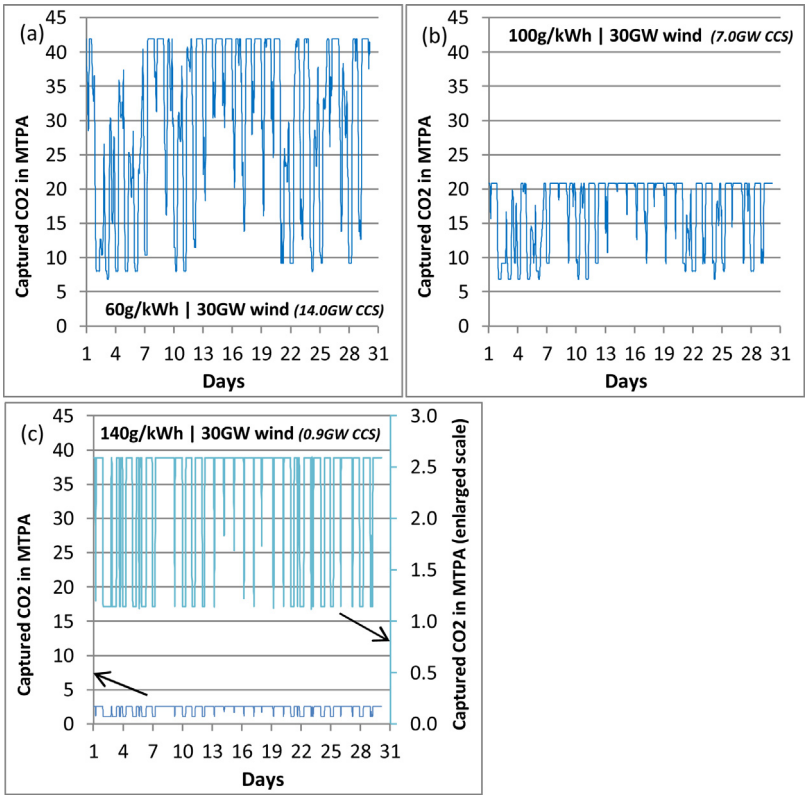

Fig. 2. Time profile of captured CO_2 in representative month for 30GW installed wind capacity in 60 g/kWh (a), 100 g/kWh (b) and 140 g/kWh (c) emission intensity scenario for 'medium' wind speeds*.

*CO_2 collectively captured by all CCS power plants in respective scenarios. Note that different numbers of CCS plants are necessary to reach respective CO_2 emission intensities in different scenarios.

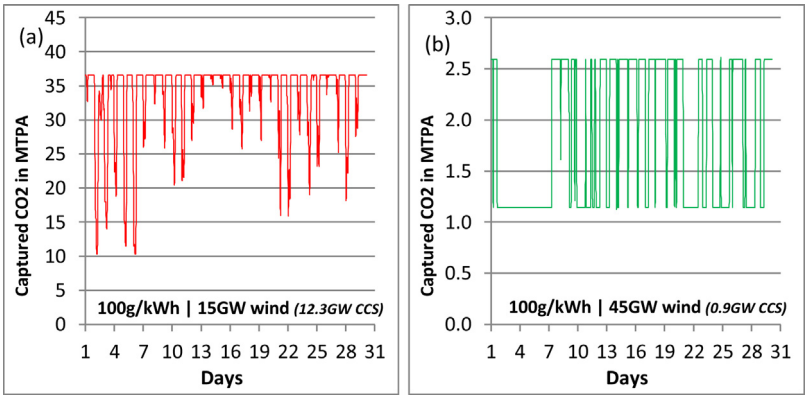

Fig. 3. Time profile of captured CO_2 in representative month for 15GW (a – red) and 45GW of installed wind capacity (b – green) in 100 g/kWh emission intensity scenario for 'medium' wind speeds*. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

*CO_2 collectively captured by all CCS power plants in respective scenarios. Note that different numbers of CCS plants are necessary to reach respective CO_2 emission intensities in different scenarios.

the low emission intensity scenarios (a). The decrease in the number of days the plants are delivering nominal amounts of CO_2 reflects the decrease in average utilisation factors of CCS plants in lower emission intensity scenarios, due to the large number of CCS plants required to reach low emission intensities. When many CCS plants are installed (i.e. installed CCS capacity is high), a significant fraction of the available CCS plants will only be required to operate and therefore capture CO_2 at periods of high net demand, which represent a relatively small fraction of time over the year. This consequently has a negative effect on their average capacity factor.[2] This compares to high emission intensity scenarios that require fewer CCS plants, which, however, typically operate large fractions of the amount of time over the year, as they are rarely constrained off the network due to low net demand. A summary of the capacity utilisation factors of the T&S systems in the individual scenarios is provided in Table 4.

The shape of most FDCs in the 15GW and 30GW installed wind power scenarios is similar. After an initial plateau of the curve on the left side of the diagram, the curves drop with increasing gradient

[2] NB: Generally the size of the CCS fleet in the low emission intensity scenarios could be reduced without compromising on CO_2 emissions if capture rates of PCC units beyond 90% were considered. This would mitigate the aforementioned negative effect on capacity utilisation caused by comparatively large CCS fleets. However, deviating the capture rate of operating PCC units from 90% is outside the scope of the current study.

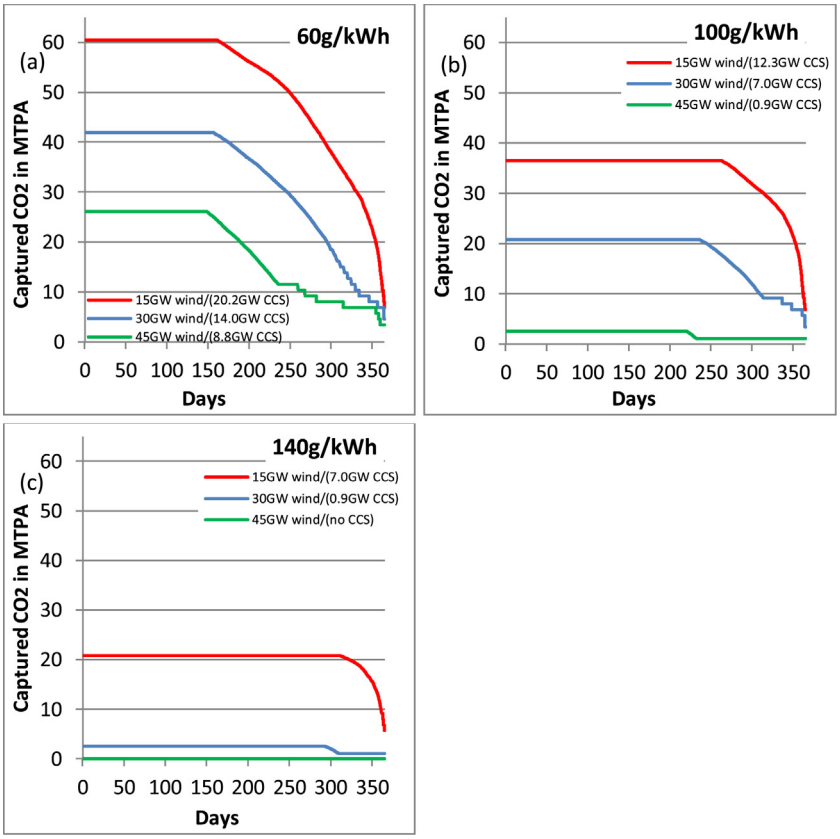

Fig. 4. CO_2 capture duration profile for 15GW (red), 30GW (blue), 45GW (green) wind capacity in 60 g/kWh (a), 100 g/kWh (b), and 140 g/kWh (c) CO_2 emission intensity scenario for 'medium' wind speeds*. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

*CO_2 collectively captured by all CCS power plants in respective scenarios. Note that different numbers of CCS plants are necessary to reach respective CO_2 emission intensities in different scenarios.

Table 4
Calculated capacity utilisation factors of T&S systems in individual core scenarios.

Installed Wind Capacity Scenario	CO_2 Emission Intensity Scenario		
	60 g/kWh	100 g/kWh	140 g/kWh
15GW	84.7%	93.7%	97.2%
30GW	77.6%	86.2%	90.3%
45GW	69.6%	78.8%	No CCS

towards the right, reaching a common level in the low and medium emission intensity scenarios. The indentations on the right of the FDCs represent individual CCS plants of the thermal fleet shutting down. The 45GW installed wind power (green) curves in all scenarios, as well as the 30GW wind power (blue) curve in the high emission intensity scenario, plateau on the right side of the graph at a lower level. This is due to significant levels of upwards spinning reserve provision required from CCS plants with high penetrations of intermittent wind power to hedge the power system against unexpected and fast increases in net demand or shortfalls of supply (e.g. generator failure), leading to sustained operation of these plants at minimum load. Upwards spinning reserve is provided by thermal plants by operating below their respective maximum output levels (e.g. at minimum stable generation load) enabling them to quickly ramp up their power output when needed. A trend can be observed towards higher levels of reserve provision required of CCS plants at higher levels of wind penetrations, which is indicated by extended plateaus of the corresponding FDCs on the right side of the diagrams.

In no scenario with actual CCS capacity installed, does the produced CO_2 flow drop to zero for a significant amount of the time. This is on one hand again due to the role of thermal power stations as reserve

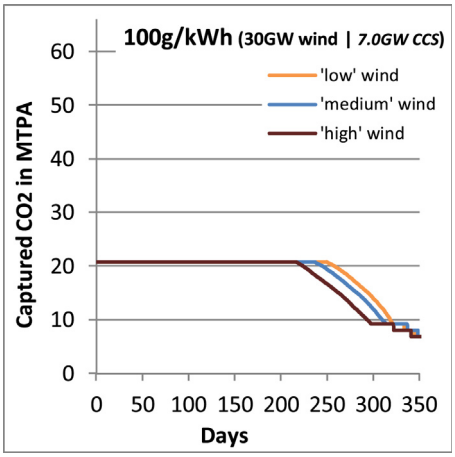

Fig. 5. CO_2 capture duration profile for 30GW wind capacity and 100 g/kWh scenario for the 'low' (orange), 'medium' (blue), and 'high' (brown) wind speed scenario. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

providers, which means that some CCS units ranking lowest in the merit order list (i.e. low operational costs and hence very cost competitive due to low CO_2 emissions and high CO_2 emission costs; just outperformed on operational cost basis by renewable and nuclear power) never get constrained off the grid and instead operate continuously at minimum stable load at low net demand levels to provide sufficient upward spinning reserve. On the other hand, having no periods of zero CO_2 flow is an effect of the constraint of a minimum level of synchronised generation of 15GW that it is assumed needs to be met by thermal generators throughout the year, to ensure sufficient inertia on the power system to limit the rate of change of frequency (as outlined in Section 2.2).

Fig. 5 provides a sensitivity analysis, showing that the shape of the FDCs over the years (i.e. in different wind speed scenarios) is similar. They differ mainly in the amount of time over the year the nominal amount of CO_2 is captured, which is related to CCS plants in the low wind scenario needing to compensate for lower yields of wind power by increasing their power and consequently CO_2 output (and vice versa for the high wind scenario). This effect also leads to an emission intensity that deviates by −6.8% and +12.8% compared to the base case in the high and low wind scenarios respectively, as the power generation fleet remains unchanged.

Overall, the analysis of absolute levels of CO_2 captured by CCS power station demonstrates a strong time variability of CO_2 flows across all modelled scenarios. Furthermore it shows that utilisation factors of CCS power stations and their reserve provision behaviour is highly dependent on the wider generation capacity mix, in particular the size of the CCS fleet and the penetration of wind power. Although a lower level of capacity utilisation of CCS infrastructure, including T&S systems, is not a problem by itself, it increases the cost per tonne of CO_2 abated, thus reducing the relative economic value of CCS vis-à-vis other low carbon policy options.

3.4. Changes in CO_2 flow

While the potential utilisation of CO_2 T&S systems can very well be described with FDCs it is also important to consider the short-term variations in the amounts of CO_2 captured by the power stations that will feed into future T&S systems. This is because it is not only the absolute level but also the size and frequency of variations in feed flow rates that can present significant challenges and operational risks to CO_2 T&S networks (see Spitz et al., 2017 for an overview of the issues associated with variable CO_2 flow rates).

The following two sections explore short-term variations in CO_2 collectively captured by CCS power plants in the respective scenarios. Section 3.4.1 focuses on net changes in captured CO_2 over different time intervals, on a rolling basis over the year. While short term variations can dampen out and be absorbed over the length of the pipeline system (particularly if active CO_2 balancing is considered within the transportation network), longer term or 'average' variations in CO_2 flow over several hours will propagate through the entire network, having a direct (although time-delayed) impact on downstream CO_2 injection profiles. Section 3.4.2 therefore explores (for selected cases) changes in the average amount of CO_2 captured over two consecutive time blocks of 6 h, again on a rolling basis over the year. 6 h is chosen as the base case for analysis as this period is considered sufficient for changes in CO_2 feed-flows to have an effect on injection profiles downstream. This corresponds to the amount of time that the FEED study team of the Peterhead CCS demonstration project in the UK (Shell, 2015) estimated that the system operator of their proposed T&S system would have to react to a fault in the downstream injection and storage system, by adjusting/stopping the feed flow rate to the transportation pipeline (of 102 km length, 20 inches outer diameter; Shell, 2016).

3.4.1. Net variations

Fig. 6 illustrates the number of times (in thousands) the net change in CO_2 flow captured collectively by the CCS power stations over time periods of 6 h (rolling basis over the year) reaches certain amplitudes (relative to nominal flow).

The 8754 load change amplitudes (rolling basis over year) were calculated according to equation (1), and stacked according to their frequency and size along the x-axes, for all respective scenarios. Consequently, adding up the size of the columns in the respective scenarios would result in 8754.

$$A_t = \frac{|(F_t - F_{t-6})|}{F_{nominal}} t \in \{7, 8...8760\} \quad (1)$$

Where A_t is flow rate change amplitude at hour t

F_t is flow rate at time t

$F_{nominal}$ is nominal flow rate in scenario

Based on the same data, and considering all CO_2 flow changes over 6hrs-periods on a rolling basis over the base year (approx. 8760), Table 5 summarises how many of them have an amplitude of 0–5%, > 30%, and > 50% of nominal flow in the respective scenarios. To account for the possibility of different pipeline lengths and sizes, and to investigate whether flow changes calculated over 6 h periods are an effect of atypically high load swings over quarterly day periods (given similarly shaped daily demand time profiles), Fig. 7 shows the variability of CO_2 flows (load changes) calculated over time periods of 1hr, 6 h and 12 h, respectively (rolling basis over the year).

Fig. 6 and Table 5 show that at lower emission intensities, load changes occur more frequently and have higher amplitudes. This can be explained by the larger number of CCS plants required in lower emission intensity scenarios, which implies that more CCS plants need to load follow leading to relatively frequent and large load changes, compared to CCS plants running predominantly base-load when fewer plants are installed in higher emission intensity scenarios. When only few CCS plants are installed, in high emission intensity scenarios, they only rank very low in the merit order (i.e. low operational costs and hence very cost competitive due to low CO_2 emissions and high CO_2 emission costs). These CCS plants are therefore less likely to be constrained off the grid (or be required to load follow) compared to the situation in low emission intensity scenarios, where many CCS plants are installed, some of which rank comparatively high in the merit order.

It is notable that in the low and medium emission intensity scenarios (Fig. 6a and b), flow remains constant (i.e. 0% rel. load change) significantly more often in the 45GW wind capacity case than in the 30GW and 15GW wind capacity cases. This is expected for two complementary reasons: first, as fewer CCS plants are deployed in the 45GW wind capacity scenario, and more power is supplied by zero emission wind power, the larger remaining carbon budget is used by non-CCS NGCC plants for load following, enabling more steady generation from CCS plants. Second, the role of thermal power stations as reserve providers means that some CCS units ranking lowest in the merit order list (outperformed on operational costs basis only by nuclear plants, of all thermal power stations) never get constrained off the grid and instead operate continuously at minimum stable load at low net demand levels to provide sufficient upwards reserve. Given that there are fewer CCS plants deployed in the 45GW wind capacity scenario than in other wind scenarios with larger CCS fleets, this role as a reserve provider can apply to a large share of them at the same time, the consequence being a steadier CO_2 flow.

Similarly, it can be seen in Fig. 6, that two scenarios (100 g/kWh emission intensity and 45GW of installed wind power; 140 g/kWh

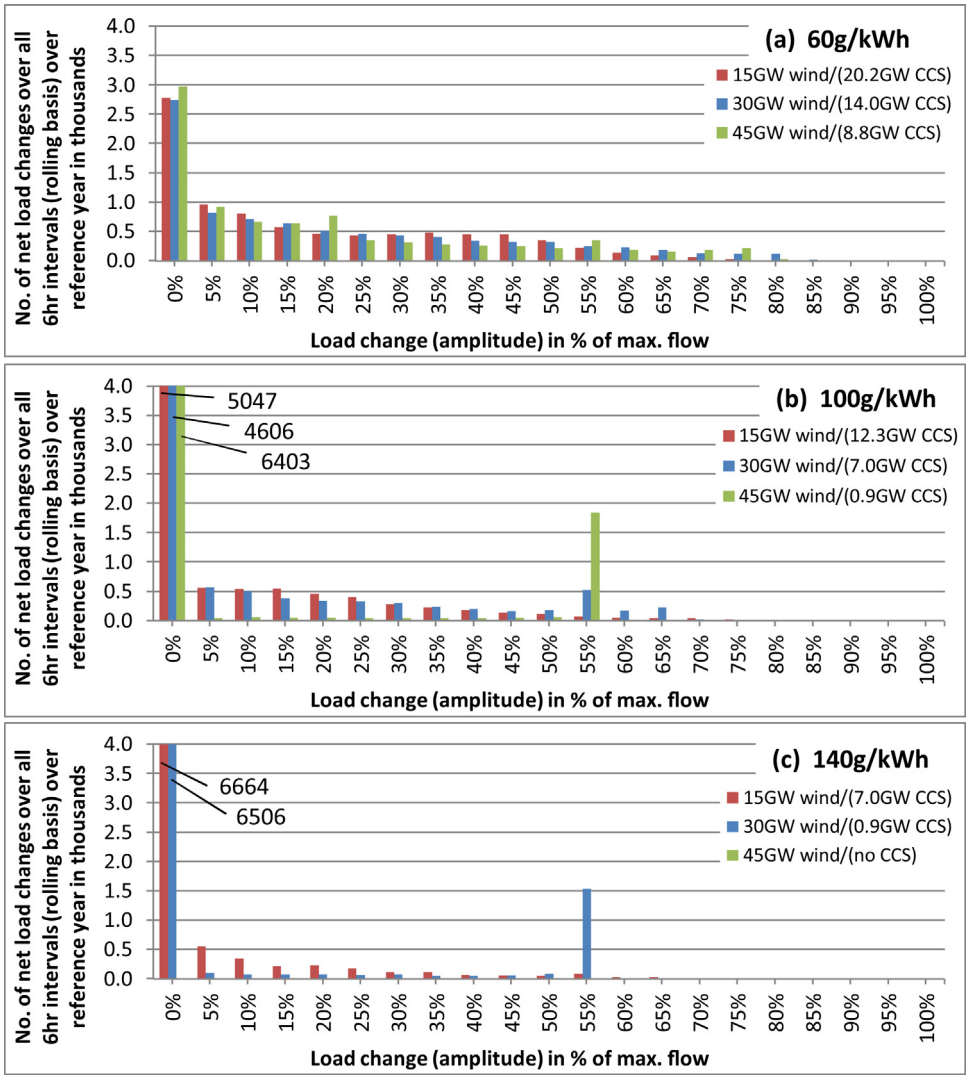

Fig. 6. Number and relative size of net changes in CO_2 collectively captured by CCS power stations over 6 h periods (rolling basis) over base year for 15GW (red), 30GW (blue), 45GW (green) wind capacity in 60 g/kWh (a), 100 g/kWh (b), and 140 g/kWh (c) CO_2 emission intensity scenario, for 'medium' wind speeds*. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

*For illustrative reasons some columns were cut off at 4000. The sum of all columns in each respective scenario equals approx. 8760 as a consequence of how graphs were calculated (rolling basis over year).

**Note that different numbers of CCS plants are necessary to reach emission intensity targets in respective scenarios.

Table 5
Amplitudes (in % of nominal flow) and frequencies of net flow rate changes over 6 h periods (rolling basis over year) in % of the total number of net flow rate changes over the year, for respective scenarios.

Rel. flow change (Amplitude)	0%–5%			> 30%			> 50%		
Scenario	15GW	30GW	45GW	15GW	30GW	45GW	15GW	30GW	45GW
60 g/kWh	37.6%	36.3%	42.4%	28.9%	30.4%	25.9%	8.2%	13.8%	14.1%
100 g/kWh	61.2%	55.2%	73.4%	11.8%	21.3%	23.7%	3.3%	11.9%	21.4%
140 g/kWh	79.8%	74.9%	No CCS	6.0%	20.6%	No CCS	2.1%	18.1%	No CCS

emission intensity and 30GW of installed wind power) show a spike at a load change amplitude of 55% of nominal flow. This load change amplitude corresponds to ramping of the CCS plants between full load and minimum load (and vice-versa). The spikes occur due to the small size of the CCS fleets in the respective scenarios: the net demand range in which the small CCS fleets can load follow at their given position in the merit order, leading to load change amplitudes other than 0% and 55%, is very narrow and reached only infrequently. Therefore, whenever net demand fluctuations require CCS plants in the respective scenarios to load follow, they are most likely to collectively ramp between full and minimum load (where they are likely to remain for reserve purposes as long as net demand is low). This effect explains why scenarios with high wind penetrations and a very small CCS fleet tend to lead to more extreme feed flow-rate fluctuations (i.e. either no change or very large relative change in flows) to CO_2 T&S systems.

Fig. 7 illustrates that load change amplitudes generally increase when calculated over longer time intervals. The pattern and load change levels within this sensitivity case show that the amplitudes

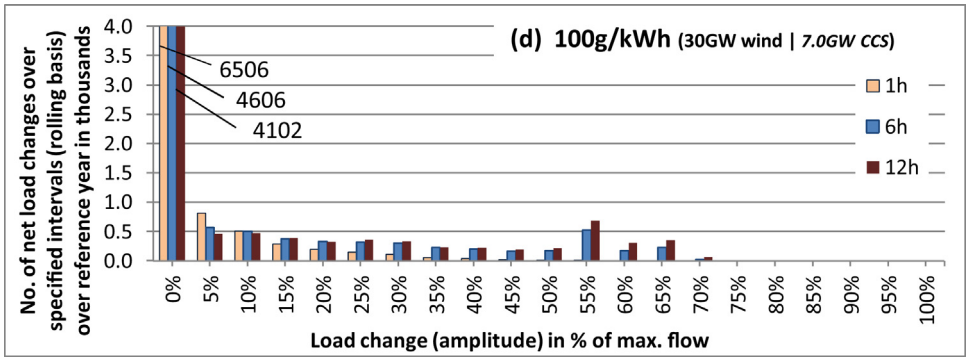

Fig. 7. Number and relative size of net changes in CO_2 captured by CCS power stations in base case ('medium' wind speed scenario, 30GW wind, 100 g/kWh) over time periods of 1hr (beige), 6 h (blue) and 12 h (dark red) (rolling basis over year) (d)*. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

*For illustrative reasons some columns were cut off at 4000. The sum of all columns in each respective scenario equals approx. 8760 as a consequence of how graphs were calculated (rolling basis over year).

**Note that different numbers of CCS plants are necessary to reach emission intensity targets in respective scenarios.

presented in Fig. 6 are not exceptionally high. Load change amplitudes and frequencies calculated over 6 h time periods are therefore not an effect of atypically high load swings over quarterly day periods, given similarly shaped daily demand time profiles, but instead fit into the wider trend.

Overall, Table 5 as well as Figs. 6 and 7 show that load changes greater than 30% or 50% over time periods of 6 h are no exceptions, but happen on a regular basis in 21% and 12% of all considered 6 h load changes in the base case, respectively. Future CO_2 T&S networks should be designed to cope with the resulting variable feed-flows. Although the results were calculated for the example case study of the GB electricity system, qualitatively the results are expected to hold true for other low carbon energy systems with large contributions of intermittent, as well as significant contributions from nuclear power.

3.4.2. Variations in average CO_2 flow over two consecutive periods

While short term 'net' variations can dampen out and be absorbed over the length of the pipeline system, longer term variations in CO_2 flow averaged over the course of several hours will have a directly associated, although time-delayed, impact on downstream CO_2 injection profiles. Representative for other emission intensity scenarios, Fig. 8 shows the frequencies and amplitudes of the variations between the average amount of CO_2 captured over two consecutive time intervals of 6 h (again on a rolling basis over the year), for 100 g/kWh emission intensity cases. The average flow rate change amplitudes were calculated according to equation (2), and stacked according to frequency and size along the x-axis. Adding up the size of the columns for the respective scenarios would consequently result in 8749.

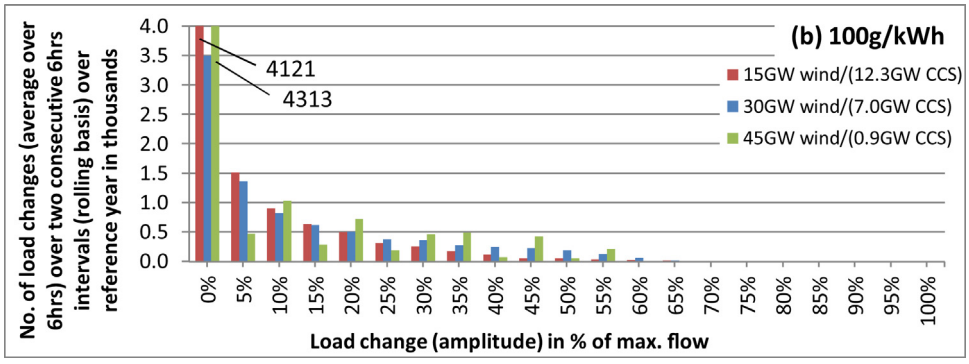

Fig. 8. Number and relative size of changes in average amount of CO_2 collectively captured by CCS power stations over two consecutive 6 h time periods for 15GW (red), 30GW (blue) and 45GW (green) installed wind capacity in 100 g/kWh CO_2 emission intensity scenario over base year (rolling basis over the year; for 'medium' wind speeds)*. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

*Note that different numbers of CCS plants are necessary to reach 100 g/kWh emission intensity.

Table 6
Amplitudes (in % of nominal flow) and frequencies of average flow rate changes over two consecutive 6 h time blocks (rolling basis over year), in % of the total number of average changes over the year, for respective scenarios.

Rel. flow change (Amplitude)	0 – 5%			> 30%			> 40%		
Scenario	15GW	30GW	45GW	15GW	30GW	45GW	15GW	30GW	45GW
60 g/kWh	33.2%	31.6%	35.0%	19.7%	23.1%	21.3%	8.5%	13.7%	13.0%
100 g/kWh	59.1%	49.6%	51.5%	6.9%	15.3%	14.8%	2.9%	8.8%	8.4%
140 g/kWh	78.5%	54.6%	No CCS	2.9%	12.1%	No CCS	1.5%	6.9%	No CCS

$$\overline{A_t} = \frac{\left|\frac{1}{6}[F_t + F_{t+1} + \ldots + F_{t+5}] - \frac{1}{6}[F_{t-1} + F_{t-2} + \ldots + F_{t-6}]\right|}{F_{nominal}} \quad t \in Z\,[7 \ldots 8755] \qquad (2)$$

Where $\overline{A_t}$ *is average flow rate change amplitude at hour t*

F_t *is flow rate at time t*

$F_{nominal}$ *is nominal flow rate in scenario*

Table 6 summarises how many of the 8749 average load changes have an amplitude of 0–5%, > 30%, and > 50% of nominal flow in the respective scenarios.

A similar trend in Fig. 8 can be observed as in Figs. 4 and 5, with the frequency of the load changes decreasing at higher amplitudes. Most notably it can be seen that the average load changes are less extreme compared to the net load changes in Section 3.4.1. However, even when assessing the CO_2 flow changes averaged over two consecutive 6 h time blocks the variability remains substantial.

This indicates that flow rate variations are often on the basis of fluctuation cycles that extend over more than $2 \times 6 = 12$ h, and that are likely heavily influenced by a common daily demand profile (as indicated also by two shifting of CCS plants in Fig. 1). This would in turn mean that it can be harder to balance the flow fluctuations, as more balancing capacity is needed to balance flows over longer time scales.

Overall, the modelling presented in this section suggests that injection wells in future CO_2 T&S networks will likely be confronted with frequent and irregular fluctuations in CO_2 feed flow rates. The extent of these, however, is subject to the availability and effectiveness of balancing options, such as line-packing.

3.5. Start-ups and shut-downs of CCS power stations

Fig. 9 displays the average number of start-ups carried out by CCS plants in all nine core scenarios, respectively, over the reference year. The columns are stacked with different colours according to how long the plants had been shut-off before start-up (in hrs).

The number of start-ups per CCS plant decreases persistently in the higher emission intensity scenarios. This is intuitive, as the higher the allowed emission intensity, the lower the number of CCS plants required. These CCS plants would be stacked up next to each other on the low side of the merit order (due to low operational costs including for CO_2 emissions; just next to nuclear plants), and thus they are less likely to shut-down due to their ability to provide power at a very competitive (low) operational cost. They are also less likely to shut-down for reserve purposes, being the only gas fired power stations online. In contrast, in scenarios with many CCS plants, even if they are stacked up on the low end, some of them are comparatively high in the merit order, which requires them to load follow and start-up/shut-down extensively.

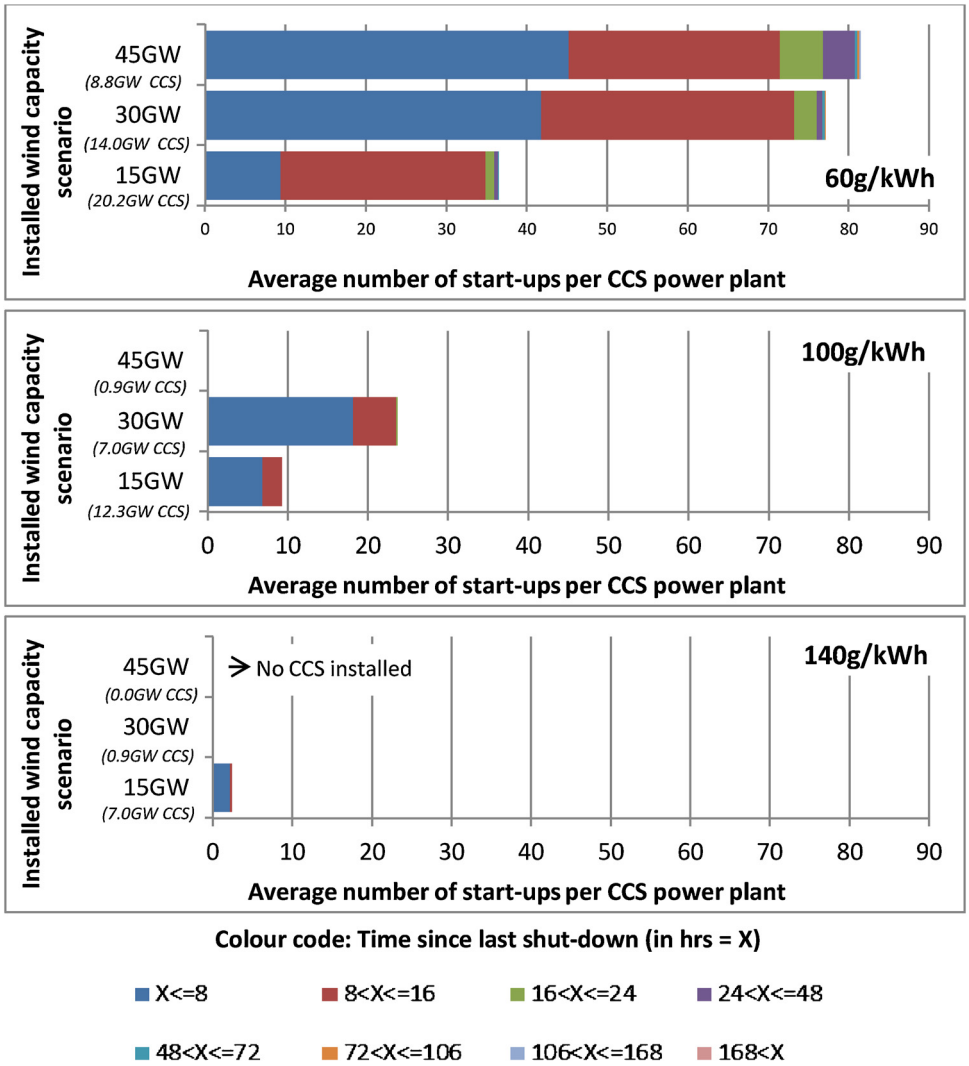

Fig. 9. Number of average start-ups per CCS power plant in 60 g/kWh (top), 100 g/kWh (middle) and 140 g/kWh (bottom) CO_2 emission intensity scenarios for different installed wind capacities in the base year. Columns are stacked in different colours to indicate time since last shut-down (see colour code above)*.

*Note that number of CCS plants is different between the cases.

This reasoning also explains, in the medium emission intensity scenario, the relatively high start-ups in the 30GW installed wind capacity case compared to the 45GW case. While in the 30GW case there are around 9 CCS plants in the capacity mix that run according to a net demand profile that is heavily influenced by the variable power output of the available wind generation capacity, the only CCS plant implemented in the 45GW case is hardly ever constrained off the grid due to its role in providing reserve. The lower penetration of wind power in the 15GW case leads to less variability of the net demand curve. Together with the relatively high number of CCS plants in this scenario, this leads to a lower average number of start-ups per CCS plant compared to the 30GW case.

The high number of CCS plants across both the low and intermediate merit order range in the low emission intensity scenario, across all wind deployment cases, makes the number of start-ups more dependent on the variability of the net demand curve. As this variability is in turn driven by the penetration of wind power generation, the number of start-ups is higher in the 45GW installed wind capacity case compared to the 30GW and 15GW cases.

Overall, Fig. 9 shows a clear trend towards increasing numbers of start-ups in scenarios with lower emission intensities, irrespective of the wind deployment scenario. An average number of start-ups between 36 and 81 in the 60 g/kWh scenario indicates significantly higher expected numbers for CCS power stations that are comparatively higher up in the merit order. Given that start-ups and shut-downs are associated with additional costs for the power plant operator (e.g. fixed start-up/shut-down costs to account for wear and tear and additional fuel consumption) this suggests that in future low-carbon energy systems dominated by variable renewable power, on/off and part load performance of CCS fossil fuel power plants may become as or even more important than the traditional performance objective of full load efficiency, requiring substantial changes to power station design.

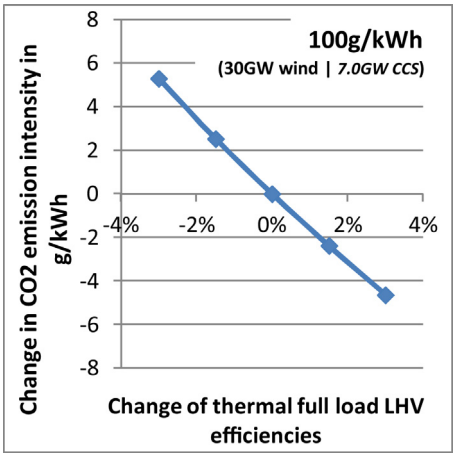

Fig. 10. Change in CO_2 emission intensity in base case ('medium' wind speeds, 30GW wind, 100 g/kWh) with increased (+1.5%, +3.0%) and decreased (−1.5%, −3.0%) full load LHV efficiencies of thermal generating plants.

3.6. Sensitivity cases

3.6.1. Thermal full load LHV efficiencies

Due to the uncertainty regarding thermal efficiencies (LHV) of thermal generators in future decades, a sensitivity case was run to explore the influence of efficiencies on the CO_2 emission intensity of the power generation fleet (including wind power). The results for the base case show that the emission intensity is approximately inversely proportional to full load efficiencies of thermal power generators (Fig. 10). A reduction of all thermal full load efficiencies (LHV) of 1% leads to an increase in the annual average CO_2 emission intensity of around 1.7 g/kWh compared to the base case. Similarly, the maximum and minimum CO_2 flow captured in the sensitivity case is inversely proportional to the LHV thermal efficiency. Whilst a maximum and minimum flow of 21.9MPTA and 3.6MPTA is captured at reduced thermal efficiency (-3% LHV efficiency compared to base case), these flows drop by 8–9% to 19.9MPTA and 3.3MTPA at the highest considered thermal efficiencies (+3% LHV efficiency compared to base case), respectively.

3.6.2. Spinning reserve requirement

A further important parameter is the amount of spinning reserve that is scheduled, hence a sensitivity study was performed based on the reference scenario (30GW wind capacity, 100 g/kWh emission intensity, wind and demand data from 2004 − see Fig. 11a). The results show that increasing the amount of scheduled spinning reserve by 0.25σ in order to secure the network against larger unanticipated changes of net demand, thus increasing security of supply, increases the CO_2 emission intensity of the power generation fleet by around 1.5 g/kWh. The effect of a varied spinning reserve requirement on the FDCs can be seen in Fig. 11b. Increasing spinning reserve requirement has the effect of reducing the time CCS plants can operate at full load, as more plants need to part-load in order to provide the required amount of reserve. The amount of the time the plants operate at part-load in turn increases. Conversely, the effect of reducing the amount of spinning reserve increases the amount of time CCS power plants can operate at full load, as the requirement for operating at lower loads for providing back-up reserve power is not as prominent.

The analysis shows that the required amount of spinning reserve is

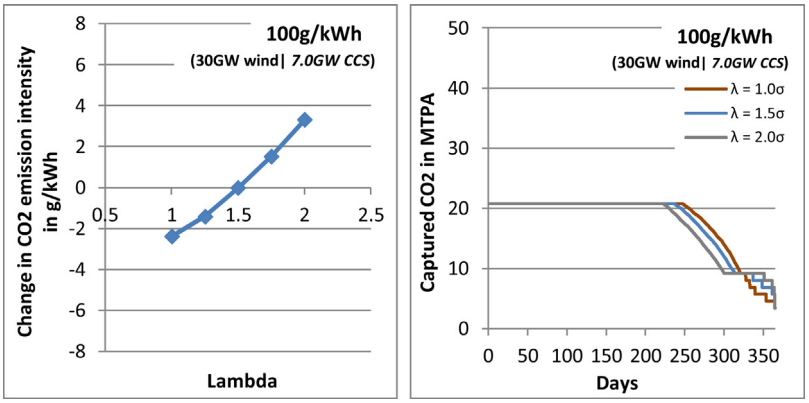

Fig. 11. a (left): Change in CO_2 emission intensity in base case with increased (+0.25σ, +0.5σ) and decreased (−0.25σ, −0.5σ) spinning reserve requirements. b (right): CO_2 capture duration profile for 30GW wind capacity in 100 g/kWh emission intensity scenario for 'medium' wind speeds for different spinning reserve requirements: (i) λ = 1.0σ (brown) (ii) λ = 1.5σ (blue) and (iii) λ = 2.0σ (grey). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

an important parameter that can modify the dispatch behaviour of power plants, and significantly affect emission levels. A more detailed analysis is therefore recommended to explore the optimal amount and ways of providing spinning reserve for reducing both system costs and emissions.

In contrast to operating profiles, the amount of spinning reserve does not directly affect the minimum and maximum flow produced by the power stations in the sensitivity cases. This is, however, an effect of minimum flow being a 'stepwise' function of the number of CCS power plants that are required to run at minimum load at the lowest annual net demand levels to satisfy reserve requirements. For the case considered here, the reduction/increase in reserve requirement across the sensitivity cases does not lead to an overstepping of a 'threshold', which would justify dispatching either more or less CCS plants at minimum net demand periods for satisfying reserve requirements at lowest cost.

3.6.3. Capture plant bypass

Finally, Fig. 12 compares FDCs for constant capture with FDCs when flexible capture operation is allowed. Flexible capture here refers to the operation of the CCS power station when the CO_2 capture unit is switched off and the base power plant recovers all but a small fraction of the energy consumption of the capture plant (i.e. 'bypass') in order to increase its power output when this is economically favourable (i.e. electricity prices are high enough to offset the increased costs for emitting more CO_2). There is ongoing policy uncertainty regarding the structure of market incentives to encourage the deployment of CCS (Errey et al., 2014) and hence how this may affect the behaviour of CCS plants.

The blue curve in Fig. 12 represents the base case with constant capture, while the beige, the red and the purple curves illustrate the flexible capture scenario with an identical power generation portfolio and CO_2 prices of 101.1£/tCO_2 (as projected by BEIS for 2035), 50£/tCO_2, and 30£/tCO_2, respectively. Due to a sufficiently high CO_2 price (making flexible capture comparatively unattractive) the blue and the beige curves resemble each other very closely, with the main difference being a slightly longer sustained operation at nominal CO_2 flow in the flexible capture scenario, that comes along with a slight decrease of the CO_2 flows produced at part-load operation, and a significantly lower minimum flow rate (0.0MPTA; for 6 h over the year). This trade-off between marginally longer operation at nominal load and reduced output at part-load operation suggests that the flexible capture option is predominantly used for provision of spinning reserve. When the option of flexible capture is available, fast shut-downs of the capture plant can free capacity that can be used for provision of reserve (Chalmers 2010, Van der Wijk et al., 2014), as well as for avoiding start-ups of gas generators for only short periods, which is both associated with additional costs for start-up/shut-down operation and additional emissions. This finding is confirmed by the CO_2 emission intensity dropping by 1.1 g/kWh, at carbon prices of 101.1£/tCO_2, when flexible capture is allowed.

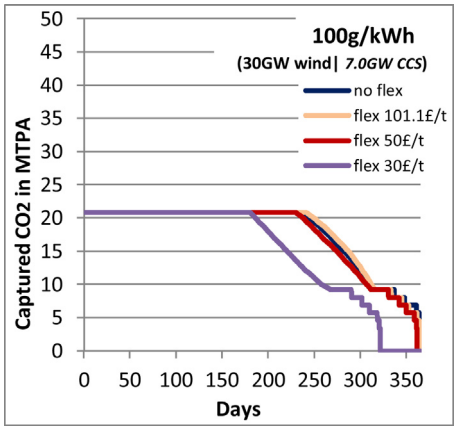

Fig. 12. CO_2 flow duration curves for constant capture (blue) and flexible capture with carbon price of 101£/tCO_2 (beige), 50£/tCO_2 (dark red) and 30£/tCO_2 (purple) for 7.9GW of CCS capacity installed. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

At lower future CO_2 prices flexible capture becomes economically more attractive, particularly at times of high electricity prices (Chalmers 2010, Van Peteghem and Delarue 2014). This is reflected in the shape of the corresponding (red and purple) FDCs that indicate that the CO_2 capture plants are shut off for a relatively small (red curve) and more substantial (purple curve) amount of time (approx. 82 h and 1046 h of 8760 h of the year, respectively) producing no CO_2 when they would under constant capture operation produce the nominal amounts. Times of zero flow that usually correspond to periods of high electricity prices are likely to increase CO_2 flow variability substantially. Whilst the positive effect of an increased amount of spinning reserve offered by CCS plants in the flexible capture scenarios counterbalances the increased emissions during periods of capture plant bypass at carbon prices of 50£/tCO_2, the annual average emission intensity increases by around 6.9 g/kWh when carbon prices are low (30£/tCO_2).

Overall, the sensitivity case shows that the option for capture plant bypass has the potential to increase the variability of CO_2 flows and times of zero flow significantly, but only at relatively low future carbon prices (e.g. 50£/tCO_2 or lower).

4. Conclusions

This study has investigated the operating behaviour of CCS power plants in an example energy system (based on the GB system) with 15GW, 30GW and 45GW of installed wind power generation capacity (corresponding to around 18%, 31% and 42% of total installed capacity). The study has important implications for policy makers and planners involved in designing future CCS systems. It has shown that:

1. Different combinations of wind and CCS power capacity can be deployed to achieve the respective annual average emission intensity targets. The individual scenarios lead to significantly different operating profiles of CCS power stations, and consequently time profiles of captured CO_2 that will feed into downstream T&S systems.
2. The capacity utilisation of the required T&S system reduces in lower emission intensity scenarios. This will lead to increased costs of the system on a per-tCO_2 throughput basis, thus reducing the relative economic value of CCS vis-à-vis other low carbon policy options.
3. High variability of CO_2 flow rates feeding into future CO_2 transportation and storage (T&S) networks can be expected over the entire year, and across nearly all scenarios. In the base-line scenario, 21% of net changes over 6h-periods were greater than 30% of the nominal flow, and 12% of the changes were greater than 50% of the nominal flow.
4. In general, CCS plants will experience more load changes over 6-h periods, and changes of greater amplitudes, under low emissions intensity scenarios, due to the greater number of CCS plants required to achieve these targets, some of which will have to load follow.
5. The overall variability of captured CO_2 flows is less dependent on wind capacity than it is on the target emissions intensity. CCS plants will operate more frequently at stable base-load under high wind capacity scenarios, as fewer CCS plants are required to meet emission targets, and more of the carbon budget is available for use by load-following non-CCS NGCC plants. However, at times of very high wind output, even these few CCS plants may have to be constrained down to minimum load, resulting in changes of high (> 50%) amplitudes, from full to minimum load and back again. It is unclear whether accommodating such high amplitude changes

will be more or less costly than coping with more frequent lower-amplitude changes, underlining the importance of further research to investigate the economics of such trade-offs.
6. The variability of load changes averaged over two consecutive 6-h periods (selected to provide an indication of the possible smoothing effect of line-packing) is less extreme, with fewer periods of larger amplitude changes and also fewer periods of zero change. However, variability remains substantial under all considered scenarios. This indicates that many CO_2 flow fluctuations are on the basis of cycles extending over more than 12 h, which will automatically lead to a higher requirement for CO_2 balancing capacity (compared to short term fluctuations), if large and frequent load changes at the injection well level are to be avoided.
7. The frequency of CCS plants starting-up (and shutting-down) is a very strong function of the target emission intensity, and to a much lesser extent of the installed wind capacity scenario. Whilst in the high target emission intensity scenarios CCS plants have on average less than 3 non-maintenance related shut downs per year, this number increases substantially to around 65 times per year across low target emission intensity scenarios. This suggests that in future low-carbon energy systems dominated by variable renewable power, greater attention will need to be paid to on/off and part load performance in CCS fossil fuel power station design.
8. The option for flexible capture could change CO_2 flow profiles considerably towards higher variability, but only at relatively low future carbon prices (e.g. approx. 50£/tCO_2 or lower).

Although the observed variability of captured CO_2 flows is unlikely to cause any particular concerns for the transportation network, they do raise serious technical issues associated with injection well cycling (Spitz et al., 2017). A number of options to mitigate CO_2 flow rate fluctuations at various points upstream in the system were outlined in Section 1. Any such solutions are, however, likely to come at an increased cost and/or decreased efficiency.

When transferring the learnings from this study to other energy systems it should be noted that demand data, wind data, and their interplay may be country specific. Other energy systems may have wind or renewable resource distributions that complement demand profiles in different ways, or power systems that are able to absorb more/less supply from renewables. The general findings of this study are nevertheless expected to hold for many different energy systems.

The present study provides a baseline estimate of the operating flexibility likely to be required by future CO_2 T&S systems, but further research in all of the areas outlined in Section 2.3 (including the effect of energy storage, electrification of transport, smart grids, other renewable energy types etc.) would be useful in order to improve our understanding of future flexibility requirements. Line-packing studies building on Aghajani et al. (2017), that rigorously examine the extent to which pipeline networks can be used to smooth out and absorb feed flow-rate variations would be particularly useful. This would enable more accurate determination of the extent to which CO_2 injection wells will need to be able to cope with varying flow rates, or alternatively, the extent to which additional flow balancing capability needs to be installed.

The key take-away message for policy-makers and planners to be aware of is that CCS is unlikely to be utilised predominantly at steady-state base load operation. Flexible operation of CCS infrastructure is likely to be required to some degree. This implies additional costs to manage or mitigate the damaging downstream (wellhead) effects of CO_2 flow variations, either at the power plant or within the transportation network, which will only be minimised if operating flexibility is better understood and anticipated at the system design stage.

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Appendix A

See Table A1.

Table A1
Generator availability factors per technology type (based on National Grid 2016b, 2016c).

Capacity type	Availability Factors
Nuclear	90%
NGCC-CCS	90%
NGCC	90%
OCGT	94%
Wind	22%

Appendix B

See Tables B1 and B2.

Table B1
Technical and techno-economic parameters for thermal plants (based on Bruce 2015 except when specified differently).

Parameters				
		Nuclear	NGCC	OCGT
$P_{g,min}$	Minimum power output (MW_e)	620	360	225
$P_{g,max}$	Maximum power output (MW_e)	1550	900	565
ρ_g^{up}	Ramp up rate (MW_e/h)	4650	300	600
ρ_g^{dn}	Ramp down rate (MW_e/h)	4650	300	600
$UT_{g,min}$	Minimum up time (h)	24	3[a]	1
$DT_{g,min}$	Minimum down time (h)	24	3[a]	1
$c_{g,t}^{fuel}$	Cost of fuel (£/MWh_{th})	3.5	21.2	21.2
e_g^{CO2}	Emission factor (tCO_2/MWh_{th})	0	0.2267	0.2267
$c_g^{O\&M}$	Variable O&M cost (£/MWh_e)	0.5	2.5	5.0
$c_g^{ramp,up}$	Upwards ramping cost (£/MW_e)	5.0	5.0	5.0
$c_g^{ramp,dn}$	Downwards ramping costs (£/MW_e)	5.0	5.0	5.0
$c_g^{start,fixed}$	Fixed start-up cost (£)	100000	10000	5000
$F_g^{start,cold}$	Fuel consumption during cold start-up (MWh_{th})	5000	1500	400
τ_g^c	Thermal cooling constant (h)	8	12	24
$c_g^{shut,fixed}$	Fixed shut-down cost (£)	25000	2500	12500
F_g^{shut}	Fuel consumption during shut-down (MW_{th})	1250	375	100

[a] Based on Hentschel et al. (2016), DIW (2016), Van den Bergh and Delarue (2015).

Table B2
Technical and techno-economic parameters for post combustion CO_2 capture units (based Bruce 2015).

Post-combustion capture plant parameters		
$P_g^{capt,fixed}$	Fixed CO_2 capture plant power consumption (MW_e)	25
$Y_{g,min}^{capt}$	Minimum CO_2 capture rate (−)	0
$Y_{g,max}^{capt}$	Maximum CO_2 capture rate (−)	0.90
$q_g^{capt,op}$	Energy requirement to capture 1 t of CO_2 (MWh_{th}/tCO_2)	0.27
$c_g^{O\&M,capt}$	CO_2 capture plant variable operation and maintenance (£/tCO_2)	1.5
c^{solv}	Cost of MEA solvent (£/kg)	2.0
$c_{g,t}^{trans}$	CO_2 transport and storage (£/tCO_2)	10.0
D_g	Total solvent degradation rate (kg/tCO_2)	1.5
D_g^{th}	Solvent degradation rate cause by thermal effects (£/tCO_2)	0.1

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