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Do tidal stream energy projects offer more value than offshore wind farms? A case study in the United Kingdom

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A B S T R A C T

Marine-based renewable energy could help the United Kingdom (UK) move towards a more sustainable and low-carbon energy system. Today, offshore wind is the prevailing marine renewable technology but there is growing progress towards developing others, such as tidal stream energy (TSE) turbines which capture kinetic energy from tidal currents. Using historical operations data from 18 wind farms and simulated generation data for two TSE sites in the UK, we estimate that TSE projects offer about \$10/MW h more in net social benefits than offshore wind projects. This estimate includes the value of energy generated, value of reduced marginal CO_2 emissions, cost of visual changes to the landscape, and cost of energy generation forecast errors. However, relative to offshore wind, the increased cost of TSE projects far outweighs the increased social benefits. The levelized cost of energy (LCOE) of TSE projects is expected to be about \$74/MW h to \$330/MW h higher than offshore wind projects through 2050. Only with optimistic LCOE projections, small TSE projects (20 MW) may be competitive (when including increased net social benefits) with small offshore wind projects by 2020.

1. Introduction

Increasing renewable electricity generation is a priority in many countries (IEA, 2017). In 2009, the United Kingdom (UK) set a goal, in coordination with other countries in the European Union (EU), to meet 15% of UK's electricity demand from renewable energy by 2020 (compared to about 8.3% in 2015 (DUKES, 2016)). In further coordination with other EU countries, the UK parliament also passed a law to reduce carbon emissions by 80% by 2050 (below 1990 levels) with annual targets set with a 5-year carbon budget (The UK National Archives, 2008). Despite the recent referendum vote for the UK to leave the EU, the UK government appears committed to continuing these renewable and climate obligations. The most recent climate budget passed for years 2028–2032 requires carbon emission reductions of about 57% by 2030, a more aggressive reduction compared to EU requirements of 40% (Vaughan, 2016). It is expected that renewable energy will play a large role in meeting emission targets.

Most renewable energy generation in the UK comes from wind power (48% in 2015), followed by biomass (35%), and the rest from solar (9%) and hydro (7%) (DUKES, 2016). At the end of 2015, the UK had 9188 MW (MW) of wind capacity located onshore and 5103 MW located offshore. Furthermore, future wind development has enormous potential in the UK. The European Environment Agency (EEA, 2009) estimates that the total unrestricted technical potential for wind power in the UK is about 4500 terawatt-hours (TW h) for onshore and another 4500 TW h for offshore – enough to power all consumption in the UK 30 times over (net energy demand in 2015 was 302 TW h, (DUKES, 2016)). However, offshore locations may offer advantages over onshore ones. First, offshore wind projects generate more energy due to stronger and more consistent wind. In 2015, the average capacity factor of existing offshore projects was 39% compared to 28% for onshore projects (DUKES, 2016). Offshore projects are also farther from population centers, and thus avoid concerns about increased noise, shadow flicker, and other human disturbances associated with onshore projects (Devine-Wright, 2005; Ek, 2002; Wolsink, 2000). There is also evidence that close proximity to onshore projects can lower residential property value, although these effects have been debated in past literature (Gibbons, 2013; Heintzelman and Tuttle, 2012; Hoen, 2010). Furthermore, recent work by Graziano et al. (2017) showed that locally sourced off-shore could potentially have important income and employment consequences for the UK's economy.

Because of these advantages, offshore wind capacity will likely surpass that of onshore. According to the Crown Estate, which controls commercial access to UK's seabed, there are about 4500 MW of new offshore wind projects currently under construction for operation by 2020, and an additional 10,000 MW of leases granted for future development (The Crown Estate, 2017).

Despite their benefits in helping to reduce carbon emissions, both onshore and offshore wind projects present several challenges. Wind

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projects generate electricity intermittently and often in unpredictable patterns (Sovacool, 2009). This presents a challenge to merchant wind farm operators, who sell energy into wholesale markets at least one hour before delivery. Missing delivery targets due to generation forecast error can carry penalties. For example, Lueken et al. (2012) find that 20 wind farms in Texas incur about $4/MW h in additional costs due to forecast error. The value of wind energy generated also depends on timing. Correlation of hourly wind energy generation with high wholesale energy prices (J.V. Lamy et al., 2016) as well as with high marginal emission reductions (Siler-Evans et al., 2013) can vary substantially by project location. Furthermore, one of the biggest challenges facing wind projects is aesthetics. There is an extensive body of literature that explores the perceived social costs of wind projects due to their impact on landscapes (Dimitropoulos and Kontoleon, 2009; Ek and Persson, 2014; Krueger et al., 2011; Ladenburg and Dubgaard, 2009). Even offshore wind projects, although farther from population centers than onshore projects, can be visible at distances beyond 40 km from shore (Sullivan et al., 2013). Lastly, there are concerns about the potential ecological impact of both onshore and offshore wind turbines, such as adverse interaction with birds, bats, and marine animals (Bailey et al., 2014; Bergström et al., 2014; Erickson et al., 2014; Loss et al., 2013; Stewart et al., 2007).

Other marine-based renewable technologies offer similar advantages to offshore wind, while avoiding some of their drawbacks. For example, tidal stream energy (TSE) projects capture kinetic energy from tidal currents that flow during the transition between high and low tide, which occurs twice per lunar day (24 h and 50 min). Unlike wind speed, tidal current speed is highly predictable using harmonic simulation tools (Blunden and Bahaj, 2006; Neill et al., 2012; Zhong and Li, 2006), which greatly facilitate energy generation forecasting. Another advantage is that, unlike offshore wind, TSE projects have little impact to the ocean landscapes since most TSE turbine technologies are fully submerged, and thus are not visible from shore (Polagye et al., 2010). Furthermore, the UK has abundant TSE resources, totaling about 95 TW h (The Crown Estate, 2012) in technical potential – enough to meet 31% of UK's net electricity demand (302 TW h in 2015, (DUKES, 2016)). It is important to point out that TSE turbines are not the same as tidal lagoon projects (also known as tidal barrage or tidal range), which are artificial walls containing embedded turbines built across an estuary or bay, such as the Swansea Bay project proposed in Wales (The Economist, 2017). Tidal lagoon projects are easily accessible for operation and maintenance since they are attached to the mainland (which helps to lower costs), but they also require large infrastructure changes to the estuary/bay and can only be sited in areas with suitable mainland geography. Unlike tidal lagoon, TSE projects are made up of stand-alone turbines fixed to the seabed, much like offshore wind turbines. TSE turbines are fully submerged, don't require large infrastructure changes to the landscape, and have less local environmental impact than tidal lagoon projects (Pelc and Fujita, 2002). Our work does not include tidal lagoons and instead focuses on TSE.

The TSE industry has recently started to gain traction. We estimate that about 20 MW of demonstration and pilot phase projects are currently deployed globally, with another 1600 MW of commercial phase projects in development for operation by 2022 (see Appendix A for a list of existing TSE projects across the world). However, ecological impacts of TSE projects are still widely uncertain since there are few projects in operation. It is expected that many of the same concerns regarding offshore wind projects (namely, impact to marine life) also apply to TSE projects (OES, 2014; Polagye et al., 2010, 2014).

The major challenge facing marine-based renewable projects like TSE, and to a lesser extent offshore wind, is cost. The current levelized cost of energy (LCOE) for offshore wind projects is about $175/MW h and $500/MW h for TSE projects[1] (Wiser, 2016; OES, 2015), compared to an average wholesale market index price of $60/MW h in the UK from 2012 to 2014 (2016$, (Elexon, 2017)).

Electricity end-users are not directly exposed to these higher costs. Instead, the UK government provides incentives for renewable technologies to increase renewable penetration and help new technologies move down the learning curve. This support is primarily realized through a "contract-for-difference" (CfD), which locks in a price ("strike price") offered to specific renewable technologies over a period of 15 years (BEIS, 2017a). The recent CfD strike price for offshore projects delivered by 2021/2022 was $136/MW h compared to $388/MW h for TSE projects. Total awards have a limited budget of $361 million so applicants must bid and compete on price to win CfD contracts (BEIS, 2017b). Furthermore, there is increased concern that financial support for renewables will decrease in the near future due to recent political changes (Vaughan, 2017). This puts more pressure on renewable projects to demonstrate economic competitiveness, and calls into question whether the large difference in CfD strike prices for one technology over another (TSE vs. offshore wind) is justified. However, the total net social benefits of TSE projects may be higher than those of offshore wind projects, which would help justify a higher public willingness-to-pay (i.e., government incentives) for the technology. This question is the underlying premise of our paper.

We aim to identify whether the difference in net social benefits between TSE and offshore justifies a difference in subsidies (i.e., CfD strike price) between the two technologies, which is currently about $252/MW h. We quantify the increased net social benefits (in $ / MW h) that TSE projects offer over offshore wind projects (i.e., "TSE social benefit premium"). For the net social benefits calculation, we consider differences between offshore wind and TSE regarding the value of energy generated, marginal CO_2 emission reductions, predictability in power generation, and visual impact on the landscape. We also discuss the ecological impacts of the two technologies based on past literature, but do not attempt to quantify or compare their associated social costs. We then compare LCOE cost projections between the two technologies through 2050 to see if/when TSE projects would be able to compete with offshore wind, given that TSE projects receive increased subsidies equal to our estimated TSE social benefit premium. Our calculations rely on generation data from 18 operational wind farms across the UK and modeled tidal current speed data from two TSE sites at the European Marine Energy Center (EMEC, 2017).

Our study is the first to quantify and compare net social benefits between offshore wind and TSE projects. We focus on TSE projects as opposed to other marine renewable technologies (ocean wave, tidal range/ lagoon, ocean thermal energy, and salinity gradient) because TSE projects have a unique combination of high resource potential in the UK (95 TW h, (The Crown Estate, 2012)), limited visual as well as environmental impact,[2] and commercial viability within the next 5 years (see Appendix A).

Several studies compare the characteristics of different marine renewable technologies, such as offshore wind and TSE. However, these studies typically focus on environmental impacts or capital costs, do not consider project performance (emission reductions, energy value, predictability, or visual impact), and often present only qualitative comparisons (Frid et al., 2012; Inger et al., 2009; Johnstone et al., 2013; Pelc and Fujita, 2002; Uihlein and Magagna, 2016).

The rest of this paper is organized as follows: in the next Section, we discuss our methods and the data we relied upon, in Section 3, we present results, and in Section 4, we conclude.

2. Methods and data

Our method relies on five steps outlined in Fig. 1. First, (1) we estimate net social benefits of both offshore wind and TSE projects and

[1] As a point of reference, the Swansea Bay tidal lagoon project is expected to have an LCOE up to around $300/MW h (Private Eye, 2017).

[2] Relative to tidal range/ lagoon projects, which are likely to induce more environmental and landscape changes (Pelc and Fujita, 2002).

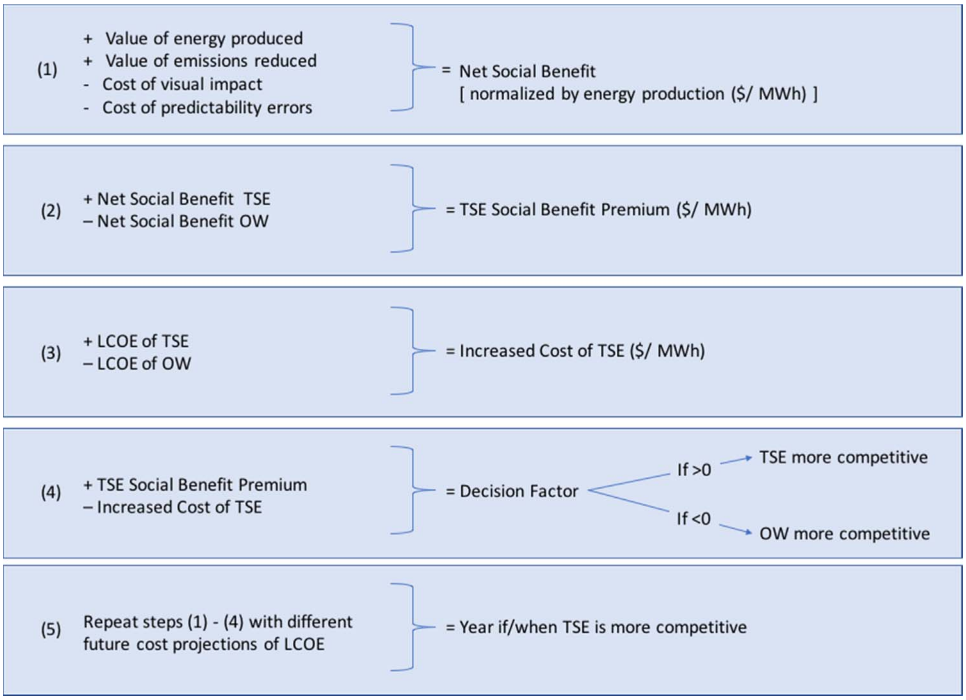

Fig. 1. Steps for comparing net social benefits vs. levelized cost of energy (LCOE) between tidal stream energy (TSE) and offshore wind (OW) projects.

normalize these benefits by total energy generation (i.e., $/MW h); second, (2) we subtract these benefits to find the "TSE social benefit premium"; (3) we then estimate the difference in LCOE between TSE and offshore wind projects; next, (4) we compare the "TSE social benefit premium" to the increased LCOE of TSE projects relative to offshore wind projects; and lastly, (5) we repeat this analysis for multiple future cost projections of LCOE for the two technologies. If the "TSE social benefit premium" is higher than the increased LCOE for TSE, we conclude that TSE projects are competitive with offshore wind projects. We rely on LCOE cost projections for offshore wind from Wiser et al. (2016) and for TSE from OES (2015), and use these forward projections to evaluate if/when TSE projects may be worthwhile based on our method. These cost projections and associated references are presented in Section 2.1.

Our net social benefit calculation includes the value of energy generated, value of emissions reduction, cost of unpredictability in power generation, and cost of visual impacts from each project type. Section 2.2 provides an explanation of the methods and datasets used to estimate each of these components. We assume that both technologies would have similar impacts to boating or fishing, local economic activity, and job creation and thus exclude these variables from our net social benefits calculation. For simplicity, we also assume that TSE and offshore wind projects have the same capacity of 200 MW, capacity factor of 37%, and distance to shore of 10 km, which reflect the average values from historical existing offshore wind projects in the UK (The Crown Estate, 2017). We also vary these assumptions in a sensitivity analysis to check how they may impact our conclusions. Lastly, all monetary amounts we report are converted to 2016 US dollars using the price conversation tables provided in Appendix D.

2.1. Levelized cost of energy (LCOE) projections for TSE and offshore wind projects

The blue line in Fig. 2 shows projections for the levelized cost of energy (LCOE) of offshore wind from Wiser et al. (2016), who conducted an expert elicitation of 163 wind experts to estimate costs for onshore and offshore projects. They find that the current LCOE (estimate from 2014) of fixed-bottom offshore wind projects is about $175/MW h, and estimate that costs will drop by 10% in 2020, 30% in 2030,

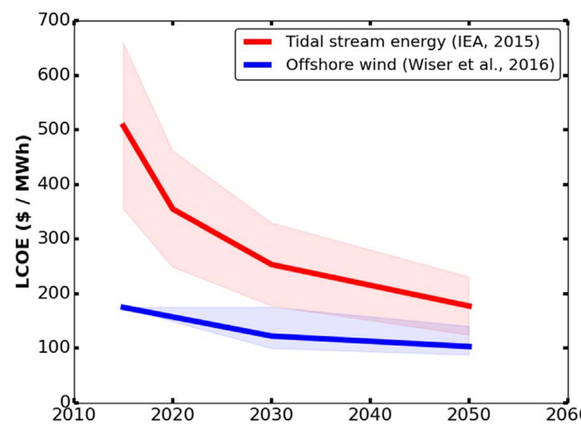

Fig. 2. Levelized cost of energy (LCOE, in 2016 $/MW h) projections for tidal stream energy projects from (OES, 2015), based on estimates of cumulative capacity deployed per year (see Appendix A), and fixed-bottom offshore wind farms from Wiser et al. (2016). Solid lines show the base case results and shading indicates high and low scenarios reported in each study.

and 41% in 2050, based on the median values gathered from experts. The authors also vary these estimates in low and high scenarios based on the 25th and 75th percentile of values from exerts, noted with blue shading in Fig. 2.

The red line in Fig. 2 shows LCOE estimates of TSE projects from Ocean Energy Systems (OES, 2015), a division of the International Energy Agency, which performed a literature review and expert elicitation of industry experts to estimate costs of TSE, wave, and ocean thermal energy conversation projects. The authors find that the LCOE for TSE is about $500/MW h today, and present estimates of cost reductions as a function of increased capacity deployed across the industry. We use this result to estimate LCOE by year by assuming 10–25 MW are deployed today, 100 MW will be deployed in 2020, 1000 MW in 2030, and 10,000 MW in 2050. These capacity targets are in line with TSE projects being developed globally (see Appendix A). Red shading in Fig. 2 shows high and low scenarios, based on 30% uncertainty margins assumed by OES (2015).

As shown in Fig. 2, by 2030 it is possible that costs of the two technologies will converge given the low-cost scenario of TSE and high-cost scenario for offshore. However, it is expected in the base case scenarios that TSE projects will cost between \$74 to \$330 /MW h (72–190%) more than offshore wind through 2050.

2.2. Net social benefit calculation method

2.2.1. Data to estimate energy generation for TSE and offshore wind projects

We received proprietary 30-min interval data on actual energy generation and forecasted energy generation (about 6 h ahead of trade delivery) from 17 operational onshore and 1 offshore wind farm in the UK from 2012 to 2014. This data was assembled from various project developers and project operators who requested to remain anonymous. One of the unique aspects of this dataset is that it is based on actual commercial operation of the projects, and thus reflects times when the project was offline due to operation and maintenance, as opposed to theoretical wind energy generation which can vary significantly (Krokoszinski, 2003). Furthermore, the dataset contains forecasted energy generation that was used to optimally bid energy into wholesale energy markets, which is critical data needed for estimating prediction errors. It would be possible to use hypothetical forecasts based on conventional forecasting methods (Wang et al., 2009; Mauch et al., 2012; Pennock and Clark, 2012), however it is unclear if these approaches reflect the day-to-day trading and commercial operation of actual projects. Our dataset provides a unique ability to estimate true forecast errors experienced in the industry. A limitation of our dataset is that it contains mainly onshore projects as opposed to offshore. Appendix C provides summary statistics of this dataset and a comparison with the EMHIRES dataset, which is publicly available, includes offshore sites, and was produced by the Joint Research Center of the European Union (Gonzalez Aparicio et al., 2016). We find that our results and conclusions are robust to using this alternative dataset.

For TSE projects, we rely on hourly tidal current speed (m/s) data from 2012 to 2013 for two tidal sites at the European Marine Energy Center in Northern Scotland (EMEC, 2017). EMEC is an internationally recognized research center for marine renewable technologies. In addition to providing testing sites for new technology, they also provide interval data at test sites where TSE projects could be viable. Since there is very little publicly available data on operational TSE projects (there are only about 20 MW of demonstration projects across the world – see Appendix A), we believe EMEC provides the best possible approximation of tidal current speed for a commercial TSE project. The first EMEC site we consider, called “Fall of Warness”, is located at the Island of Eday and was selected as a testing facility for dozens of tidal devices. The second site, called “Meygen”, is in Pentland Firth where about 500 MW of commercial projects are currently in development (see Appendix A). We estimate energy generation at each site by applying an assumed power curve, which is the relation between power output (MW) for a specific turbine relative to tidal current speed (m/s).

We rely on the power curve of Marine Current Turbine's (MCT) SeaGen tidal turbine, which is 1.2 MW and has been in operation since 2008 in Strangford Lough, Northern Ireland, and thus represents a relatively mature and commercially viable TSE technology (Fraenkel, 2010). This version of MCT's tidal turbine makes use of a monopole structure (like an offshore wind turbine) with a horizontal cross-beam where the turbines are attached. The cross-beam can be raised and lowered, allowing for the turbines to be easily serviced. The resulting SeaGen turbine therefore has a visible portion above the water level as noted in Fig. 3. However, MCT, now owned by Atlantis Resources, is developing a fully submerged (i.e., not visible) version of this device without a monopole or crossbeam called the SeaGen U (Tidal Energy Today, 2015), which we assume will have the same power curve. In total, approximately 200 devices would be required for a 200 MW project (assuming 1 MW per device).

Note that although we only represent 2 tidal sites in our analysis, results can be generalized to other tidal projects across the United Kingdom. This is because energy generation from TSE's occurs between high and low tide which are constantly shifting by about 50 min each calendar day. The timing of high and low tide does vary by geography and therefore by site, however; all sites are subject to the same shifting peaks. Therefore, TSE sites should share a similar distribution of maximum energy generation per hour (albeit different maximums).

Fig. 3. Image of MCT's SeaGen tidal turbine, reproduced from Fraenkel (2010).

A limitation of both the TSE and wind datasets is that the time-period is limited, which reflects the scarcity of data surrounding TSE projects. In Section 3, we therefore present our results in ranges, which are based on estimates from a diverse set of projects (18 geographically diverse wind farms, 2 tidal sites, and an alternative wind dataset presented in Appendix C). Thus, we are confident that our range of results reflects the broader uncertainty in wind and TSE generation across a larger timeframe.

2.2.2. Value of energy generated

We estimate the value of energy generated for TSE and offshore projects by multiplying hourly energy generation from 2012 to 2014 by the market index price in the same hour, which reflects the price of wholesale electricity in the short-term market (Elexon, 2017). We then normalize this cost by total energy generation to arrive at energy value in \$/ MW h. Eq. (1) summarizes this calculation for each hour, t.

$$Energy\ \ Value\ \ in\ \ \$\ \ per\ \ MWh = \frac{\sum_t^T (Energy\ \ Produced)_t * (Market\ \ Index\ \ Price)_t}{\sum_t^T (Energy\ \ Produced)_t} \tag{1}$$

There is likely a difference in energy value between TSE and offshore projects due to the nature by which each renewable resource occurs. In Fig. 4A, plotted on the left y-axis are average market index prices in the Great Britain from 2012 to 2014 (bold black line) for each hour of the day on the x-axis. Prices often spike around 9 a.m. and again around 5 p.m., corresponding to home energy consumption patterns. These peak periods therefore indicate – on average – when energy generation is most valued on the wholesale market. On the right y-axis of Fig. 4A is the average capacity factor per hour of the day for one of 18 wind farms from our sample for December 7, 2012 through December 10, 2012. The pattern of capacity factor (i.e., energy generation) varies wildly depending on the day. For example, on December 7, 2012, the wind farm generated around 80% of its maximum capacity before and during the first high price period at 9 a.m., and then decreased to close to 0% afterwards. Variability in prices also affects energy value. Fig. 4B shows prices on December 7, 2012 in real-time (as

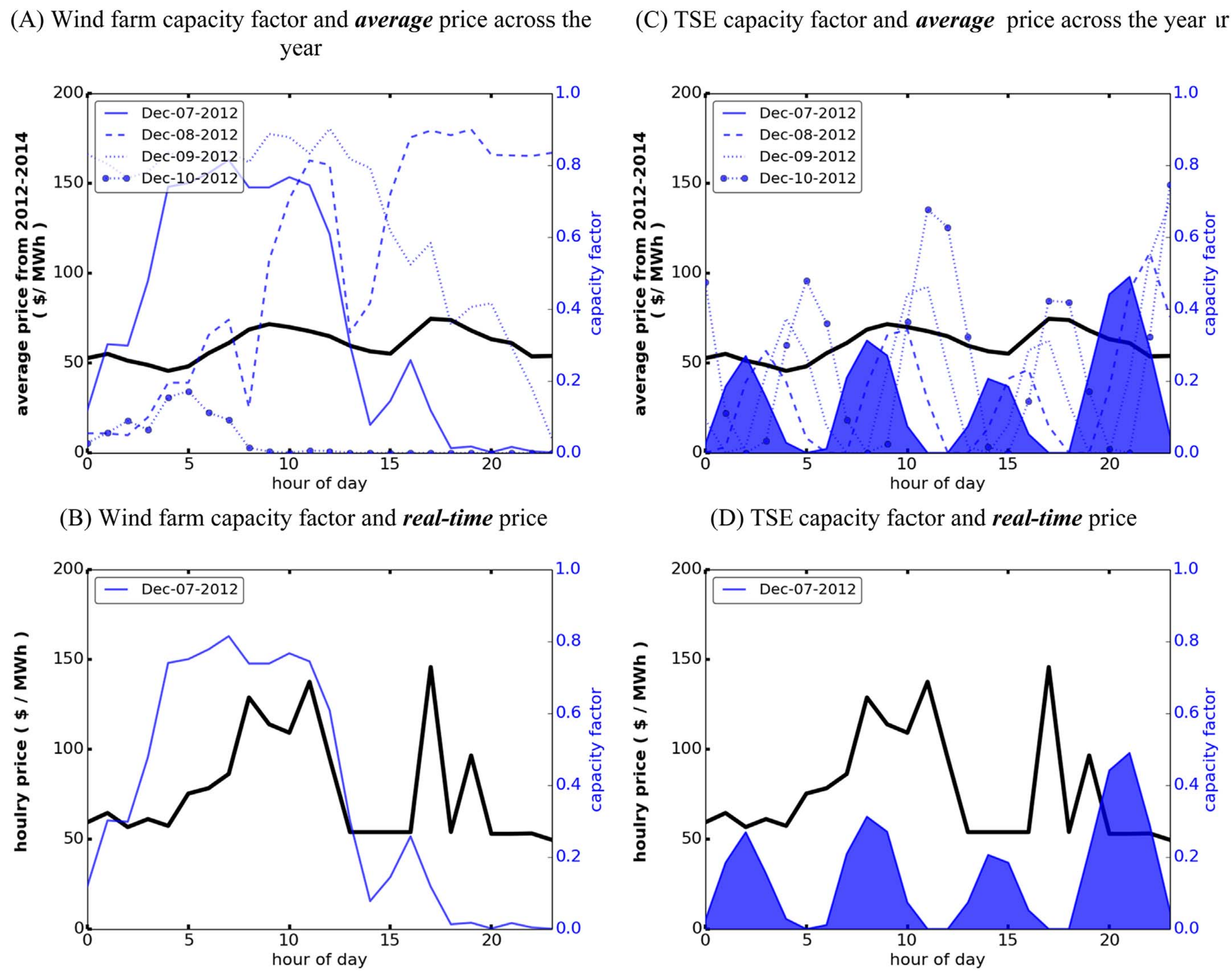

Fig. 4. Capacity factor and market index price in Great Britain plotted by hour day for select days. The wind farm data is one of the 18 wind farms from our sample. The TSE data is from the Meygen site. A and C show capacity factor compared to the *average* hourly energy price. B and D show capacity factor and *real-time* energy price got the same day.

opposed to average over the year). Prices spiked to around \$150/MW h in the evening when the wind farm's capacity factor dropped off. Therefore, when estimating energy value, it is important to capture the temporal variation in both energy generation and energy value as we do in Eq. (1).

Fig. 4B shows the same graph for the TSE project at Fall of Warness. Tidal energy follows a cyclical pattern with 4 peaks that correspond to hours when tides are in transition from high to low tide and vice versa (occurring twice per day). This pattern repeats each lunar day, which is 50 min longer than a calendar day – therefore, the occurrence of high and low tide shifts each calendar day by about 1 h. For example, as shown in Fig. 4C, on December 7, 2012 energy generation from the Meygen site misses the second high-price period around 5 p.m., but not on December 9, 2012 when it hits both high-price periods. These shifting peaks result in similar total energy generation per hour of day throughout the year. Fig. 4D shows the increased volatility in real-time prices compared to TSE energy generation.

2.2.3. *Value of reduced CO_2 emissions*

Both TSE and offshore wind projects will reduce CO_2 emissions by displacing generation from existing fossil fuel power plants in the UK. However, even if both projects generate the exact same amount of energy, the *timing* of when each project generates will have a different impact on the emissions displaced. There is a growing body of literature that has estimated marginal emissions factors (MEF, $kgCO_2$/MW h) which represents the average CO_2 intensity per hour of an electricity system given all generators (Bettle et al., 2006; Siler-Evans et al., 2012; Hawkes, 2014). Such analyses have important implications regarding carbon abatement strategies. For example, Siler-Evans et al. (2013) showed that despite having higher capacity factors in Midwestern US, onshore wind farms achieve greater social benefits in Northern US through larger reductions in marginal CO_2, NO_x, and SO_2 emissions.

We account for marginal CO_2 emissions by relying on results from Hawkes (2010), who provides estimates on average MEF by total electricity demand in Great Britain (Hawkes, 2010, Fig. 4). We use these estimates to approximate MEF by hour of year using 2012–2014 electricity demand data in Great Britain from National Grid (2017). We then use these estimates (in $kgCO_2$/ MW h) to approximate the marginal CO_2 reduction value (MRV_{CO2}, \$/MW h) by assuming a carbon price of \$34/ton CO_2 (in 2016\$) from Nordhaus (2017). Eq. (2) summarizes this calculation. Lastly, we estimate the average value of reduced CO_2 for each project (ARV_{CO2}, \$/MW h) by computing the weighted average of MRV_{CO2} (\$/MW h) by energy generated (MW h), noted in Eq. (3). AVR_{CO2} therefore represents the average value that a renewable energy project offers by offsetting CO_2 emissions on the energy system in Great Briton.

Table 1
Assumptions for estimating costs of the visual impact from an offshore wind project 8–10 km from shore.

	Value	[low – high] scenarios	Source
$ cost / home/ year	$112	[$42 - $158]	Average and [min-max] from Table 2
# homes affected	22,600		Average of existing offshore wind projects in UK[a]
MW of project	200		Average of existing offshore wind projects in UK[b]
capacity factor	37%	[32–40%]	Average and 25th–75th percentile of existing offshore wind projects in UK[c]

[a] (4C Offshore, 2017; Brinkhoff, 2017; ONS, 2011).
[b] (The Crown Estate, 2017).
[c] (Energy Numbers, 2016).

$$MRV_{CO2}\ \ in\ \ \$\ \ per\ \ MWh = \left(\frac{kgCO2}{MWh}\right)_t * \frac{ton}{907.185kg} * \frac{\$}{ton} \tag{2}$$

$$ARV_{CO2}\ in\ \$\ per\ MWh = \frac{\sum_t (Energy\ Produced)_t * (MRV_{CO2})_t}{\sum_t (Energy\ Produced)_t} \tag{3}$$

2.2.4. Energy prediction error cost

There are also costs associated with inaccurate estimates in power generation. In the UK, National Grid levies a cost to generators that deviate from their scheduled power generation. This is in the form of two prices called the system buy price (SBP) and system sell price (SSP). Normally, a generator receives the market index price (MIP) for the energy generated. However, if they are short generation from what they traded beforehand, then to fulfill their obligation they must buy energy to fill the gap in generation at the SBP, which is typically *higher* than the MIP. Similarly, if generators are long generation, they can sell the excess energy but will receive the SSP, which is typically *lower* than the MIP. Therefore, the cost of prediction error in any given hour t, is provided in Eq. (4).

$$\begin{aligned} Prediction\ \ Error\ \ Cost\ \ (short)_t &= (actual\ \ MW_t - forecasted\ \ MW_t) \\ &*(SBP_t - MIP_t) Prediction\ \ Error \\ &Cost\ \ (long)_t \\ &= (forecasted\ \ MW_t - actual\ \ MW_t) \\ &*(MIP_t - SSP_t) \end{aligned} \tag{4}$$

In our analysis, we estimate the prediction error costs for offshore wind using actual forecast (~ 6 h ahead, values that were used to execute trades) for 18 operational wind farms in the UK. We also rely on publicly available market imbalance prices from 2012 to 2014 (Elexon, 2017). We then normalize total prediction costs over this period by total energy generated to arrive at total predictability cost in $/MW h, as noted in Eq. (5). This method is similar to that provided in Lueken et al. (2012) who found that wind farms in Texas incur predictability costs of about $4/ MW h.

$$Prediction\ \ cost\ \ in\ \ \$\ \ per\ \ MWh = \frac{\sum (Prediction\ \ Error\ \ Cost)_t}{\sum (Energy\ \ Produced)_t} \tag{5}$$

To present an optimistic case for TSE projects, we assume that energy generation is perfectly forecasted. This assumption is reasonable since predictions for tidal patterns are very accurate especially within one day, as demonstrated in Lyard et al. (2006).

2.2.5. Visual impact cost

We assume that the tidal stream energy (TSE) project considered would be fully submerged and therefore would not be visible from shore. Therefore, visual costs would only occur for the offshore wind project, which we assume will be built 10 km from shore, the average distance for projects in the UK (see Appendix B).

To estimate the visual costs of offshore wind, we perform the following calculation. First, we multiply an assumed visual cost per home ($ / home / year) by the number of homes affected by the project. This multiplication yields total visual cost. We then divide this number by average energy generation of an offshore project (capacity in MW x capacity factor × 8760 h per year), which yields visual costs normalized by energy generated ($/MW h). Eq. (6) summarizes this calculation.

$$\begin{aligned} &visual\ \ cost\ \ in\ \ \$\ \ per\ \ MWh \\ &= \frac{(visual\ \ cost/home/year)x(\#homes\ \ affected)}{(MW\ \ of\ \ project)x(capacity\ \ factor)x(8760\ \ hours)} \end{aligned} \tag{6}$$

We identify visual cost per home by conducting a literature review (see sub-section below) of studies that estimate willingness-to-pay (WTP) and willingness-to-accept (WTA) for limited visual impact from offshore projects. Average visual costs from these studies are $112/ home/year, which we assume in our analysis. We also range this assumption in high and low sensitivity scenarios from $42 to $158/ home/year, the maximum and minimum identified (see Table 1). Next, we estimate the number of homes affected by using population data of towns nearby existing offshore projects in the UK. We identified these towns using maps of existing wind projects (4C Offshore, 2017), gathered population data for these towns (Brinkhoff, 2017), and assumed each home had approximately 2.3 residents, the average across the UK (ONS, 2011). This results in 22,600 homes affected on average per offshore wind project, which we use as our base case assumption for our analysis. For capacity, we assume both the offshore wind and TSE project are 200 MW, which represents the average of operational offshore wind projects in the UK (The Crown Estate, 2017). This results in 50 turbines assuming the average offshore turbine size of 4 MW (The Crown Estate, 2017). Lastly, we assume the capacity factor for both projects is 37% (average of existing offshore projects (Energy Numbers, 2016)), and also perform high and low sensitivity scenarios of 32% and 40% (25th and 75th percentile of past projects).

2.2.5.1. Supporting literature for visual cost ($/ per home / year).

Ladenburg and Dubgaard (2009) conducted a discrete choice experiment (DCE) throughout Denmark to measure the willingness-to-pay (WTP) of various characteristics about offshore wind projects. These included the number of turbines (49, 100, or 144), distance from shore (8 km, 12 km, 18 km, or 50 km), total number of projects in Denmark, and annual cost per household. Distance from shore was used

Table 2
Visual impact cost per home per year (2016 $) from an offshore wind project 8–10 km from shore.

	$ / home / year	# of turbines	Location	Method
Ladenburg and Dubgaard (2009)	$143	44–149	Denmark	DCE
Krueger et al. (2011)	$42	500	USA	DCE
J.V. Lamy et al. (2016)	$156	3	USA	DCE
Westerberg et al. (2011)	$60	30	France	DCE
Gibbons (2013)	$158	NA	United Kingdom	hedonic methods

as a metric to measure the perceived "visual dis-amenity" caused by the project. The authors find that across their sample of 365 participants, participants were willing to pay an additional $143 (2016 $) per year on average to site new projects 50 km from shore instead of 8 km. At this increased distance, it is unlikely that participants would notice the project. For example, with a sample of participants in the United Kingdom, Sullivan et al. (2013) found that participants in the UK were only able to see existing offshore wind projects located 42 km or more from shore "after extended, close viewing; otherwise [they were perceived as] invisible". Thus, Ladenburg and Dubgaard (2009) estimated WTP of $143 per year represents the perceived visual cost to participants in Denmark for an offshore project 8 km from shore.

Krueger et al. (2011) performed a similar discrete choice study using the same approach with 564 participants in the US State of Delaware and found different results depending on where participants lived. For a 500-turbine offshore wind project 10 km from shore, participants who live inland perceived almost no cost; $1 per year (2016 $) compared to $42 per year for those living on the coast. This trend was confirmed in other US states. Lamy et al. (2016) estimated the preferences for onshore compared to offshore wind projects for participants in two coastal towns in Massachusetts compared to participants from the rest of the United States. The authors find that the coastal towns were strongly opposed to the prospect of a 3-turbine offshore wind project 8 km from shore due its visual impact to the landscape. These participants had WTP values of about $13 per month, or $156 per year (2016 $), to avoid locating the project offshore instead of onshore, which was thought to be less taxing on the landscape. The US-wide sample shared this preference, but only had an average WTP value of $1.9 per month ($23 per year). Lastly, another discrete choice study by Westerberg et al. (2011) found that beach tourists in Languedoc Roussillon, France would have to receive about $60 per vacation week (in 2016 $, weighted average value by population segment tested) to compensate for the visual impact caused by a 30-turbine offshore project 8 km from shore. For simplicity, we assume that one vacation week in this location equates to one year.

In addition, Gibbons (2013) used historical home sales price data in the UK to estimate the impact to home value resulting from onshore wind development. The author finds that wind farms located within 8–14 km reduce home value by 1.6%, equivalent to a loss of $158 (2016, $) per year. Gibbons attributes these losses to the visual impacts from the nearby projects. Although these estimates are for onshore projects, we assume that the same set of preferences and values hold for offshore projects.

3. Results and discussion

In this Section, we present estimates of the "TSE social benefit premium" offered by TSE projects over offshore wind projects, compare this premium to differences in cost projections, explore how results may change depending on project size, and provide a brief description of potential ecological concerns between the two project types.

3.1. What is the "TSE social benefit premium" over offshore wind projects?

In total, TSE projects offer about $10/MW h more in net social benefits than offshore wind farms (i.e., "TSE social benefit premium"), ranging between $4.5 and $17/ MW h. Based on the estimated LCOE difference between the two technologies (Section 2.1), this value is well below the increased LCOE for TSE projects through 2050 ($74 to $330/ MW h). This suggests that offshore wind projects are likely more competitive than TSE projects for the foreseeable future, even when including the increased net social benefits of TSE.

Table 3 summarizes the net social benefits and costs between the two project types (both assumed to be 200 MW and 10 km from shore). We find that the value of energy generation for offshore projects ranged from $57 to $61/MW h across the 18 wind farms in our sample, with an average of $59/MW h, compared to $62–63/MW h for the two TSE sites. These differences reflect the differences in correlation between wholesale market prices (which were about $60/MW h on average in our dataset) and energy generation. The TSE projects we analyzed appear to have slightly higher correlation, yielding an average increased value of $3.0 /MW h. The value of reduced CO_2 emissions is about the same between the two project types, at $16.9–17.4/MW h across wind projects and $16.6–16.9/MW h for the two TSE projects. Regarding social costs, we find that offshore wind farms incur costs of $3.23/ MW h on average ($2.4–5.9/MW h across projects) due to errors in predicting energy generation. This is consistent with past literature which estimated wind predictability cost of $2–6/MW h (DeMeo et al., 2005; Lueken et al., 2012; Wiser and Bolinger, 2014). We also find that offshore projects incur social costs of about $3.85/MW h on average ($1.3 to $6.4/MW h across projects) due to visual dis-amenities.

Table 3
Net social benefits (costs) normalized by energy generated (2016 $/ MW h) of offshore wind farm compared to a tidal stream energy project (TSE) in the UK, both 200 MW and 8–10 km from shore.

	Offshore wind		TSE		Difference	
	Avg,	All projects	FoW[a]	Meygen	Avg.	All projects
Value of energy	$59.4	[$57.4 - $61.1]	$62.0	$62.9	$3.00	[$1.84 - $5.54]
Value of emission reduction	$17.1	[$16.9 - $17.4]	$16.6	$16.9	($0.37)	[($0.02) – ($0.52)]
Predictability cost	($3.23)	[($2.44) – ($5.94)]	$0[b]	$0[b]	$3.23	[$2.44 - $5.94]
Visual impact cost	($3.85)	[($1.34) – ($6.4)]	$0[b]	$0[b]	$3.85	[$1.34 - $6.4]
Net Social Benefits	$69.5		$78.6	$79.8	$9.7	[$4.5 - $17.2]

[a] FoW = Fall of Warness.
[b] Assumption to present best case for TSE.

3.2. What about smaller projects?

Our comparison so far focused only on TSE and offshore wind projects that are 200 MW. Results might be different when considering projects with fewer turbines, especially regarding visual impact. Therefore, in this section, we explore how results might change given the TSE or offshore wind project was 20 MW, equivalent to 5 offshore wind turbines. Smaller projects are particularly relevant in remote areas with less demand. For example, the first offshore wind farm in the United States consists of only 5 turbines located in the State of Rhode Island on Block Island (2016).

There is some evidence that a smaller number of wind turbines would result in lower overall perceived visual cost. Dimitropoulos and Kontoleon (2009) showed with a discrete choice experiment in Greece that an onshore project with 2–6 turbines had over 3 times the WTA (i.e., required compensation) than the same project with 21–40 turbines. However, it is not clear that this result would hold for offshore projects. Preference can be different between offshore compared to onshore wind projects and depend on the community studied (Ek and Persson, 2014; J. Lamy et al., 2016). Furthermore, as noted in our literature review in Section 2.2.5, visual costs reported in J. Lamy et al. (2016) with only 3 offshore turbines in Massachusetts ($156 per home per year) are similar to those reported in Ladenburg and Dubgaard (2009) with 49–149 turbines in Denmark ($143 per home per year). Also, Ladenburg and Dubgaard (2009) found no significance difference in preferences when varying the number of turbines from 49 to 149. Therefore, we make a simplifying assumption that total visual costs for a 5-turbine offshore project (20 MW) would be the same as for a 50-turbine project (200 MW).

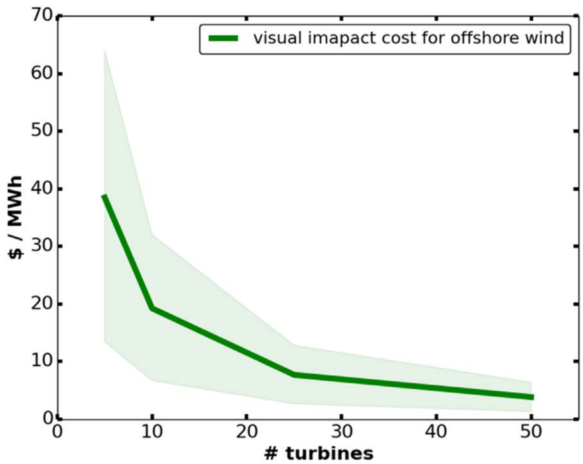

Fig. 5. Visual impact cost estimates ($ / MW h) per number of turbines (4 MW each) for an offshore wind farm located 8–10 km from shore. Shading shows high and low scenarios from Table 1 in Section 2.2.5.

Fig. 5 shows visual impact costs in $/MW h for an offshore project by number of turbines. Visual costs for a 50-turbine offshore wind project are as before, $3.85/MW h (Table 3). However, for a project with 5 turbines, normalized costs per MW h increase to $38.5/MW h due to the same (assumed) total visual cost, but less energy output. This increases the "TSE social benefit premium" to $45.5/MW h, or between $17.2/MW h and $75.5/MW h when varying assumptions from Table 1 in Section 2.2.5. This suggests that in 2020, small TSE projects could be more competitive than small offshore projects, assuming the high cost scenario for offshore wind and low cost scenario for TSE projects from Fig. 2 in Section 2.1. Note however that the base case difference in cost is still about 2–7 times the "TSE social benefit premium" from today to 2050.

3.3. Ecological impacts

We do not attempt to quantify or compare the ecological impacts between offshore wind and TSE projects, but instead provide a brief description of potential concerns noted in past literature.

Bailey et al. (2014) conducted a literature review of the environmental impacts from offshore wind projects. During the construction phase, the authors find that there is likely to be noise and vibration disturbances to marine mammals, which in Europe, mainly consist of harbor porpoises and seals. However, the construction phase is temporary and the associated impacts are unlikely to lead to mortality. Noise may also affect some fish species by disrupting communication and migration, but, as the authors point out, these effects are highly uncertain due to lack of sufficient data (Bailey et al., 2014). During operation, the biggest concern is impacts to seabirds, which risk collision with rotating blades and complications due to project avoidance. However, several studies have shown that impacts to birds are likely minimal. Cook et al. (2014) estimate that within-wind farm avoidance rates for seagulls (i.e., the percentage of birds who avoid close proximity with the project) are 99% across 20 existing wind projects in the UK (17 onshore, 3 offshore). Similarly, for a 72-turbine offshore project in Denmark, Desholm and Kahlert (2005) found that less than 1% of ducks and geese approach the project close enough to be at risk of collision. But as Stewart et al. (2007) points out, negative impact to birds may indeed be significant despite the poor evidence collected to date. Further, the authors argue that impacts are highly dependent on the species studied, sites considered, and methods used (Stewart et al., 2007).

Impacts to bats resulting from offshore projects are also of concern. Using acoustic data of bat activity in the US, Pelletier et al. (2013) find that migratory bats are equally likely to be recorded in offshore locations (up to 13 miles at sea) as onshore locations. However, the authors caution that there is still considerable uncertainty regarding the extent, pattern, and timing of offshore bat migration as well as potential interactions with offshore wind projects. More research is needed to explore risks to both birds and bats, which is made particularly challenging due to the complications of monitoring fatalities in offshore locations (Bailey et al., 2014).

Offshore wind projects may also alter marine life habitats and/or food webs (Bailey et al., 2014). However, these effects may be positive. There is evidence that man-made structures, like offshore wind or TSE turbines, can create enhanced habitats of fish species, bethnic organisms, and plants (Bergström et al., 2014; Inger et al., 2009; Langhamer, 2012; Wilhelmsson et al., 2006). However, these new habitats may also negatively disrupt existing species through the introduction of new entrants (Langhamer, 2012). Another potential benefit could result from the sheltering effect – offshore projects require minimum safe distances from turbines, which has been shown to improve marine life due to minimized boat traffic and fishing (Bailey et al., 2014).

There is little data regarding interaction between marine life and TSE projects, whose motor, rotating blades, and power electronics are fully submerged (unlike with offshore wind projects). However, several workshops have explored possible outcomes. Polagye et al. (2010) summarizes a workshop conducted by 70 experts from industry, academia, and government on the potential ecological impacts of tidal devices in the United States. The workshop participants raised concerns about potential impact to habitats, fish migration, resident fish around the TSE device, marine mammals (whales, seals, dolphins, etc.), seabirds, and overall ecosystem interactions. These impacts could result from collision risk with the rotating blades, chemical effects from the device materials, acoustic effects, electromagnetic effects, or physical interference with local habitats. The main conclusion from the workshop was that more data is required to properly evaluate environmental impacts, especially impacts to large marine mammals, which the authors caution would likely be a "show-stopper" for TSE project development (Polagye et al., 2010).

Another workshop of 105 participants was conducted by Ocean Energy Systems (OES, 2014) to evaluate best practices for monitoring environmental effects. Risk of collision/evasion for mammals and fish was the largest concern among participants. The major recommendation from the workshop was to accelerate research efforts at existing TSE sites to monitor potential adverse interactions such as collision, evasion, avoidance, and passage through the turbine (OES, 2014). There is some evidence that TSE blades rotate slow enough (25–50 rpm) to allow small sea animal to pass through unharmed, and that the use of protective fences could prevent larger animals from interacting with the TSE device (Pelc and Fujita, 2002). Polagye et al. (2014) summarize the various instruments and technologies required to improve acoustic and optical monitoring of TSE sites. One of the biggest technical challenges identified was the need for software that can efficiently collect/process data and increase compatibility across instruments. For example, Wiesebron et al. (2016) show how extreme value analysis (EVA) of acoustic data can improve monitoring.

4. Conclusions and policy implications

In this work, we estimate the net social benefits from TSE projects compared to offshore wind farms, as well as their private annualized costs (in the form of LCOE). We find that the increased net social benefits of TSE projects relative to offshore wind farms (defined as the difference in value of energy generated, marginal CO_2 emission reductions, predictability in power generation, and visual impact on the landscape) is about $10/MW h, which is too low to justify choosing TSE over offshore wind projects, both now and in the foreseeable future. The cost of TSE projects (LCOE of $177 to $507/MW h through 2050) far exceeds the that of offshore wind farms ($103 to $175/MW h). This cost difference is also reflected in current UK government support for the two technologies (i.e., CfD strike price of $136/MW h for offshore wind and $388/MW h for TSE). However, despite TSE's higher costs and similar net social benefits to offshore wind, supporting both technologies may be worth pursuing to ensure a diverse mix of renewable energy options for future development.

This paper focused only on TSE vs. offshore wind, today's prevailing marine renewable technology. However, there are other technologies that are also competing with TSE including tidal barrage, wave energy, ocean thermal energy, and – perhaps most threatening – floating offshore wind. Floating offshore turbines offer similar reductions in visual impact to TSE projects since they enable wind turbines to be located up to 200 km from shore (Myhr et al., 2014), where they are not visible (Sullivan et al., 2013). Floating offshore wind also benefits from the existing experience and cost reductions from fixed-bottom offshore projects. Furthermore, by 2020, it is expected that the LCOE of floating offshore technology will only be about 15% higher ($23/MW h) than fixed-bottom, and by 2030, only about 10% higher ($13/MW h) (median cost projections from Wiser et al. (2016). Therefore, floating offshore wind projects likely present the most economical means to reduce visual impacts of offshore wind.

Lastly, optimal project development depends on the specific site considered. We make several simplifying assumptions to better understand the overall tradeoffs between TSE and offshore wind projects. However, some sites may be better-suited for TSE, and others for offshore wind. Our analysis provides guidance to project developers and policymakers to help consider the full social benefit and cost of their siting decisions at any scale, which is critical for responsible renewable development.

Acknowledgements

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Appendix A

See Table A1

Table A1
Table of tidal stream energy (TSE) projects that are operational or in development[b].

	MW	Status	Year	Country	owner/ developer	turbines	Source
Kislaya Guba Tidal Power	1.7	existing	1968	Russian	RusHydro	RusHydro	[1]
Maine Tidal Energy	1.2	existing	2014	US	Ocean Renewable Power Company	Ocean Renewable Power Company	[1]
Meygen Tidal Stream 1A	6	existing	2016	UK	Atlantis	Andriz Hydro Hammerfest	[1]
Oosterschelde Storm Barrier	1.2	existing	2015	Netherlands	Tocardo International	Tocardo International	[1]
Sabella	1	existing	2015	France	Sabella	Sabella	[1]
Alstom - EMEC	1	existing	2013	UK	Alstom	Alstom	[1]
Bluewater Energy - EMEC	1	existing	2016	UK	Bluewater Energy	Bluewater Energy	[1]
Cape Sharp Tidal	4	existing	2016	Canada	Open Hydro	Open Hydro	[1]
Scotsrenewable - EMEC	2	existing	2016	UK	Scotrenewables	Scotrenewables	[1]
Strangford Lough	1.2	existing	2012	UK	Marine Current Turbines	MCT	[1]
Brims Tidal Array	200	in dev.	2020[a]	UK	SSE Renewable Holdings	Open Hydro	[2]
Brough Ness	100	in dev.	2020	UK	Marine Current Turbines	MCT	[2]
Digby Gut	2	in dev.	2017	Canada	Fundy Tidal	Tocardo International	[1]
Fiar Head	100	in dev.	2021	Ireland	DP Marine Energy	Deme BluePower	[2]
Holyhead Deep	10	in dev.	2022[a]	UK	Minesto	Minesto	[2]
Kvalsund Tidal Sails	3	in dev.	2017	Norway	Tidal Sails	Tidal Sails	[1]
Lashy Sound	30	in dev.	2020	UK	Scotrenewables Tidal Power	Scotrenewables Tidal Power	[2]
Magallanes - EMEC	2	in dev.	2017	UK	Magallanes Renovables	Magallanes Renovables	[1]
Meygen Tidal Stream 1B	6	in dev.	2018	UK	Atlantis	Andriz Hydro Hammerfest	[1]
MeyGen Tidal Stream phase 2B	392	in dev.	2020	UK	Meygen, Atlantis Resources	Meygen, Atlantis Resources	[2]
Minas Energy FORCE	4	in dev.	2017	Canada	Minas Energy	Tocardo International	[1]
Mull of Galloway	30	in dev.	2022[a]	UK	Marine Current Turbines	Marine Current Turbines	[2]
Mull of Kintyre, Argyll	3	in dev.	2022[a]	UK	Nautricity, Argyll	Nautricity	[2]
Mundra Tidal Farm	250	in dev.	2022[a]	India	Atlantis	Atlantis	[1]
Ness of Duncansby	100	in dev.	2022	UK	Atlantis	Andritz Hydro	[2]
Paimpol	1	in dev.	2017	France	EDF	Open Hydro	[1]
Portland Bill	30	in dev.	2022[a]	UK	Marine Current Turbines	Marine Current Turbines	[2]
Ramsey Sound, Pembrokeshire	1.2	in dev.	2022[a]	UK	Tidal Energy Limited	Tidal Energy Limited	[2]
Rystraumen Tidal Test	2	in dev.	2017	Norway	Enova SF	Flumill	[1]
Skerries, Anglesey	10	in dev.	2022[a]	UK	Marine Current Turbines	Marine Current Turbines	[2]
Sound of Islay	10	in dev.	2022[a]	UK	ScottishPower Renewables	Andritz Hydro	[2]
St David's Head, Pembrokeshire	10	in dev.	2022[a]	UK	Tidal Energy Limited	Tidal Energy Limited	[2]
Strangford Lough Array	20	in dev.	2021	Ireland	Marine Current Turbines	Marine Current Turbines	[2]
Westray South	200	in dev.	2022	UK	DP Marine Energy	–	[2]
Atlantis and DP Energy FORCE	20	under constr.	2017	Canada	Atlantis	Irvine Shipbuilding	[1]
MeyGen Tidal Stream phase 2A	86	under constr.	2017	UK	Meygen, Atlantis Resources	Atlantis Resources	[2]

[1] (4C Offshore, 2017).
[2] (The Crown Estate, 2017) and project owner/ developer websites.
[a] Estimated year, not reported by source.
[b] Table only includes tidal stream projects (not tidal barrage) that are > 1 MW and that were listed as in development, under construction, or operational. This list is only approximate to the authors' best ability at the date of publication and is subject to the very rapid and dynamic pace of the industry.

Appendix B

See Table B1

Table B1
Table of operational offshore wind projects in the UK[a].

Name	Nameplate capacity (MW) [1]	# turbines [1]	Capacity factor (%) [2]	Km to shore [3]	Year [3]	Country [1]	Nearby Towns [3]	Population [4]
Barrow	90	30	35.9	7	2006	England	Barrow-in-Furness	67,515
Beatrice	10	2	14.6	23	2007	Scotland	Buckie	8640
Blyth Offshore	3.8	2	18.0	1.6	2000	England	Blyth	37,886
Burbo Bank	90	25	34.8	7	2007	England	Crosby, Hoylake, Wallasey	124,994
Greater Gabbard	504	140	42.2	23	2012	England	Felixtowe, Harwich, Walton-on-the-Naze, Frinton-on-the-Sea, Orford, Aldeburgh, Leiston, Coldfair Green	70,214
Gunfleet Sands 1 & 2, 3	184.8	50	36.6	7	2010	England	Clacton-on-sea, Jaywick	57,371
Gwynt y Môr	576	160	31.7	17	2015	Wales	Prestatyn, Gronant, Talacre, Kinmel Bay, Abergele, Colwyn Bay, Llanddulas, Myndd Marian	67,888
Humber Gateway	219	73	41.1	10	2015	England	Easington, Holmpton, Patrington	8379
Kentish Flats	90	30	32.0	10	2005	England	Herne Bay, Whitstable, Warden, Leysdown-on-Sea	75,677
Lincs	270	75	42.0	8	2013	England	Skegness, Chapel St. Leonards	25,082
London Array	630	175	41.1	20	2013	England	Margate	64,286
Lynn and Inner Dowsing	194.4	54	33.9	5	2009	England	Skegness, Chapel St. Leonards	25,082
Methil	7	1	12.0	0.05	2013	Scotland	Methil	10,750
North Hoyle	60	30	28.6	7	2003	Wales	Prestatyn, Llanddulas, Myndd Marian	19,335
Ormonde	150	30	35.9	9.5	2012	England	barrow-in-furness	67,515
Rhyl Flats	90	25	35.4	8	2009	Wales	Kinmel Bay, Abergele, Colwyn Bay, Llanddulas, Myndd Marian	49,436
Robin Rigg	180	60	32.3	11	2010	Scotland	Seaton, Flimby, Maryport, Workington, Stainburn	39,701
Scroby Sands	60	30	34.3	2.5	2004	England	Great Yarmouth	98,667
Sheringham Shoal	316.8	88	37.4	17	2012	England	Blakeeney, Sheringham, Beeston Regis, West Runton, East Runton, Cromer	18,505
Teesside	62.1	27	36.4	1.5	2013	England	Redcar	37,211
Thanet	300	100	31.5	11	2010	England	Margate, Broadstairs, Ramsgate	130,498
Walney	367.2	102	34.7	14	2010	England	Barrow-in-Furness	67,515
Westermost Rough	210	35	45.0	10	2015	England	Withernsea, Tunstall	6363
West of Duddon Sands	389	108	42.5	15	2014	England	Barrow-in-Furness	67,515

[1] (The Crown Estate, 2017).
[2] (Energy Numbers, 2016).
[3] Estimated from map provided by (4C Offshore, 2017).
[4] 2015 population estimate from Brinkhoff (2017).
[a] Table only includes offshore wind projects that were listed as operational. This list is only approximate to the authors' best ability at the date of publication and is subject to the very rapid and dynamic pace of the industry.

Appendix C. Wind dataset and comparison with publicly available sources

Table C1 provides statistics of the data for years 2012–2014 from the commercially operational wind farms (i.e., “commercial data”) used in our analysis as well as the estimated energy value, emissions value, and predictability cost per wind farm reported in Table 3 of Section 3.1. Table C2 shows similar statistics using publicly available data for years 2012–2014 from the EMHIRES dataset (i.e., “publicly available data”), which provides hourly wind generation from 1986 to 2015 by aggregated NUTS 1 region as well as one country-wide estimate for offshore wind (Gonzalez Aparicio et al., 2016). Lastly, Table C3 compares the difference in results between the two datasets. To compute this difference, results for each site in the commercial data was subtracted from results for the corresponding UK region in the publicly available dataset.

Capacity factors for the commercial data range from 21% to 40% compared to from 12% to 28% in the publicly available data for the common regions between the two datasets. This difference is likely for two reasons: (1) the commercial projects were specifically selected in areas with high capacity factors to be financially viable, and (2) the publicly available data only provide hypothetical generation for windfarms within an entire region, not within particularly windy areas of that region. This leads to resulting energy value estimates that are $7 to $10/MW h higher for the commercial dataset, and emission reduction value estimates that are higher by a maximum of $0.5/MW h. However, even when accounting for these differences between datasets, the resulting “TSE social benefit premium” if using the publicly available data would only increase by a maximum of $10/MW h to $20/MW h, which is still well below the increased LCOE of TSE projects of $74 to $330/MW h expected through 2050 (see Section 2.1). Therefore, our conclusions are robust to using either wind dataset.

Table C1
Summary statistics of 18 commercial wind farms used in analysis.

Site ID	Region in UK	capacity factor (mean)	capacity factor (std. dev.)	energy value	emissions value	predictability cost
1	East Midlands	27.6%	27.1%	$60.8	$17.2	$2.6
2	East Midlands	26.1%	27.1%	$60.4	$17.2	$2.7
3	East Midlands	26.4%	25.4%	$61.1	$17.1	$3.2
4	East of England	24.9%	26.0%	$60.6	$17.2	$2.6
5	East of England	20.8%	21.6%	$60.9	$17.3	$3.3
6	North East	23.3%	25.8%	$59.9	$17.3	$3.1
7	North East	28.6%	29.6%	$58.8	$17.1	$2.6
8	North East	29.3%	30.9%	$60.7	$17.2	$3.4
9	North East	24.3%	24.2%	$58.9	$17.0	$3.6
10	North East	25.7%	27.2%	$57.4	$16.9	$5.9
11	Scotland	31.0%	31.1%	$59.8	$17.2	$3.6
12	Scotland	30.9%	31.0%	$59.1	$17.0	$4.8
13	Scotland	25.5%	28.8%	$57.4	$17.2	$2.7
14	Scotland	22.2%	22.3%	$57.7	$17.0	$2.4
15	Scotland	40.3%	35.0%	$57.5	$16.9	$2.5
16	Scotland	36.8%	32.1%	$58.6	$17.0	$3.6
17	Whales	31.9%	30.4%	$59.8	$16.9	$2.7
18	Yorkshire and the Humber	21.7%	25.2%	$60.6	$17.4	$2.7
MEAN		27.6%	27.8%	$59.4	$17.1	$3.2

Table C2
Summary statistics of hypothetical wind farms aggregated by NUTS 1 region from the EMHIRES dataset (Gonzalez Aparicio et al., 2016).

NUTS 1 Region	UK Region	capacity factor (mean)	capacity factor (std. dev.)	energy value	emissions value
UK_offshore		25.8%	19.0%	$50.7	$16.7
UKF	East Midlands[a]	16.6%	17.0%	$51.2	$16.9
UKH	East of England[a]	12.4%	11.3%	$51.7	$16.8
UKI	London	48.0%	37.0%	$51.4	$16.9
UKC	North East[a]	28.1%	27.7%	$50.5	$16.8
UKD	North West	11.1%	10.0%	$49.5	$16.7
UKN	Northern Ireland	43.4%	34.8%	$50.0	$16.7
UKM	Scotland[a]	14.9%	13.0%	$49.6	$16.8
UKJ	South East	3.5%	3.0%	$51.8	$16.8
UKK	South West	48.8%	35.3%	$51.2	$16.8
UKL	Wales	9.9%	8.6%	$50.3	$16.8
UKG	West Midlands	53.7%	39.9%	$50.3	$16.8
UKE	Yorkshire and the Humber[a]	16.2%	15.2%	$51.1	$16.8
MEAN		25.6%	20.9%	$50.7	$16.8

[a] UK region common to Table C1.

Table C3
Difference in results between Table C1 and Table C2 datasets.

Site ID	Region in UK	capacity factor (mean)	energy value	emissions value
1	East Midlands	11.0%	$9.7	$0.3
2	East Midlands	9.5%	$9.3	$0.4
3	East Midlands	9.8%	$10.0	$0.2
4	East of England	12.5%	$8.9	$0.4
5	East of England	8.4%	$9.2	$0.4
6	North East	-4.8%	$9.4	$0.5
7	North East	0.5%	$8.4	$0.3
8	North East	1.2%	$10.2	$0.3
9	North East	-3.8%	$8.4	$0.2
10	North East	-2.4%	$6.9	$0.1
11	Scotland	16.1%	$10.2	$0.4
12	Scotland	16.0%	$9.5	$0.1
13	Scotland	10.6%	$7.8	$0.4

(continued on next page)

Table C3 (*continued*)

Site ID	Region in UK	capacity factor (mean)	energy value	emissions value
14	Scotland	7.3%	$8.1	$0.2
15	Scotland	25.3%	$7.9	$0.1
16	Scotland	21.9%	$9.0	$0.2
17	Wales	22.1%	$9.5	$0.1
18	Yorkshire and the Humber	5.5%	$9.5	$0.5

Appendix D. Price conversion calculation

All currencies were converted to real-time 2016 levels using the consumer price indices noted in Table D1. Currencies were then converted to US dollars using the exchange rates noted in Table D2.

Table D1
Consumer price index by country (2016 = 1.0; Source = (OECD, 2017)).

	US	Denmark	Greece	Sweden	UK	France
2000	1.4	1.3	1.4	1.2	1.38	1.3
2001	1.4	1.3	1.3	1.2	1.37	1.2
2002	1.3	1.3	1.3	1.2	1.35	1.2
2003	1.3	1.2	1.2	1.1	1.33	1.2
2004	1.3	1.2	1.2	1.1	1.31	1.2
2005	1.2	1.2	1.2	1.1	1.29	1.1
2006	1.2	1.2	1.1	1.1	1.26	1.1
2007	1.2	1.2	1.1	1.1	1.23	1.1
2008	1.1	1.1	1.1	1.1	1.19	1.1
2009	1.1	1.1	1.0	1.1	1.16	1.1
2010	1.1	1.1	1.0	1.0	1.13	1.1
2011	1.1	1.0	1.0	1.0	1.08	1.0
2012	1.0	1.0	1.0	1.0	1.05	1.0
2013	1.0	1.0	1.0	1.0	1.02	1.0
2014	1.0	1.0	1.0	1.0	1.01	1.0
2015	1.0	1.0	1.0	1.0	1.01	1.0
2016	1.0	1.0	1.0	1.0	1.00	1.0

Table D2
Exchange rate by currency from March 20, 2017. (Source = (x-rates, 2017).

	USD	DKK	EURO	SKK	GBP
Currency / USD	1.00	6.92	0.93	8.82	0.81

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