Role and Value of Tidal Stream Generation in the Future UK Energy System

A REPORT FOR OFFSHORE RENEWABLE ENERGY CATAPULT

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Executive Summary

The emergence of new low-carbon technologies such as Tidal Stream (TS) generation opens opportunities to harness the full potential of renewable energy resources in UK waters. According to the Offshore Renewable Energy Catapult (ORE Catapult), the UK has potential sites to connect 6 to 17 GW of TS, supplying 21 – 60 TWh/year of electricity which is about 6% - 17% of the current annual UK electricity demand, i.e. around 350 TWh.These technologies can improve the diversity of low-carbon resources to supply the electricity demand needed by the UK and be exported to neighbouring regions to support decarbonisation in Europe and gain economic benefits through energy trading. However, TS is relatively new, and it is unclear how the penetration of such technology will impact the overall energy system and what is needed to facilitate cost-effective integration of such technologies and other technologies.

In this context, this report aims to address those questions. A spectrum of case studies considering different penetration of TS, locational constraints, different scenarios for sensitivity studies with various heat decarbonisation strategies, TS costs, interconnector capacities, system flexibility, wind profiles, access to hydrogen market and future technology improvement have been analysed to investigate the role and quantify the system benefits of TS and their drivers in the future UK net-zero energy system (2050). An integrated whole energy systems model (IWES) is used to quantify the system impacts of different scenarios. IWES is a least-cost optimisation model that can simultaneously minimise long-term investment and short-term operating costs across multi-energy systems (electricity, heating, hydrogen) from the supply side, energy network to the end-customers while meeting the required carbon targets and system security constraints.

Key findings

The key findings can be summarized as follows:

Role and value of Tidal Stream technologies

- Tidal Stream technologies provide alternative low-carbon energy sources that can be seamlessly integrated with other low-carbon technologies in the net-zero emission systems.
- While TS can be operated in synergy with other technologies, it also competes and can displace a mix of generation technologies such as offshore wind, biomass with CCS, gas and hydrogen power generation but not nuclear. The variability of TS could not replace the role of nuclear that can provide zero-carbon energy with a firm capacity and controllable to some extent. TS variability could be firmed with energy storage, but it will incur additional costs and energy losses, and therefore, it may not be cost-optimal from the system perspective.
- The gross energy system benefits of TS are around 49 – 55 £/MWh. The results indicate a cost range for TS to compete against other low-carbon technologies. The figures are system-specific and depend on the assumptions of other technologies.
- Most of the benefits are related to savings in energy infrastructure investment costs, indicating the long-term value of TS. The long-term predictability of TS energy with high accuracy also

provide certainty on its long-term benefits. This is in contrast to other renewable technologies such as wind and solar PV, whose annual energy outputs vary substantially.

- While TS affect mostly the electricity system, where most system benefits are derived, the studies also demonstrate and quantify the indirect impact of TS technologies on the hydrogen system, gas usage, and carbon removal and storage requirements. TS reduces residual emissions and volume of sequestered carbon; therefore, the costs of offsetting emissions and storing carbon become less. The results highlight the sector coupling between electricity and other system components, and therefore, the value of TS (or any new) technologies should be assessed in a holistic manner considering its impact on the whole energy system.

Drivers for Tidal Stream technologies

- The gross system benefits of TS are location specific. TS in England and Wales has around 2.5% - 4% higher value than TS in Scotland. The TS value of Scotland is slightly lower due to transmission investment requirements to transport power from Scotland to England, where the bulk of demand is located.
- The gross system benefits of TS will also depend on how the heat demand will be decarbonized in future. The benefits of TS in the pathways with high electricity demand, such as deep electrification and hybrid heating, are higher than in the hydrogen pathway.
- Lower offshore wind capacity factor intensifies the system benefits of TS and vice versa. The gross system benefits of TS with a 52% offshore wind capacity factor are 40% higher than the benefits in a system with the median wind (60% average). On the other hand, having a 64% offshore wind capacity factor will reduce the system benefits of TS by 20%.
- The gross system benefits of TS is the highest when the energy system flexibility is low. The results also suggest that the storage requirements to maximise the value of TS is relatively small from the system perspective.
- If the cost of TS is low, e.g. £40/MWh, the model proposes 20.8 GW installed capacity demonstrating that it is competitive against offshore wind and other technologies (although the LCOE of offshore wind is £35/MWh[1]) and still brings a net benefit of £0.6bn/year savings in system costs.
- Increasing interconnection capacity will reduce the gross system benefits of TS from £2bn/year to £1.7bn/year as the system flexibility increases.
- The studies considering the possibility of exporting hydrogen under various prices demonstrate that the hydrogen market may bring uncertainty on the TS deployment as it will also affect the capacity of other renewables

The work described in this report flags several areas that need to be studied in more detail in future, including:

- The role and value of TS and energy storage if a more ambitious net-zero target is taken, e.g. by 2040 instead of 2050 (considering Scotland's net-zero target by 2045).
- Further analysis of optimal generation capacity, considering not only the least-cost options but also political, sociological and commercial aspects, supply chain, and GVA creation.

[1] The model proposed around 80 GW of offshore wind by 2050.

- North Sea energy integration which involves the integration between hydrogen and electricity and multi-national energy and offshore transmission islands
- Robust deployment of TS considering uncertainty and variation of renewables profiles which vary year by year
- A potential strong synergy with other marine technologies such as tidal lagoon and wave power. Having coordinated development of marine power technologies may reduce the system integration challenges of those technologies and allow more cost-effective utilisation of the infrastructure built to support those developments.

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Abbreviation

ATR	Auto Thermal Reformer that produces hydrogen from natural gas
BECCS	BioEnergy plants with CCS. BECCS produces hydrogen or power
BEIS	Department for Business, Energy and Industrial Strategy
BF	Bottom-fixed offshore wind
CCGT	Combined Cycle Gas Turbine (natural gas)
CCS	Carbon Capture and Storage. In power generation, it refers to CCGT with CCS
CE	Continental Europe
DACCS	Direct Air Carbon Capture and Storage
DNO	Distribution Network Operators
DR	Demand response
DH	District heating
H2	Hydrogen
HP	Heat Pumps
HHP	Hybrid heating (natural gas boiler + heat pump)
IE	Ireland
IWES	Integrated Whole Energy System model
LCoE	Levelised cost of electricity
NG OCGT	Open Cycle Gas Turbine (natural gas)
ORE	Offshore Renewable Energy
OSW	Offshore Wind farms
P5/50/95	Wind profile scenarios (5: low, 50: average, 95:high)
PV	Photovoltaic
Reformer	Methane reformer (Auto Thermal) with CCS
TS	Tidal Stream

Chapter 1. Introduction

1.1 Context

The UK energy system is facing unprecedented challenges over the next few decades. Meeting the carbon emission reduction targets will require intensive expansion of low-carbon electricity generation technologies, such as renewables, nuclear and Carbon Capture and Storage (CCS) and decarbonisation of heat and transport sectors. The emergence of new low-carbon technologies such as Tidal Stream (TS) generation, besides other marine low-carbon technologies, opens opportunities to harness the full potential of renewable energy resources in UK waters. According to ORE Catapult, the UK has potential sites to connect 6 to 17 GW of TS, supplying 21 – 60 TWh/year of electricity. This is about 6% - 17% of the current annual UK electricity demand, i.e. around 350 TWh. The technologies can improve the diversity of low-carbon resources to supply the electricity demand needed by the UK and be exported to neighbourhood regions to support decarbonisation in Europe and gain economic benefits through energy trading. However, TS is relatively new, and it is unclear how the penetration of such technology will impact the overall energy system and what is needed to facilitate cost-effective integration of such technologies and other technologies.

As demonstrated in our previous work[2], the system integration cost of new technologies depends on many factors, both internal, external and system specifics. For example, it depends on the temporal availability of energy resources, penetration level, connection location, regional network strength, interconnection capacity, system flexibility, cost of system balancing, and energy demand. Previous studies indicate that system flexibility will be a key enabler for this transformation to a cost-effective low-carbon energy system. Flexibility is essential for the system that relies on variable energy sources

[2] A list of previous work is provided as follows:

- Carbon Trust, G.Strbac, D.Pudjianto,"Flexibility in Great Britain," May 2021 – Available at: https://publications.carbontrust.com/flex-gb/analysis/
- G.Strbac, D. Pudjianto, et al,"Analysis of Alternative UK Heat Decarbonisation Pathways", a report to the Committee on Climate Change, June 2018. Available at: https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Pathways.pdf
- G.Strbac, D.Pudjianto, F.Teng, D. Papadaskalopoulos, G.Davies, and A.Shakoor,"Roadmap for Flexibility Services to 2030," a report to the Committee on Climate Change, London, May 2017. Link: https://www.theccc.org.uk/wp-content/uploads/2017/06/Roadmap-for-flexibility-services-to-2030-Poyry-and-Imperial-College-London.pdf
- D. Sanders, A. Hart, M. Ravishankar, G. Strbac, M. Aunedi, D. Pudjianto, and J. Brunert, "An analysis of electricity system flexibility for Great Britain," a report to Carbon Trust, 2016.
- G.Strbac, M.Aunedi, "Whole-system cost of variable renewables in future GB electricity system," a report for Innogy, Renewable Energy Systems and ScottishPower Renewables,
- G. Strbac, M. Aunedi, D. Pudjianto, F. Teng, P. Djapic, R. Druce, A. Carmel, and K. Borkowski, "Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies," Imp. Coll. London, NERA Econ. Consult., 2015.

such as wind, solar, and tidal power. Several recent studies by Imperial College London quantified the whole-system value of flexibility in future low-carbon systems and its importance to mitigate the integration costs of low-carbon technologies (including offshore and onshore wind, solar PV, biomass, CCS and nuclear). Therefore, this study will consider a range of flexible technology options, including the use of energy storage, demand-side response (DSR) and cross-border interconnection to other systems to facilitate the integration of TS into the UK energy system.

1.1 Objectives

This study aims to provide modelling evidence to inform UK policy regarding the role and value of tidal stream power generation in the future UK low-carbon energy system and assess the cost-efficient deployment of tidal stream technologies across various energy system development scenarios. The analysis investigates how the deployment of tidal stream power will benefit the broader energy system (beyond electricity) and shape the portfolio of low-carbon energy resources, the required network and storage infrastructure, and the operational flexibility needed to facilitate cost-effective integration of the offshore wind while maintaining system security and resilient against weather extremities. A spectrum of sensitivity studies has also been performed to analyse the drivers for the tidal stream technology and the competition and synergy with other technologies.

1.2 Summary of case studies

A range of case studies has been analysed to meet the objectives and facilitate the investigation of the value of tidal stream technologies, focusing on the 2050 net zero-emission system. As a summary, the case studies look into various aspects such as:

- **Impact of TS penetration** – identifying how the value of TS changes depending on the total installed TS capacity in the system. Three scenarios are used, i.e. Low (5.9 GW), Core (11.8 GW) and High (17 GW). The results of this scenario are compared with the counterfactual, i.e. a scenario without TS.
- **Impact of TS in Scotland and England** – aiming to understand the impact of deploying TS in Scotland and England
- **Impact of heat decarbonisation strategies** using either electrification, hydrogen or hybrid approach – to analyse the impact of different electricity and hydrogen demand backgrounds on the value of TS
- **Impact of different wind profiles** – to understand the sensitivity of the TS benefits considering a year with low, medium and high wind conditions
- **Impact of system flexibility** – to analyse the flexibility requirement and how it affects the system value of TS
- **Impact of TS cost** – investigating how much TS could be deployed if the LCOE of TS is £40/MWh, £50/MWh, and £75/MWh
- **Impact of interconnectors** – to understand the role of GB electricity interconnection with Europe on the value of TS
- **Impact of hydrogen export**– to analyse the impact of enabling hydrogen export on the value of TS

- **Impact of future TS technology** – to analyse the energy system benefits of improving power coefficient of TS

The case studies are summarised in Table 1-1.

Table 1-1 List of scenarios being studied

Assumptions	Description	Core	Sensitivities
Tidal stream	Located in Scotland, Wales and South West England	11.8 GW	5.9 GW, 17 GW Constrain Scotland/England
Heat decarbonisation strategy	Domestic heat decarbonisation strategy based on three scenarios: electrification, deployment of hydrogen or Hybrid	Hybrid	H2, Electric
Wind power	Wind profiles from Met Office (P5 [low wind], P50 [median], P95[high wind])	P50	P5,P95
Level of system flexibility	Level of energy system flexibility provided by demand response and distributed storage	Medium Up to 25% demand response Up to 10 GW distributed storage	Low, High
LCoE in 2050	Levelised cost of electricity for different technologies in 2050	BF: £35/MWh FW: £35/MWh Nuclear: £60/MWh Solar: £44/MWh Onshore wind:£30/MWh Tidal: n/a	Tidal: £40, £50, £75/MWh
Interconnectors capacity	Interconnection capacity between GB and Europe (access to European electricity market)	20 GW	12 GW, 30 GW
Hydrogen export	Opening hydrogen market access outside the UK	No	Yes, with market prices of £1.6/kg H_2 and £2/kg H_2
Power coefficient	Power coefficient of tidal technology, representing conversion efficiency of the device	0.41	0.5
Carbon target	Annual carbon emissions target including emissions from power, heat, transport sectors	Net-zero by 2050	

1.3 Tidal stream scenarios

To facilitate the studies, ORE Catapult and the University of Plymouth provided the TS installed capacity, costs and locations across the GB as shown below:

Project name	Country	Array power capacity (MW)
Orkney		
Westray Firth	Scotland	260
North Ronaldsay Firth	Scotland	70
Pentland Firth		
Pentland Firth Shallow	Scotland	352
Pentland Firth Deep	Scotland	4700
Northern Ireland		
Strangford Lough	Northern Ireland	40
East Raithlin Sound	Northern Ireland	35
Raithlin Island	Northern Ireland	62
West Coast		
West Islay + Islay	Scotland	690
Kyle Rhea	Scotland	20
Mull of Kintyre	Scotland	120
Mull of Galloway	Scotland	100

Project name	Country	Array power capacity (MW)
Wales		
Holyhead (Morlais)	Wales	560
Ramsey Island	Wales	130
Uwchmynydd (Bardsey)	Wales	6
England		
Bristol Channel - Minehead	England	125
Bristol Channel - Barry & Mackenzie Shoal	England	65
English Channel		
Portland Bill	England	30
Isle of Wight	England	300
Alderney Race	Channel Islands	3600
Big Russel	Channel Islands	11
East Casquets	Channel Islands	425
West Casquets	Channel Islands	140
TOTAL (all projects)		11841

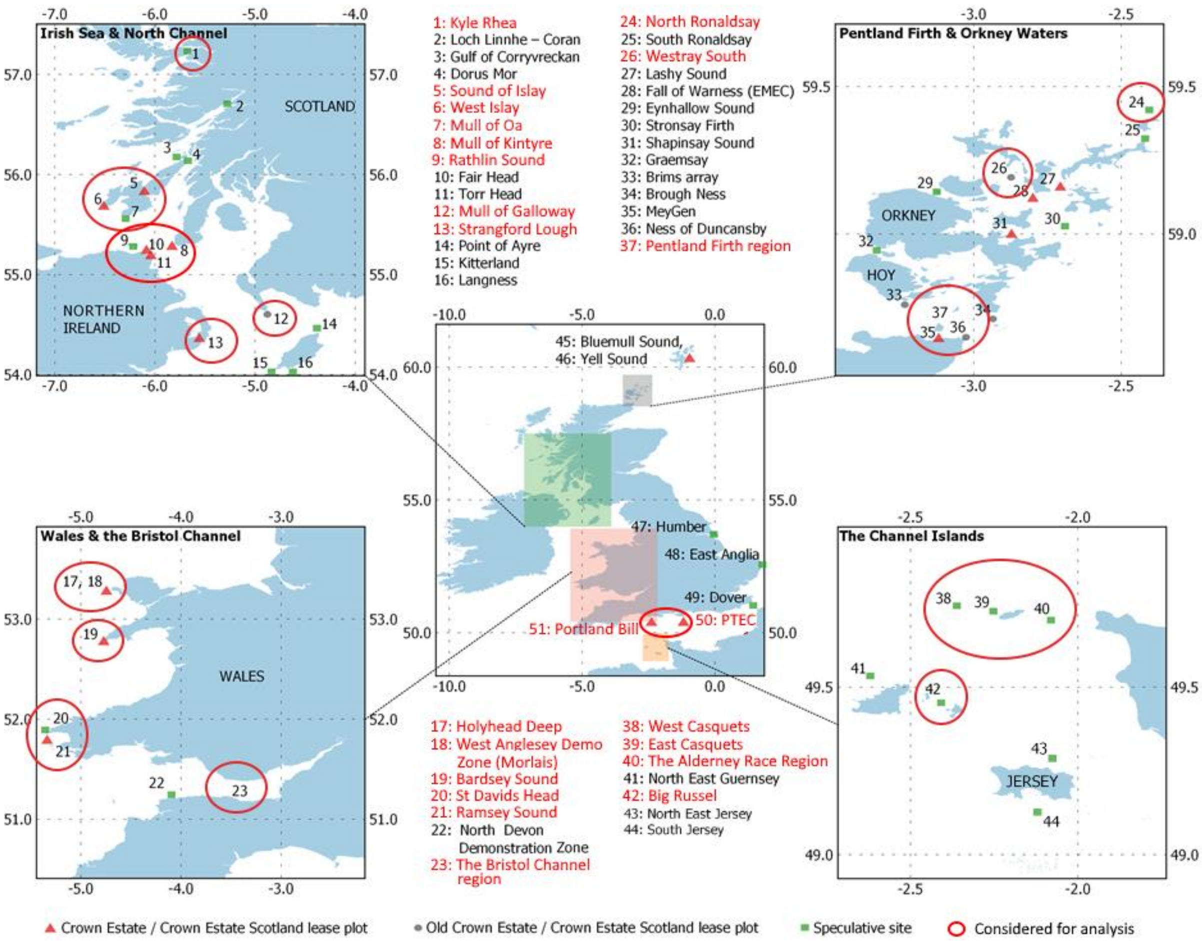


Figure 1-1 Installed capacity and locations of Tidal Stream. Sites considered for the Core scenario are shown in red.

The locations and capacities were selected according to the Carbon Trust study “UK Tidal Current Resource and Economics Study”. Published in 2011, this is the last national-level resource study that has been conducted. It provides locations and estimated annual production for about 30 sites across the UK, subject to environmental constraints.

Depth averaged tidal flow speed data with a duration of 1 month was obtained for each site from regional scale hydrodynamic models. Harmonic extrapolation was implemented to extend the data sets to 1 year duration, at 30 minute resolution. The annual flow speed data sets were used to derive the power time-series for each farm. The rated power of each farm dictated its maximum power output. The total swept area of each farm was chosen such that each farm achieved a capacity factor of 40%. A turbine cut in speed of 1 m/s was implemented. This work, carried out by the Universities of Plymouth and Edinburgh, resulted in a baseline installed capacity of 11.8GW.

The locations of TS were then mapped into 14 DNO regions modelled in the energy system optimisation tool described shortly in section 0. For each site, 10 mins output profiles were provided. The profiles were converted to one hourly resolution maintaining the maximum and minimum output of Tidal Stream each day and the daily energy output.

1.4 Summary of the approach

An integrated whole energy systems model (IWES) was used to quantify the system impacts of different scenarios. IWES is a least-cost optimisation model that can simultaneously minimise long-term investment and short-term operating costs across multi-energy systems (electricity, heating, hydrogen) from the supply side, energy network to the end-customers while meeting the required carbon targets and system security constraints. IWES also optimises the deployment of flexibility technologies such as energy storage (thermal, electricity, hydrogen), demand response technologies (e.g. smart electric vehicle charging system with and without vehicle-to-grid capability, industrial and commercial sector demand response), interconnection with Europe, electrolysers, and generation flexibility to ensure adequate generation capacity during the peak demand with low renewable outputs.

Figure 1-2 illustrates the interactions across different system components considered in IWES. Figure 1-3 shows that the model considers the energy system from the local district level to a national system and the UK and European energy systems' interactions. IWES also considers the system operational requirements such as frequency response and reserves (which has a timeframe of milliseconds to minutes), dispatch problems (hours, days or seasons), and long-term investment problems (years) simultaneously.

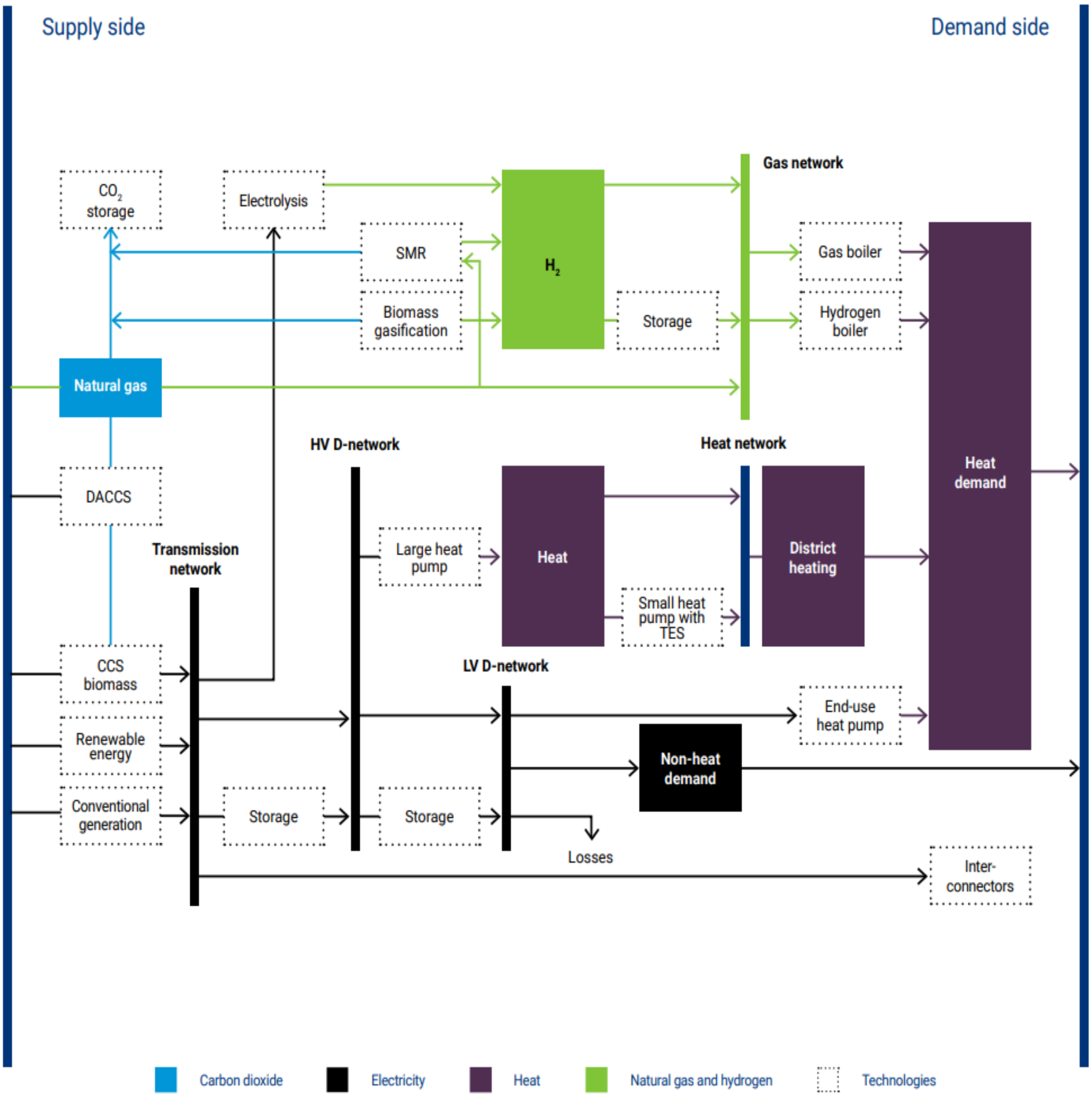


Figure 1-2 Integrated whole-energy system model

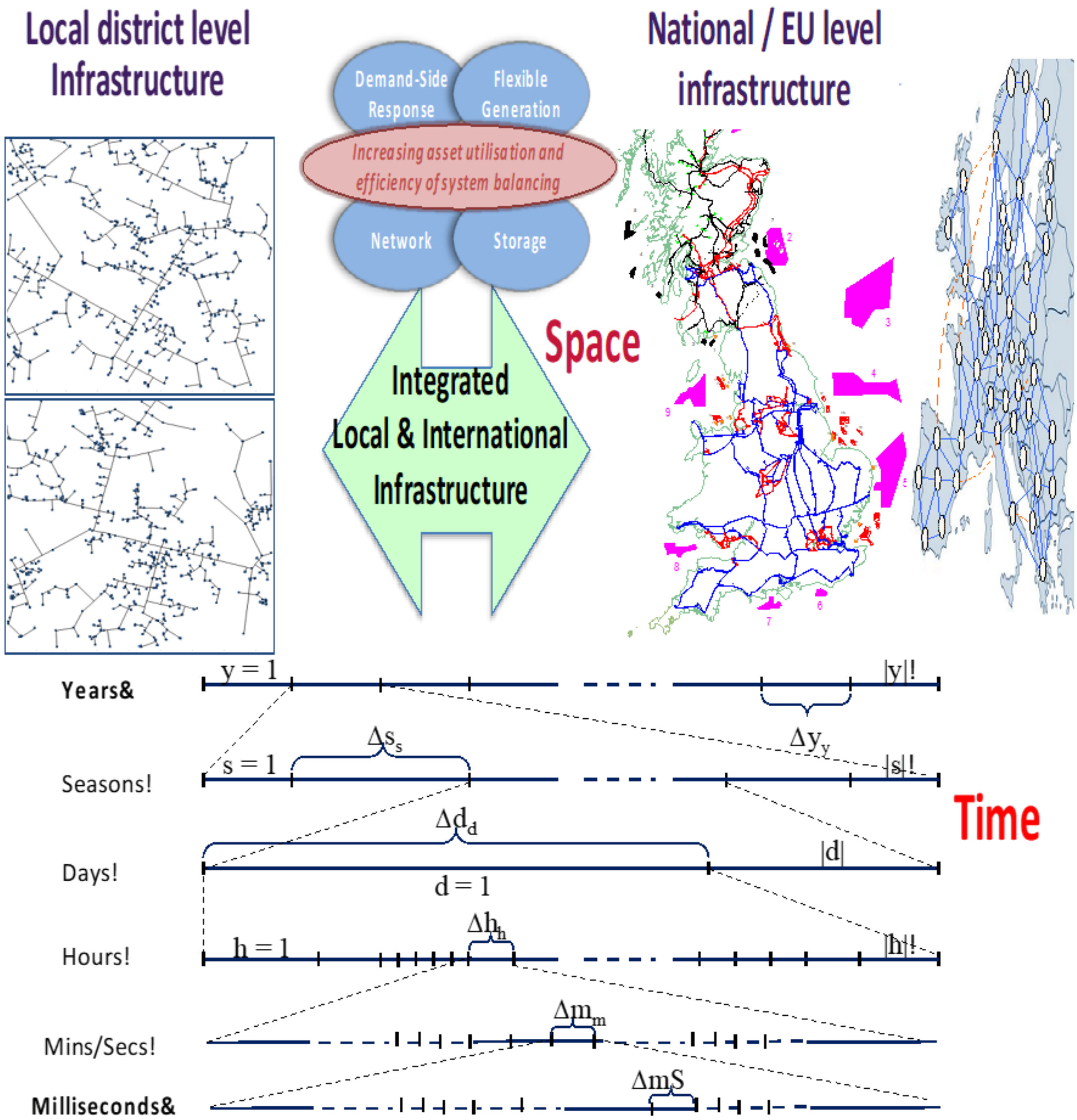


Figure 1-3 Temporal and spatial aspects considered in IWES

Annual system costs and the energy system infrastructure proposed by the model in different scenarios can be compared to analyse the factors that may influence the volume and how TS is deployed in the system. In order to identify the system benefits and implications of TS, the optimal design of the system with TS in question is compared with the design without TS. The latter will serve as a reference or counterfactual system.

A more detailed description of the model can be found in Appendix B.

Chapter 2. System Benefits and Implications of Tidal Stream

In this chapter, the results of the core scenario described in section 1.3 have been analysed. Before going into the details presented in subsequent sections, the key findings of the study are summarized as follows:

- Tidal Stream technologies provide alternative low-carbon energy sources that can be seamlessly integrated with other low-carbon technologies in the net-zero emission systems.
- While TS can be operated in synergy with other technologies, it also competes and can displace a mix of generation technologies such as offshore wind, biomass with CCS, gas and hydrogen power generation but not nuclear. The variability of TS could not replace the role of nuclear that can provide zero-carbon energy with a firm capacity and controllable to some extent. TS variability could be firmed with energy storage, but it will incur additional costs and energy losses, and therefore, it may not be cost-optimal from the system perspective.
- TS brings £2.8bn/year gross energy system savings. The gross system benefits[3] of TS are around 49 – 55 £/MWh. It can provide indicative cost figures for TS to compete against other low-carbon technologies. The figures are system-specific and depend on the assumptions of other technologies.
- Most of the benefits are Capex related, indicating the long-term value of TS.
- While TS mostly affects the electricity system, where most system benefits are derived, TS also indirectly impacts the hydrogen system, gas usage, and carbon removal and storage requirements. It highlights the sector coupling between electricity and other energy vectors, and therefore, the value of TS (or any new) technologies should be assessed in a holistic manner considering its impact on the whole energy system.

2.1 Gross benefits of Tidal Stream

The modelling results suggest that the gross system benefits of TS in 2050 are between 49 and 55 £/MWh[4]. These figures are derived from the difference between the annual system costs of a scenario with and without TS divided by the annual electricity production of TS. TS brings £2.8bn/year gross energy system savings as the annual system costs decrease from £92.6bn/year (no tidal) to £89.8bn/year (High TS deployment – 17GW) shown in Figure 2-1. As the studies use the same input data except for the level of TS, it can be concluded that the changes in how the system is designed and operated and the related costs can be attributed to TS.

3 It does not include the cost of Tidal Stream.
4 All costs are presented as real value in 2020.

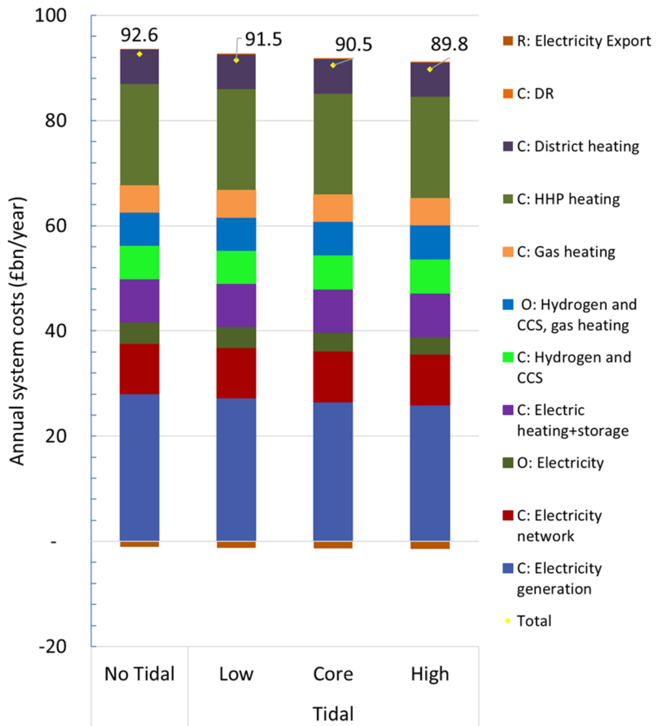


Figure 2-1 Annual system costs of various cases: No Tidal, Low (5.92 GW), Core(11.84 GW), High(17GW)

5.92 GW of TS reduces the system cost by around £1bn/year while 11.84 GW and 17 GW of TS brings £2bn and £2.738bn/year gross benefits. It is worth noting that the cost of TS is not considered in this calculation. By dividing the gross benefits with the installed capacity or the annual energy production of TS, the average gross benefits per unit of TS energy are found between 49 and 55 £/MWh. The calculation is summarised in Table 2-1.

Table 2-1 Average gross benefits of TS per unit capacity or energy

	Low	Core	High
Annual system cost (£m/year)	91,530	90,608	89,870
Gross benefits (£m/year)	1,078	2,000	2,738
TS capacity (GW)	5.92	11.84	17.00
Benefits (£/kW per year)	182.01	168.89	161.04
TS energy production (TWh)	19.50	39.01	56.01
Benefits (£/MWh per year)	55.27	51.26	48.88

The results of the studies indicate that TS in 2050 could be competitive if its LCOE is lower than £48.88/MWh - £55.27 MWh. Lower LCOE provides a net system benefit, while a higher LCOE increases the system cost. The modelling results also suggest that the benefits of TS will decrease with the increased penetration of TS in the system. Alternative technologies with the highest cost will be removed first to maximise the impact of TS and minimise the costs. The value of the subsequent TS capacity will tend to be lower.

2.2 System impact of TS

By comparing the cost of each system component optimised by IWES for the system with and without TS, the impact of TS on different system component costs are identified, as shown in Figure 2-2. The positive changes mean additional system costs and the negative changes mean cost savings due to TS.

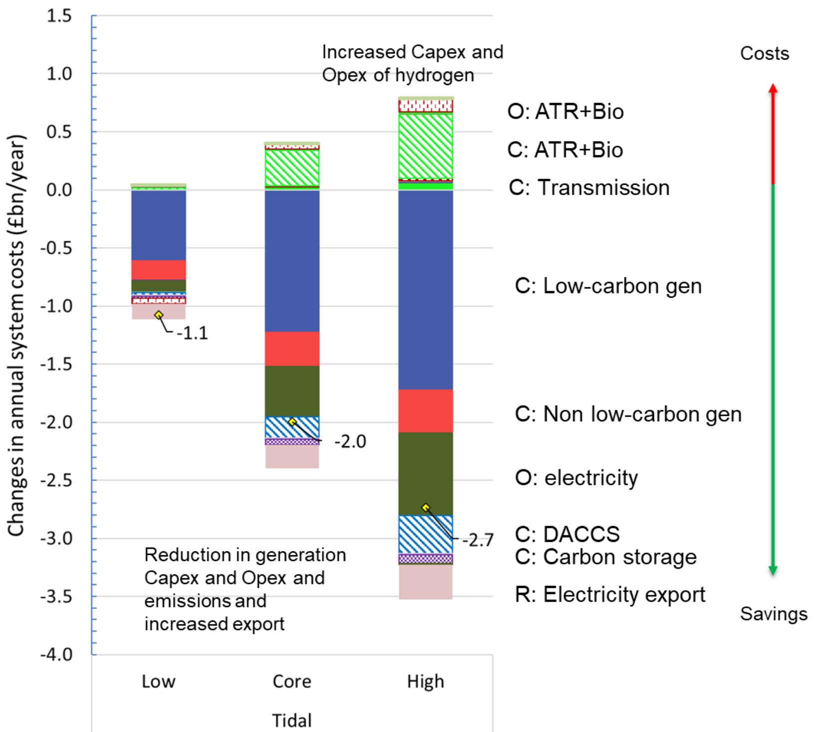


Figure 2-2 The changes in annual system costs attributed to TS

The modelling results demonstrate that TS reduces:

- The generation Capex (both low and non-low carbon technologies) by 0.6 – 1.7 £bn/year depending on low/core/high scenarios. This will be discussed in more detail in section 2.3. It is worth reiterating that TS Capex is not considered in this study;
- Electricity Opex due to less gas and biomass fuel usage in the electricity sector will also be discussed in section 2.3.
- Capex of carbon removal technologies such as DACCS and Capex of carbon storage - the results indicate that the indirect impact of TS in these cases is to reduce residual emissions and sequestered carbon; therefore, the costs of offsetting emissions and storing carbon become lower.

In addition, TS also increases the revenue from exporting electricity from GB to Europe.
On the other hand, some system costs increase, for example:

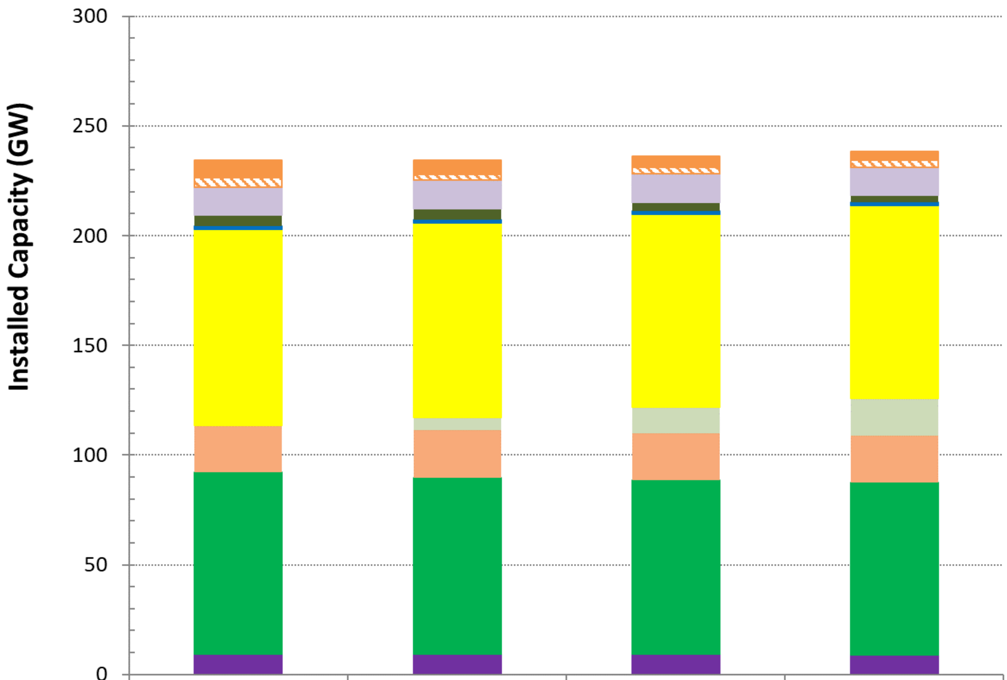
- Capex of transmission by around £0.1bn/year due to the locations of TS
- Capex and Opex of hydrogen production technologies from gas and biomass due to a shift from biomass for electricity to hydrogen production; this will be discussed in the next section.

The analyses above indicate the system components affected by TS penetration. It is worth highlighting that most of the TS impacts are related to savings in energy infrastructure investment costs (Capex related), indicating the long-term value of TS. Savings in Opex are between 13% and 22% of the total TS energy system benefits.

2.3 Impact of TS on the power generation mix

As shown in the previous figure, the largest impact of TS is on the costs of electricity generation, indicating some changes in the optimal generation mix proposed by the model. The optimal mix for different cases are shown in Figure 2-3, and the changes in power generation capacity due to TS are depicted in Figure **2**-**4**. The modelling results suggest the following:

- TS can substitute a mix of generation technologies such as offshore wind (the most affected), PV, biomass CCS, hydrogen CCGT (H2 CCGT) and conventional CCGT using natural gas (NG CCGT). Since TS can displace thermal generators, the model indicates that TS has a 20% - 30% capacity value based on the ratio of displaced thermal generator capacity and TS installed capacity. The result should be taken cautiously because the core study assumes certain flexibility from demand response and distributed storage, which helps improve the capacity credit of variable renewable generation.
- Consequently, the annual electricity production from the technologies displaced by TS becomes less. The results are shown in Figure 2-5. The reduction is high on offshore wind and biomass (with CCS). This reduction allows TS energy to be absorbed by the system demand. There is also a reduction in the use of NG CCGT. These reductions lead to the electricity Opex reduction, as discussed earlier in section 2.2.
- TS is not a substitute for nuclear power generation. Even with a high TS penetration (17 GW), the reduction in nuclear capacity is very modest, i.e. around 0.2 GW. The results indicate that the model does not suggest that TS displace nuclear's role as a baseload low-carbon generation and firm capacity.



	No Tidal	Low	Core	High
		Tidal		
NG CCGT	8.1	6.6	4.9	4.0
H2 CCGT	4.2	2.7	3.0	3.3
Storage	12.7	12.7	12.7	12.7
Biomass CCS	5.2	5.1	4.0	3.2
Hydro	1.5	1.5	1.5	1.5
PV	89.3	88.7	88.1	88.0
TS	-	5.9	11.8	17.0
Onshore Wind	21.5	21.7	21.5	21.4
Offshore Wind	82.7	80.3	79.1	78.4
Nuclear	9.3	9.3	9.3	9.1

Figure 2-3 Optimal generation portfolio in the scenarios without and with TS

The volume of energy storage proposed by the model in all scenarios considered here is 12.7 GW. It consists of 10 GW new distributed electricity storage and 2.7 GW existing Pumped Hydro Electricity Storage. The impact of TS on the energy storage requirements is discussed further in section 3.4.

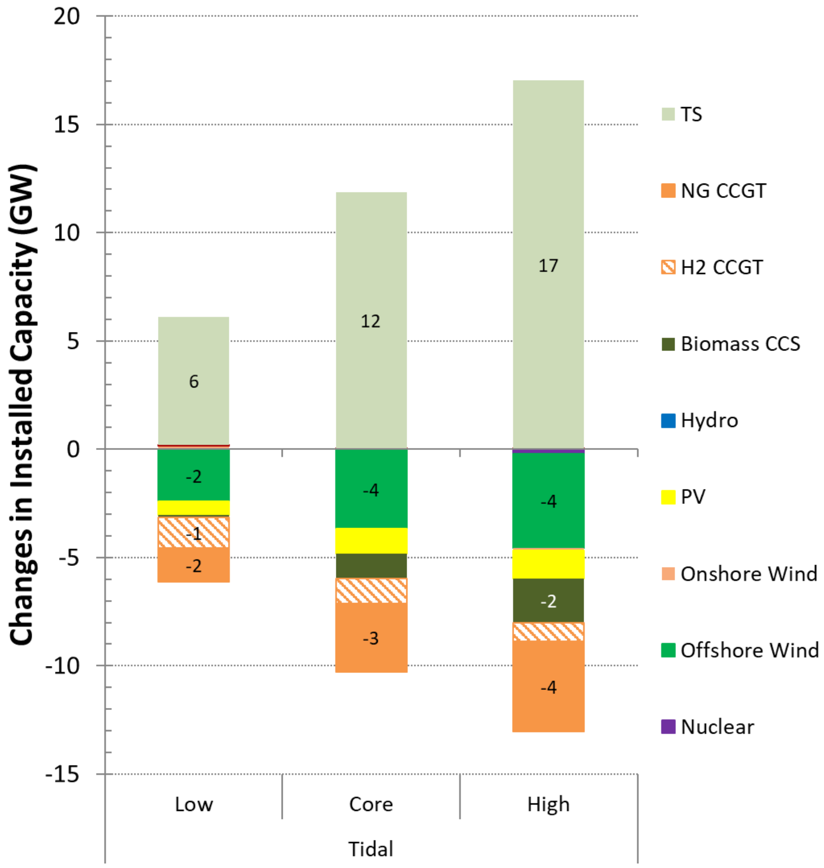


Figure 2-4 Changes in power generation capacity due to TS

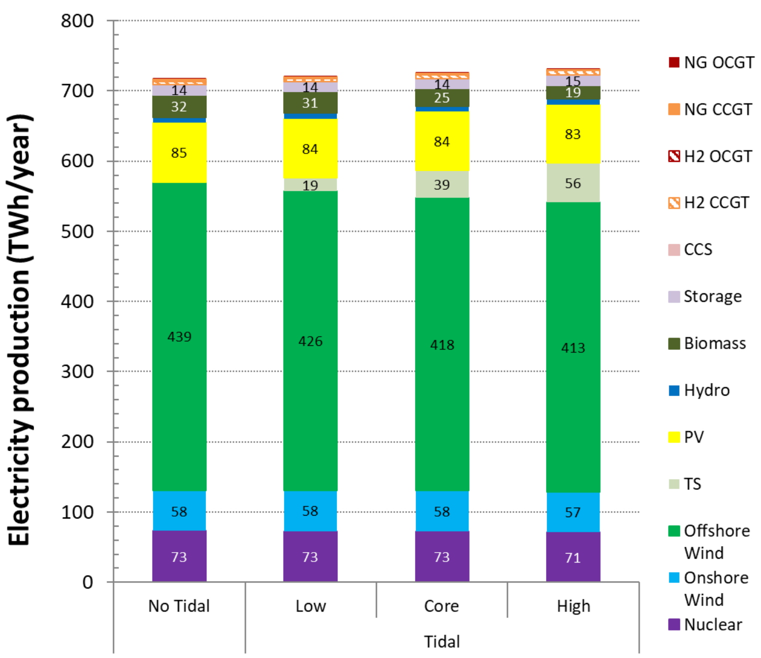


Figure 2-5 Impact of TS on the annual electricity production

2.4 Impact of TS on electricity demand

The impact of TS on electricity demand is relatively modest. The annual electricity demand for various sectors covered in the model is shown in Figure 2-6. The modelling results demonstrate that the TS does not incentivise more electricity usage for heating in the hybrid heating scenario. The annual heat supply from various heat appliances is shown in Figure 2-7.

Increased electricity demand is observed only for hydrogen production processes as there is a shift from biomass for power to biomass for hydrogen and increased electricity export. In the scenarios studied, TS does not trigger more electrolysers nor substantially increase electricity storage activities. It is worth noting that the model optimises the storage usage and uses the electricity directly rather than storing it first to reduce energy conversion and efficiency losses.

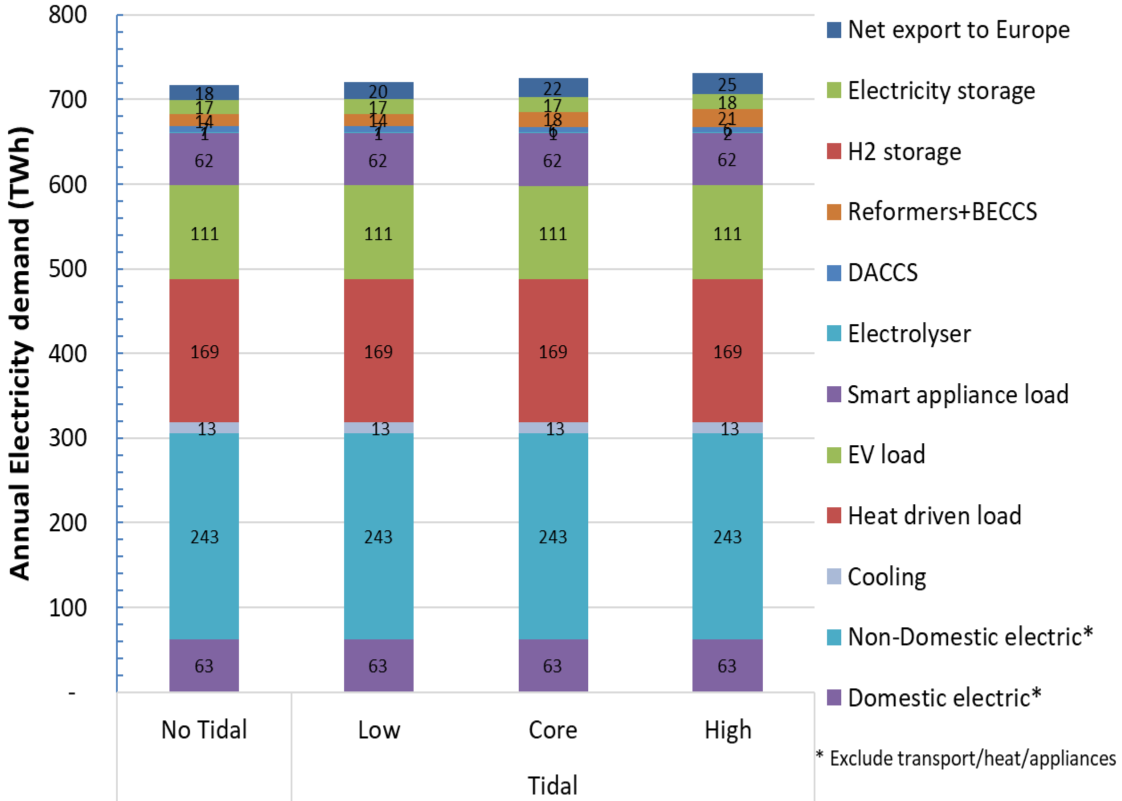


Figure 2-6 Annual electricity demand

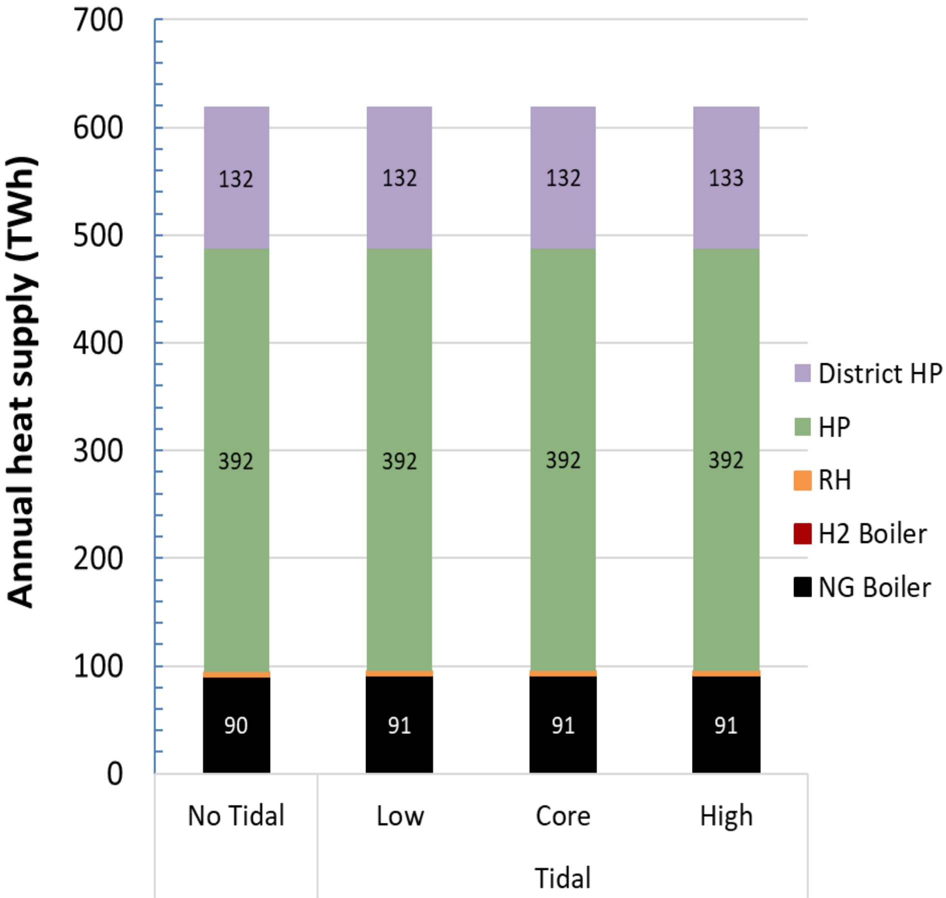
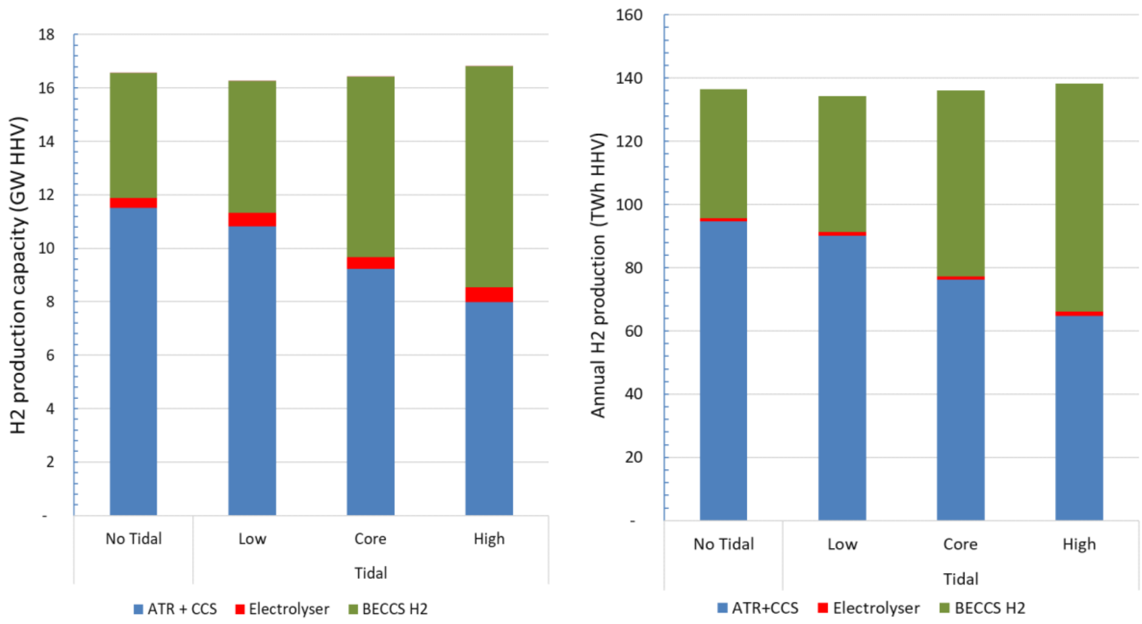


Figure 2-7 Annual heat supply from various appliances

2.5 Impact of TS on hydrogen production

The impact of TS on hydrogen production is driven by the shift of biomass from producing electricity to hydrogen. The shift allows TS energy to be integrated into the electricity system, but as the bioenergy is needed to offset emissions, the shift to hydrogen reduces the hydrogen production from the Auto Thermal Reforming process (ATR) with CCS. It reduces natural gas consumption for hydrogen production.

The modelling results highlight the cross-sector impact of TS.



(a) Hydrogen production capacity (b) Annual hydrogen production

Figure 2-8 Annual hydrogen production capacity under different scenarios

Due to the cost assumptions and scenario used in this study, the volume of green hydrogen (i.e. hydrogen produced from renewable energy) is relatively small. The results indicate that the cost of green hydrogen is relatively higher than the hydrogen production from methane via ATR+CCS or bioenergy with CCS (BECCS H2). As the system in these scenarios has relatively sufficient flexibility from energy storage, interconnection, and demand flexibility, the need for using electrolysers to reduce renewable curtailment and provide energy system balancing is relatively low.

2.6 Impact on emissions and carbon stored

The modelling assumption for all scenarios is net-zero emissions of the GB system by 2050. This means that there is a requirement for carbon-negative and carbon-removal technologies to balance emissions from hard to decarbonise sectors and heat.

By reducing gas consumption and shifting biomass to produce hydrogen instead of electricity, there is a reduction in the volume of carbon emissions offset by DACCS from 21 MtCO2/year in “No Tidal” to 18 MtCO2/year in “High”. It reduces DACCS required capacity and its associated Capex, as discussed earlier in section 2.2.

The results are shown in Figure 2-9, which shows the carbon emissions from different sectors. The positive value refers to the residual emissions from hard-to-decarbonise sectors (including aviation, shipping, waste, agriculture, land use, other fuels used in transport, rail demand and some industrial processes), methane reformers producing hydrogen, and unabated gas heating (natural gas boilers). The negative value comes from carbon-negative technologies such as bioenergy (biomethane and hydrogen production via biomass gasification with CCS) and carbon-removal technologies such as DACCS. The emissions from the electricity sector include emissions from all generation technologies, primarily from unabated fossil-fuel plants such as CCGT and OCGT without CCS, gas CCS, and biomass with CCS.

There is also a saving in the volume of carbon captured, with 6Mt CO_2/year reduction – a decrease from around 92 $MtCO_2$/year ("No Tidal) to 86 $MtCO_2$/year ("High") - due to the reduction in gas consumption, less usage of DACCS, and more efficient carbon capture in hydrogen production processes. These results shown in Figure 2-10 may not be a direct impact of TS but a cascading impact due to the shift of biomass from power to hydrogen production. However, this impact should be considered and accounted for as the impact of TS.

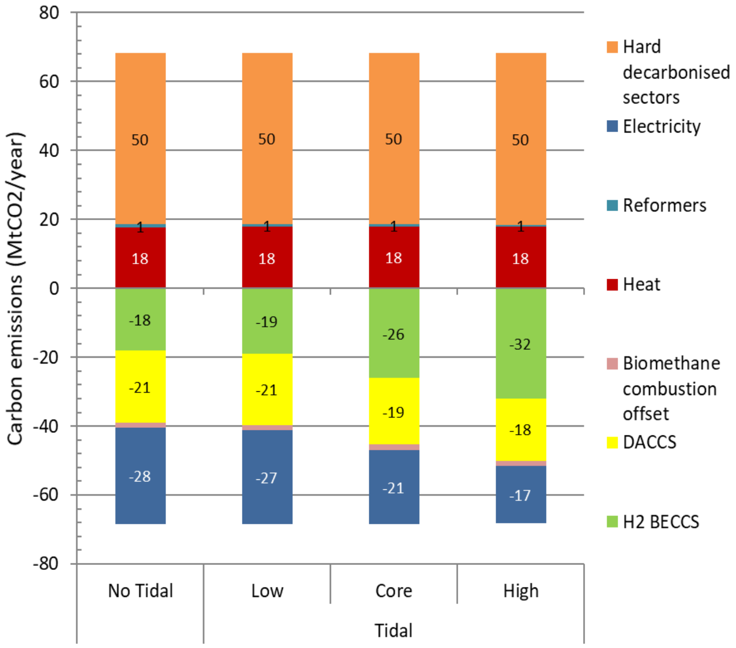


Figure 2-9 Residual emissions and carbon offsets from different sectors

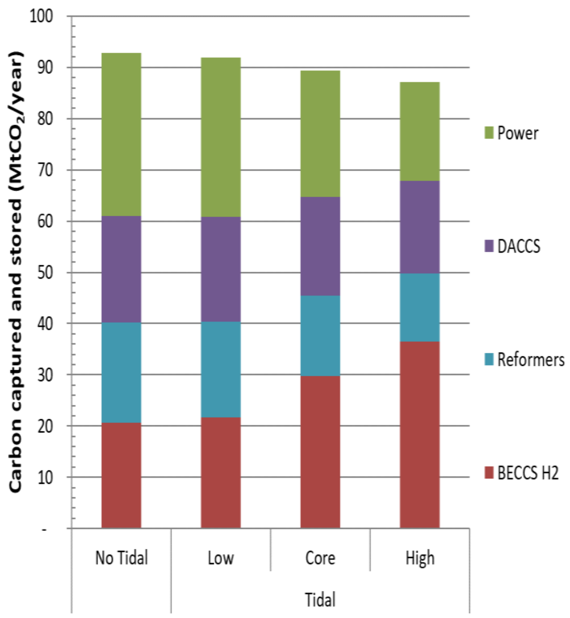


Figure 2-10 Volume of carbon captured and stored in different cases

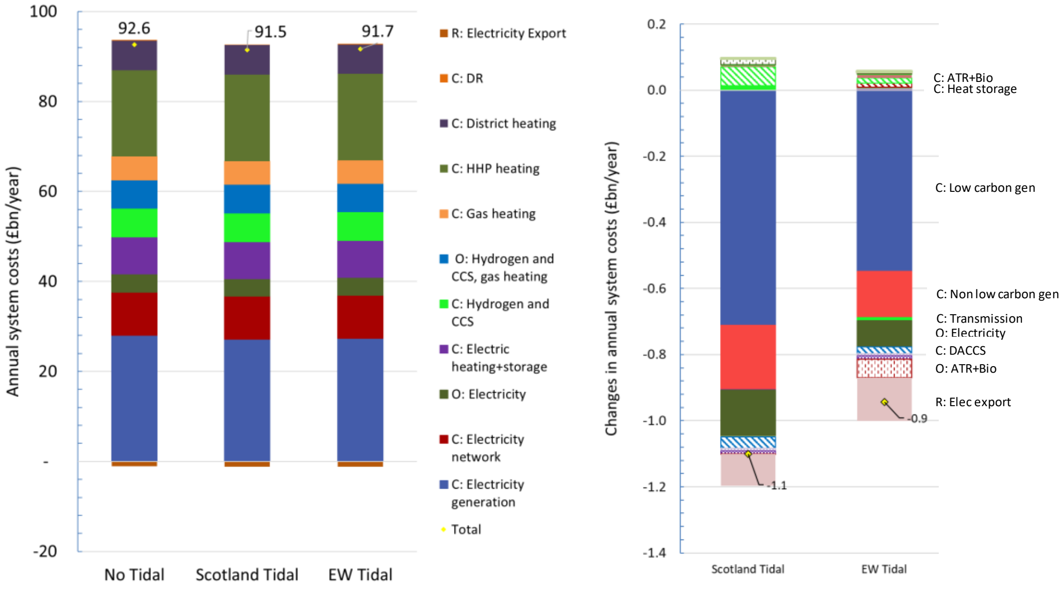
Chapter 3. Value Drivers for Tidal Stream

A spectrum of sensitivity studies has been performed and analysed to identify and understand the implications of having different assumptions or scenarios on the value of TS. Before going to more details, the key findings of the analyses are summarized below:

- The gross system benefits of TS are locational specific. TS in England and Wales has around 2.5% - 4% higher value than TS in Scotland. The TS value of Scotland is slightly lower due to transmission investment requirements to transport power from Scotland to England, where the bulk of demand is located.
- The gross system benefits of TS will also depend on how the heat demand will be decarbonized in future. The benefits of TS in the pathways with high electricity demand, such as deep electrification and hybrid heating, are higher than in the hydrogen pathway.
- Lower offshore wind capacity factor intensifies the system benefits of TS and vice versa. The gross system benefits of TS with a 52% offshore wind capacity factor are 40% higher than the benefits in a system with the median wind (60% average). On the other hand, having a 64% wind capacity factor will reduce the system benefits of TS by 20%.
- The gross system benefits of TS is the highest when the energy system flexibility is low. The results also suggest that the storage requirements to maximise the value of TS is relatively small from the system perspective.
- If the cost of TS is low, e.g. £40/MWh, the model proposes 20.8 GW installed capacity demonstrating that it is competitive against offshore wind and other technologies (although the LCOE of offshore wind is £35/MWh) and still brings a net benefit of £0.6bn/year savings in system costs.
- Increasing interconnection capacity will reduce the gross system benefits of TS from £2bn/year to £1.7bn/year as the system flexibility increases.
- The studies considering the possibility of exporting hydrogen under different prices demonstrate that the hydrogen market may bring uncertainty on the TS deployment as it will also affect the capacity of other renewables.

3.1 Impact of TS deployment in Scotland, England and Wales

The value of TS is locational specific. For example, the average gross value of TS deployed in Scotland is £51.55/MWh, but slightly higher in England and Wales, £53.39/MWh. These numbers were derived using the same approach as described previously. Two cases were analysed; the first case only considers 6 GW TS in Scotland, and the second case considers 5 GW TS in England and Wales. The annual system costs of those two cases and the counterfactual are shown in Figure 3-1(a). The difference between the costs of those two cases against the counterfactual is shown in Figure 3-1(b).



(a) Annual system costs (b) Changes in annual system costs

Figure 3-1 System benefits of Tidal Stream deployed in Scotland or England and Wales

Table 3-1 shows the numbers used in calculating the gross benefits of TS in those cases.

Table 3-1 Average gross benefits of TS per unit capacity or energy

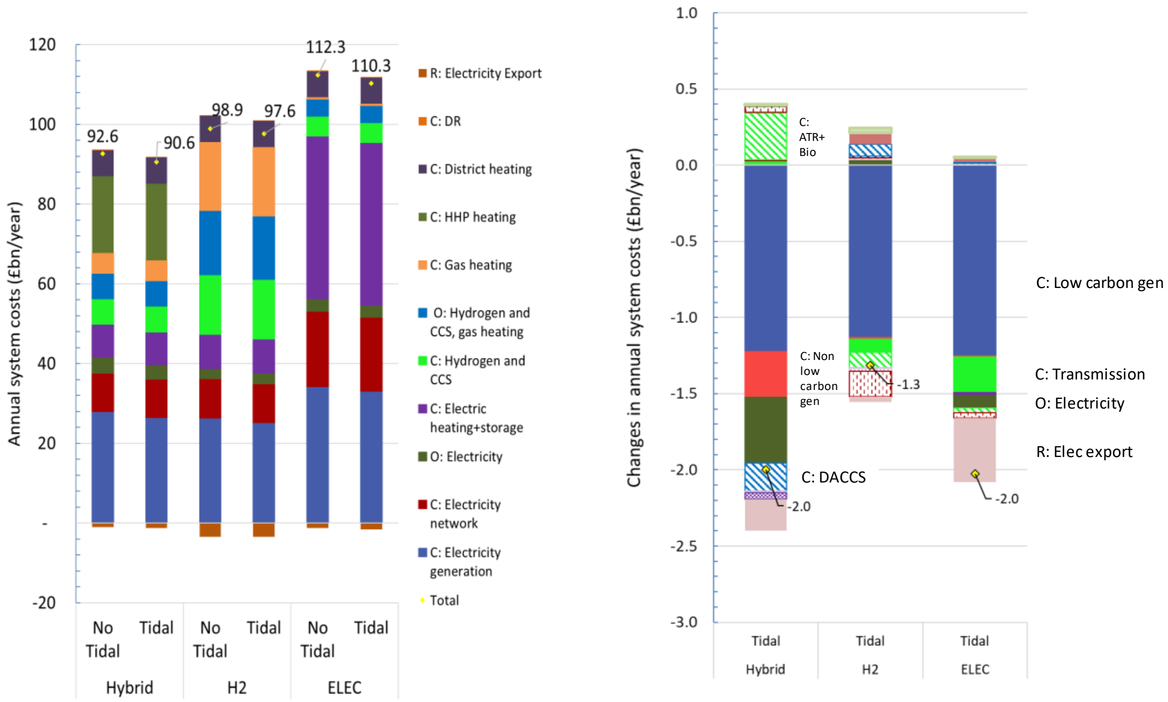
	TS Scotland	TS England and Wales
Annual system cost (£m/year)	91,508	91,665
Gross benefits (£m/year)	1,100	943
TS capacity (GW)	6	5
Benefits (£/kW per year)	170.57	174.85
TS energy production (TWh)	21.34	17.66
Gross benefits (£/MWh per year)	51.55	53.39

The modelling results suggest that the impact of TS in Scotland or England and Wales are very similar, with the most impact in the savings in electricity generation cost. For England and Wales, the effect is to slightly reduce transmission cost, while there is a slight increase in transmission cost for Scotland. The value of TS in Scotland can also be slightly lower than in England and Wales due to a higher installed capacity. As discussed in the previous chapter, the value of TS declines with increased installed capacity, so it is expected that the locational specific difference should be lower. Nevertheless, the results -shown in Figure 3-1(b) - demonstrate the different system implications of TS depending on their locations.

3.2 Gross benefits of Tidal Stream in different heat decarbonisation scenarios

The value of TS is also energy system specific depending on how the system will develop in future. One of the key factors that influence the shape of the future system is how heat demand will be decarbonised. The impact of TS on three systems with different heat decarbonisation scenarios are considered: hybrid heating (the core scenario), hydrogen (H2), and electrification (ELEC). Depending on the selected scenario, the composition of electricity, hydrogen, and gas demand will differ, affecting the optimal energy infrastructure and operation requirements and the system benefits of TS.

The modelling results suggest that TS brings energy system savings in all three future scenarios with different heat decarbonisation strategies. However, the benefits of TS will vary depending on the adopted heat decarbonisation pathway. The annual system costs of “No Tidal” and “Tidal” cases for each scenario are shown below in Figure 3-2(a). The benefits of TS in hybrid heating (HHP-NG) and deep electrification (ELEC) are similar, around £2bn/year, while TS benefits in the hydrogen pathway (H2) is much less, i.e. £1.3bn/year –due to much lower electricity demand as the majority of heat demand is supplied by hydrogen. The system benefits of TS can be seen in Figure 3-2(b).



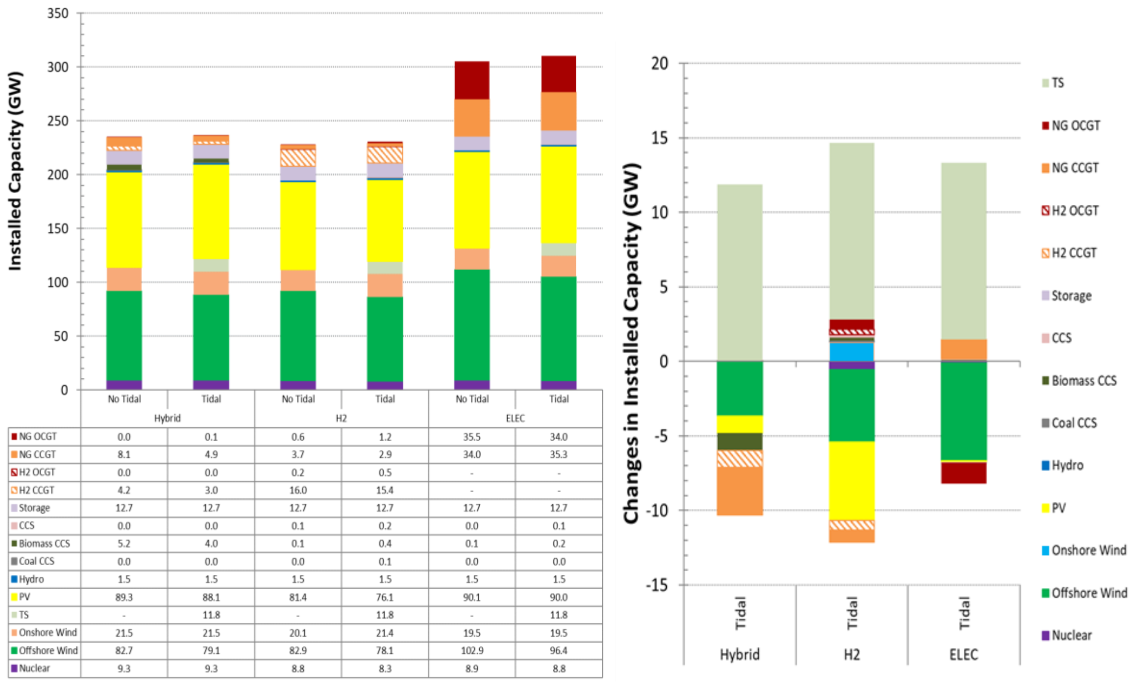
(a) Annual system costs

(b) Impact of TS on system costs

Figure 3-2 System benefits of TS in different heat decarbonisation pathways

In all pathways, the main benefit of TS is the reduction in generation CAPEX, which is largely expected as the capacity of TS will reduce other generation capacities, as discussed in section 2.3. However, there are also some differences; in H2 and ELEC scenarios, there are some savings associated with transmission costs but fewer savings in electricity Opex than those in Hybrid. In H2, there are savings associated with Capex and Opex of hydrogen production using ATR with CCS, but the Capex of electrolysers and DACCS increase. In ELEC, the impact on the hydrogen system is marginal, but TS’s inclusion will increase further electricity export to Europe. The results highlight the complex interactions across all energy system components that should be considered holistically to minimise overall costs.

Inserting 11.8 GW of TS will change the optimal generation portfolio proposed by the model. Figure 2-16(a) shows the installed capacities of each generation technology in different scenarios, while the changes in generation capacity after inserting the TS generation are shown in Figure 3-3(b). It is interesting to observe that the generation capacities that TS can displace are different in each scenario. However, the savings in the Capex of low-carbon generation are relatively similar.



	Hybrid		H2		ELEC	
	No Tidal	Tidal	No Tidal	Tidal	No Tidal	Tidal
NG OCGT	0.0	0.1	0.6	1.2	35.5	34.0
NG CCGT	8.1	4.9	3.7	2.9	34.0	35.3
H2 OCGT	0.0	0.0	0.2	0.5	-	-
H2 CCGT	4.2	3.0	16.0	15.4	-	-
Storage	12.7	12.7	12.7	12.7	12.7	12.7
CCS	0.0	0.0	0.1	0.2	0.0	0.1
Biomass CCS	5.2	4.0	0.1	0.4	0.1	0.2
Coal CCS	0.0	0.0	0.0	0.1	0.0	0.0
Hydro	1.5	1.5	1.5	1.5	1.5	1.5
PV	89.3	88.1	81.4	76.1	90.1	90.0
TS	-	11.8	-	11.8	-	11.8
Onshore Wind	21.5	21.5	20.1	21.4	19.5	19.5
Offshore Wind	82.7	79.1	82.9	78.1	102.9	96.4
Nuclear	9.3	9.3	8.8	8.3	8.9	8.8

(a) Optimal generation capacity

(b) Changes in optimal generation capacity

Figure 3-3 Optimal generation portfolio for each scenario and the changes in generation mix due to TS

The modelling results also indicate that TS may drive the shift between different generation technologies. For example, more onshore wind, biomass, hydrogen and natural gas OCGT are needed in H2 with TS while replacing more nuclear, offshore wind and PV capacity.

3.3 Gross benefits of Tidal Stream in a system with different wind profiles

In the 2050 scenarios used for the analysis, offshore wind is the largest electricity source. An increased amount of variable energy sources means that the system must be designed to withstand different wind conditions. In this case, the system benefits of TS are evaluated with three different wind profiles: P5 (low), P50 (median), and P95 (high), representing wind profiles in a period with low, average, and high wind output. Based on the wind profile data from Met Office and ORE Catapult, the offshore wind capacity factors in P5, P50 and P95 are 52%, 60%, and 64%, respectively.

The modelling results demonstrate that the system savings attributed to TS are higher in P5 than in P50 and decrease further in P95. The results are shown in Figure 3-4.

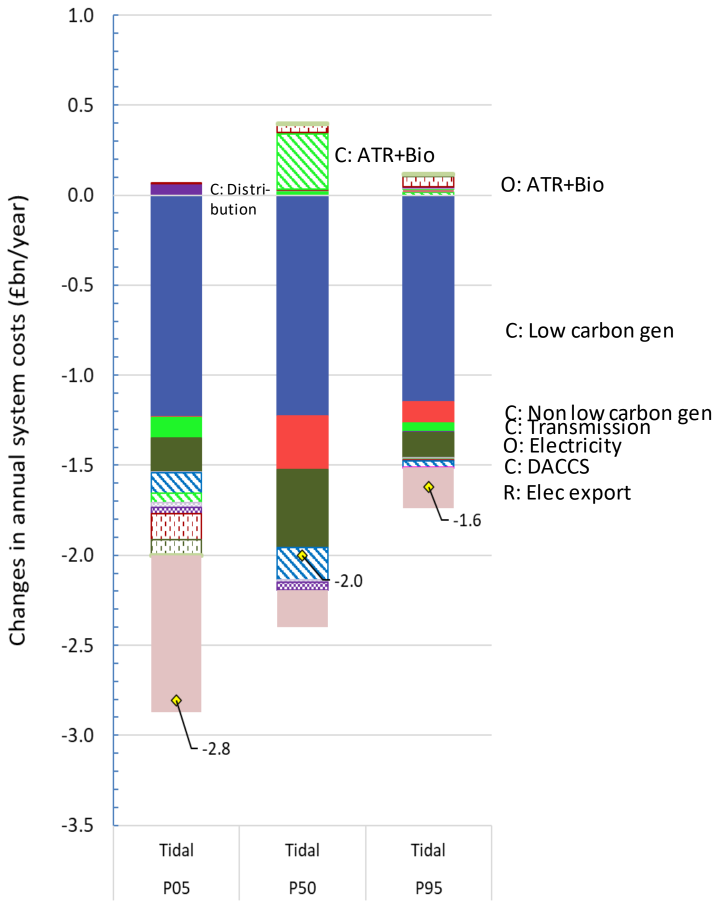
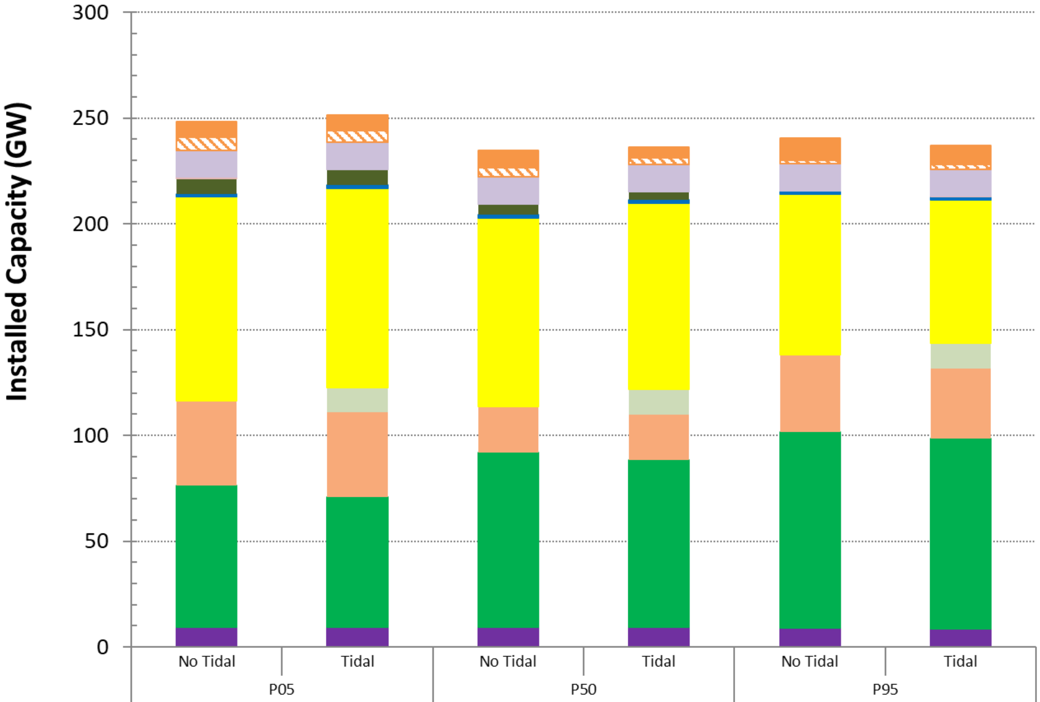


Figure 3-4 Optimal generation portfolio as modelling results for scenarios with 65 GW to 150 GW offshore wind installed capacity

Lower offshore wind capacity factor intensifies the system benefits of TS and vice versa. The gross system benefits of TS with a 52% capacity factor are 40% higher than the benefits in a system with the median wind (60% average). With a lower wind capacity factor, the competitiveness of TS relative to wind increases. Besides the savings in generation Capex, the second largest savings are in the increased revenue for exporting electricity. A lower wind capacity factor will drive other renewables such as PV. PV output peaks in summer when the electricity demand is relatively low. Therefore, as TS output is not strongly seasonal, this will increase electricity export, especially during summer. It is worth highlighting that in P5, the installed generating capacity must be higher to offset the lower capacity factor, and the inclusion of TS allows more electricity export. The optimal generation capacity for each case is shown in Figure 3-5.

On the other hand, having a 64% wind capacity factor will reduce the system benefits of TS by 20%.



	P05 No Tidal	P05 Tidal	P50 No Tidal	P50 Tidal	P95 No Tidal	P95 Tidal
NG CCGT	7.3	7.3	8.1	4.9	10.5	8.7
H2 CCGT	6.0	5.7	4.2	3.0	1.5	2.2
Storage	12.7	12.7	12.7	12.7	12.7	12.7
CCS	0.7	0.2	0.0	0.0	0.0	0.1
Biomass CCS	7.2	7.2	5.2	4.0	0.0	0.1
Hydro	1.5	1.5	1.5	1.5	1.5	1.5
PV	96.4	94.2	89.3	88.1	76.0	68.0
TS	-	11.8	-	11.8	-	11.8
Onshore Wind	40.0	40.0	21.5	21.5	36.5	33.3
Offshore Wind	67.1	61.6	82.7	79.1	92.8	89.7
Nuclear	9.3	9.3	9.3	9.3	8.9	8.7

Figure 3-5 Optimal generation portfolio for cases with different wind profiles

3.4 Impact of flexibility on the value of TS

The emergence of smart building energy management systems, smart appliances, smart EV charging systems, vehicle-to-grid (V2G), and distributed storage opens opportunities to increase the system flexibility to follow renewable outputs and alleviate the system operation challenges in balancing supply and demand. Improving flexibility will reduce the system integration costs of renewables and minimise the overall cost.

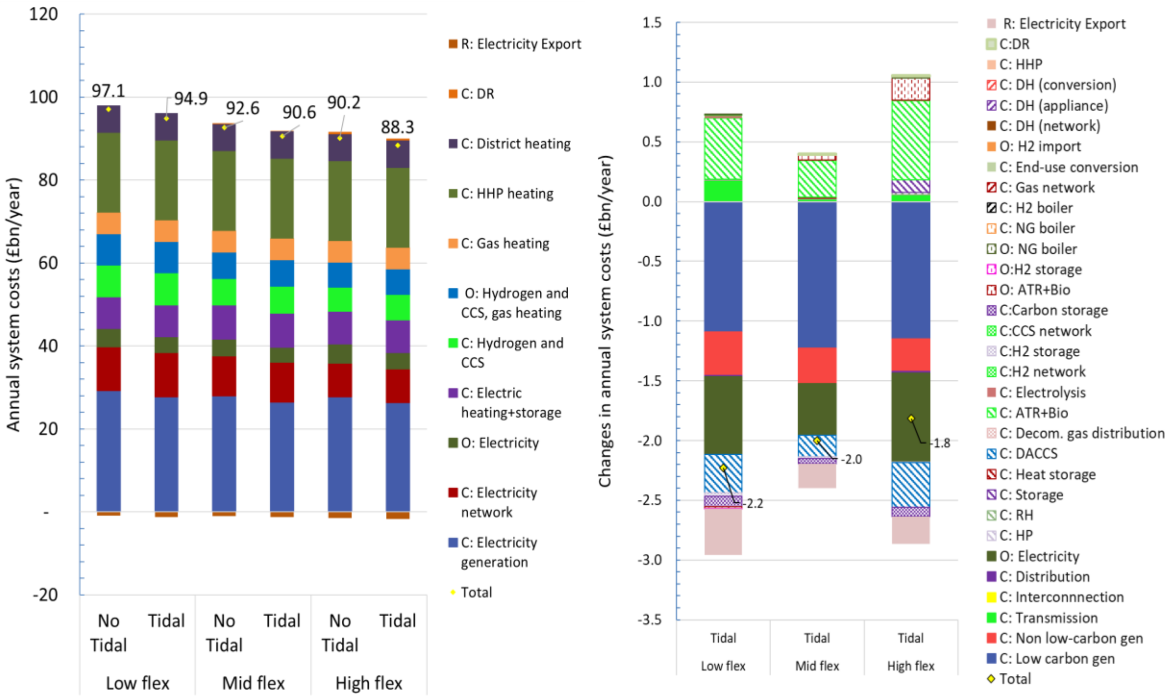
In this context, a set of studies was analysed to understand the impact of different levels of system flexibility on the value of TS. There are three flexibility scenarios considered for these studies:

- Low flexibility means no demand response and no new distributed storage
- Medium flexibility means 25% of potential demand response capacity is available, and the model is allowed to build up to 10 GW new distributed storage

- High flexibility means all potential demand response capacity is available (at cost) by model, and there is no limit for distributed storage.

The modelling results demonstrate that improving flexibility from low to high reduces the annual system costs from £97.1bn/year to £90.2bn/year for “No Tidal” and from £94.9bn/year to £88.3bn/year in “Tidal” case. The benefits of flexibility are £6.9bn/year for “No Tidal” and £6.6bn/year for the “Tidal” case. The results are shown in Figure 3-6a.

The modelling results suggest that TS benefits all systems with different flexibility scenarios. As TS improves system flexibility, the benefits of TS is higher in a low-flex system. For example, the total benefit is £2.2bn/year down in “Low flex” to £2bn/year in “Mid Flex”. The total benefit declines further to £1.8bn in the “High flex” case. The results are shown in Figure 3-6b.



(a) Annual system costs (b) Changes in annual system costs

Figure 3-6 System benefits of Tidal Stream in systems with different flexibility levels

Improving system flexibility will reduce investment and usage of high-cost or high-carbon energy resources such as biomass CCS and thermal plants, which will reduce the value of TS as the volume and cost of alternative technologies that can be displaced are lower. The changes in generation mix after incorporating TS in the system are shown in Figure 3-7. The results are consistent with the previous findings discussed in section 2.3; TS displaces a mix of generation technologies or incentivises a shift in some power technologies or even allocation of biomass energy resources from power to hydrogen production, as discussed in section 2.5. For example, in “High flex”, there are additional onshore wind, storage and hydrogen CCGT while displacing offshore wind, PV, biomass with CCS and natural-gas CCGT. The graph shows that when the system becomes more flexible, the volume of other technologies that TS can displace becomes smaller.

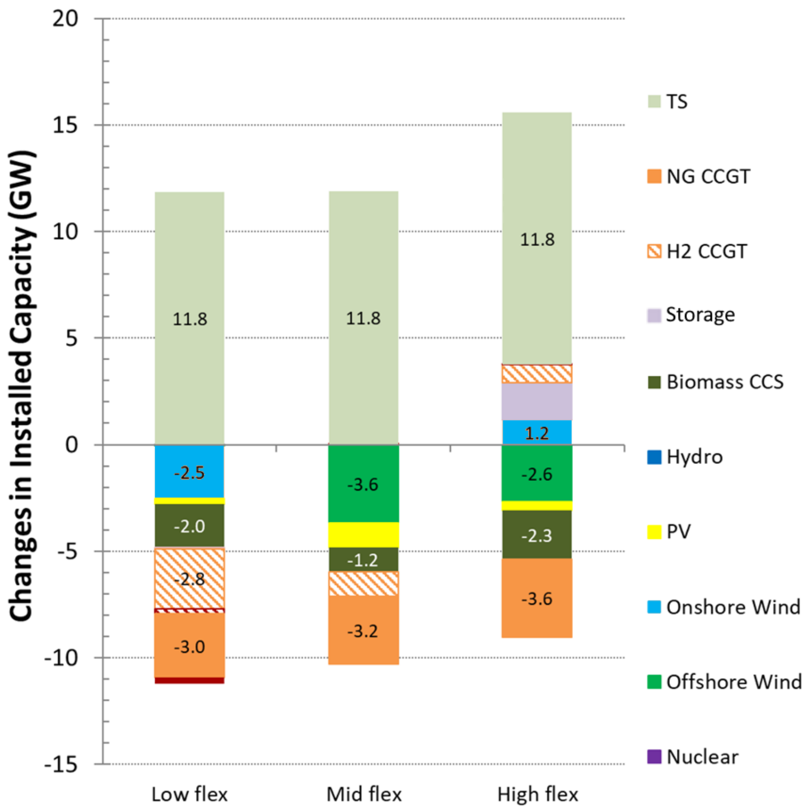


Figure 3-7 Generation technologies displaced by TS

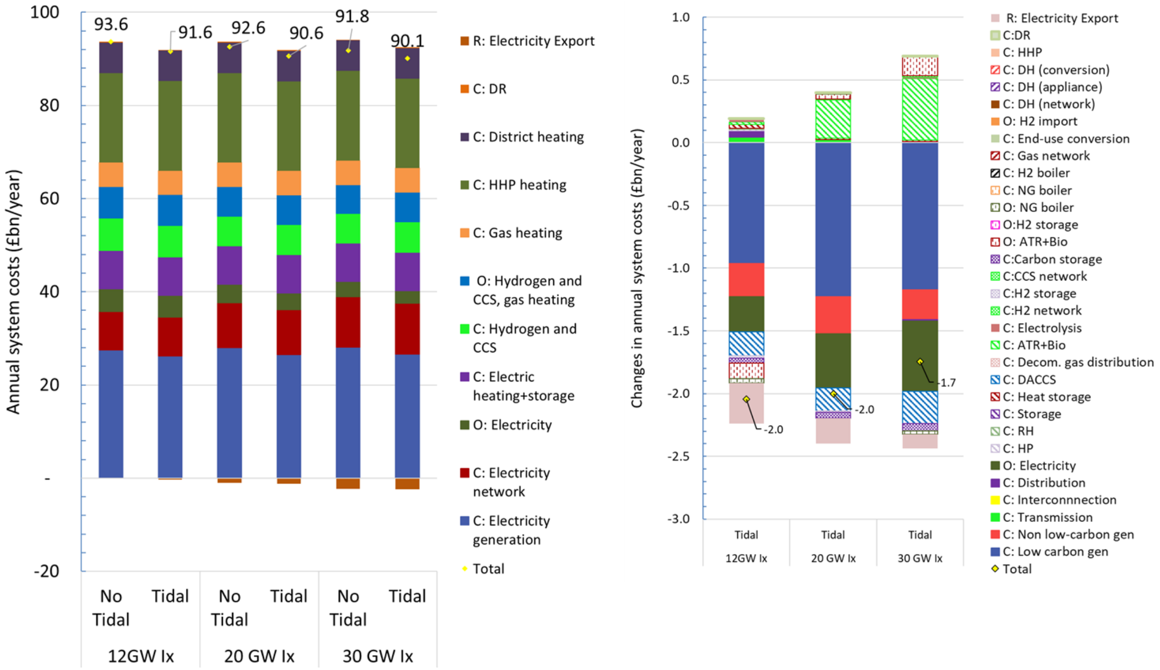
In "High flex", the integration of TS also leads to an increase in electricity storage requirements, which may be the case for "Mid flex" as well but could not be observed because of the modelling assumption that limits the capacity of new distributed electricity storage to 10 GW only. In "High flex", that constraint is relaxed. However, the additional storage capacity needed is relatively small (1.7GW) compared to the installed capacity of TS (11.8 GW). The results suggest that the storage requirements to maximise the value of TS is relatively small from the system perspective. These indicate that the variability of TS does not increase demand for additional energy storage. The storage will be used more frequently for the overall system benefits rather than balancing the TS energy with demand.

3.5 Impact of GB interconnection capacity with Europe

Interconnectors enable energy exchange and sharing of system capacity and balancing resources between the UK and Europe to support cost-efficient system operation and high utilization of low-carbon energy. The study investigates the impact of different interconnection capacities: 12 GW, 20 GW, and 30 GW on the value of TS.

The modelling results, as shown in Figure 3-10(a), demonstrate that TS brings benefits between 1.7 – 2 £bn/year depending on the scenarios with different interconnection capacities. The results show that having a higher interconnection capacity can reduce the annual system costs from £93.6bn/year down to £91.8bn/year in the "No Tidal" case, and similarly from £91.6bn/year down to £90.1bn/year in "Tidal" case. However, increasing interconnection capacity reduces the gross system benefits from

£2bn/year to £1.7bn/year. Similar to “High-flex”, increasing interconnection capacity improves system flexibility, and therefore, the value of TS decreases, as shown in Figure 3-10(b).



(a) Annual system costs

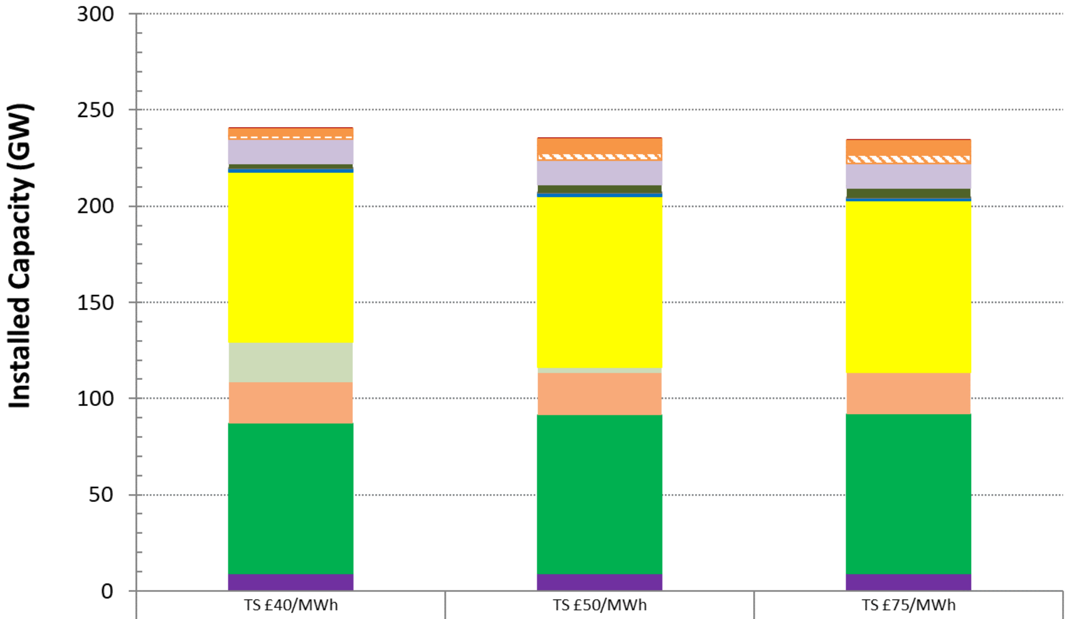
(b) Changes in annual system costs

Figure 3-8 System benefits of Tidal Stream in systems with different interconnection capacities

3.6 Optimised TS capacity as a function of its LCOE

There is still an uncertainty in the future cost of TS as it still continues to be developed and yet to be deployed on a mass scale. In this context, a range of sensitivity studies is carried out to understand the impact of various LCoEs of TS on its deployment and energy system costs. Earlier, the per-unit energy of TS gross system benefits was calculated around 48.88 – 55.27 £/MWh with the range of capacity installed between 5.9 GW and 17 GW, as discussed previously in section 2.1. In these studies, the optimisation model was run considering the levelized cost of TS. Three LCOE figures are used: £40/MWh, £50/MWh, and £75/MWh. The volume of TS and other technologies deployed in the system in each case are shown in Figure 3-9.

The model proposes 20.8 GW, 3.1 GW, and no TS capacity when the LCOE of TS is £40/MWh, £50/MWh, and £75/MWh, respectively. The results align with the previous analyses as the range of TS LCOE should be between £40/MWh and £50/MWh to compete against other technologies. It is worth highlighting that even with £50/MWh, which is around £15/MWh higher than the LCOE of offshore wind, the model still proposes 3.1GW of TS. It demonstrates that TS will have more benefit to the system than installing additional wind as it improves diversity in renewable outputs. The model will consider the system integration cost of technologies, including TS and wind. As the system integration cost increases with higher renewable penetration, TS becomes competitive against the additional renewable capacity at a certain point. A paper by D.Coles[5] reviewing the UK and British Channel Islands practical tidal stream energy considers 11.5 GW by 2050 as a reasonable target.



	TS £40/MWh	TS £50/MWh	TS £75/MWh
NG OCGT	0.0	0.1	0.1
NG CCGT	3.9	7.9	8.1
H2 OCGT	0.0	0.0	0.0
H2 CCGT	1.9	3.4	4.1
Storage	12.7	12.7	12.7
CCS	0.0	0.0	0.0
Biomass CCS	2.7	4.6	5.2
Coal CCS	0.0	0.0	0.0
Hydro	1.5	1.5	1.5
PV	88.6	89.0	89.3
TS	20.8	3.1	0.0
Onshore Wind	21.5	21.6	21.5
Offshore Wind	78.0	82.3	82.7
Nuclear	9.0	9.3	9.3

Figure 3-9 Optimal generation portfolios with the inclusion of TS cost

However, if the LCOE of TS is too high (e.g. £75/MWh – this figure does not indicate at which level of cost TS will not be selected), the model suggests not installing TS at all. It indicates that the TS are replaceable by other technologies.

Considering the cost of TS, the net benefit of having TS in the energy mix is up to £0.6bn/year when the LCOE of TS is £40/MWh; the net benefit is modest (£0.1bn/year) when the LCOE of TS is £50/MWh, as shown in Figure 3-10.

[5] D. Coles *et al.*, "A review of the UK and British Channel Islands practical tidal stream energy resource," *Proc. R. Soc. A Math. Phys. Eng. Sci.*, vol. 477, no. 2255, Nov. 2021, doi: 10.1098/rspa.2021.0469. https://royalsocietypublishing.org/doi/10.1098/rspa.2021.0469#d626710e2878s

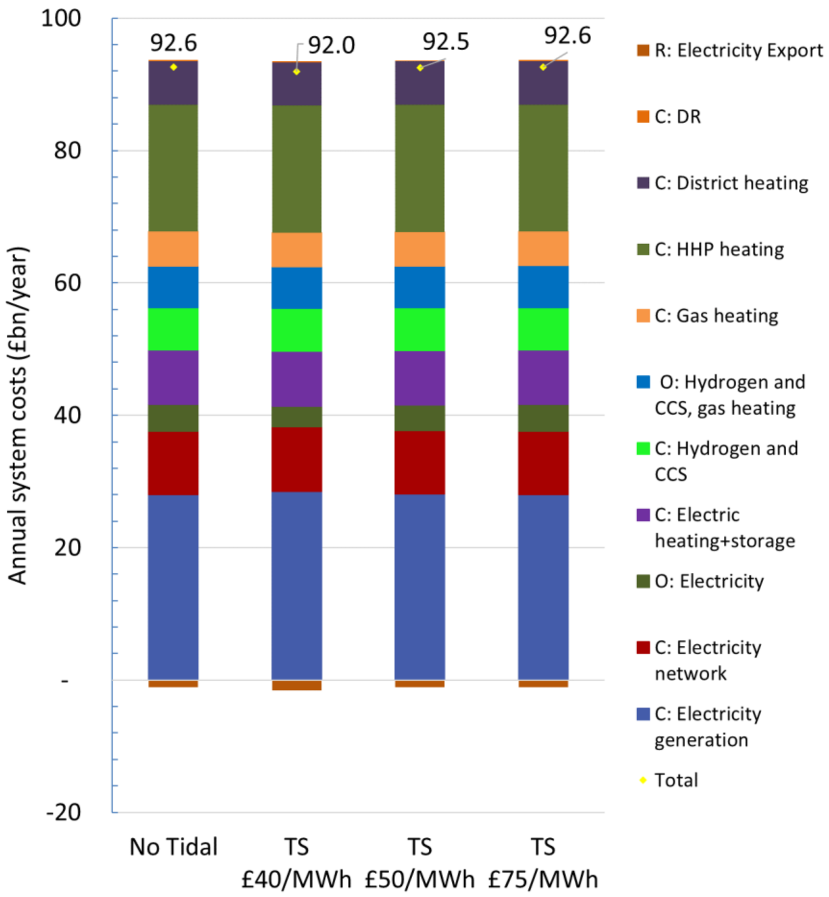


Figure 3-10 Annual system costs of scenarios without and with Tidal (LCOE: 40,50,75 £/MWh)

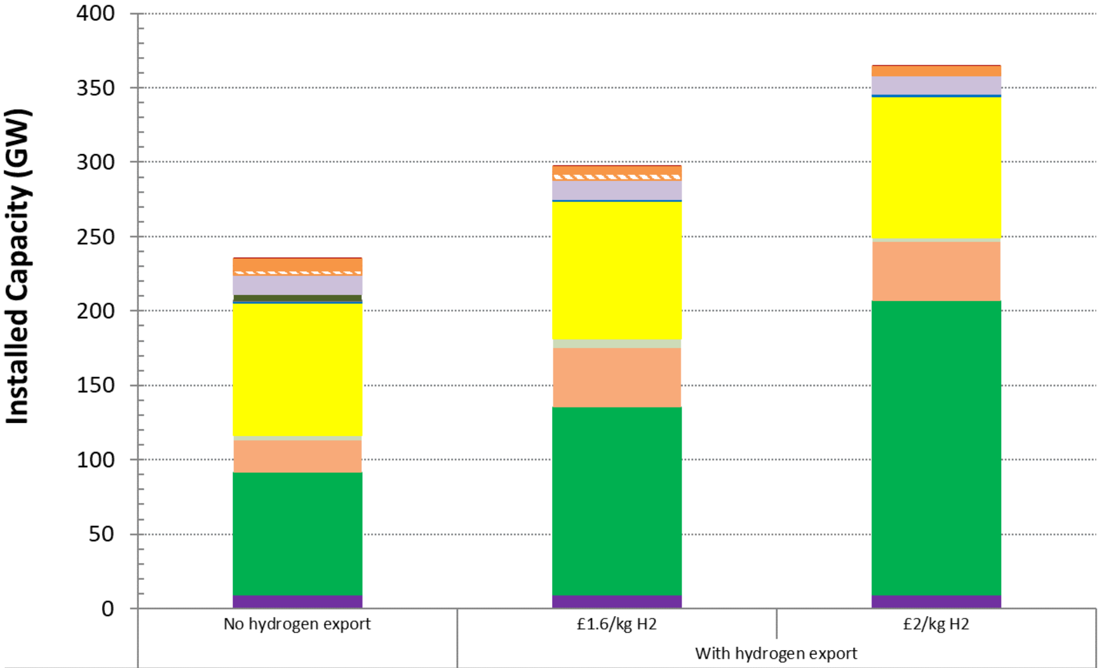
Therefore, it can be concluded that if the cost of TS can be as low as £40/MWh (note that LCOE of offshore wind is around £35/MWh), these technologies have advantages and are competing against the other renewable energy resources.

3.7 Impact of hydrogen export

Enabling hydrogen export internationally opens market opportunities for the vast marine energy sources in the UK. If the market prices are sufficiently high, access to the hydrogen market can incentivise substantial investment in offshore renewables. The previous studies for Floating Wind Centre of Excellence (FW COE)[6] demonstrated that enabling hydrogen export can drive the model to deploy more than 200GW of offshore wind in the UK. In this context, the impact of enabling hydrogen export on the investment of Tidal Stream technologies is analysed. An additional study was performed using the LCOE of £50/MWh for TS and the hydrogen market price of £1.6/kg H_2 and £2/kg H_2.

[6] D.Pudjianto, and G.Strbac, "Role and Value of Floating Offshore Wind Generation in the Future UK Energy System", a report for Floating Wind Centre of Excellence, September 2021

The modelling results suggest that the hydrogen market may bring uncertainty on the TS deployment in the system as high hydrogen market prices tend to increase offshore and onshore wind capacity. The results in Figure 3-11 show that the capacity of TS increases from 3.1 GW to 6.2 GW when the model is allowed to export hydrogen with £1.6/kg H2. However, when the hydrogen price increases further to £2/kg H2, more than 71GW of offshore wind is added to the system, and the TS capacity decreases to 2.7 GW.



	No hydrogen export	£1.6/kg H2	£2/kg H2
NG OCGT	0.1	0.1	0.1
CSP	-	-	-
NG CCGT	7.9	4.9	5.8
H2 OCGT	0.0	0.1	0.1
H2 CCGT	3.4	4.2	0.2
Storage	12.7	12.7	12.7
CCS	0.0	0.1	0.0
Biomass CCS	4.6	0.0	0.0
Coal CCS	0.0	0.0	0.0
Hydro	1.5	1.5	1.5
PV	89.0	92.5	94.9
TS	3.1	6.2	2.7
Onshore Wind	21.6	40.0	40.0
Offshore Wind	82.3	125.8	197.3
Nuclear	9.3	9.3	9.3

Figure 3-11 Optimal generation portfolio without and with hydrogen export

The results suggest that the impact of enabling hydrogen export on TS deployment varies, and it is not always positive; however, this may change if TS becomes more competitive with offshore wind power.

3.8 Impact of future technology improvement

A set of studies is also carried out to identify the impact of future TS technology improvement, which improves the power coefficient of the technologies (from 0.44 to 0.50). A comparison between the capacity factor of the "Medium" (base-case) and "High" scenarios is shown in Figure 3-12. After considering losses, the “High” scenario represents 5.4% to 9.6% capacity factor improvements in different TS sites.

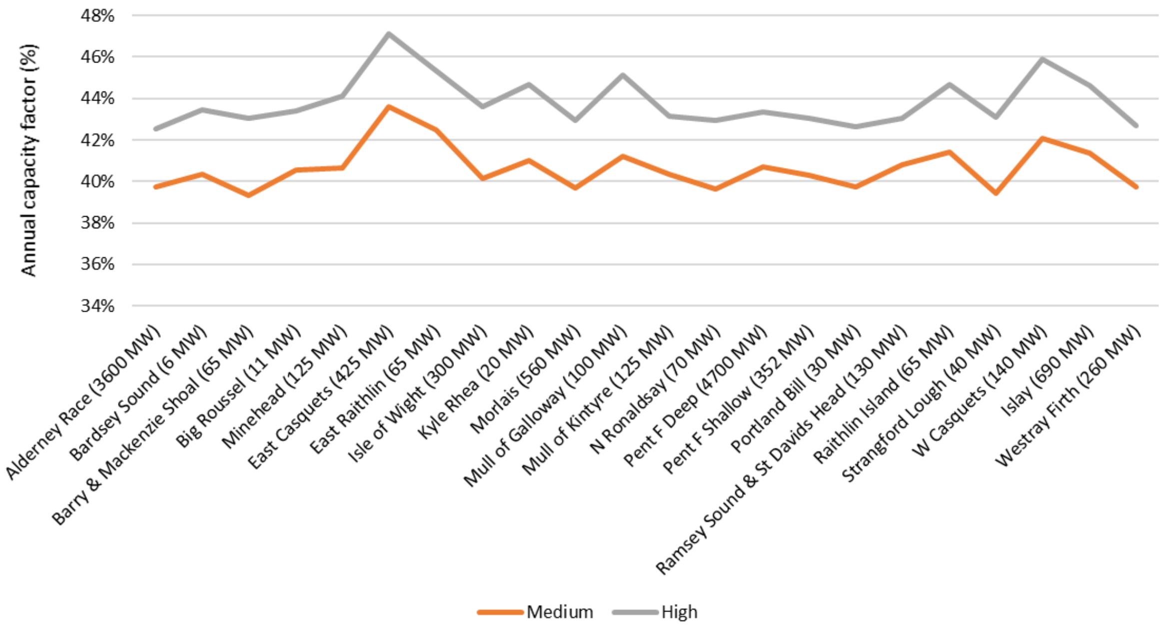
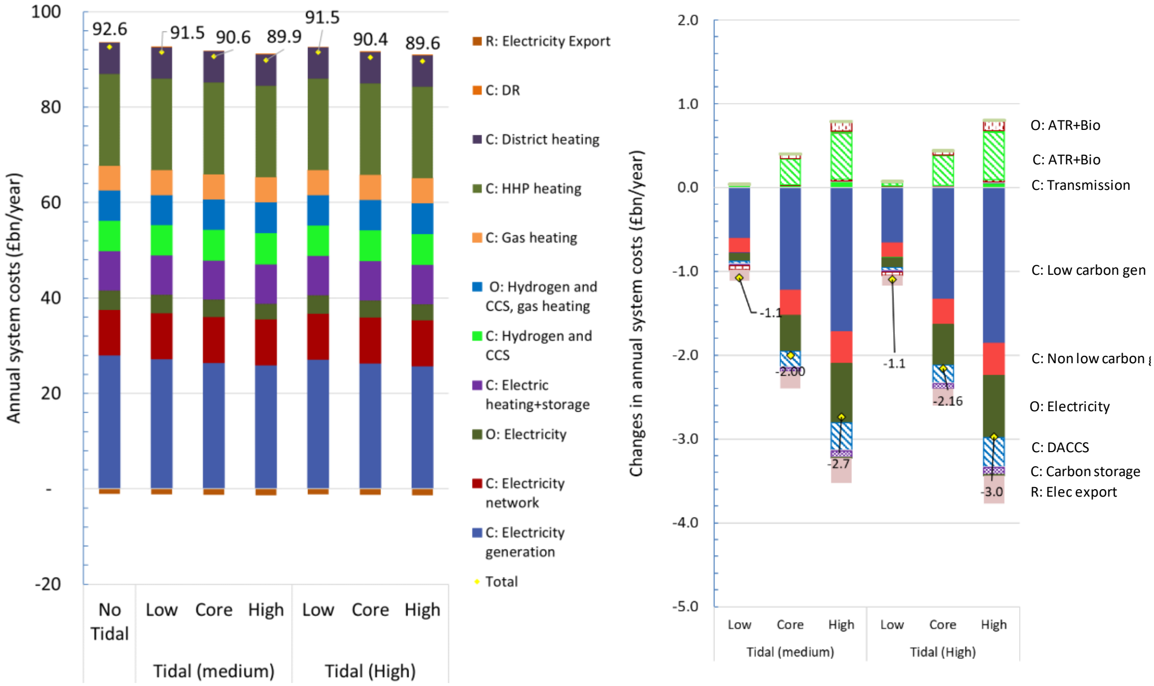


Figure 3-12 A comparison between TS annual capacity factor in “Medium” and “High” scenarios

The modelling results demonstrate that improving the TS power coefficient will reduce the annual system costs. For example, in “Core”, the capacity factor improvement reduces the annual system costs from £90.6bn/year to £90.4bn/year, as shown in Figure 3-13(a). The results also show that the gross system benefits of TS will also increase in line with the increased capacity factor in the “High” scenario. The increased benefits are around 10% for the “Core” and “High” penetration scenarios but lower in the “Low” case, as shown in Figure 3-13 (b).



(a) Annual system costs (b) Changes in annual system costs

Figure 3-13 Annual system costs of scenarios with "Medium" and "High" power coefficients of Tidal Stream technologies

In both scenarios ("Medium" and "High"), the components where the savings occur are the same but with slightly different magnitude. It implies that the future technology improvement will affect those cost components such as Capex and Opex of electricity generation, Capex of DACCS and carbon storage and revenue of electricity export while there will be an increase in hydrogen system costs.

As the system value of TS increases, it is expected that the competitiveness of TS also increases. Therefore, the volume of TS deployed can be higher if the TS capacity factor can be improved.

An additional sensitivity study is carried out to understand the impact of TS LCOE on the annual energy system costs using the "High" power coefficient scenario. The results demonstrate that lower TS LCOE will bring higher net energy system benefits. There is no more benefit when the TS LCOE reaches £55/MWh, indicating that the target LCOE range for TS is below £55/MWh by 2050 to be competitive.

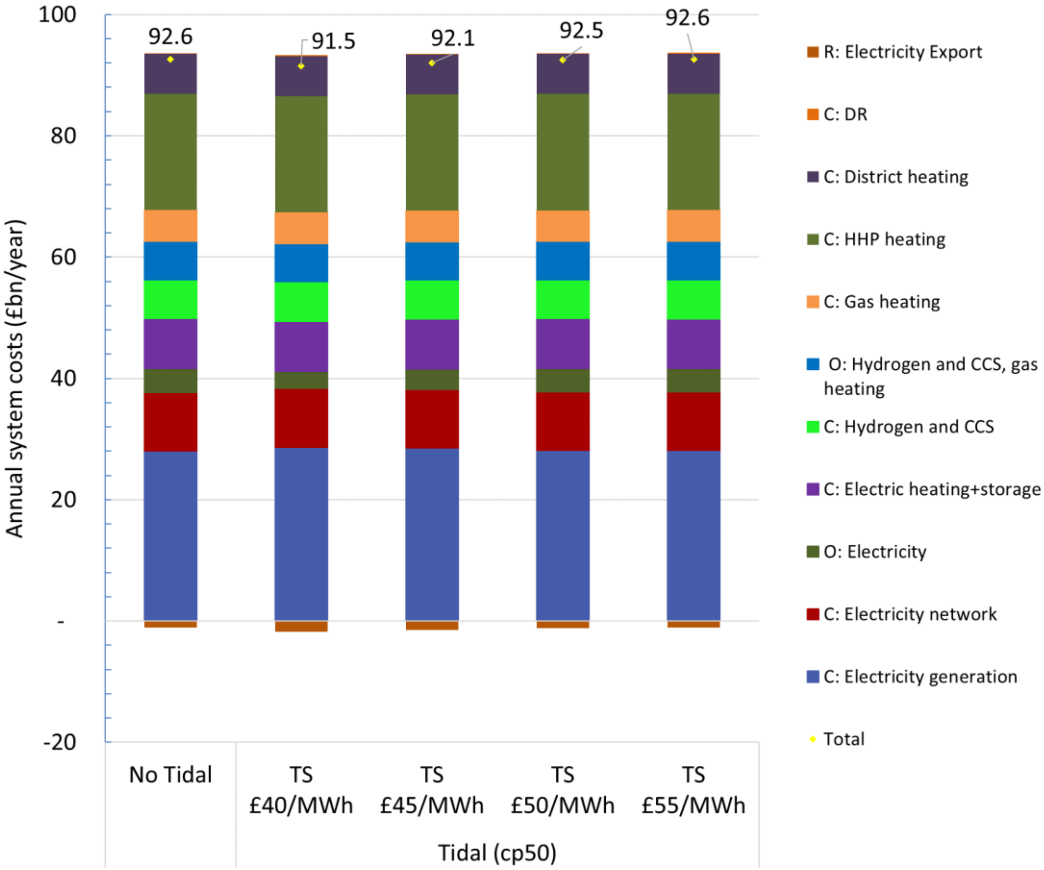


Figure 3-14 Annual system costs of scenarios with different TS LCOEs (£40/MWh to £55/MWh) using the "High" power coefficient scenario

It is worth highlighting that all results are sensitive to the technical and cost assumptions used in the studies, and the results may change if the assumptions are different.

Chapter 4. Conclusions

A spectrum of case studies considering different penetration of TS, locational constraints, heat decarbonisation strategies, TS cost, interconnectors, hydrogen export, flexibility and wind profiles have been analysed to investigate the role and quantify the value of TS in the future UK energy system. An IWES is used to quantify the system impacts of different scenarios. IWES is a least-cost optimisation model that can simultaneously minimise long-term investment and short-term operating costs across multi-energy systems (electricity, heating, hydrogen) from the supply side, energy network to the end-customers while meeting the required carbon targets and system security constraints.

4.1 Key findings

The key findings can be summarized as follows:

Role and value of Tidal Stream technologies

- Tidal Stream technologies provide alternative low-carbon energy sources that can be seamlessly integrated with other low-carbon technologies in the net-zero emission systems.
- While TS can be operated in synergy with other technologies, it also competes and can displace a mix of generation technologies such as offshore wind, biomass with CCS, gas and hydrogen power generation but not nuclear. The variability of TS could not replace the role of nuclear that can provide zero-carbon energy with a firm capacity and controllable to some extent. TS variability could be firmed with energy storage, but it will incur additional costs and energy losses, and therefore, it may not be cost-optimal from the system perspective.
- The gross system benefits[7] of TS are around 49 – 55 £/MWh. It can provide indicative cost figures for TS to compete against other low-carbon technologies. The figures are system-specific and depend on the assumptions of other technologies.
- Most of the benefits are Capex related, indicating the long-term value of TS. This is supported by the long-term predictability of TS energy with high accuracy. This is in contrast to other renewable technologies such as wind and solar PV, whose annual energy outputs vary substantially. While TS affect mostly the electricity system, where most system benefits are derived, the studies also demonstrate and quantify the indirect impact of TS technologies on the hydrogen system, gas usage, and carbon removal and storage requirements. TS reduces residual emissions and volume of sequestered carbon; therefore, the costs of offsetting emissions and storing carbon become less. The results highlight the sector coupling between electricity and other system components, and therefore, the value of TS (or any new) technologies should be assessed in a holistic manner considering its impact on the whole energy system.

[7] It does not include the cost of Tidal Stream.

Drivers for Tidal Stream technologies

- The gross system benefits of TS are locational specific. TS in England and Wales has around 2.5% - 4% higher value than TS in Scotland. The TS value of Scotland is slightly lower due to transmission investment requirements to transport power from Scotland to England, where the bulk of demand is located.
- The gross system benefits of TS will also depend on how the heat demand will be decarbonized in future. The benefits of TS in the pathways with high electricity demand, such as deep electrification and hybrid heating, are higher than in the hydrogen pathway.
- Lower offshore wind capacity factor intensifies the system benefits of TS and vice versa. The gross system benefits of TS with a 52% capacity factor are 40% higher than the benefits in a system with the median wind (60% average). On the other hand, having a 64% wind capacity factor will reduce the system benefits of TS by 20%.
- The gross system benefits of TS is the highest when the energy system flexibility is low. The results also suggest that the storage requirements to maximise the value of TS is relatively small from the system perspective.
- If the cost of TS is low, e.g. £40/MWh, the model proposes 20.8 GW installed capacity demonstrating that it is competitive against offshore wind and other technologies (although the LCOE of offshore wind is £35/MWh[8]) and still brings a net benefit of £0.6bn/year savings in system costs.
- Increasing interconnection capacity will reduce the gross system benefits of TS from £2bn/year to £1.7bn/year.
- The studies considering the possibility of exporting hydrogen under different prices demonstrate that the hydrogen market may bring uncertainty on the TS deployment as it will also affect the capacity of other renewable power technologies.

4.2 Future work

The work described in this report flags several areas that need to be studied in more detail in future, including:

- The role and value of energy storage if a more ambitious net-zero target was established, e.g. by 2040 instead of 2050. The studies demonstrate significant battery storage capacity requirement in the system with deep electrification, and therefore implementing rapid electrification may drive the need for battery storage.
- Further analysis of optimal generation capacity, considering not only the least-cost options but also political, sociological and commercial aspects, supply chain, and GVA creation.
- Another area for strong planning and operation coordination is the North Sea energy integration, which involves integrating hydrogen and electricity and multi-national energy and offshore transmission islands.

[8] The model proposed around 80 GW of offshore wind by 2050.

- Robust deployment of TS considering uncertainty and variation of renewables profiles – the modelling results demonstrate that the benefits of TS are higher in a system with low wind conditions. It would be ideal for developing an approach to determine the optimal TS considering a range of uncertainty in the assumptions, different wind profiles considering different years, and other factors. Moreover, the long-term reliability of a system with high wind penetration is not clear. During the winter peak, there could be very low wind for a few weeks, as the low-wind event may correlate with the extremely cold weather conditions. This will stress the system capacity, and sufficient generation and storage capacity will be needed to deal with such eventualities. As the system should be designed against different renewable output conditions that may vary year to year, there will be a need to evaluate the value of TS under those conditions simultaneously. In that context, the value of TS which the outputs are more predictable (short to long-term), could be higher.
- There is also potential strong synergy with other marine technologies such as tidal lagoon and wave power. Having coordinated development of marine power technologies may reduce the system integration challenges of those technologies and allow more cost-effective utilisation of the infrastructure built to support those developments.

Appendix A Energy system background and key assumptions

Figure A- 1 shows the 2050 GB annual energy demand in TWh used in the analysis.

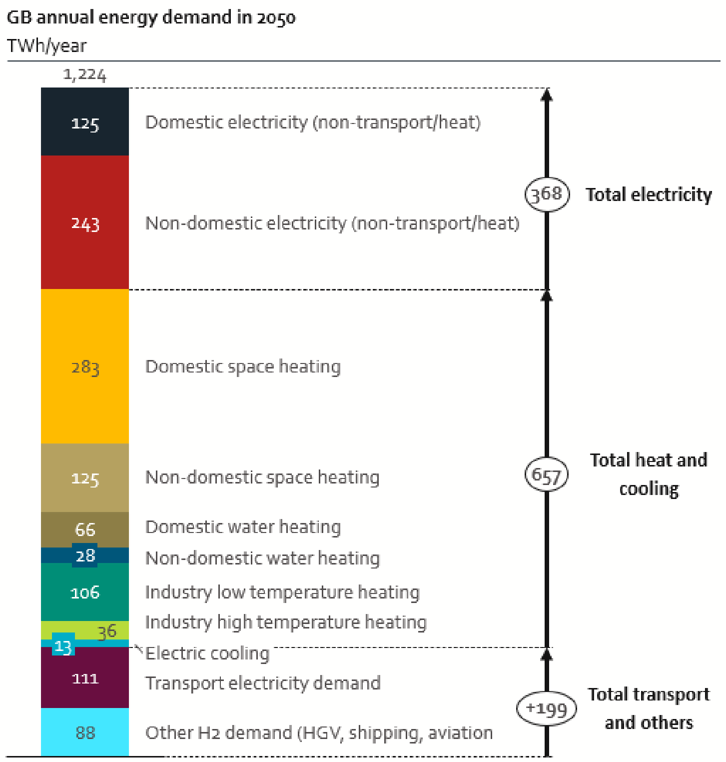


Figure A- 1 2050 GB annual energy demand (TWh/year)

The energy system infrastructure and operation in IWES are optimised to meet the annual energy demand and net-zero emissions requirements. The UK is assumed to be energy positive at the annual level (total annual demand is less or equal to annual production), and the interconnectors are used for short-term energy/power exchanges with adjacent countries. The study also assumes that hydrogen production in the UK should be sufficient to meet the hydrogen demand.

Other key input data and assumptions are summarised in the following table.

Category	Key input data and assumptions for central scenarios
Year	2050
Carbon emissions	Net-zero on an annual basis (GB system) Need to offset emissions from “hard to decarbonise” sectors: 50 $MtCO_2$/year
Bioenergy	173 TWh (input)
Negative emission technologies	BECCS for power, hydrogen, methane DACCS with electricity and hydrogen heating
CCS	Carbon storage and CCS network are available and optimised by the model

<table>
<tr><td>Category</td><td>Key input data and assumptions for central scenarios</td></tr>
<tr><td></td><td>Cost of storing carbon: £15/tCO_2
All CCS technologies (except BECCS) are developed in regions with carbon storage terminals (Scotland, North East England, North Wales, East Midlands, East England)</td></tr>
<tr><td>Transport decarbonisation</td><td>Electrification and hydrogen</td></tr>
<tr><td>Heat decarbonisation</td><td>Few possible pathways for on-gas-grid customers:
1. Electrification (a combination between ASHP and resistive heating)
2. Hydrogen boiler
3. Hybrid heating with electric heating (ASHP and resistive heating) and gas boiler
District heating networks (DHNs) supply 20% of heat demand.
DHNs are in urban areas only and supplied by G/WSHP with a flat COP (3).
The heat demand of off-gas-grid customers is supplied by electric heating.
ASHP needs at least 2kWh thermal storage. DHN storage is around 20kWh/household.

The model optimises additional thermal storage.</td></tr>
<tr><td>Hydrogen technologies</td><td>Three main hydrogen production technologies:
- Auto Thermal Reformers with CCS
- Electrolysis (Proton Exchange Membrane, Alkaline, and Solid Oxide)
- BECCS (gasification)
<table>
<tr><th>Technology</th><th>Capex (£/kW)</th><th>Fixed Opex (£/kW/year)</th><th>Efficiency (%)</th><th>CO_2 Capture Rate (%)</th></tr>
<tr><td>ATR + CCUS</td><td>364</td><td>24.4</td><td>89%</td><td>96%</td></tr>
<tr><td>Solid Oxide Electrolyser</td><td>700</td><td>50.0</td><td>84%</td><td></td></tr>
<tr><td>Alkaline</td><td>455</td><td>29.3</td><td>82%</td><td></td></tr>
<tr><td>Proton Exchange Membrane</td><td>340</td><td>29.3</td><td>82%</td><td></td></tr>
<tr><td>Biomass Gasification + CCUS (H2 BECCS)</td><td>1,173</td><td>103.4</td><td>69%</td><td>95%</td></tr>
</table></td></tr>
<tr><td>Hydrogen storage</td><td>Two technologies:
- Underground storage (Cheshire Basin, East Yorkshire, East Irish Sea and Wessex)
- Overground storage – around 350 GWh distributed storage is needed to enable meeting hydrogen peak demand</td></tr>
<tr><td>Hydrogen network</td><td>A transmission network for hydrogen will be needed in addition to natural gas National Transmission System
Gas distribution will be hydrogen compatible in 2050</td></tr>
<tr><td>Gas price</td><td>2.18/kWh</td></tr>
<tr><td>Demand flexibility</td><td>Maximum potential flexibility:
- 20% from Industrial and Commercial customers
- 40% from smart appliances
- 80% from smart EV
Heat storage is used to modulate the heat-led electricity demand.
Flexibility services include load-shifting for arbitrage, capacity, network congestion, and ancillary services (frequency response and reserves)</td></tr>
<tr><td>Optimisation</td><td>Flexibility is used to reduce the whole-system cost (not only distribution)</td></tr>
</table>

Category	Key input data and assumptions for central scenarios
Distribution network cost	The cost function is derived using representative fractal networks considering GB distribution network characteristics for urban and rural systems with different customer densities. 14 DNO regions are modelled.

References:

Most of the input assumptions are based on the assumptions used in:

1. CCC studies (2018) – "Analysis of Alternative UK Heat Decarbonisation Pathways", available at: https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Pathways.pdf
2. Carbon Trust (2021) – Flexibility in GB, available at: https://publications.carbontrust.com/flex-gb/analysis/

Appendix B Modelling approach

To study the interaction between multi-energy vectors and analyse the impacts of alternative decarbonisation strategies on the UK energy infrastructure in 2050, a range of scenarios can be simulated and optimised using the Integrated Whole-Energy System (IWES) model developed by Imperial. The IWES model incorporates detailed modelling of the electricity system and heating options, including district heating, heat network, heat pumps (air/ground source, Hybrid), and hydrogen infrastructure. IWES models the complex interactions across those energy vectors, as shown in Figure B- 1.

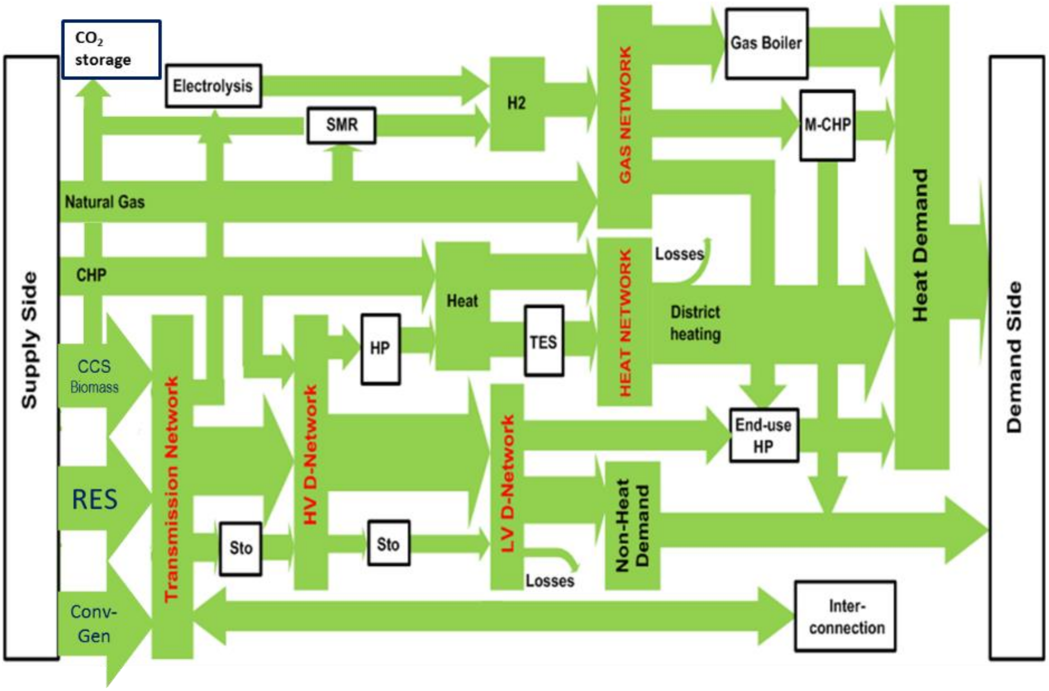


Figure B- 1 Interaction between gas, heat, and electricity systems

In IWES, the multi-energy system's short-term operation and long-term investment decisions are optimised simultaneously to minimise the overall system costs by maximising synergies in system expansion planning and operation within agreed constraints such as a specified carbon target. The model covers both local district and national/international level energy infrastructure details, including energy-flow interactions with mainland Europe via interconnectors, as illustrated in Figure B- 2. This functionality is essential since those aspects are complexly intertwined and need to be analysed simultaneously in the whole-energy system context.

The GB energy system is divided into 14 regions following the distribution network areas to provide sufficient spatial granularity to capture the regional characteristics. Each region has two (or more) different representative district characteristics (e.g. urban and rural systems). IWES also considers the interactions between the GB energy system, Ireland, and continental Europe and cross-border energy exchange and sharing capacity and flexibility.

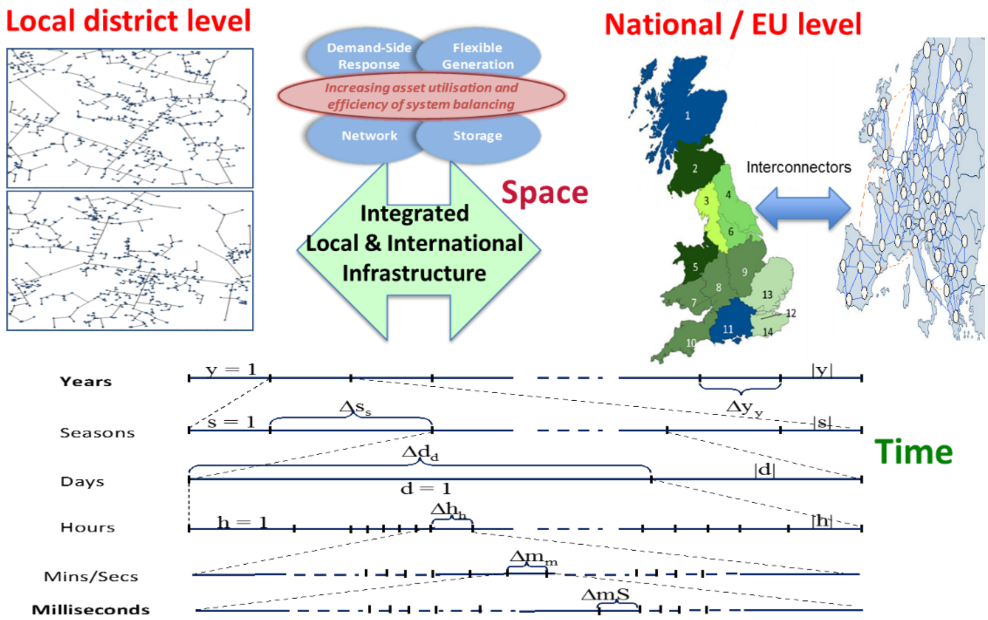


Figure B- 2 Coordinated decisions across various timeframes and location interactions in the integrated modelling of low-carbon systems

IWES optimises the energy supply portfolio, transmission and distribution infrastructure, and energy storage simultaneously to capture system components' interactions. For example, a more extensive distribution capacity may be needed to enable the flexibility of end-users to follow renewable output. IWES also optimises the technical needs for real-time supply and demand balancing, including frequency regulation and balancing reserve (seconds and minutes time-scale) while considering critically essential changes in the system inertia (which is vital for zero-carbon energy system) while reflecting on the dynamic parameters and technical limitations of the selected portfolio of energy sources and flexibility technologies. The benefits of system flexibility provision can be analysed across various energy vectors.

IWES model has been applied to investigate the value of system flexibility[9], evaluate the performance and system implications of different heat decarbonisation pathways[10], quantify the benefits of hydrogen and electricity integration involving electrolysers and hydrogen-fuelled power generation, identify the role of carbon removal technology for net-zero, understand the impact of local versus

[9] Carbon Trust, G.Strbac, D.Pudjianto,"Flexibility in Great Britain," May 2021 – Available at: https://publications.carbontrust.com/flex-gb/analysis/

[10] G.Strbac, D. Pudjianto, et al,"Analysis of Alternative UK Heat Decarbonisation Pathways", a report to the Committee on Climate Change, June 2018. Available at: https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Pathways.pdf

whole-system optimisation and the importance of ESO-DSO coordination, identify the system integration cost of renewables[11], and the value of long-duration energy storage[12].

The IWES model considers more than 30 different cost categories. However, for simplicity, the annual system costs are presented and grouped into fewer high-level cost categories, including eleven Capital expenditure (C), two Operating costs (O) and one Revenue (R) categories described as follows:

Table B-1 Detailed and higher-level cost categories

Detailed cost category	Higher-level cost mapping	Description (all capital costs are annuitized[13] and operating costs are annual)
C: Low carbon gen	C: Electricity generation	Capital cost of wind, PV, hydro, nuclear, gas CCS, power BECCS, and H2-based generation.
C: Non low-carbon gen	C: Electricity generation	Capital cost of traditional fossil-fuel-based generation such as CCGT, OCGT and CHP
C: Transmission	C: Transmission and interconnection	Capital cost of the GB transmission network, including onshore and offshore (but not interconnection)
C: Interconnection	C: Transmission and interconnection	Capital cost of GB interconnectors
C: Distribution	C: Distribution networks	Capital cost of reinforcing electricity distribution network
O: Electricity	O: Electricity	Fuel cost, no-load cost and start-up cost of power generation. The cost of hydrogen as a fuel is excluded here[14] but included in the Capex and Opex of hydrogen.
C: HP	C: Electric heating	Capital cost of heat pump devices, installation cost and the annual fixed operating and maintenance cost
C: RH	C: Electric heating	Capital cost of resistive heating devices, installation cost and the annual fixed operating and maintenance cost. RH is not used in this study, but it is part of the IWES model.
C: Storage	C: Electricity and thermal storage	Capital cost of electricity storage in the system; it includes the cost of pumped hydro and battery energy storage system

11 G. Strbac, M. Aunedi, D. Pudjianto, F. Teng, P. Djapic, R. Druce, A. Carmel, and K. Borkowski, "Value of Flexibility in a Decarbonised Grid and System Externalities of Low-Carbon Generation Technologies," Imp. Coll. London, NERA Econ. Consult., 2015.

12 D.Pudjianto, Luis Badesa, G.Strbac," Whole-system value of long-duration energy storage in a net-zero emission energy system for Great Britain," a report for SSE Renewables, Feb 2021.

13 The annuitisation of capital cost considers hurdle rates and payment periods.

14 Because of this, the Opex for electricity in IWES can produce lower estimates than other models, notably BEIS's Dynamic Dispatch Model

Detailed cost category	Higher-level cost mapping	Description (all capital costs are annuitized[13] and operating costs are annual)
C: Heat storage	C: Electricity and thermal storage	Capital cost of domestic and district heating thermal energy storage
C: DACCS	C: Hydrogen and CCS	Capital cost of DACCS[15]
C: Decom. gas distribution	C: Electric heating	this cost occurs only in the Electric scenario as most of the gas distribution network is no longer used, and therefore, it should be decommissioned. The cost is estimated at £1bn/year. A small proportion of gas distribution connected to large customers (e.g. industry) and BECCS to hydrogen is maintained.
C: ATR+Bio	C: Hydrogen and CCS	Capital cost of building ATR with CCS and the biomass gasification with CCS for hydrogen production
C: Electrolysis	C: Hydrogen and CCS	Capital cost of various electrolysers: Proton Exchange Membrane (PEM), Alkaline, Solid Oxide Electrolyser (SOE)
C: H2 network	C: Hydrogen and CCS	Capital cost of building a national hydrogen transmission network. It is assumed that the national gas transmission is retained.
C:H2 storage	C: Hydrogen and CCS	Capital cost of both underground and overground storage
C: CCS network	C: Hydrogen and CCS	Capital cost of building the CCS network
C: Carbon storage	C: Hydrogen and CCS	Cost of storing carbon captured by CCS. It is assumed that the carbon storage cost is £15/tCO_2.
O: ATR+Bio	O: Hydrogen and CCS	Fuel cost used by ATR with CCS and BECCS to produce hydrogen[16]
O:H2 storage	O: Hydrogen and CCS	Operating cost of hydrogen storage
O: NG boiler	O: Hydrogen and CCS	Cost of natural gas used by the boilers
C: NG boiler	C: Gas heating	Cost of natural-gas-based boilers, installation, and the annual fixed operating and maintenance costs
C: H2 boiler	C: Gas heating	Cost of hydrogen-based boilers, installation, and the annual fixed operating and maintenance costs
C: Gas network	C: Gas heating	Cost of retaining the present gas distribution network. It is applied to the H2 and Hybrid pathways.
C: DH (network)	C: District heating	Cost of district heating networks, including the operating and maintenance cost

15 The cost information on DAC is based on the 2018 report by the US National Academies titled "Negative Emissions Technologies and Reliable Sequestration: a research agenda."

16 Operating cost of electrolysers is part of the power sector costs.

Detailed cost category	Higher-level cost mapping	Description (all capital costs are annuitized[13] and operating costs are annual)
C:DH (appliance)	C: District heating	Cost of household heat infrastructure needed for the district heating system, e.g. metering, heat control, and connection to the main heat network
C:DH (conversion)	C: District heating	Cost of decommissioning natural-gas appliances including replacing the gas hob and gas oven with an electric hob and oven and adding the hot-water storage system
C: HHP	C: HHP heating	Capital cost of heat pump, natural gas or hydrogen boiler, control system and the fitting cost.
C: DR	C: Demand response	Capital cost of demand response technologies
R: Electricity Export	R: Electricity Export	Estimated revenue from electricity export (calculated based on the average electricity cost)