**Cite this article**
Vandercruyssen D, Baker S, Howard D and Aggidis G (2024)
Tidal range generation: combining the Lancaster zero-dimension generation and cost models.
*Proceedings of the Institution of Civil Engineers – Energy* **177(2)**: 49–62,
https://doi.org/10.1680/jener.22.00077

**Research Article**
**Paper 2200077**
Received 06/12/2022;
Accepted 24/04/2023;
First published online 16/05/2023



**Energy**

# Tidal range generation: combining the Lancaster zero-dimension generation and cost models

**David Vandercruyssen** CEng, FICE, FIStructE, MCIHT
Research student, School of Engineering, Renewable Energy and Fluid Machinery Group, Lancaster University, Lancaster, UK (Orcid:0000-0002-3474-3406) (corresponding author: d.vandercruyssen@lancaster.ac.uk)

**Simon Baker** MRes
Research student, School of Engineering, Renewable Energy and Fluid Machinery Group, Lancaster University, Lancaster, UK

**David Howard** PGCE, MBES, MIALE, FRES
Fellow of UK CEH, UK Centre for Ecology & Hydrology, Lancaster Environment Centre, Lancaster, UK (Orcid:0000-0003-4494-7450)

**George Aggidis** Eur Ing, CEng, CMarEng, MASME, FIMarEST, FEI, FIET, FIMechE
Head of Energy, School of Engineering, Renewable Energy and Fluid Machinery Group, Lancaster University, Lancaster, UK (Orcid:0000-0002-5175-4529)

**Financial viability and political will ultimately determine if tidal range power schemes are developed. This research aims to demonstrate a robust system to make initial estimates of capital costs for tidal range schemes that can be compared between systems and options. A levelised cost of energy (LCOE) is used to compare a tidal range barrage (Morecambe Bay) and a coastal tidal lagoon (North Wales) in the UK; the schemes are set in context with other common energy sources. The results show the Morecambe Bay barrage generates marginally more electricity than the North Wales coastal lagoon and has a shorter impoundment at lower cost. However, the economic arguments for both schemes are similar; both are viable as the LCOE shows. Despite being shown to be financially viable, the sources of funding may remain a problem. Financial returns and two potential public funding mechanisms are discussed. The approach using two simple models makes a strong case for more detailed analysis and, in the current environmental, economic and social climate serious decisions must be taken.**

**Keywords:** Economics & finance/offshore energy/power stations (non-fossil fuel)/UN SDG 7: Affordable and clean energy/UN SDG 9: Industry, innovation and infrastructure/UN SDG 13: Climate action

## Notation

| | |
|---|---|
| $C_b$ | cost/m length of bund (£/m) |
| $C_c$ | cost/m of cofferdam (£) |
| $C_p$ | cost of powerhouse section per turbine unit (£) |
| $C_s$ | cost of a single sluice structure (£) |
| $H_b$ | height of bund from crest to seabed (m) |
| $H_o$ | rated head of turbine (m) |
| $L_b$ | length of bund (km) |
| $L_c$ | length of cofferdam measured as total width of powerhouses plus sluices (m) |
| $N_s$ | number of sluices |
| $N_{t+g}$ | number of turbines and powerhouses |
| $P_e$ | rated power of each generator (MW) |
| R1 | rate for turbo-generator (£m$^{-1.5}$/MW) |
| R2 | rate for powerhouse (£/m$^3$) |
| R3 | rate for sluice (£/m$^3$) |
| R4 | rate for cofferdam (£/m$^3$) |
| R5 | rate for bund (£/m$^3$) |
| R6 | rate for precast concrete (£/m$^3$) |
| $W_p$ | width of powerhouse unit (m) |
| $W_s$ | width of sluice (m) |

## 1. Introduction

This is the third in a series of papers by the authors on tidal range generation in Great Britain (GB) (Vandercruyssen *et al.*, 2022a, 2022b). The first paper compares case studies of power generation from a coastal lagoon and an estuarine barrage. It uses the Lancaster 0D (zero-dimension) tidal range model to estimate the annual electricity production (AEP) for various combinations of turbine numbers, generator ratings and sluice ratios (SRs). The 0D method is known to overestimate electricity production but is ideal for rapid assessment of options. More detailed analyses are only possible after feasibility studies when site-specific data are available. The second paper in the series develops a cost model for tidal range schemes that can be used for first estimates of capital costs and ranking schemes in order of financial returns. The cost model requires limited site-specific information and is intended for pre-feasibility estimates only. The goal here is to combine both the models described in the first two papers to estimate the most economic configuration of each scheme based on capital cost and AEP. Industrialised countries must reduce their carbon dioxide emissions to mitigate climate change by replacing fossil fuel use with renewable energy. Tidal range power has enormous potential, but at present only limited exploitation, due to multiple factors, including the economic environment, the historic relative cheapness of fossil fuels, environmental issues and the high initial financial outlay. The decision to develop a scheme is heavily dependent on costs and returns. For any large scheme, due diligence is needed to examine and externalise all costs and benefits, but the process should move through phases of increasing intensity and detail. An initial overview of the proposed development should be transparent, robust, low cost and rapid; it should highlight uncertainties, risks and the internal rate of return (IRR) on capital expenditure (Capex).

Several published studies have examined the power generation from tidal range schemes in GB (Aggidis and Benzon, 2013; Aggidis and Feather, 2012; Burrows *et al*., 2009a, 2009b; Neill *et al*., 2018; Waters and Aggidis, 2016). However, if included, estimation methods and the prices of capital items and consumables are considered confidential and usually only the total cost of the scheme is published.

The methodology described here draws on the work carried out at Lancaster University. It uses the Lancaster 0D model (Vandercruyssen *et al*., 2022a) to estimate AEP for specific schemes, under scenarios that optimise the potential power generation and costs using different numbers of turbines, generator ratings and SRs. The AEP is combined with the Lancaster cost model (Vandercruyssen *et al*., 2022b) to generate initial estimates of the capital costs of tidal range schemes.

The capital costs of schemes are expressed as a rate for each TWh per year of energy generated allowing them to be ranked by total cost of AEP, leading to a levelised cost of energy (LCOE) shown in Section 6; the approach can also be used to set tidal range power in the context of other energy sources and pose a stronger argument for its deployment. It is also possible to optimise the components within an individual scheme to obtain the lowest LCOE.

For demonstration, two potential sites are used as case studies, namely an estuary (Morecambe Bay) and a coastal lagoon (North Wales). Both sites have commercial proposals that represent a traditional approach of an estuarine barrage with a more novel coastal lagoon. LCOE can be used to determine which is more cost effective and allow them to be compared to other schemes.

## 2. The Lancaster cost model

The cost of the main components of a tidal range scheme has been based on five main components, each described by a cost rate ($R$) weighted by sub-component parameters. In all cases, except the turbine costs, the rate is based on the cost per cubic metre of materials required. The components are:

- turbo-generator (T-G)
- powerhouse or turbine hall
- sluice structures
- temporary cofferdam
- bund or barrage embankment

Locks will be required for most schemes but are not costed separately as they are essentially the same form and similar cost as sluices. Locks will remain open during slack tides. The number of locks will be small compared to the number of sluices.

The final rates in the paper by Vandercruyssen *et al*. (2022b) are expressed in pounds sterling (£) from 2016 as they were benchmarked against values from the operational scheme at Lake Sihwa in South Korea (2011) and the proposed tidal lagoon at Swansea Bay UK (2016). Using the UK construction price index (CPI) for new infrastructure construction (ONS, 2023) to bring prices up to date the index ratio is 117.5/101.1 = 1.16, see Table 1.

R5 represents the rate for an earth bund. R6 represents the rate for precast concrete caissons as an alternative to bunds. Details of the five equations giving the cost of each component are given by Vandercruyssen *et al*. (2022b).

## 3. Case studies

The examples are those used by Vandercruyssen *et al*. (2022a), which analysed AEP using different combinations of

Table 1. Rates of conversion from 2016 to 2022 using UK CPI (ONS, 2023) for cost rates (R) of the Lancaster cost model

| | T-G | Powerhouse | Sluices | Cofferdam | Bund | Precast caissons |
|---|---|---|---|---|---|---|
| Rates | R1 | R2 | R3 | R4 | R5 | R6 |
| Values: £/m$^3$ (2016) | 3.66 | 258 | 283 | 47 | 18 | 311 |
| Values: £/m$^3$ (2022) | 4.25 | 299 | 328 | 55 | 21 | 360 |

components: for example, number of turbines, generator ratings and SR. For both demonstration sites an earth bund option is costed pending design of precast concrete sections which will be discussed in a subsequent paper.

### 3.1 Morecambe Bay

The Morecambe Bay barrage is promoted by Northern Tidal Power Gateways (NTPG) (2020b). Their initial proposal employed 125 × 8 m dia. turbines with 30 MW generators.

The published barrage length is 17 km stretching from east of Heysham, on the southern shore, to west of Ramspide in Cumbria in the north. The seabed level along the line of the barrage is approximately −5 m OD (ordnance datum Newlyn) for 12 km of the length and −10 m OD for the remaining 5 km. In the cost model, the rated head of the turbine is taken as 75% of the spring tidal range. The mean spring tidal range is 8.5 m, giving an approximate rated head of 6.4 m. The mean high water springs (MHWS) level is 4.77 m OD (NTSLF, 2023). The published estimated capital costs are shown in Table 2, reproduced from NTPG (2020b). The published figures have been updated to 2022 prices using the CPI for new infrastructure (ONS, 2023); the increase from January 2019 to January 2022 is 1.14.

### 3.2 North Wales coastal lagoon

This scheme is promoted by North Wales Tidal Energy (NWTE) (2023). NWTE proposes up to 125 × 8 m dia. 20 MW turbines. The seabed level along the line of the barrage is approximately −5 m OD for 12 km, −10 m OD for 8 km and −15 m OD for 12 km. The mean spring tidal range is 7.2 m, giving an approximate rated head of 5.4 m. The MHWS level is 3.51 m OD (NTSLF, 2023). The published estimated cost was £7.0 billion (George, 2020).

## 4. Costs for proposed schemes

### 4.1 Turbo-generators

Using Equation 16 from Vandercruyssen *et al*. (2022b) with the updated rates from Table 1 gives the estimated costs of T-Gs in Table 3 at 2022 prices. The rated heads of the turbines, $H_o$, are approximately 75% of the spring tidal range as used by Fay and Smachlo (1983) and Vandercruyssen *et al*. (2022a) – that is, $H_o = 5.4$ m for North Wales, $H_o = 6.4$ m for Morecambe Bay.

### 4.2 Cost of powerhouse and sluice systems

The efficiency of bulb turbines increases with the runner diameter. Those at Lake Sihwa were 7.6 m in diameter and were manufactured over 10 years ago. All the proposed runners are 8.0 m in diameter, which is about the largest considered to be available to date. The mean spring tide ranges for North Wales and Morecambe Bay are 7.2 and 8.5 m, respectively. The costs for a powerhouse (Table 4) are estimated using Equation 3 from Vandercruyssen *et al*. (2022b) with the updated rates from Table 1.

The definition used here for the SR is the total area of sluice aperture divided by the total area of the turbine runners. The sluices are assumed to be 15 m wide × 15 m high, giving an area of 225 m$^2$. The turbine runners are 8.0 m in diameter, giving an area for each of 50.3 m$^2$. Thus, for an SR of 1 the total area of sluices matches the total area of turbine runners with approximately nine turbines for two sluices. Using Equation 4 from Vandercruyssen *et al*. (2022b), the cost of a 15 m square sluice is also calculated in Table 4. Thus, for an SR of 1, there will be 0.22 sluices for every T-G unit.

### 4.3 Cost of cofferdams

The cost per metre of the cofferdams is taken from Equation 5 of Vandercruyssen *et al*. (2022b). The height $H_b$ is the same as

Table 2. Summary of costs for Morecambe Bay in £m as published (2019) and at current prices (2022)

| | Morecambe Bay | |
|---|---|---|
| **Estimated costs** | **2019** | **2022** |
| Barrage only | 7082 | 8073 |
| Barrage roads | 48 | 55 |
| Enabling road infrastructure | 145 | 165 |
| Professional services and connection to the national grid. | 688 | 784 |
| Total scheme costs | 7963 | 9078 |

Table 3. Estimated costs per T-G set (£m, 2022)

| | | Generator rating: MW | | | | |
|---|---|---|---|---|---|---|
| **Site** | **$H_o$ rated head: m** | **10** | **15** | **20** | **25** | **30** |
| North Wales | 5.4 | 14.5 | 20.9 | 27.1 | 33.1 | |
| Morecambe Bay | 6.4 | | 19.2 | 24.9 | 30.4 | 35.9 |

Table 4. Cost in £m of powerhouses and sluices for North Wales and Morecambe Bay

| | North Wales | Morecambe Bay |
|---|---|---|
| Mean spring tidal range: m | 7.2 | 8.5 |
| Cost of each powerhouse, $C_p$: £m | 5.8 | 6.8 |
| Cost of each sluice gate, $C_s$: £m | 9.6 | 11.3 |

Table 5. Cost of cofferdam per metre for North Wales and Morecambe Bay

| | North Wales | Morecambe Bay |
|---|---|---|
| Freeboard: m | 3.00 | 3.00 |
| MHWS: m OD | 3.51 | 4.77 |
| Sea bed at turbines: m OD | −15.00 | −15.00 |
| Height of bund, $H_b$: m | 21.51 | 22.77 |
| Cost of cofferdam, $C_c$: £/m | 23 712 | 26 571 |

Table 6. Total cost of cofferdams (£m) for various numbers of units with a SR of 1

| | $N_{t+g}$ | | | | |
|---|---|---|---|---|---|
| Site | 100 | 120 | 125 | 140 | 160 |
| North Wales | 45.76 | 54.92 | 57.20 | 64.07 | 73.22 |
| Morecambe Bay | 51.28 | 61.54 | 64.10 | 71.80 | 82.05 |

the crest level minus the level of the seabed at the turbines. The cost of the cofferdam per metre length is shown in Table 5.

The length of the cofferdam is considered to be proportional to the length of the powerhouse units and sluices ($L_c$). The width of the powerhouse unit ($W_p$) is taken as 16 m, for 8 m dia. turbines, and the width of each sluice ($W_s$) as 15 m. Thus, the total length of cofferdams for various numbers of T-G units ($N_{t+g}$) is calculated by Equation 1, giving the total cost in Table 6.

1. $$L_c = N_{t+g}(16 + (15 \times 0.22)) = N_{t+g} \times 19.3$$

### 4.4 Cost of bunds

The crest level of the bund is assumed to be the MHWS level plus 2 m for storm surges and 1 m freeboard for waves. This figure will need to be a few metres higher if a public road or railway is required as part of the scheme. Also, provision will be required to allow increasing the crest level in line with rising sea levels.

Using the published equations (Vandercruyssen *et al*., 2022b) and the data in Sections 3.1 and 3.2, the resulting cost/m of the alternative bunds are given in Table 7. Obviously, the bund with the 1:3 slope costs more than the one with the steeper 1:2 slope as it requires more fill material. However, assuming the same materials, the steeper slope is likely to require better compaction so the rate may vary slightly. Both options include an allowance for rock armour protection.

### 4.5 Estimates for case studies

The estimated costs of the components for the two case studies are given in Table 8. In a previous paper (Vandercruyssen *et al*., 2022b), the authors initially increased the capital costs by 30% of the civil engineering costs to allow for preliminaries (prelims), surveys, design and contingencies as used in the government-funded study of the River Severn *Interim Options Analysis Report* (Parsons Brinckerhoff Ltd, 2008). However, given the scarce data on turbine costs, efficiencies in reverse flow and triple regulation, the authors now believe the 30% figure should be applied to all costs. Inaccuracies will arise from errors in the rates and the assumed depths; published costs are usually overestimated due to pre-feasibility conservatism. However, the method shown should be suitable for pre-feasibility estimates and ranking schemes in order of financial return.

Both estimates are close to the developers' published figures. The details of cost estimates of these and any other proposed scheme cannot be tested against existing values as the components are not published due to commercial concerns. The following text shows how the estimated costs can be reduced by optimising the components.

## 5. Optimisation

The proposed rates can also be used to optimise the components within a particular scheme to minimise LCOE, most notably:

Table 7. Estimated cost of bunds for the Morecambe Bay barrage and the North Wales lagoon

| | | | | | Cost of bund, $C_b$: £/m (2022) | | |
|---|---|---|---|---|---|---|---|
| Scheme | Crest level: m OD | Seabed level: m OD | Overall height of bund, $H_b$: m | Width of crest: m | Embankment at 1 in 2 | Embankment at 1 in 3 | Length, $L_b$, at this height: km |
| Morecambe Bay | 7.8 | −5 | 12.8 | 20 | 17 633 | 23 762 | 12 |
| barrage | 7.8 | −10 | 17.8 | 20 | 28 259 | 38 651 | 5 |
| North Wales | 6.5 | −5 | 11.5 | 10 | 12 800 | 17 992 | 12 |
| coastal lagoon | 6.5 | −10 | 16.5 | 10 | 21 830 | 31 012 | 8 |
| | 6.5 | −15 | 21.5 | 10 | 32 960 | 47 182 | 12 |

Table 8. Summary of estimated scheme capital costs for Morecambe Bay and North Wales

| Scheme | T-G rating, $P_e$: MW | Number of units, $N_{t+g}$ | Costs: £m | | | | | | | Capital cost: £bn (2022) | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Total T-Gs | Powerhouse | Sluice | Cofferdam | Bund embankment | | Prelims and contingencies | | |
| | | | | | | | Length, $L_b$: km | Cost, $C_b$: £/km | | | |
| Reference | | | Table 3 | Table 4 | Table 4 | Table 6 | Table 7 | | At 30% | Estimate | Published |
| Morecambe | 30 | 125 | 125@35.9m | 125@6.8m | 28@11.3m | Equation 8 | 12.0 | 17.6 | | 7.89 | 8.07 |
| Bay | | | | | | | 5.0 | 28.3 | | | |
| | | | 4488 | 850 | 316 | 64 | 353 | | 1821 | | |
| North Wales | 20 | 125 | 25@27.1m | 125@5.8m | 28@9.6m | Equation 8 | 12.0 | 12.8 | | 6.71 | 7.00 |
| coastal | | | | | | | 8.0 | 21.8 | | | |
| lagoon | | | | | | | 12.0 | 33.0 | | | |
| | | | 3388 | 725 | 269 | 57 | 724 | | 1549 | | |

- the generator rating
- the output with different numbers of turbines
- SR.

To illustrate how these factors influence LCOE the 0D modelling output is used. Figure 1 shows the AEP plotted against numbers of T-Gs. The solid lines represent North Wales lagoon (NW) and the dashes represent Morecambe Bay barrage (MB). For NW, the gap between the 10 and 15 MW lines is wider than the gap between the 15 and 20 MW lines. This indicates that there may be savings to be made by reducing the generator rating. The curves for Morecambe Bay show that the 20 and 30 MW generators, with SR = 1, are also close.

## 5.1 Generator rating

For best performance, the diameter of the turbine runners must be as large as possible to maximise the flow and turbine efficiency. The maximum diameter currently considered practical to manufacture is 7.6–8.0 m. Figure 1 shows the relationship between the generation output and the number of T-Gs of different ratings. For $125 \times 30$ MW machines, the predicted annual generation from Morecambe Bay is 6.58 TW/ha. The generation from the same number of 20 MW machines is 6.39 TW/ha, representing only a 3% reduction in output. It has been shown that the cost of the T-G is a function of the generator rating for a given rated head (Table 3). Thus, the cost of a 20 MW T-G with the same 6.4 m rated head is 70% that of the 30 MW machine. From Table 8 the 125 turbines represent 69% of the total capital cost. Reducing the generators to 20 MW saves 52% of the overall Capex for only a 3% reduction in annual generation.

## 5.2 Number of turbines against generation output

The AEP is asymptotic, gradually flattening as the number of units increases. Figure 1 shows this consistently for all scenarios. The costing approach employed here enables the number of units for a particular scheme to be optimised against cost. The Morecambe Bay scheme has proposed both 125 units (NTPG, 2020a) and 160 units (Baker, 2021). Table 9 shows the calculation of costs and AEP for both schemes with various numbers of units. For an SR of 1, a single $15 \times 15$ m sluice will be required for every 4.5 turbines of 8 m diameter. It is assumed that the costs of bunds and contingencies will be the same for all options.

Table 9 shows that costs per TWh are significantly lower with smaller generators for both schemes. In terms of costs, the optimum for Morecambe Bay involves 120 turbines with 20 MW generators. However, 120 turbines for Morecambe Bay are not capable of maintaining the existing low tide levels against the higher predictions of sea level rise; the relationship will be examined in a subsequent paper. For North Wales, the

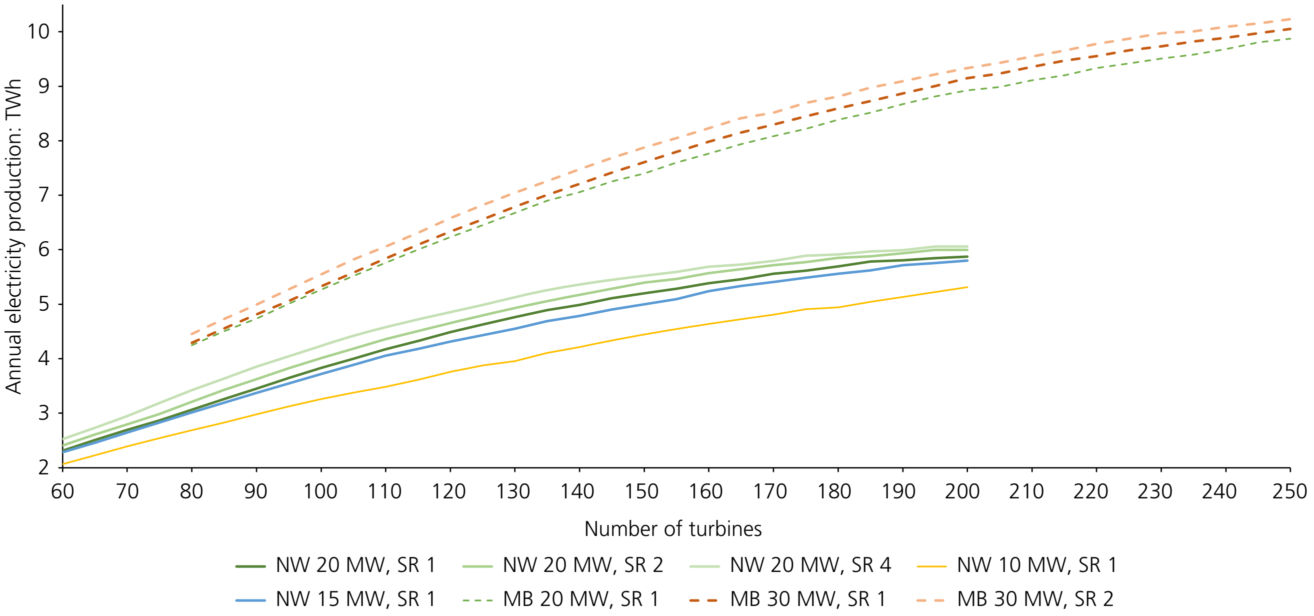


**Figure 1.** AEP for a Morecambe Bay barrage and North Wales coastal lagoon with various numbers of turbines, generator ratings and SRs

most cost-effective option is 100 turbines with 15 MW generators. The cost per TWh for the estuarine barrage is 74% of that for the coastal lagoon.

The last column in Table 9 shows the estimated annual carbon dioxide ($CO_2$) offset, valued as the equivalent power generation from combined cycle gas turbines (CCGTs) operating at maximum commercial rate of 350 kg/MWh (Bass *et al.*, 2011). Bass *et al.* (2011) measured the carbon dioxide emissions from a grid-connected CCGT under various operating conditions over a period of 3 months. During cold and hot the carbon dioxide emissions increased to 470 and 590 kg/MWh, respectively. If the goal is to generate as much renewable electricity as possible and maximise the carbon dioxide offset, then the optimum arrangements are different, as highlighted in italics in Table 9, at a slightly increased cost per TWh. Should a carbon tax credit system be available, then the economics will change in favour of more installed capacity to displace gas generation. The optimised generation from Table 9 would save 2.18 Mt (million tonnes) of carbon dioxide per annum from Morecambe Bay and 1.55 Mt from North Wales.

Carbon dioxide payback periods are another parameter to be considered in all new constructions. Hammons (2011) studied this for two of the proposed Severn estuary schemes and predicted carbon dioxide payback times of 5–8 months. This is the most rapid payback for power generation and compares favourably against other low carbon dioxide technologies such as nuclear power (SDC, 2006).

### 5.3 Number of units against the SR

Sluices influence the efficiency of operation of a tidal barrage and the ability to maintain the tidal range over the seasonal cycle. Figure 1 includes the AEP for North Wales with SRs of 1, 2 and 4 for 20 MW machines. The costs of sluices and cofferdams and the total scheme costs are taken from Tables 4, 5 and 9 respectively. Assuming 125 turbines with 20 MW generators, the costs per TWh are given in Table 10 for various SRs. For this configuration the minimum cost per TWh comes from an SR of 2.

## 6. Levelised cost of energy

The LCOE is a method devised to compare the costs of different forms of electricity generation. Currently there is no internationally agreed or standardised approach (Aldersey-Williams and Rubert, 2019). In simple terms, the LCOE is the net present value (NPV) of the total Capex and the total operating expenses (Opex) across the lifetime of the project divided by the NPV of the total predicted electricity generated across its lifetime. The LCOE model avoids speculation about future energy prices. It serves as an indication as to whether the project is economically viable and allows high-level strategic decisions over energy sources to be made.

**Table 9.** Calculation for estimated costs and annual generation for different numbers or turbines and generator ratings

| Scheme | T-G rating: MW | Number of units, $N_{t+g}$ | Costs: £m | | | | | | | | Annual gen.: TWh | Cost rate: £m/TWh | Annual carbon dioxide offset: Mt |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Turbines | Power-houses | Sluices | | Cofferdams | Bunds | Prelims and contingencies @30% | Total cost | | | |
| | | | | | $N_s$ | Total cost | | | | | | | |
| Morecambe Bay | 20 | 120 | 2988 | 816 | 26 | 298 | 62 | 353 | 1355 | 5873 | 6.23 | **942** | 2.18 |
| | | 140 | 3486 | 952 | 31 | 348 | 72 | 353 | 1563 | 6774 | 7.06 | 960 | 2.47 |
| | | 160 | 3984 | 1088 | 35 | 398 | 82 | 353 | 1771 | 7676 | 7.76 | 989 | 2.72 |
| | 30 | 120 | 4308 | 816 | 26 | 298 | 62 | 353 | 1751 | 7589 | 6.33 | 1199 | 2.22 |
| | | 140 | 5026 | 952 | 31 | 348 | 72 | 353 | 2025 | 8776 | 7.21 | 1217 | 2.52 |
| | | 160 | 5744 | 1088 | 35 | 398 | 82 | 353 | 2299 | 9964 | 7.98 | 1249 | 2.79 |
| North Wales coastal lagoon | 15 | 100 | 2090 | 580 | 22 | 210 | 46 | 724 | 1095 | 4746 | 3.71 | **1279** | 1.30 |
| | | 125 | 2613 | 725 | 28 | 263 | 57 | 724 | 1314 | 5696 | 4.43 | 1286 | 1.55 |
| | | 160 | 3344 | 928 | 35 | 337 | 73 | 724 | 1622 | 7027 | 5.24 | 1341 | 1.83 |
| | 20 | 100 | 2710 | 580 | 22 | 210 | 46 | 724 | 1281 | 5552 | 3.83 | 1449 | 1.34 |
| | | 125 | 3388 | 725 | 28 | 263 | 57 | 724 | 1547 | 6703 | 4.63 | 1448 | 1.62 |
| | | 160 | 4336 | 928 | 35 | 337 | 73 | 724 | 1919 | 8317 | 5.38 | 1545 | *1.88* |

Values in bold show the cheapest for each scheme, those in italics the greatest carbon dioxide offset

Ocean Energy Systems (OES) investigated various LCOE models and proposed a standardised method for ocean systems (OES, 2015), see Equation 2. They gave examples for tidal stream, wave energy and ocean thermal energy conversion. They included a discount rate ($r$) to balance out the effect of schemes with different lifespans over the lifetime of the project ($N$-years).

$$2.\quad \text{LCOE} = \frac{\sum_{t=0}^{N}(\text{Cost}_t/(1+r)^{\text{year}})}{\sum_{t=0}^{N}(\text{Electrical energy}/(1+r)^{\text{year}})} = \frac{£}{\text{MWh}}$$

OES assumed a discount rate of 10% for contingency as emerging technologies (OES, 2015). For a 120-year project with two plants in operation, a rate of 5% is proposed. The following assumptions are made.

- The Capex is spread equally over a 7-year construction programme.
- The bund will be completed after year 6 and half the units will be generating. Full generation after year 7.
- Opex is 1.5% of Capex per year over 40 years.
- T-Gs will be upgraded or replaced on a 40-year cycle.

With a discount rate of 5%, the LCOE for the two case studies is given in Table 11; figures describe the first 40 years of operation. Note that the lowest LCOE for both schemes is the same configuration as those identified in Table 9 using the simpler Capex/AEP ratio.

To consider the costs for the second and third 40 years of operation, the following assumptions are made.

- T-Gs will be upgraded or replaced on a rolling basis, assuming over 5 years, there will be only 80% availability of the turbines over this period. The cost for T-Gs is taken as the same as the current new cost.
- To allow for raising the crest of the bund, the new Capex also includes 10% of the original bund cost.

Other items are expected to be maintained by the annual Opex budget which remains the same for all operational years.

Table 12 shows that the LCOE for the second 40-year period of operation; the third 40-year period is the same as the second: both are an average of 57% of the LCOE for the first 40 years. Without inflation or changes in relative costs, the cost of electricity for future generation falls; additionally, flood protection from rising sea levels is provided. These calculations do not include any allowance for carbon dioxide credit or other benefits such as transport, health, tourism or conservation.

Table 10. Effect of various SRs on annual generation for North Wales

| | Sluices | | | | | |
|---|---|---|---|---|---|---|
| SR | Number | Total: £m | Extra cost of cofferdams: £m | Total cost: £m | Annual gen.: TWh | Cost per TWh: £m |
| 1 | 28 | 263 | 0 | 5696 | 4.63 | 1230 |
| 2 | 56 | 526 | 10 | 5706 | 4.79 | 1190 |
| 4 | 112 | 1052 | 20 | 6242 | 4.99 | 1251 |

Discounting methods that attempt to convert values in the future into today's prices are essential for comparison between long-term projects, but their subjective nature is clearly problematic. After 40 years the discount factor is 0.15 for a rate of 5% per year, so any costs or profits after this period have little effect on the LCOE. By calculating the subsequent 40-year periods separately, the LCOE is considerably cheaper.

The LCOE for the first 40 years is comparable with projected costs for combined cycle gas power generation based on *Projected Costs of Generating Electricity* (IEA and NEA, 2020), which predicts the LOCE for gas in Europe is around £60/MWh. However, in the 2 years since publication in 2020 gas prices have quadrupled due to energy shortages caused by the Ukraine crisis. As the Opex includes the cost of fuel, the LCOE for gas will now be considerably higher. The LCOE values in Tables 11 and 12 are significantly lower than the figures quoted by OES (2015) for wave and tidal stream power.

## 7. Revenue

Historic half-hourly wholesale electricity prices in Britain are published (Elexon, 2022) and can be downloaded. The half-hourly sell prices from recent years are summarised in Table 13 as the average for each slot throughout the year. The maximum and minimum price for any slot in the year is also given. (Further details are provided in the online supplementary material.)

While the price of British electricity reflects the cost of fuel (mainly gas), it is also determined by demand, with an initial reduction due to Covid-19 (2019–2020) followed by a boom (2021) that has been exacerbated by the war in Ukraine (2022). Prices will increase unless cheaper sources can replace fossil fuels or the demand decreases; cheaper sources are likely to be locally resourced and renewable. Replacing fossil fuels and increasing demand are likely to increase future electricity prices. Cost–benefit analysis requires a forecasting of the price of fuel for the next 40 years and is regularly carried out for the power generating industry. The variation in the price of electricity is commonly greater than the variation in the capital cost of construction and, as described above, is dependent on both the demand for and availability of power; the installation of tidal range schemes will cause the pricing profile to change.

The average earnings anticipated can be increased to reflect price optimisation. Harcourt *et al*. (2019) showed that optimising for price gave a 23% improvement on average market price for Swansea Bay. In the absence of a similar study for these examples, the authors will assume a 10% increase in average price is possible. There will be no generation at negative rates because the turbines can be set to run free; in fact, they could be run in pump mode to balance the system and take advantage of the negative price. It remains to be seen if the high gas price since 2021 continues; if so the economics of tidal range electricity are significantly stronger. The UK government's stated intention of phasing out natural gas is certainly not going to reduce electricity prices in the short to medium term.

### 7.1 Financial support mechanisms

Currently, the government has two potential support mechanisms that could provide public finance to assist renewable energy. The principal one is contract for difference (CfD), which has been used extensively for wind farms and gives the developer a guaranteed price per MWh for electricity generated. The agreement is for a defined period (usually for 20–40 years) that is negotiated with the government regulator before detailed designs are drawn up. The developer works on the build, own and operate (BOO) principle. The developer and their financial backers carry all the risks of design, construction and operation and no income is received until the scheme is operational. For tidal range schemes, this could be 4 years for design and 6 or 7 years for construction. For mega projects the risks are high and finance will be expensive, discouraging private investors. Investors are reluctant to consider projects with an IRR of less than 10–15%.

The alternative support mechanism is called regulated asset base (RAB) and has been used for major infrastructure projects, such as London Crossrail and Heathrow Airport Terminal 5. It is being considered for new offshore wind and has been approved for the Sizewell C nuclear power station (Makovšek and Veryard, 2016). The mechanism employs a risk-sharing approach with backing from the government regulator. The risk sharing and profit margins are agreed between the developer and regulator before detailed design. Consequently, the investors carry less risk and the available interest rates will be about half that of the CfD mechanism.

**Table 11.** LCOE for the first 40 years including construction

| Scheme | T-G rating: MW | Number of units, $N_{t+g}$ | Total Capex: £m | Annual gen.: TWh | Year<br>Discount factor @5% | Construction<br>1<br>1.00 | <br>2<br>0.95 | <br>7<br>0.75 | Operation and maintenance<br>8<br>0.71 | <br>9<br>0.68 | <br>40<br>0.15 | Totals | LOCE: £m/TWh £/MWh |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Morecambe Bay | 20 | 120 | 5873 | 6.23 | Costs: £m | 839.01 | 799.05 | 626.08 | 62.61 | 59.63 | 13.14 | 6149.52 | **80.12** |
| | | | | | AEP: TWh/year | | | 2.33 | 4.43 | 4.22 | 0.93 | 76.76 | |
| | 20 | 140 | 6774 | 7.06 | Costs: £m | 967.76 | 921.68 | 722.16 | 72.22 | 68.78 | 15.16 | 7093.26 | 81.60 |
| | | | | | AEP: TWh/year | | | 2.63 | 5.02 | 4.78 | 1.05 | 86.93 | |
| | 20 | 160 | 7676 | 7.76 | Costs: £m | 1096.60 | 1044.38 | 818.30 | 81.83 | 77.93 | 17.17 | 8037.55 | 84.08 |
| | | | | | AEP: TWh/year | | | 2.90 | 5.52 | 5.25 | 1.16 | 95.60 | |
| | 30 | 120 | 7589 | 6.33 | Costs: £m | 1084.15 | 1032.52 | 809.01 | 80.90 | 77.05 | 16.98 | 7946.30 | 101.96 |
| | | | | | AEP: TWh/year | | | 2.36 | 4.50 | 4.28 | 0.94 | 77.94 | |
| | 30 | 140 | 8776 | 7.21 | Costs: £m | 1253.76 | 1194.06 | 935.58 | 93.56 | 89.10 | 19.63 | 9189.51 | 103.51 |
| | | | | | AEP: TWh/year | | | 2.69 | 5.12 | 4.88 | 1.08 | 88.77 | |
| | 30 | 160 | 9964 | 7.98 | Costs: £m | 1423.46 | 1355.67 | 1062.20 | 106.22 | 101.16 | 22.29 | 10433.26 | 106.17 |
| | | | | | AEP: TWh/year | | | 2.98 | 5.67 | 5.40 | 1.19 | 98.27 | |
| North Wales lagoon | 15 | 100 | 4746 | 3.71 | Costs: £m | 677.93 | 645.65 | 505.89 | 50.59 | 48.18 | 10.62 | 4968.95 | **108.76** |
| | | | | | AEP: TWh/year | | | 1.38 | 2.64 | 2.51 | 0.55 | 45.69 | |
| | 15 | 125 | 5696 | 4.43 | Costs: £m | 813.71 | 774.96 | 607.20 | 60.72 | 57.83 | 12.74 | 5964 | 109.33 |
| | | | | | AEP: TWh/year | | | 1.65 | 3.15 | 3.00 | 0.66 | 54.55 | |
| | 15 | 160 | 7027 | 5.24 | Costs: £m | 1003.91 | 956.10 | 749.13 | 74.91 | 71.35 | 15.72 | 7358 | 114.05 |
| | | | | | AEP: TWh/year | | | 1.95 | 3.72 | 3.55 | 0.78 | 64.52 | |
| | 20 | 100 | 5552 | 3.83 | Costs: £m | 793.08 | 755.31 | 591.81 | 59.18 | 56.36 | 12.42 | 5813 | 123.25 |
| | | | | | AEP: TWh/year | | | 1.43 | 2.72 | 2.59 | 0.57 | 47.16 | |
| | 20 | 125 | 6703 | 4.63 | Costs: £m | 957.64 | 912.04 | 714.61 | 71.46 | 68.06 | 15.00 | 7019 | 123.11 |
| | | | | | AEP: TWh/year | | | 1.73 | 3.29 | 3.13 | 0.69 | 57.02 | |
| | 20 | 160 | 8317 | 5.38 | Costs: £m | 1188 | 1132 | 887 | 88.66 | 84.44 | 18.61 | 8709 | 131.35 |
| | | | | | AEP: TWh/year | | | 2.01 | 3.83 | 3.64 | 0.80 | 66.30 | |

Values in bold are the lowest values

**Table 12.** LCOE for the second 40-year period of operation; the third period is the same as the second

| | | | Capex 40: £m | | | | | Upgrade | | | Operation and maintenance | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Scheme | T-G rating: MW | Number of units | Cost of turbines | 10% of bund cost | Prelims etc. @30% | Annual gen.: TWh | Year<br>Discount factor @5% | 41<br>1.00 | 42<br>0.95 | 45<br>0.82 | 46<br>0.78 | 47<br>0.75 | 79<br>0.16 | 80<br>0.15 | Totals | LOCE: £m/TWh £/MWh |
| Morecambe Bay | 20 | 120 | 2988 | 35.3 | 907 | 6.23 | Costs: £m | 865.30 | 748.72 | 646.69 | 62.09 | 59.13 | 12.41 | 11.82 | 4720 | 44.27 |
| | | | | | | | AEP: TWh/year | 4.99 | 4.75 | 4.10 | 4.88 | 4.65 | 0.98 | 0.93 | 106.63 | |
| | 20 | 140 | 3486 | 35.3 | 1056 | 7.06 | Costs: £m | 1018.52 | 872.06 | 753.22 | 71.38 | 67.98 | 14.27 | 13.59 | 5492 | 45.48 |
| | | | | | | | AEP: TWh/year | 5.65 | 5.38 | 4.65 | 5.53 | 5.27 | 1.11 | 1.05 | 120.76 | |
| | 20 | 160 | 3984 | 35.3 | 1206 | 7.76 | Costs: £m | 1159.22 | 995.36 | 859.74 | 89.48 | 601.57 | 126.25 | 120.24 | 15182.62 | 114.32 |
| | | | | | | | AEP: TWh/year | 6.21 | 5.91 | 5.11 | 6.08 | 5.79 | 1.22 | 1.16 | 132.81 | |
| | 30 | 120 | 4308 | 35.3 | 1303 | 6.33 | Costs: £m | 1195.72 | 1075.54 | 929.04 | 101.37 | 96.54 | 20.26 | 19.30 | 6942.92 | 64.12 |
| | | | | | | | AEP: TWh/year | 5.06 | 4.82 | 4.17 | 4.96 | 4.72 | 0.99 | 0.94 | 108.28 | |
| | 30 | 140 | 5026 | 35.3 | 1518 | 7.21 | Costs: £m | 1412.49 | 1253.35 | 1082.63 | 75.65 | 455.97 | 95.69 | 91.14 | 13907.19 | 112.76 |
| | | | | | | | AEP: TWh/year | 5.77 | 5.49 | 4.74 | 5.65 | 5.38 | 1.13 | 1.08 | 123.33 | |
| | 30 | 160 | 5744 | 35.3 | 1734 | 7.98 | Costs: £m | 1593.23 | 1431.13 | 1236.21 | 59.36 | 56.53 | 11.86 | 11.30 | 7942.07 | 58.17 |
| | | | | | | | AEP: TWh/year | 6.38 | 6.08 | 5.25 | 6.25 | 5.95 | 1.25 | 1.19 | 136.52 | |
| North Wales lagoon | 15 | 100 | 2090 | 72.4 | 649 | 3.71 | Costs: £m | 562.22 | 535.45 | 462.54 | 0.00 | 0.00 | 0.00 | 0.00 | 2555.84 | 40.27 |
| | | | | | | | AEP: TWh/year | 2.97 | 2.83 | 2.44 | 2.91 | 2.77 | 0.58 | 0.55 | 63.47 | |
| | 15 | 125 | 2613 | 72.4 | 805 | 4.43 | Costs: £m | 698.07 | 664.83 | 574.31 | 0.00 | 0.00 | 0.00 | 0.00 | 3173 | 41.87 |
| | | | | | | | AEP: TWh/year | 3.54 | 3.38 | 2.92 | 3.47 | 3.31 | 0.69 | 0.66 | 75.79 | |
| | 15 | 160 | 3344 | 72.4 | 1025 | 5.24 | Costs: £m | 888.26 | 845.97 | 730.78 | 0.00 | 0.00 | 0.00 | 0.00 | 4038 | 45.05 |
| | | | | | | | AEP: TWh/year | 4.19 | 3.99 | 3.45 | 4.10 | 3.91 | 0.82 | 0.78 | 89.63 | |
| | 20 | 100 | 2710 | 72.4 | 835 | 3.83 | Costs: £m | 723.42 | 688.98 | 595.16 | 0.00 | 0.00 | 0.00 | 0.00 | 3289 | 50.19 |
| | | | | | | | AEP: TWh/year | 3.06 | 2.92 | 2.52 | 3.00 | 2.86 | 0.60 | 0.57 | 65.52 | |
| | 20 | 125 | 3388 | 72.4 | 1038 | 4.63 | Costs: £m | 899.57 | 856.74 | 740.08 | 0.00 | 0.00 | 0.00 | 0.00 | 4089 | 51.63 |
| | | | | | | | AEP: TWh/year | 3.70 | 3.53 | 3.05 | 3.63 | 3.45 | 0.73 | 0.69 | 79.21 | |
| | 20 | 160 | 4336 | 72.4 | 1323 | 5.38 | Costs: £m | 1146.18 | 1091.60 | 942.97 | 0.00 | 0.00 | 0.00 | 0.00 | 5210 | 56.57 |
| | | | | | | | AEP: TWh/year | 4.31 | 4.10 | 3.54 | 4.22 | 4.02 | 0.84 | 0.80 | 92.11 | |

**Table 13.** Elexon half-hourly sell price summary

| Year | Sell price: £/MWh | | |
|---|---|---|---|
| | Average | Maximum | Minimum |
| 2016 | 40.0 | 1528.7 | −100.0 |
| 2017 | 45.1 | 1509.8 | −73.1 |
| 2018 | 57.4 | 990.0 | −150.0 |
| 2019 | 41.9 | 375.0 | −88.0 |
| 2020 | 34.9 | 2242.3 | −70.5 |
| 2021 | 113.2 | 4037.8 | −70.0 |
| 2022 | 200.2 | 4036.0 | −90.3 |
| 2023 to 22 May | 117.3 | 1950.0 | −128.1 |
| Average | 76.1 | 2102.8 | |

RAB is better suited to a 120-year tidal range project, benefitting both parties and saving money for the electricity customers in the long run. Under RAB, income is available from financial closure of the agreement (i.e. before construction starts) so that the effective debt built up in the project is reduced. Price support is unlikely to be required after a period of 40 years when a plant upgrade would be required. Another benefit of RAB is that the regulator can stipulate broader conditions such as tidal range management for specific objectives. Constraints could include stopping generation early to provide flood protection or pumping to match existing low water levels for ecological reasons.

### 7.2 Return on investment

To highlight the impact of funding costs and support mechanisms on the economic viability of schemes, the IRR has been calculated for the case studies. The support price (electricity support price in £/MWh, see Table 14) is adjusted to give an IRR = 10% for CfD and 5% for RAB.

In addition to the assumptions detailed in Section 6, revenue and costs are assumed to increase at roughly the same rate so inflation is ignored in the analysis. Under these assumptions, the IRR is calculated in a spreadsheet as shown in Table 14. The analysis is carried out over 40 years of operation.

While not comprehensive – for example, tax is not included – the approach is adequate to indicate the impact of methods of funding. The RAB model gives a price of electricity less than half that from the CfD model. The RAB price, for both schemes, is below the average wholesale electricity price since 2020, from Table 13. This analysis demonstrates that tidal range is economically viable when the RAB method of funding is used.

Even with CfD funding the support price is lower than the average for 2022. Currently there is much concern that some wind generation operators are making excessive profits. The

**Table 14.** IRR analysis

| Scheme | Construction cost: £bn | Annual generation: TWh | Funding method | Electricity support price: £/MWh | IRR over 45 years: % | Construction costs: £m | | | | Revenue – O&M costs: £m | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | 1 | 2 | 6 | 7 | 8 | 44 | 45 |
| Morecambe Bay | 5.87 | 6.23 | CfD | 138 | 10.0 | −839 | −839 | −839 | −408 | 772 | 772 | 772 |
| | 5.87 | 6.23 | RAB | 65 | 5.0 | −661 | −661 | −661 | −636 | 317 | 317 | 317 |
| North Wales lagoon | 5.70 | 4.43 | CfD | 188 | 10.0 | −814 | −814 | −814 | −398 | 747 | 747 | 747 |
| | 5.70 | 4.43 | RAB | 89 | 5.0 | −641 | −641 | −641 | −617 | 309 | 309 | 309 |

O&M, operation and maintenance

payment system allows some of them to benefit from high wholesale electricity prices due to the increased cost of gas generation.

For the foreseeable future, electricity will always be required. The RAB model of funding is better suited to long-term infrastructure projects. It is vital to plan for large infrastructure projects as it is likely to be at least 11 years before such schemes are productive.

After the first 40 years the electro-mechanical equipment will be refurbished or replaced on a rolling programme. The cost will be about half the original capital cost, while the revenue will continue at about 80–90% throughout the refit period of 5–10 years. Thus, the IRR for the remaining 80 years of the project will be about double that of the first 40 years. No further subsidies will be required.

## 8. Discussion

The best decision is one that balances the costs, benefits and risks but how does one define the cost? In terms of civil construction, it is usually regarded as the sum of the money paid for components such as plant hire, materials and labour. However, the price that is paid is dependent also on perceived risk and market factors. The price starts with the cost but is then affected by factors such as the following.

- Is the construction sector buoyant or are contractors short of work?
- How many suitable capable contractors are there? Large-scale projects such as tidal range schemes are likely to require international consortia formed from several contractors with multiple skills, including dredging, marine construction, precasting, turbine supply and so on.
- What are the rate-limiting components? The availability of elements such as precast concrete will dictate the number and location of casting yards around the Irish Sea.
- Can the costs of financing major construction work be met? The outlay over 6 or 7 years of construction, prior to receiving any income will create a large debt to be serviced. International financing costs could add, say, 40–50% to the construction costs. Although interest rates may be rising, government bonds and gilts are looking weak, making green bonds look attractive to pension funds looking for long-term investments. These could reduce the financing cost.
- Are resources under high demand? Physical components (e.g. aggregate and cement) and skilled labour could be scarce in a competitive market.

The construction of a tidal barrage or lagoon is a major operation with a significant supply chain. A single project could be managed by bespoke provision, but at increased costs. The manufacture of equipment would need the development and provision of facilities that must be balanced by the size of the market for the product. Industry can respond – for example, the recent boom in design and manufacture of electric cars has been driven by major governments around the world stating their intent to replace diesel and petrol cars. For ~20 MW hydro turbines, the current world market is a handful of machines per year. Based on just these two proposed schemes, the demand in the UK would be ~285 machines over a period of 5–10 years. This new market will drive innovation to increase performance, durability and possible alternatives to the bulb turbines.

Producing a minimum of 285 turbines within a few years is probably beyond the capacity of the existing manufacturers. It should not be difficult to persuade them to establish additional manufacturing and/or assembly plants within the UK, creating a major industry with jobs and export potential for many years to come. Turbines and generators will need major refurbishment or replacement every 40 years, which will be done on a rotational basis. This will present opportunities for design and manufacturing improvements to match future conditions.

Public funding is needed to support large infrastructure development. It can be in different forms; the two presented here reflect shared risk in the initial construction period (RAB) or guarantees of payment for power produced (CfD). The consequences are clear: RAB reduces the initial outlay but has a lower rate of return while CfD continually shows increased profits after a shorter payback period (14 years compared to 21 years). The former may still be favoured by developers as it spreads the risk.

Developing a novel scheme is a chicken-and-egg situation. To obtain funding, the developer needs an estimate of the capital cost, but that can only be made once a design has been prepared. A feasibility study is required to gather data, undertake a preliminary design and produce a cost estimate. However, a developer cannot obtain funding for a feasibility study without providing an investor a cost estimate! The Lancaster 0D and cost models break the cycle and offer simple, robust and transparent initial estimates. In the absence of detailed published estimates from previous tidal range schemes, the models presented are proposed for initial pre-feasibility costs. The total values approximately match published figures.

## 9. Conclusions

The Lancaster cost model has estimated the capital cost of two proposed tidal range schemes suitable for pre-feasibility study estimates. When combined with 0D modelling of power production it can be used to rank schemes in terms of economic return.

The method can also be used to optimise the size and number of generators and the best SR for any scheme.

The RAB method of funding is most appropriate for such large, long-term, multifunctional infrastructure schemes. If adopted, there are several schemes in GB that would be economic now; surveys and feasibility studies should be started immediately.

The economic rates of return are almost high enough to attract interest from commercial investors. The results are only a rapid, partial examination of the system, but are encouraging enough as to warrant more detailed research and feasibility studies. In the current economic, environmental and social climates these schemes appear to be viable commercially.

Not included in the cost–benefit analysis are:

- the environmental and land-use benefits of flood protection
- social–economic benefits to local residences and business
- conservation, protecting habitats and species.

## Disclaimer

The lead author is also a director of NWTE. None of the information included in this paper is directly from or can be attributed to NWTE.

This research did not receive any specific grant from funding agencies in the public, commercial or not-for-profit sectors.

## Acknowledgement

The authors thank fellow research students from Lancaster University School of Engineering, Energy, Renewable Energy group for their help and support; in particular, former student Nathan Pycroft.

### REFERENCES

Aggidis GA and Benzon DS (2013) Operational optimisation of a tidal barrage across the Mersey estuary using 0-D modelling. *Ocean Engineering* **66**: 69–81, https://doi.org/10.1016/j.oceaneng.2013.03.019.

Aggidis GA and Feather O (2012) Tidal range turbines and generation on the Solway Firth. *Renewable Energy* **43**: 9–17, https://doi.org/10.1016/j.renene.2011.11.045.

Aldersey-Williams J and Rubert T (2019) Levelised cost of energy – a theoretical justification and critical assessment Author links open overlay panel. *Energy Policy* **124**: 169–179, https://doi.org/10.1016/j.enpol.2018.10.004.

Baker S (2021) *Development of Tidal Energy Generation Modelling Using Morecambe Bay as a Case Study Under Different Environmental, Storage and Demand Scenarios.* MRes dissertation, Lancaster University, Lancaster, UK. See https://eprints.lancs.ac.uk/id/eprint/151442/1/2020bakermres.pdf (accessed 23/05/2023).

Bass RJ, Malalasekera W, Willmot P and Versteeg HK (2011) The impact of variable demand upon the performance of a combined cycle gas turbine (CCGT) power plant. *Energy* **36(4)**: 1956–1965, https://doi.org/10.1016/j.energy.2010.09.020.

Burrows R, Walkington IA,Yates NC, Hedges TS and Li M (2009a) Tidal energy potential in UK waters. *Proceedings of the Institution of Civil Engineers – Maritime Engineering* **162(4)**: 155–164, https://doi.org/10.1680/maen.2009.162.4.155.

Burrows R, Walkington I, Yates N *et al.* (2009b) *Tapping the Tidal Power Potential of the Eastern Irish Sea*. Joule Project JIRP106/03, University of Liverpool, Liverpool, UK. See https://livrepository.liverpool.ac.uk/3005967/2/Joule-Tide-Final-Rpt_Dec09_inc_Appendices.pdf (accessed 24/05/2023).

Elexon (2022) *Half Hourly Open Settlement Data*. Elexon, London, UK. See https://www.elexon.co.uk/data/open-settlement-data/ (accessed 22/02/2022).

Fay JA and Smachlo MA (1983) Capital cost of small-scale tidal power plants. *Journal of Energy* **7(6)**: 536–541, https://doi.org/10.2514/3.62695.

George A (2020) Tidal lagoon could replace Wylfa. *North Wales Chronicle*, 23 September. See https://www.northwaleschronicle.co.uk/news/18742300.tidal-lagoon-replace-wylfa/ (accessed 24/05/2023).

Hammons TJ (2011) Tidal power in the UK and worldwide to reduce greenhouse gas emissions. *International Journal of Engineering Business Management* **3(2)**: 16–28.

Harcourt F, Angeloudis A and Piggott MD (2019) Utilising the flexible generation potential of tidal range power plants to optimise economic value. *Applied Energy* **237**: 873–884, https://doi.org/10.1016/j.apenergy.2018.12.091.

IEA (International Energy Agency) and NEA (Nuclear Energy Agency) (2020) *Projected Costs of Generating Electricity.* IEA, Paris France and Organisation for Economic Co-operation and Development/NEA, Boulogne-Billancourt, France. See https://www.iea.org/reports/projected-costs-of-generating-electricity (accessed 22/08/2022).

Makovšek D and Veryard D (2016) *The Regulatory Asset Base and Project Finance Models: An Analysis of Incentives for Efficiency.* OECD Publishing, Paris, France, International Transport Forum Discussion Papers No. 2016/01. See https://www.oecd-ilibrary.org/transport/the-regulatory-asset-base-and-project-finance-models_5285ca82-en (accessed 24/05/2023).

Neill SP, Angeloudis A, Robins PE *et al.* (2018) Tidal range energy resource and optimization – past perspectives and future challenges. *Renewable Energy* **127**: 763–778, https://doi.org/10.1016/j.renene.2018.05.007.

NTPG (Northern Tidal Power Gateway) (2020a) *Protecting the Environment & Mitigating Climate Change.* NTPG, Manchester, UK.

NTPG (2020b) https://northerntidalpowergateways.co.uk/ (accessed 06/03/2023).

NTSLF (National Tidal and Sea Level Facility) (2023) *Real-time Data – UK National Tide Gauge Network*. National Oceanography Centre, Southampton, UK. See https://ntslf.org/data/uk-network-real-time (accessed 07/06/2023).

NWTE (North Wales Tidal Energy) (2023) https://www.northwalestidalenergy.com (accessed 06/03/2023).

OES (Ocean Energy Systems) (2015) *International Levelised Cost of Energy for Ocean Energy Technologies*. OES, Lisbon, Portugal. See https://www.ocean-energy-systems.org/oes-projects/levelised-cost-of-energy-assessment-for-wave-tidal-and-otec-at-an-international-level/ (accessed 07/06/2023).

ONS (Office for National Statistics) (2023) *Construction Output Price Indices*. ONS, Newport, UK. See https://www.ons.gov.uk/businessindustryandtrade/constructionindustry/datasets/interimconstructionoutputpriceindices (accessed 24/05/2023).

Parsons Brinckerhoff Ltd (2008) *Analysis of Options for Tidal Power Development in the Severn Estuary – Interim Options Analysis Report. Volume 1*. Department for Energy and Climate Change, London, UK. See https://webarchive.nationalarchives.gov.uk/ukgwa/20101209161505/http://www.decc.gov.uk/publications/basket.aspx?FilePath=What+we+do%2fUK+energy+supply%2fEnergy+mix%2fRenewable+energy%2fSevern+Tidal+Power+feasibility+study%2f1_20090715085042_e_%40%40_OptionsforTidalPowerDevelopmentintheSevernEstuartyAnalysisReportVolume1.pdf&filetype=4 (accessed 24/05/2023).

SDC (Sustainable Development Commission) (2006) *The Role of Nuclear Power in a Low Carbon Economy*. SDC, London, UK. See https://research-repository.st-andrews.ac.uk/bitstream/handle/10023/2271/sdc-2006-nuclear-low-carbon-economy.pdf;sequence=1 (accessed 24/05/2023).

Vandercruyssen D, Baker S, Howard D and Aggidis G (2022a) Tidal range electricity generation: a comparison between estuarine barrages and coastal lagoons. *Heliyon* **8(11)**: e11381, https://doi.org/10.1016/j.heliyon.2022.e11381.

Vandercruyssen D, Howard D and Aggidis G (2022b) A model of the costs for tidal range power generation schemes. *Proceedings of the Institution of Civil Engineers – Energy*, https://doi.org/10.1680/jener.22.00058.

Waters S and Aggidis GA (2016) A world first: Swansea Bay Tidal lagoon in review. *Renewable and Sustainable Energy Reviews* **56**: 916–921, https://doi.org/10.1016/j.rser.2015.12.011.