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Manuscript title: Tidal range power generation: case studies combining the Lancaster 0-D generation and cost models

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Abstract

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); 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.

Highlights

- Initial estimation of capital cost for tidal range case studies using 5-main components
- Optimisation of generator rating, number of turbines and sluices
- Levelised cost of energy (LCOE).
- Revenue and funding mechanisms.

Keywords: Offshore Renewable Energy; Economics & finance; Power stations (non-fossil fuel); UN SDG 7: Affordable and clean energy; UN SDG 9: Industry, innovation and infrastructure; UN SDG 13: Climate action

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1 Introduction

This is the third in a series of papers by the authors on tidal range generation in Great Britain (Vandercruyssen et al., 2022a; Vandercruyssen et al., 2022b). The first paper compares case studies of power generation from a coastal lagoon and an estuarine barrage. It uses the Lancaster 0-D tidal range model to estimate the annal electricity production (AEP) for various combinations of turbine numbers, generator ratings and sluice ratios (ref). The 0-D 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 is 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. Our 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 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.

Several published studies have examined the power generation from tidal range schemes in Great Britain (GB) (Aggidis and Benzon, 2013; Aggidis and Feather, 2012; Burrows et al., 2009a; Burrows et al., 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 0-D Model (Vandercruyssen et al., 2022a) to estimate the annual electricity production (AEP) for specific schemes, under scenarios that optimise the potential power generation and costs using different numbers of turbines, generator ratings and sluice ratios. 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 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 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.

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2 The Lancaster Cost Model

The cost of the main components of a tidal range scheme has been based on 5-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 meter of materials required. The components are:

- Turbo-generator
- 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 (Vandercruyssen et al., 2022b) are expressed in pound 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 for new infrastructure construction (Office for National Statistics, 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 alternative to bunds. Details of the 5-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 components: e.g., numbers of turbines, generator ratings, and sluice ratio. 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 NTPG (Northern Tidal Power Gateway, 2020b). Their initial proposal employed 125 x 8m diameter 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 -5m OD (Newlyn) for 12-km of the length and -10m 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 8.5m, giving an approximate rated head of 6.4m. Mean high water springs (MHWS) level is 4.77m OD (The National Oceanography Centre). The published estimate of capital costs are shown in Table 2 reproduced from (Northern Tidal Power Gateway, 2020b). Their published figures have been updated to 2022 prices using the Construction Price Index (CPI) for new infrastructure (Office for National Statistics, 2023); the increase from Jan-19 to Jan-22 is 1.14.

3.2 North Wales Coastal Lagoon

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

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4 Costs for Proposed Schemes

4.1 Turbo-generators

Using Eqn. 16 from (Vandercruyssen et al., 2022b) with the updated rates from Table 1, gives the estimated costs of turbo-generators 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; Vandercruyssen et al., 2022a); i.e., H_o = 5.4m for North Wales, H_o = 6.4m 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 7.6m diameter and were manufactured over 10 years ago. All the proposed runners are 8.0m diameter, which is about the largest considered to be available to date. The mean spring tide ranges for North Wales and Morecambe Bay are 7.2m and 8.5m respectively. The costs for a powerhouse (Table 4) are estimated using Eqn. 3 from (Vandercruyssen et al., 2022b) with the updated rates from Table 1.
The definition used here for the sluice ratio is the total area of sluice aperture divided by the total area of the turbine runners. The sluices are assumed to be 15m wide x 15m high, giving an area of 225 m^2. The turbine runners are 8.0m diameter, giving an area for each of 50.3 m^2. Thus, for a sluice ratio of 1 the total area of sluices matches the total area of turbine runners with approximately 9 turbines for two sluices. Using Eqn. 4 from (Vandercruyssen et al., 2022b), the cost of a 15m square sluice is also calculated in Table 4. Thus, for a sluice ratio of 1, there will be 0.22 sluices for every turbo-generator unit.

4.3 Cost of cofferdams.

The cost per meter of the cofferdams is taken from Eqn. 5 of (Vandercruyssen et al., 2022b) . The height H_b is the same as 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 16m, for 8m diameter turbines, and the width of each sluice (W_s) as 15m. Thus, the total length of cofferdams for various numbers of turbo-generator units (N_{t+g}) is calculated by Eqn 1, giving the total cost in Table 6.

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

4.4 Cost of Bunds

The crest level of the bund is assumed to be the mean high-water springs (MHWS) level plus 2m for storm surges and 1m 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 & 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.

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4.5 Estimates for case studies.

The estimated costs of the components for the two case studies are given in Table 8. In the previous paper (Vandercruyssen et al., 2022b) the authors initially increased the capital costs by 30% of the civil engineering costs to allow for preliminaries, surveys, design, contingencies as used in the government funded study of the River Severn Interim Options Analysis Report, (IOAR) (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 over estimated 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:

- The generator rating.
- The output with different numbers of turbines.
- the sluice ratio.

To illustrate how these factors influence LCOE the 0-D modelling output is used. Figure 1 shows the AEP against numbers of turbo-generators. The solid lines represent North Wales Lagoon (NW) and the dashes represent Morecambe Bay Barrage (MB). For NW the gap between 10-MW and 15-MW lines is wider than the gap between the 15-MW 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 20-MW 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 to 8.0m diameter. Figure 1 shows the relationship between the generation output and the number of turbo-generators of different ratings. For 125 x 30-MW machines the predicted annual generation from Morecambe Bay is 6.58 $TWha^{-1}$. The generation from the same number of 20-MW machines is 6.39 $TWha^{-1}$, representing only a 3% reduction in output. It has been shown that the cost of the turbo-generator is a function of the generator rating for a given rated head, Table 3. Thus, the cost of a 20-MW turbo-generator with the same 6.4m 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 versus 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 (Northern Tidal Power Gateway, 2020a) and 160 units (Baker, 2021). Table 9 shows the calculation of costs and AEP for both schemes with various numbers of units. For a sluice ratio of 1, a

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single 15x15m sluice will be required for every 4.5 turbines of 8m 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 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 most cost-effective option is 100-turbines with 15-MW generators. The cost/TWh for the estuarine barrage is 74% of that for the coastal lagoon.

The last column in Table 9 shows the estimated annual CO_2 offset, valued as the equivalent power generation from a combined cycle gas turbines (CCGTs) operating at maximum commercial rate of 350 kg/MWh (Bass et al., 2011). Bass et al measured the CO_2 emissions from a grid connected CCGT under various operating conditions over a period of 3-months. During cold or hot starts the CO_2 emissions increased to 470 and 590 kg/MWh respectively. If the goal is to generate as much renewable electricity as possible and maximise the CO_2 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 of CO_2 per annum from Morecambe Bay and 1.55 Mt from North Wales.

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

5.3 Number of units versus the sluice ratio

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 sluice ratios of 1, 2 & 4 for 20-MW machines. Taking the costs of sluices from Table 4, the cost of cofferdam from Table 5, the total scheme costs from Table 9 and assuming 125 turbines with 20-MW machines, with various sluice ratios, is shown in Table 10. For this configuration the minimum cost per TWh comes from a sluice ratio of 2.

6 Levelised Cost of Energy

The Levelised Cost of Energy (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 Capital Expenditure (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.

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

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$$LCOE = \frac{\sum_{t=0}^{N} \frac{Cost_t}{(1+r)^{year}}}{\sum_{t=0}^{N} \frac{Electrical\ Energy}{(1+r)^{year}}} = \frac{£}{MWh} \quad (2)$$

OES assumed a discount rate of 10% for contingency as emerging technologies (Ocean Energy Systems, 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.
- Turbo-generators 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: -

- the turbo-generators 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 turbo-generators 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 first 40-years. Without inflation or changes in relative costs, the cost of electricity for future generations falls as well as providing flood protection from rising sea levels. These calculations do not include any allowance for carbon credit or other benefits such as transport, health, tourism or conservation.

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 (International Energy Agency and NEA OECD Paris, 2020); which predicts the LOCE for gas in Europe is around £60/MWh. However, in the two 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 in Table 11 & 12 values are significantly lower than the figures quoted by OES (Ocean Energy Systems, 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 price 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.

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Whilst 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 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 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 (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 principle 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 to 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) principal. 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 Internal Rate of Return (IRR) of less than 10 to 15%.

The alternative support mechanism is called Regulated Asset Base (RAB) and has been used for major infrastructure projects, such as London Cross Rail, and Heathrow Airport Terminal 5. It is being considered for new offshore wind and approved for Sizewell C nuclear (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 of that of the CfD mechanism. RAB is better suited to a 120-year tidal range project benefitting both parties and saves 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.

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7.2 Return on Investment

To highlight the impact of funding costs and support mechanisms on the economic viability of schemes, the Internal Rate of Return (IRR) has been calculated for the case studies. The support price (electricity support price £/MWh 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.

Whilst not comprehensive, e.g., 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 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 project 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, whilst the revenue will continue at about 80 to 90% throughout the refit period of 5 to 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:

- Is the construction sector buoyant or are contractors short of work?
- How many suitable capable contractors are there? Large scale projects like tidal range schemes are likely to require international consortia formed from several contractors with multiple skills including dredging, marine construction, pre-casting, turbine supply, etc.
- What are the rate limiting components? The availability of elements such as pre-cast 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.

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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 to 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 whilst CfD continually shows increased profits after a shorter payback period (in the example 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 0-D and cost models breaks the cycle and offers 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 0-D 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 sluice ratio for any scheme.

Regulated Asset Base (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.

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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

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Notation

C_b	Cost/m of bund, m2.
C_c	Cost/m of cofferdam, US$ or GB£.
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-1.5MW-1.
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 pre-cast concrete, $m-3.
W_s	Width of sluice, m.
W_p	Width of powerhouse unit, m.

Glossary

0-D	Zero-dimension model for tidal range power generation.
AEP	Annual Electricity Production
Capex	Capital Expenditure
CCGT	Combined Cycle Gas Turbines
CfD	Contract for Difference funding model
CO_2	Carbon Dioxide
CPI	Construction Price Index UK
GB	Great Britain
IRR	Internal Rate of Return, finance function.
LCOE	Levelised Cost of Energy
Mt	Million tonnes

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MW Power in megawatts.
MWh Energy in megawatt hours.
NPV Net present value
NTPG Northern Tidal Power Gateway
NWTE North Wales Tidal Energy Ltd
OD Ordnance Datum Newlyn in metres
Opex Operating Expenditure
RAB Regulated Asset Base funding model
SR Sluice Ratio
T-G Turbo generator
TWh Energy in terawatt hours.
$TWha^{-1}$ Terawatt hours per annum

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Table 1 Rates of conversion from 2016 to 2022 using UK CPI (Office for National Statistics, 2023) for cost rates (R) of the Lancaster Cost Model

	Turbo-Generator	Power-house	Sluices	Cofferdam	Bund	Pre-cast Caissons
Rates	R1	R2	R3	R4	R5	R6
Values £, 2016	3.66	258	283	47	18	311
Values £, 2022	4.25	299	328	55	21	360

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

Estimated Costs £m	Morecambe Bay	
	2019	2022
Barrage only	£7,082	£8,073
Barrage roads	£48	£55
Enabling road infrastructure	£145	£165
Professional services and connection to the National Grid.	£688	£784
Total scheme costs	£7,963	£9,078

Table 3 Estimated costs per turbo-generator set (£m, 2022)

Site	Ho Rated head (m)	Generator rating MW				
		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

Site	North Wales	Morecambe Bay
mean spring tidal range (m)	7.2	8.5
C_p Cost of each powerhouse, (£m)	5.8	6.8
C_s Cost of each sluice gate, (£m)	9.6	11.3

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

C_c Cost of cofferdams, £/m	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
H_b height of bund, (m)	21.51	22.77
C_c cost of cofferdam, (£/m)	£23,712	£26,571

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

Site	N_{t+g}				
	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

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

Scheme	Crest level (m OD)	Seabed level (m OD)	O/A height of Bund H_b (m)	Width of crest (m)	C_b Cost of bund £/m, 2022		L_b Length at this height (km)
					Embankment at 1 in 2	Embankment at 1 in 3	
Morecambe Bay Barrage	7.8	-5	12.8	20	17,633	23,762	12
	7.8	-10	17.8	20	28,259	38,651	5
North Wales Coastal Lagoon	6.5	-5	11.5	10	12,800	17,992	12
	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	P_e turbo-generator rating MW	N_{t+g} Number of units	Costs £m							Capital Cost (£bn, 2022)	
			Total turbo-generators	Power-house	Sluice	Coffer dam	Bund embankment		Prelims & contingencies		
							L_b Length (km)	C_b Cost (£k/m)			
Reference			Table 3	Table 4	Table 4	Table 6	Table 7		at 30%	Estimate	Published
Morecambe Bay	30	125	125 @ £35.9m	125 @ £6.8m	28 @ £11.3m	equ 8	12.0 5.0	£17.6 £28.3		7.89	8.07
			£4,488	£850	£316	£64	£353		£1,821		
North Wales Coastal Lagoon	20	125	125 @ £27.1m	125 @ £5.8m	28 @ £9.6m	equ 8	12.0 8.0 12.0	£12.8 £21.8 £33.0		6.71	7.00
			£3,388	£725	£269	£57	£724		£1,549		

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Table 9 Calculation for estimated costs and annual generation for different numbers or turbines and generator ratings. Figures in bold show the cheapest for each scheme, those in italics the greatest carbon offset.

Scheme	T-G rating (MW)	No. of units	Costs £m								Annual gen TWh	cost rate £m/TWh	Annual CO_2 mt offset
			turbines	power-houses	Sluices		Cofferdams	Bunds	Prelims & contingency @30%	Total cost			
		N_{t+g}			N_s	Total cost							
Morecambe Bay	20	120	£2,988	£816	26	£298	£62	£353	£1,355	£5,873	6.23	**942**	2.18
		140	£3,486	£952	31	£348	£72	£353	£1,563	£6,774	7.06	960	2.47
		160	£3,984	£1,088	35	£398	£82	£353	£1,771	£7,676	7.76	989	2.72
	30	120	£4,308	£816	26	£298	£62	£353	£1,751	£7,589	6.33	1,199	2.22
		140	£5,026	£952	31	£348	£72	£353	£2,025	£8,776	7.21	1,217	2.52
		160	£5,744	£1,088	35	£398	£82	£353	£2,299	£9,964	7.98	1,249	*2.79*
North Wales Coastal Lagoon	15	100	£2,090	£580	22	£210	£46	£724	£1,095	£4,746	3.71	**1,279**	1.30
		125	£2,613	£725	28	£263	£57	£724	£1,314	£5,696	4.43	1,286	1.55
		160	£3,344	£928	35	£337	£73	£724	£1,622	£7,027	5.24	1,341	1.83
	20	100	£2,710	£580	22	£210	£46	£724	£1,281	£5,552	3.83	1,449	1.34
		125	£3,388	£725	28	£263	£57	£724	£1,547	£6,703	4.63	1,448	1.62
		160	£4,336	£928	35	£337	£73	£724	£1,919	£8,317	5.38	1,545	*1.88*

Table 10 Effect of various sluice ratios on annual generation for North Wales

Sluice ratio	Sluices		Extra cost of cofferdams (£m)	Total cost £m	Annual gen TWh	cost per TWh
	No	Total £m				
1	28	263	0	5,696	4.63	1,230
2	56	526	10	5,706	4.79	1,190
4	112	1,052	20	6,242	4.99	1,251

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Table 11 Levelised cost of energy for the first 40-years including construction. Figure highlighted in bold are the lowest values

Scheme	T-G rating (MW)	No. of units	Total CAPEX £m	Annual gen TWh		Construction			Operation & Maintenance			Totals	LOCE £m/TWhr £/MWhr
					Year	1	2	7	8	9	40		
		N_{t+g}			Discount factor @5%	1.00	0.95	0.75	0.71	0.68	0.15		
Morecambe Bay	20	120	£5,873	6.23	Costs £m	£839.01	£799.05	£626.08	£62.61	£59.63	£13.14	6149.52	80.12
					AEP (TWhr/y)			2.33	4.43	4.22	0.93	76.76	
		140	£6,774	7.06	Costs £m	£967.76	£921.68	£722.16	£72.22	£68.78	£15.16	7093.26	81.60
					AEP (TWhr/y)			2.63	5.02	4.78	1.05	86.93	
		160	£7,676	7.76	Costs £m	£1,096.60	£1,044.38	£818.30	£81.83	£77.93	£17.17	8037.55	84.08
					AEP (TWhr/y)			2.90	5.52	5.25	1.16	95.60	
	30	120	£7,589	6.33	Costs £m	£1,084.15	£1,032.52	£809.01	£80.90	£77.05	£16.98	7946.30	101.96
					AEP (TWhr/y)			2.36	4.50	4.28	0.94	77.94	
		140	£8,776	7.21	Costs £m	£1,253.76	£1,194.06	£935.58	£93.56	£89.10	£19.63	9189.51	103.51
					AEP (TWhr/y)			2.69	5.12	4.88	1.08	88.77	
		160	£9,964	7.98	Costs £m	£1,423.46	£1,355.67	£1,062.20	£106.22	£101.16	£22.29	10433.26	106.17
					AEP (TWhr/y)			2.98	5.67	5.40	1.19	98.27	
North Wales Lagoon	15	100	£4,746	3.71	Costs £m	£677.93	£645.65	£505.89	£50.59	£48.18	£10.62	4968.95	108.76
					AEP (TWhr/y)			1.38	2.64	2.51	0.55	45.69	
		125	£5,696	4.43	Costs £m	£813.71	£774.96	£607.20	£60.72	£57.83	£12.74	£5,964	109.33

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					AEP (TW hr/y)			1.65	3.15	3.00	0.66	54.55	
		160	£7,027	5.24	Costs £m	£1,003.91	£956.10	£749.13	£74.91	£71.35	£15.72	£7,358	114.05
					AEP (TW hr/y)			1.95	3.72	3.55	0.78	64.52	
	20	100	£5,552	3.83	Costs £m	£793.08	£755.31	£591.81	£59.18	£56.36	£12.42	£5,813	123.25
					AEP (TW hr/y)			1.43	2.72	2.59	0.57	47.16	
		125	£6,703	4.63	Costs £m	£957.64	£912.04	£714.61	£71.46	£68.06	£15.00	£7,019	123.11
					AEP (TW hr/y)			1.73	3.29	3.13	0.69	57.02	
		160	£8,317	5.38	Costs £m	£1,188	£1,132	£887	£88.66	£84.44	£18.61	£8,709	131.35
					AEP (TW hr/y)			2.01	3.83	3.64	0.80	66.30	

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Table 12 Levelised cost of energy for the second 40-year period of operation; the third period is the same as the second.

Scheme	T-G rating (MW)	No. of units	CAPEX 40			Annual gen TWh		Upgrade			Operation & Maintenance				Totals	LOCE £m/TWhr £/MWhr
			Cost of turbines	10% of bund cost	Prelims etc @ 30%		Year	41	42	45	46	47	79	80		
							Discount factor @ 5%	1.00	0.95	0.82	0.78	0.75	0.16	0.15		
Morecambe Bay	20	120	£2,988	35.3	£907	6.23	Costs £m	£865.30	£748.72	£646.69	£62.09	£59.13	£12.41	£11.82	£4,720	44.27
							AEP (TWhr/y)	4.99	4.75	4.10	4.88	4.65	0.98	0.93	106.63	
		140	£3,486	35.3	£1,056	7.06	Costs £m	£1,018.52	£872.06	£753.22	£71.38	£67.98	£14.27	£13.59	£5,492	45.48
							AEP (TWhr/y)	5.65	5.38	4.65	5.53	5.27	1.11	1.05	120.76	
		160	£3,984	35.3	£1,206	7.76	Costs £m	£1,159.22	£995.36	£859.74	£89.48	£6601.57	£126.25	£120.24	15182.62	114.32
							AEP (TWhr/y)	6.21	5.91	5.11	6.08	5.79	1.22	1.16	132.81	
	30	120	£4,308	35.3	£1,303	6.33	Costs £m	£1,195.72	£1,075.54	£929.04	£101.37	£96.54	£20.26	£19.30	6942.92	64.12

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							AEP (TWhr/y)	5.06	4.82	4.17	4.96	4.72	0.99	0.94	108.28	
		140	£5,026	35.3	£1,518	7.21	Costs £m	£1,412.49	£1,253.35	£1,082.63	£75.65	£455.97	£95.69	£91.14	13907.19	112.76
							AEP (TWhr/y)	5.77	5.49	4.74	5.65	5.38	1.13	1.08	123.33	
		160	£5,744	35.3	£1,734	7.98	Costs £m	£1,593.23	£1,431.13	£1,236.21	£59.36	£56.53	£11.86	£11.30	7942.07	58.17
							AEP (TWhr/y)	6.38	6.08	5.25	6.25	5.95	1.25	1.19	136.52	
North Wales Lagoon	15	100	£2,090	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 (TWhr/y)	2.97	2.83	2.44	2.91	2.77	0.58	0.55	63.47	
		125	£2,613	72.4	£805	4.43	Costs £m	£698.07	£664.83	£574.31	£0.00	£0.00	£0.00	£0.00	£3,173	41.87
							AEP (TWhr/y)	3.54	3.38	2.92	3.47	3.31	0.69	0.66	75.79	
		160	£3,344	72.4	£1,025	5.24	Costs £m	£888.26	£845.97	£730.78	£0.00	£0.00	£0.00	£0.00	£4,038	45.05
							AEP (TWhr/y)	4.19	3.99	3.45	4.10	3.91	0.82	0.78	89.63	

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	20	100	£2,710	72.4	£835	3.83	Costs £m	£723.42	£688.98	£595.16	£0.00	£0.00	£0.00	£0.00	£3,289	50.19
							AEP (TWhr/y)	3.06	2.92	2.52	3.00	2.86	0.60	0.57	65.52	
		125	£3,388	72.4	£1,038	4.63	Costs £m	£899.57	£856.74	£740.08	£0.00	£0.00	£0.00	£0.00	£4,089	51.63
							AEP (TWhr/y)	3.70	3.53	3.05	3.63	3.45	0.73	0.69	79.21	
		160	£4,336	72.4	£1,323	5.38	Costs £m	£1,146.18	£1,091.60	£942.97	£0.00	£0.00	£0.00	£0.00	£5,210	56.57
							AEP (TWhr/y)	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	1,528.7	-100.0
2017	45.1	1,509.8	-73.1
2018	57.4	990.0	-150.0
2019	41.9	375.0	-88.0
2020	34.9	2,242.3	-70.5
2021	113.2	4,037.8	-70.0
2022	200.2	4,036.0	-90.3
2023 to 20-Apr	125.8	1,950.0	-128.1
Average	76.1	2,102.8	

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Table 14 Internal Rate of Return 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

Figure 1 Annual electricity production (AEP) for a Morecambe Bay barrage and North Wales coastal lagoon with various numbers of turbines, generator ratings, and sluice ratios.

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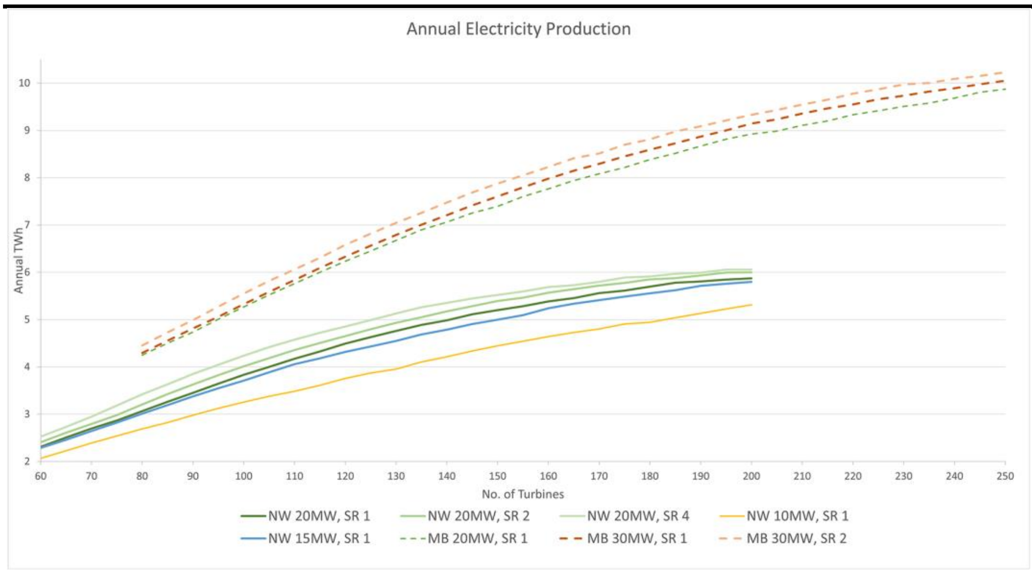

Figure 01

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