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Mechanisms for reducing the cost of tidal stream energy

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Abstract—**Recent developments in the tidal stream energy industry have seen the completion of demonstration and pre-commercialisation arrays that are now operational and connected to grid. Importantly, these projects are delivering proof of concept that provide a platform for the commercialisation of tidal stream energy, and the development of larger scale arrays in the near future. An important key performance indicator for any energy project is levelized cost of energy, a metric that is commonly used to assess cost competitiveness of projects across the energy sector. This paper gives tangible examples of how the levelized cost of energy is reducing in the tidal stream energy industry, from a leading technology and site developer's first hand perspective. We focus predominantly on cost of energy reduction that is achievable through economies of scale, such as increases to rotor diameter, generator rating and hub height. Examples are also given for how economies of volume (e.g. number of turbines), technology innovation (e.g. sub-sea hubs to connect turbines sub-sea) and finance (e.g. cost of capital) are bringing down cost of energy significantly. Results show that even a relatively small increase in rotor diameter and generator rating of 2 m (i.e. +11%) and 0.5 MW (+30%) respectively can result in significant uplifts in energy yield per turbine of 29%, and a reduction in levelized cost of energy of around 20%. These economies of scale are achievable in the near term (circa. 1 year from now) and are consistent with the design of the new AR2000 turbine, which is the upgrade to the AR1500 that is operational as part of the MeyGen Phase 1A array. Results presented here show that more significant economies of scale that are achievable further into the future can lead to a doubling of the energy yield per turbine to further reduce levelized cost of energy.**

Index Terms—**Tidal stream energy, levelized cost of energy, economies of scale and volume, technology innovation, financing.**

I. Introduction

SIGNIFICANT cost reductions in tidal stream energy are expected in the near-term as the industry transitions from pre-commercial to commercial arrays. A recent cost analysis by the Offshore Renewable Energy Catapult (OREC) recently concluded that the Levelized Cost of Energy (LCoE) for tidal stream could reduce by 70% by the time 1 GW of cumulative installed capacity has been deployed [1]. Achieving this cost reduction can help the tidal stream energy sector to realise its potential to contribute significantly to the future clean energy mix at regions of high tidal energy resource. For the UK, this potential has been estimated at around 29 TWh, which is equivelant to an install capacity of 8.5 GW [2] with an assumed capacity factor of 0.4.

Figure 1 shows OREC's LCoE projection for tidal stream energy as a function of cumulative deployment capacity [1]. Results are based upon aggregated data from multiple tidal stream developers. This includes developers of horizontal and vertical axis devices, and device capacities that range from kilowatt to megawatt scale. The OREC forecast from the aggregated data shows an LCoE of £150/MWh by 100 MW of cumulative installed capacity, £130/MWh by 200 MW cumulative capacity and £90/MWh by 1 GW of cumulative capacity. Based on OREC's analysis, LCoE reductions will be driven initially by economies of scale and volume, and enhanced by specific innovations and ongoing learning by doing. LCoE forecasts for megawatt scale devices only are expected to be lower than this aggregated forecast for kilowatt and megawatt devices.

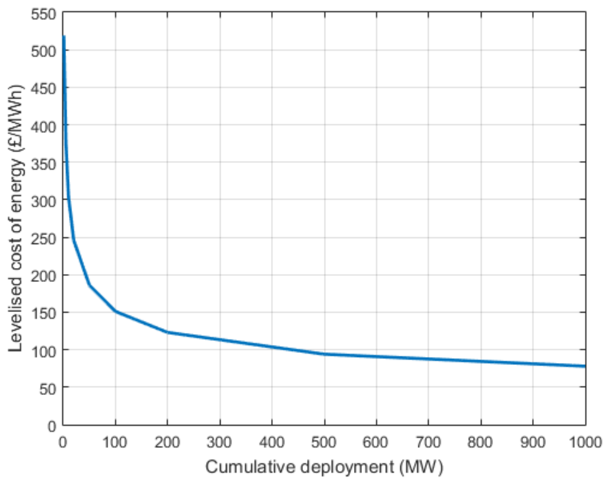

Fig. 1. Offshore Renewable Energy Catapult's projected levelized cost of energy with respect to cumulative capacity.

Similar LCoE reduction has been achieved in the wind industry with the support of subsidies. Subsidies have provided the necessary support for the installed capacity of wind power in Europe to reach 1 GW over a thirteen year period. This was doubled to 2 GW over the next three years. 5 GW of installed wind power capacity was achieved in Europe over the following two years, up to 2012 [3]. Since then large windfarms have achieved Contract for Difference (CfD) strike prices significantly below £100/MWh.

Tidal stream energy also presents opportunities for UK technology developers and supply chain companies. This net cumulative benefit to the UK is estmated to be worth £95 million per year by 2030 [1].

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A clear understanding of the mechanisms and timeliness for bringing down the cost of tidal energy relative to competing technologies is needed in order to inform future subsidy support and stimulate market investment. This paper provides insight into the near and long term mechanisms that are driving down cost of tidal energy from a turbine technology and site developer perspective. We focus predominantly on economies of scale with regards to the turbine technology, such as rotor diameter and rated power. These economies of scale reflect the transition from the AR1500 turbine, which is installed as part of the MeyGen Phase 1A project, the world's largest grid connected tidal stream turbine array project, to the AR2000, which is the upgrade to the AR1500 [4].

II. Economies of Scale

A. Rotor diameter

Figure 2 illustrates the effects of increasing rotor diameter on a turbine's power curve. The benefit from increasing rotor diameter is two-fold; (a) it reduces the rated speed of the turbine so that the turbine operates at rated power for longer periods of time, and (b) it increases the generated power of the turbine when the turbine is operating at below rated power (i.e. it improves sub-rated performance).

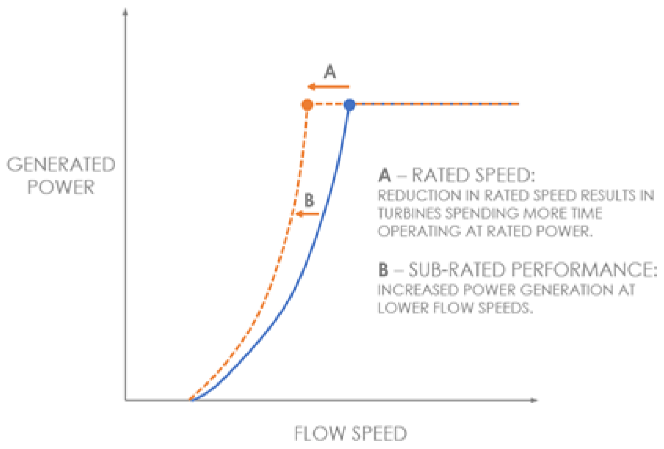

Fig. 2. Illustration of the effect of increasing rotor diameter on the power curve of a tidal stream turbine.

Figure 3 illustrates the limitations on the rotor size of tidal stream turbines. The rotor diameter is limited by the depth of water the turbine is installed in. There is a minimum clearance requirement between (a) the sea bed and the bottom of the rotor, and (b) the top of the rotor and the free surface. At MeyGen the minimum clearance required between the top blade tip height and the free surface is 8 m at lowest astronomical tide (LAT). This clearance allows vessels encountered locally to navigate safely over the turbines without colliding with the top of the rotor. At MeyGen the minimum clearance between the sea bed and the bottom blade tip height is 4.5 m. These clearance criteria mean that a turbine located at 36 m depth (LAT) has a maximum allowable rotor diameter of 23.5 m.

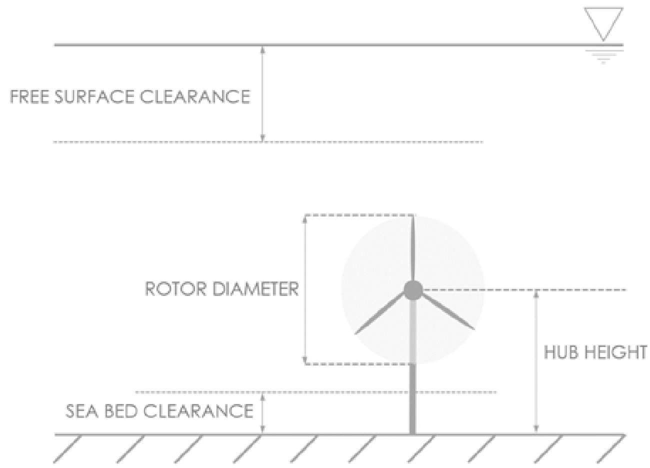

Fig. 3. Illustration of the clearance criteria with the sea bed and the free surface.

B. Hub height

Figure 4 illustrates a typical flow shear profile. This illustrates increase in flow speed with with elevation above the sea bed. Approximately one-third of the total available power is in the bottom half of the water column, and approximately two-thirds of the total available power is in the top half of the water column. Increasing the hub height of the turbine allows the turbine rotor to be located in a higher energy region of the water column to increase energy yield.

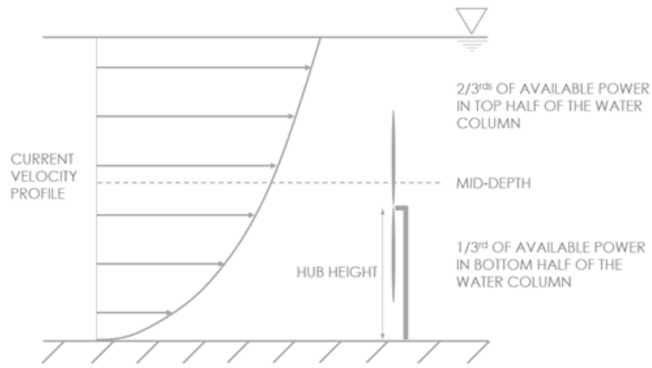

Fig. 4. Illustration of the current velocity profile relative to the hub height of a tidal turbine.

C. Rated power

Figure 5 illustrates the effect of increasing the rated power on the power curve of a tidal stream turbine. Increasing the rated power allows the turbine to generate more power at the higher flow speeds. The rated speed increases as a result of increasing the rated power. This means the turbine spends less time operating at its new, higher rated power, but nevertheless total energy yield is increased.

III. Method

D. Rotor diameter

The uplift in annual energy yield from increasing rotor diameter was quantified. The annual flow time-series at a location at the MeyGen site was obtained

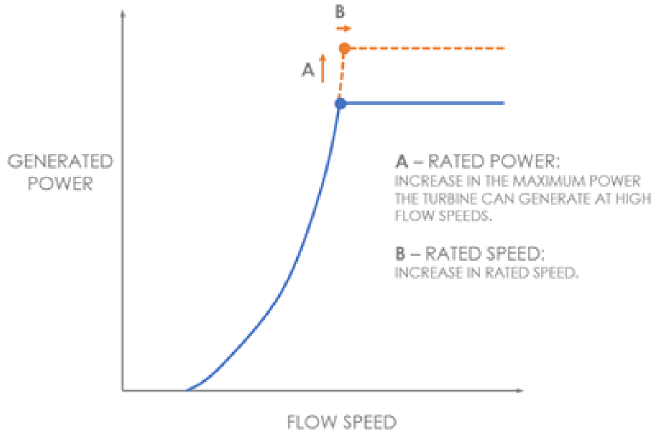

Fig. 5. Illustration of the effect of increasing rated power on the power curve of a tidal stream turbine.

from a validated hydrodynamic model. The power curve for the AR1500 was used to estimate energy yield based on the flow timeseries. The power curve has recently been verified during the power curve testing campaign using field measurements of the onset flow to the turbine. The annual energy yield was estimated for a series of rotor diameters, ranging from 18 m, which is the current rotor diameter of the AR1500, to 24 m, which is in line with the new AR2000, which is designed to have a maximum rotor diameter of 24 m [4].

E. Hub height

The uplift in yield from increasing hub height was quantified using the same approach presented above for rotor diameter. The annual energy yield was estimated for a series of hub heights, ranging from 14 m, to 19 m, which is the maximum hub height of the AR1500 based on the clearance constraints between the top of the rotor and the free surface shown in Figure 3. The rotor diameter and rated power were kept constant at 18 m and 1.5 MW respectively during the analysis.

F. Rated power

The uplift in yield from increasing rated power was quantified using the same approach presented above for rotor diameter and hub height. The annual energy yield was estimated for turbines with a range of rated power, from 1.5 MW, which is the current rated power of the AR1500, to 3 MW. Increases in rated power are considered in combination with rotor diameter. This is necessary when considering the optimum turbine specification for a given resource, since rotor diameter dictates the total power that is available to the turbine, and rated power dictates the level of power shedding.

G. Levilized cost of energy

We estimate the reduction in LCoE that is achievable as a result of implementing economies of turbine scale. levelized cost of energy (LCoE) from a project is the total lifetime cost of that project (from construction to decommissioning), divided by the energy output over its lifetime. Costs and generation occurring in the future are discounted to a net present value using a discount factor which reflects the expected cost of funding for the project. In order to estimate the LCoE of larger scale turbines, the potentially higher capital expenditure (CAPEX) of manufacturing the larger turbine must be accounted for. To do this, we consider three different CAPEX scenarios. An ”Optimistic” case assumes no increase in CAPEX as a result of the changes to the turbine specification. A ”Base” case assumes a 5% increase in CAPEX. A ”Pessimistic” case assumes a 10% increase in CAPEX. We discuss the sources of additional CAPEX, and ways that these can be mitigated.

A discount rate of 12% was implemented, however results are relatively insensitive to discount rate given that the same discount rate is used to estimate the LCoE of the AR1500 and the AR2000 and that results are presented for the change in LCoE only. A project life of 25 years was assumed. It was assumed that all OPEX costs of the turbine, including installation and decommissioning remain the same as for the AR1500.

IV. RESULTS

H. Rotor diameter

Figure 6 shows the relationship between rotor diameter and estimated annual energy yield. Results for energy yield are normalised by the energy yield of the AR1500, which we denote as E_0. Increasing the rotor diameter by 11% from 18 m to 20 m increases annual energy yield by 13%. Increasing the rotor diameter by 22% from 18 m to 22 m increases annual energy yield by 24%. Increasing the rotor diameter by 33% from 18 m to 24 m increases annual energy yield by 34%. This demonstrates that significant increases in annual energy yield are achievable, even with relatively small increases to rotor diameter.

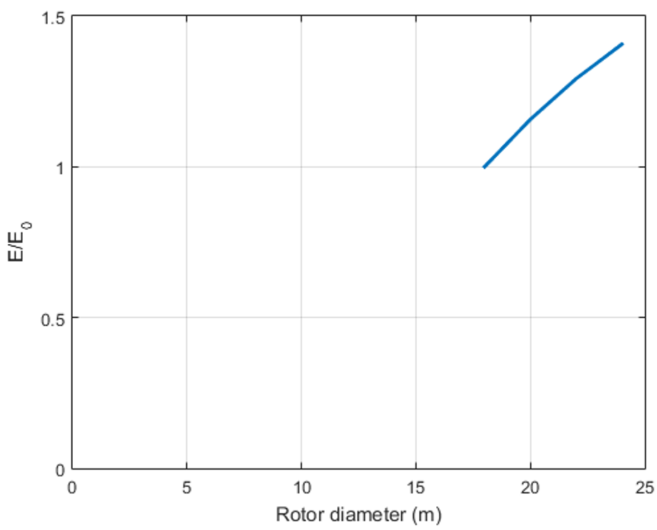

Fig. 6. Relationship between rotor diameter and annual energy yield. Results are normalised by the estimated annual energy yield of the AR1500 with its current rotor diameter of 18 m and hub height of 14 m, which is referred to as E_0

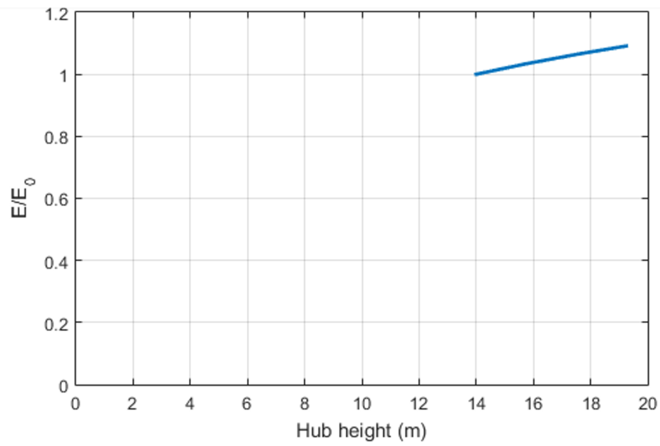

Fig. 7. Relationship between hub height and estimated annual energy yield. Results are normalised by the estimated annual energy yield of the AR1500 at a hub height of 14 m, which is referred to as E_0.

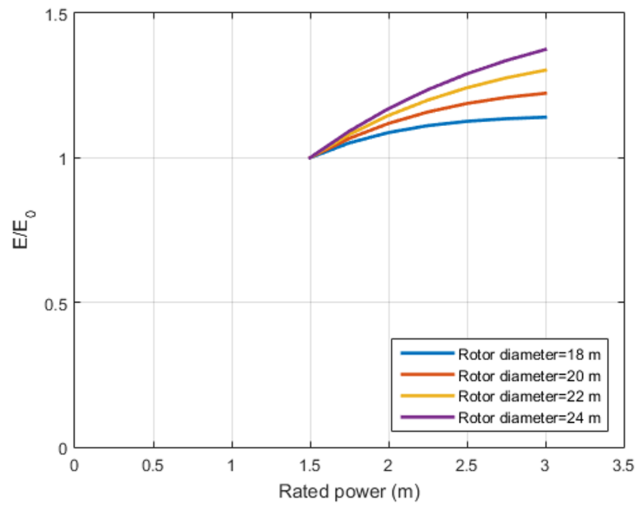

Fig. 8. Relationship between rated power and annual energy yield. Results are normalised by the estimated annual energy yield of a turbine with a 1.5 MW rated power, which is referred to as E_0.

I. Hub height

Figure 7 shows the relationship between the hub height of the rotor and the estimated annual energy yield. Results are normalised by the energy yield of the AR1500 at its current hub height, which is referred to as E_0. Results show that increasing the hub height from 14 m to 19 m increases the energy yield by approximately 10%. This relationship is approximately linear, meaning there is around a 2% increase in energy yield per metre that the hub height is increased.

J. Rated power and rotor diameter

Figure 8 shows the relationship between rated power and annual energy yield, for a range of four different rotor diameters. In all cases, as turbine rating increases, there is an increase in annual energy yield, however there is a diminishing return on yield. This diminishing return can be supressed by increasing the rotor diameter as well. For example, increasing the rated power of a turbine with an 18 m rotor diameter from 1.5 MW to 2 MW gives a 9% increase in annual energy yield. The same increase in rated power of a 20 m rotor diameter turbine gives a 12% increase in annual energy yield. The same increase in rated power of a 24 m rotor diameter turbine gives a 17% increase in annual energy yield. The reason for this, as demonstrated in Figure 2, is that increasing the rotor diameter reduces the rated speed of the turbine. As a result, the turbine generates more power when operating in below-rated flows speeds, and reaches rated power at a lower flow speed so that it spends more time at rated power.

Figure 9 shows the relationship between rotor diameter, turbine rating and energy yield to demonstrate the co-dependency between rotor diameter and turbine rating with respect to energy yield. The contour plot (Figure 9) demonstrates that (a) increasing rotor diameter only always leads to an increase in energy yield, and that (b) increasing rated power only may lead to an initial increase in energy yield, but that there is a diminishing return.

In reality the optimal turbine specification must consider rated power and rotor diameter together. This is demonstrated in the right hand plot (Figure 9), as results show that increasing the turbine rating only leads to a relatively small small increase in energy yield before any further increase in rotor diameter yields only no further increase in energy yield.

Demonstrated another way, increasing the energy yield of the turbine by 10% can be achieved in several ways, three of which are summarised in Table I. Scenario 1 (i.e. increasing rotor diameter only) limits the locations the turbine can be installed due to depth constrictions described in Section 2a. Scenario 2 (i.e. increasing rated power only) reduces capacity factor by 50%, which suggests that the cost of increasing the turbine rating to 3 MW may not be worth the additional yield that is achieved. Scenario 3 (i.e. increasing rotor diameter and rated power) is the most suitable solution for maximising energy yield in a cost-effective manner because the capacity factor is kept high and there are only modest increases in turbine rating and rotor diameter.

K. Levelized cost of energy

The preceding sections have demonstrated that significant increases in energy yield per turbine are achievable from economies of scale. This raises the question; what uplift in yield is achievable from economies of scale that are being implemented on the next generation of tidal stream turbines? Here we consider a 20 m rotor diameter, 2 MW turbine with a hub height of 15 m. This turbine specification is in line with the new AR2000. The AR2000 has been in development since September 2016 and is expected to be deployed on future phases of the MeyGen project. It is expected to be available for commercial sale at teh end of 2019 [4]. Table II provides a comparison of the turbine specification and normalised energy yield of the AR1500, the AR2000 and an AR3000 to be delivered in the longer term. Results are visualised in Figure 10. The results are presented relative to the AR1500.

The AR2000 achieves a 29% increase in energy yield relative to the AR1500. This is achieved with a 2 m in-

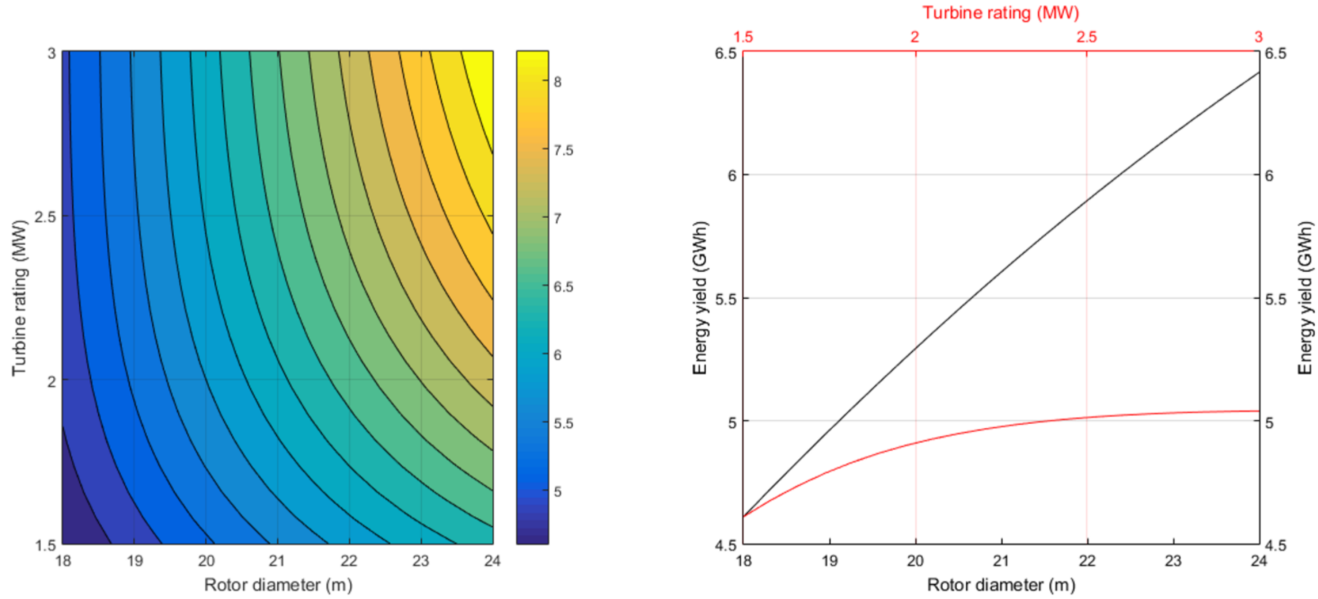

Fig. 9. (Left) Contour plot showing the relationship between rotor diameter, turbine rating and annual energy yield. (Right) Relationship between rotor diameter and energy yield (black line) with fixed rated power, as well as turbine rating and energy yield (red line) with fixed rotor diameter.

TABLE I
SUMMARY OF THE TURBINE SPECIFICATION OPTIONS FOR A TEN PERCENT INCREASE IN ENERGY YIELD OVER THE AR1500.

Scenario	Rated power	Rotor diameter	Uplift in yield	Change in capacity factor
1	1.5 MW	19.3 m	10%	0%
2	3.0 MW	18.0 m	10%	-50%
3	1.7 MW	19.0 m	10%	0%

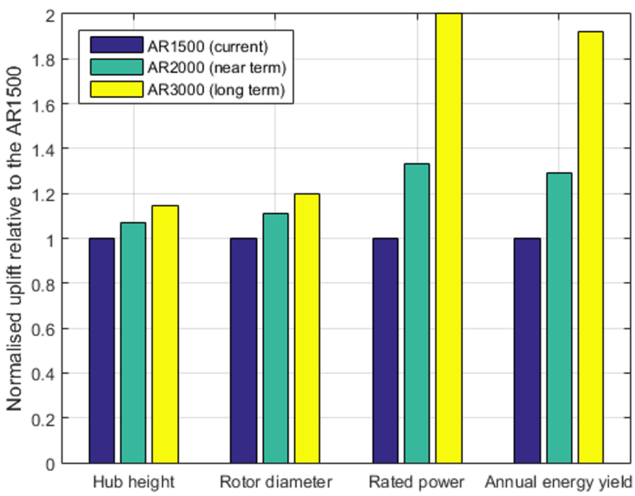

Fig. 10. Comparison between the turbine specification and performance of the current AR1500, the new AR2000 and a future AR3000 concept.

crease in rotor diameter, 0.5 MW increase in generator rating and 1 m increase in hub height. Looking further into the future, an AR3000 would achieve an increase in energy yield of 92% on the AR1500. This is achieved with a 6 m increase in rotor diameter and a 1.5 MW increase in rated power relative to the AR1500. The following section considers the impact of the uplift in energy yield on LCoE.

Table III summarises the projected LCoE reduction from the uplift in yield of the AR2000 relative to the AR1500. Results show that the LCoE reduction ranges between 17-23% depending on the increase in CAPEX of the turbine. This demonstrates a significant, near term reduction in LCoE, that is achievable by implementing relatively small modifications to the turbine specification, even in the pessimistic case considered here.

Additional CAPEX from increases in turbine scale is attributed mainly to higher loading as a result of larger blades, increased hub height and increased generator size. Regardless of this, it is possible to limit CAPEX increase. For the AR1500, design loads had a considerable degree of conservatism, which is acceptable and necessary for a first in class device. As such it is possible to reduce the conservatism of future turbine generations, whilst maintaining suitable safety factors in line with standards for tidal stream turbine design [5]. For this reason the most likely reduction in LCoE is somewhere between the Pessimistic and Optimistic scenarios considered here.

V. DISCUSSION

Results in Section IV have demonstrated the significant uplift in yield per turbine and reduction in LCoE that is achievable through simple economies of turbine scale. In addition, economies of volume, technical innovation and financing have the potential to bring

TABLE II
COMPARISON OF THE TURBINE SPECIFICATION AND TURBINE PERFORMANCE OF THE EXISTING AR1500, THE NEW AR2000, AND A FUTURE AR3000 CONCEPT.

	AR1500	AR2000	AR3000 (concept)
Turbine specification			
Hub height	14 m	15 m	19 m
Rotor diameter	18 m	20 m	24 m
Rated power	1.5 MW	2 MW	3 MW
Turbine performance			
Normalised energy yield	1	1.29	1.92

TABLE III
SUMMARY OF CAPEX INCREASE AND LCOE REDUCTION BY TRANSITIONING FROM THE AR1500 TO THE AR2000 AT MEYGEN.

	Pessimistic	Base	Optimistic
CAPEX increase	10%	5%	0%
LCoE reduction	17%	20%	23%

additional cost reductions, as has been seen in the wind industry. For example, analysis of recent UK Offshore Wind auction bid prices by OREC highlight that the most significant cost reduction has come through cost of capital, with debt proportions and margins and, at least as significantly, cost of equity, having reduced dramatically. In time, this type of reduction should also apply for tidal stream [1]. In this section we briefly outline some examples of how LCoE is being driven down by through these concurrent mechanisms.

L. *Economies of volume*

To date tidal stream turbine arrays have been developed to demonstrate technologies using a relatively small number of turbines. Demonstration arrays are necessary to validate innovations that have not been implemented on previous projects but are necessary to reduce the long-term cost of electricity. Examples of these technology developments are outlined in Section Vb below.

An example economy of volume is the spread of cost across turbines when mobilising and de-mobilising vessels for offshore operations. Mobilisation is the process of preparing the vessel from the quayside to carry out offshore operations. De-mobilisation is the process of restoring the vessel to its pre-installation state once it has returned to the quayside after conducting the offshore operation. It is typical for the time required to mobilise and de-mobilise a vessel to take-up a significant proportion of the total vessel time when installing small arrays.

Table IV compares the estimated mobilisation and de-mobilisation time for the installation of the MeyGen Phase 1A (6 MW array) and MeyGen Phase 1C (75 MW array). There is a reduction in the number of mobilisation and de-mobilisation time per turbine of 33% and 12% respectively as a result of the economy of volume associated with the MeyGen Phase 1C array. This results in a total reduction in time for mobilisation and de-mobilisation per turbine of 26%, thereby reducing the vessel hire costs by a similar amount. Typically in the UK vessel costs vary temporally depending on demand, but as a rough estimate can range between £40,000 – £100,000/day. In addition to the installation of the turbines, vessels are hired to install foundations and cables, and retrieve and re-install the turbines every 5 years, which is the designed turbine maintenance period. As a result vessel hire accounts for a large proportion of the total OPEX budget, so a 26% reduction in vessel days accounts for a very large OPEX saving over the life of a project. As the economy of volume increases further by installing more turbines, this cost saving will improve further.

M. *Technology development - subsea hub*

The subsea hub provides a central point to join connector cables from multiple turbines to a single export cable that goes to shore. Atlantis are currently designing a gravity based subsea hub that can connect seven turbines to a single export cable and a single converter. The subsea hub houses an offshore transformer to increase the export voltage. The subsea hub reduces the number of export cables and onshore power converters required. This leads to:

- Cost savings in procurement of cables and power converters. A single export cable and converter is needed per 7 turbines, rather than one each per turbine
- Reduction in installation time and cost. This includes the time and cost of cable laying. For MeyGen, this also includes the cost requirement for Horizontal Directional Drilling (HDD) operations to bring export cables to shore. Note that other sites may not require HDD.
- Reduction in maintenance costs for infrastructure.
- Reduction in electrical losses in the export cable.
- Smaller onshore building to house converters, with lower cost and time to build and reduced visual impact.
- Smaller seabed footprint and lower risk of cables becoming tangled.

To provide an initial indication of the reduction in balance of plant that is achievable by implementing sub-sea hubs, we consider two 7 turbine arrays located 2 km from shore. The features of the two arrays are summarised in Table V, where "Array 1" does not a sub-sea hub, and "Array 2" does. As a result of the reduction in the number of export cables, converters

TABLE IV
COMPARISON OF THE NUMBER OF MOBILISATION AND DE-MOBILISATION DAYS FOR MEYGEN PHASE 1A VS. PHASE 1C.

	MeyGen 1A	MeyGen 1C	% difference
Number of turbines	4	36	+800%
Mobilisation days	3	18	+500%
Mobilisation days/turbine	0.75	0.5	-33%
De-mobilisation days	1.5	12	+700%
De-mobilisation days/turbine	0.38	0.33	-12%
Total mob + de-mob days/turbine	1.13	0.83	-26%

TABLE V
BREAKDOWN OF INFRASTRUCTURE IN ARRAY 1 AND 2.

	Array 1	Array 2
Turbines	7	7
Subsea hubs	0	1
Export cables	7	1
Bore holes	7	1
Converters	7	1

and bore holes, sub-sea hubs can enable an LCoE reduction of around 20%.

Other technology developments include, but are not limited to:

- Wet mate connectors - When installing the turbine, wet mate connectors allow the turbine - export cable connection to be made sub-sea, rather than on the vessel as is the case with dry mate connectors. Wet mate connectors simplify the offshore operations, enabling a turbine to be installed onto its foundation in less than 60 minutes. Turbines with dry mate connectors cannot be fully installed within the same slack tide because the export cable must be brought onto the vessel in order to connect it to the turbine. As a result the installation cost for a turbine with a wet mate connector is 65% lower than the same turbine with a dry mate connector.
- Control system upgrades – improvements to rotor efficiency through improved control. In the future this may include linkage between forward looking ADCPs with the control system so that re-active torque and blade pitching can react to oncoming turbulent eddies and wave induced orbital motion.

N. Financing - cost of capital

It is essential that existing demonstration projects provide validation for the innovations they include in order to build investor confidence in tidal stream turbine technology. The success of demonstration arrays such as MeyGen Phase 1A will significantly reduce the return requirements from both debt and equity investors for future phases. This is achieved through lower return expectations on both debt and equity to reflect the reduced risk of the more established technology, and through an increase in leverage. The key performance indicators for this are rotor efficiency, capacity, projected energy yield and reliability. As we have seen in offshore wind, the hurdle rate should continue to fall as more capacity is installed, and operating hours increase. Table VI summarises results from a lessons learnt assessment from the construction phase of MeyGen Phase 1A [7] Results show that at the time of writing, the performance of the MeyGen Phase 1A array far exceeds it's requirements set out contractually. As this continues and more turbines come online the cost of capital is expected to fall in line with the levels observed in the wind industry.

Other financing mechanisms helping reduce costs include insurance. As more projects are developed and demonstrated and the causes and likelihood for claims are better understood, insurance costs will decrease further. The range of insurance products available to tidal stream projects is low, generally expensive and the availability of cover is limited. However, the availability of cover is increasing, and this is being supported by the increased operational experience being gained from operational projects like MeyGen Phase 1A. As the experience of developers grows, and the number of successful installation and retrieval activities increases the availability of cover will continue to increase and the premiums will reduce. This is being further supported by the increased reliability of devices and further innovation in the sector. Again, the MeyGen project is an example of such an innovation with a new connection management system that has been developed allowing for sub-sea, wet-mate connectors to be demonstrated successfully in real world conditions. Such innovations reduce the need for additional cable lifting operations from the seabed onto a vessel deck for connection as would be required with a dry mate connector. The reduction in such marine operations involving cables is significant from an insurance perspective as this is where most claims in the offshore wind sector have taken place. In a report from 2016 [6], cable failures in offshore wind accounted for 77% of the total global cost of offshore wind farm losses in 2015.

VI. CONCLUSIONS

The impact of near-term economies of scale on LCoE have been quantified by comparing the energy yield and LCoE of the AR1500 turbine, which is currently operational as part of the MeyGen Phase 1A array, with future turbines currently being designed by SIMEC Atlantis Energy, such as the AR2000. The upgrades in scale of the AR2000 relative to the AR15000 are an increase in rotor diameter from 18 m to 20 m, an increase in rated power from 1.5 MW to 2 MW and an increase in hub height of 1 m. These economies of scale result in an increase in annual energy yield of 29% per turbine. This is achievable with a relatively low increase in CAPEX, resulting in a reduction in LCoE

TABLE VI
COMPARISON BETWEEN CONTRACTUAL AND ACTUAL KEY PERFORMANCE INDICATORS FROM THE MEYGEN PHASE 1A PROJECT.

Performance indicator	Contractual	Actual	Difference
Average power coefficient	0.38	0.41	+8%
Capacity factor	33%	41%	+20%
Lifetime energy yield estimate	370 GWh	450 GWh	+18%

of around 20%. Results show that further economies of scale after the AR2000 can increase energy yield by around 90% per turbine relative to the AR1500. Mechanisms for LCoE reduction are not limited to economies of scale. As demonstrated in this paper, significant cost savings are also achievable from economies of volume, technology innovation and financing. For example, sub-sea hubs reduce the balance of plant significantly to achieve similar levels of LCoE reduction as the near term economies of scale demonstrated in this paper.

VII. Further work

Work is ongoing to build on the LCoE results presented in this paper by refining estimates for the CAPEX required to implement increases in rotor diameter, hub height and rated power. In addition, work is under way to optimise the micro-siting and specification of the MeyGen Phase 2 array, which has a capacity of 398 MW (i.e. the total cumulative capacity of the MeyGen project including Phase 1). This work will also aid in better understanding the LCoE reduction that is achievable in the longer term than the next generation of turbine.

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