Energy Management System Control Strategy to Optimise Whole System Benefits of the ITEG Technologies

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Executive Summary

The Integrating Tidal energy into the European Grid (ITEG) project aims to develop and demonstrate a state-of-the-art energy solution combining a tidal stream turbine with an electrolyser. This report considers control strategies for the energy management system (EMS) of the combined technologies from the perspective of whole energy system impacts in a least cost, decarbonised Orkney energy system.

During the study a simple model was developed to simulate an EMS for the ITEG technologies, based on half-hourly electricity market prices. This enabled investigation of the impacts of various control strategies on the benefits which the ITEG technologies could offer to the whole energy system (locally and to the wider region). The model assumed a 2MW tidal turbine with 530kW electrolyser with a 10,000kWh (250kg) hydrogen store.

Regularly switching off an electrolyser for short periods of time is likely to have an adverse effect on its lifetime and increase operational costs. Therefore, to accommodate this, a minimum electrolyser power level was set. When the price-driven controls would switch the electrolyser off, or adjust the power level below this minimum, it instead continues to run at the minimum level. To explore the impact of this feature, the minimum level was set to 10% (based on advice from Elogen).

Table 1 compares the results of three scenarios, where:

- **Maximum System Value** operates the combined system to match the electrolyser load factors that result in a least cost, decarbonised Orkney energy system (prioritising societal benefit)
- **Revenue Maximise** operates the combined turbine-electrolyser system to maximise revenue for the combined system owner/operator (prioritising operator's benefit)
- **Minimum Turndown** modifies the Maximum System Value scenario by setting an electrolyser minimum load factor of 10%

Table 1 – Comparison of different EMS control strategies modelled

Scenario	Maximum System Value	Revenue Maximise	Minimum Turndown
Average Electrolyser Load Factor	11%	51%	20%
Hydrogen Production (MWh)	192	890	345
Hydrogen Retail Value (£k)	£15.4	£71.2	£27.6
Electricity Grid Import (MWh)	2.5	17.9	61.1
Import Retail Cost (£k)	-£0.1	£0.7	£7.8
Electricity Grid Export (MWh)	3,244	2,344	3,102
Export Retail Value (£k)	£173.9	£129.9	£166.0
Sum Cash Flow (£k)	£189.3	£200.4	£185.7

It is clear that there is a trade-off between prioritising societal benefit, in the form of a least-cost whole energy system, and prioritising benefit to the owner/operator of the turbine-electrolyser plant.

When controlled to maximise whole energy system benefits, the electrolyser load factors and associated hydrogen production are lower than when the objective is to maximise owner/operator revenues. However, this is likely to increase overall system costs related to hydrogen distribution and may include additional electricity network costs depending on the precise timing of electricity import for electrolysis and turbine generated electricity export compared to wider system supply and demand.

It is also notable that the reduced load factor for the electrolyser actually results in quite a small change in overall cashflow to the combined turbine-electrolyser plant owner/operator (accounting for both hydrogen sales and electricity sales and purchases all together). Thus, although there is a trade-off between societal and operator benefits, it is less stark than it would first appear.

The optimum quantity of hydrogen to produce is sensitive to the price differential between electricity and hydrogen. When electricity prices are high the value of selling electricity directly can be higher than the value of hydrogen which could be created from that electricity. This trade-off will be closely related to the electrolyser efficiency, with higher efficiency resulting in hydrogen production at higher electricity prices. From the perspective of maximising revenue to the commercial owner/operator it is worthwhile to use electricity to produce hydrogen when the cost, or export opportunity cost, of electricity required to produce a unit of hydrogen is less than the value of that unit of hydrogen.

A minimum turn-down value for the electrolyser significantly increases its hydrogen production relative to the whole-system cost-optimal value. Battery energy storage could be explored as a means to mitigate this loss of system benefit by providing the whole system benefits achieved through managing energy flows between generation and electrolysis in order to manage electricity import and export from the combined technology site, although this would carry additional capital and operational costs.

This analysis has shown that it is possible to adjust control strategies to suit priorities for particular locations and to optimise the benefits to the operator and to society dependent on those priorities. This can have significant impacts on the operation of the ITEG technologies (including notably the electrolyser load factors) and on the societal whole system benefits. If control strategies are optimised for whole system societal benefits, then the impact on the plant operator’s cash flow is relatively modest, though in some cases it may be necessary for this shortfall to be made up by other means.

1 Introduction

1.1 The ITEG Project

The Integrating Tidal energy into the European Grid (ITEG) Project aims to develop and demonstrate a state-of-the-art energy solution combining a tidal stream turbine with an electrolyser. This aims to overcome technical and commercial challenges associated with the use of abundant renewable energy resources in regions with weak or constrained electricity grids – a combination which is characteristic of island communities – and to use hydrogen to capture this green energy and enable decarbonisation of the wider energy system and the many domestic and commercial users of energy.

The integrated solution was intended to combine Orbital's next generation 2 MW floating tidal energy converter, the Orbital O2 2MW (Figure 1), with a custom built 500kW Elogen electrolyser[1] (Figure 2) and an onshore energy management system (EMS) to be deployed at the European Marine Energy Centre (EMEC)'s hydrogen production site on the Orkney island of Eday.

The development, deployment and demonstration of these technologies is carried out within the ITEG project 'Investment' and 'Implementation' work packages.

Figure 1 – Orbital O2 tidal energy converter (courtesy Orbital Marine Power)

[1] Note that the project objectives were modified, at a relatively late stage during the project, to reflect the supply challenges suffered by Elogen. These resulted in a number of strategic changes at the Caldale, Fall of Warness site specifically, namely (a) not installing the intended Elogen electrolyser; (b) making use instead of a pre-existing electrolyser on site which was modified and used to demonstrate the concept of the tidal generation and electrolysis technology combination, EMS control, etc; and (c) including a new flow-cell battery on site. The analysis in this report (conducted prior to some of these changes) includes use of the originally-intended electrolyser rating at Caldale, as well as use of the pre-existing unit alongside it, and of the flow-cell battery. Much of the analysis is concerned with roll-out at greater scale across the archipelago, which is not materially affected by these changes. The findings therefore remain valid, and this report has not otherwise been amended to reflect the on-site changes.

Figure 2 – Elogen electrolyser

1.2 Whole Energy System Modelling

Within the 'Long Term Impacts' work package (WPLT), Energy Systems Catapult (ESC) carried out detailed modelling of the whole energy system for the Orkney archipelago, using ESC's proprietary EnergyPath Networks^{TM} (EPN) local area energy system modelling tool. A number of scenarios were developed to study different potential pathways to a net zero carbon energy system and different roles which the ITEG technologies might play in that transition to net zero.

That whole system analysis was reported in Deliverable LT.4.2 titled "Whole Energy System Analysis: Long Term Impacts on the Orkney Energy System". The report sets out in detail the methodology, scenarios modelled, potential routes to net zero for Orkney, and the potential contribution of ITEG technologies within the transition. Finally, it sets out conclusions relating to the impact of the ITEG technologies on the whole local energy system, and the techno-economic conditions for their successful deployment.

The potential for roll-out of the ITEG technologies across North West Europe was also briefly studied. This considered some of the specific factors which might lead to valuable deployment – in particular the tidal resource available, the potential for hydrogen demand, and the strength of the electricity transmission system – in order to identify areas in which deployment would be of most value to the system. This was reported in Deliverable LT.2.3 titled "Opportunities for Roll-Out of Tidal Generation with Electrolysis Across North West Europe ".

1.3 Energy Management System Modelling

To complement that whole-system analysis, ESC also carried out a small study (straddling both 'Implementation' and 'Long Term Impacts' work packages) to determine the effect of varying control strategies for the ITEG Energy Management System (EMS). This focused particularly on the impact of EMS control strategies on the benefits which the ITEG technologies could offer to the whole energy system (locally and to the wider region). This study is the subject of the present deliverable LT.4.4 titled "Energy Management System Control Strategy to Optimise Whole System Benefits of the ITEG Technologies".

Other deliverables within the ITEG project from EMEC and from the University of Caen, as well as prior analyses from EMEC, have studied the impact of varying EMS control strategies on:

- maximising hydrogen production (and associated value); and
- maximising commercial revenue and benefits to the operators of the ITEG plant.

ESC's analysis differs from these by studying the impact on the whole energy system benefits, building on the system modelling carried out using EPN – rather than the commercial benefits to the operators (although these are also assessed). It therefore provides a valuable complementary perspective to those other analyses, enabling EMS control strategies to be assessed as comprehensively as possible.

1.4 Installation of ITEG Technologies

The ITEG technologies may be installed either as combined units or separately (as modelled by ESC in different scenarios, with various advantages of each, as set out in Deliverable LT.4.2):

- The tidal turbines and electrolysers may be co-located, with hydrogen production at the tidal array substation, as demonstrated at EMEC's Fall of Warness site on the island of Eday in Orkney.
- Alternatively, the electrolysers may be located remotely from the tidal array substation, in order to minimise the distance between the hydrogen production and the demand for it.

For EMEC's Fall of Warness site at Eday, with a small number of co-located turbines and electrolysers, there is a single combined EMS covering the site. In future, whether units are co-located or located remotely from each other, and whether in small numbers or much larger arrays, the core principles of EMS control strategies can be applied in the same manner even where they may be physically implemented in processors in multiple locations. Thus the impacts of those control strategies on the benefits to the whole energy system are equally applicable.

1.5 Potential Systems Benefits of the ITEG Technologies

There are several different kinds of whole-system benefits which the ITEG technologies could contribute:

- Tidal generation, of course, provides zero-carbon electricity. It is also completely predictable, and its generation profile complements that of wind to provide together a more diverse and steady energy supply.
- Hydrogen can contribute to the decarbonisation of many sectors. It is particularly important in enabling decarbonisation of certain industries with intensive high-temperature energy demands that are difficult to meet using electric sources. It can also be stored at scale somewhat more easily than electricity.
- Individually and together, these technologies can help achieve cost-effective, resilient, net-zero-carbon energy systems, as evidenced by the whole-system modelling and optimisation study set out in Deliverable LT.4.2.
- There are potentially other forms of system benefits, beyond those associated with bulk energy provision, which could be offered in the form of a range of system services procured by network operators to improve network stability or reduce investments in network reinforcement.

System Services

Examples of system services include frequency stabilisation services such as Dynamic Containment, where an energy asset is rewarded for making itself available to provide brief bursts of energy, or reductions in demand, at short notice when a fault causes the frequency of the national grid to deviate from its normal value. Other examples include demand response, where an energy consumer reduces consumption at particular times to manage peak demand on the system, or demand turn-up where an energy consumer increases demand to help relieve stress from high renewable production.

While the national electricity system operator procures system services such as frequency response and balancing, the local distribution network operators tend to deal only with constraint management, reducing demand or generation when parts of the network would exceed their capacity – often by means of an active network management system – although this is expected to change to some extent with the transition of Distribution Network Operators (DNOs) to Distribution System Operators (DSOs).

Since the ITEG unit installed on Eday currently operates within an active network management zone, where local generation often exceeds the network capacity and results in curtailment, we have ruled out near-term participation in several types of system benefit provision for this study, including frequency services. This is because the provision of system services which involve additional injections of energy rely on some network capacity to export power being unused for the majority of the time. In other words, a connection which is often exporting at its maximum capacity (such as one of Orkney's 33kV inter-island cables or the interconnector to the UK mainland) often has no spare capacity to increase export on demand. Reserving capacity on this connection to enable the provision of these services would require increased renewable curtailment for much of the time, which is unlikely to be an attractive proposition.

However, this context could be different if the technologies were rolled out in different geographical locations, or if electricity demand or network capacity were to increase on Orkney. Indeed, in certain scenarios modelled (see Deliverable LT.4.2) the use of electrolysers does have the effect of increasing both local electricity demand and thus network headroom, and it is possible that such conditions might make it somewhat easier to provide network services.

In addition to the effects of these network constraints, certain types of system benefit are onerous to provide due to high upfront costs or complexity, so that participation is only viable for very large generators or consumers of energy – the balancing mechanism being an example of this. In these cases, aggregators (such as Piclo) can combine multiple small sources of system benefits to build a sufficiently large source to allow commercially viable trading with the national electricity system operator, or the local distribution system operator where available.

Supply and Demand Balancing

Although the provision of system services is therefore challenging in current circumstances, there may still be opportunities for the combination of ITEG technologies to provide additional system benefit (beyond its ability to support optimal system decarbonisation through bulk energy provision). One such opportunity is in its ability to turn load up when renewable curtailment is occurring locally, and down during peak demand times, by varying the power setting of the electrolyser. Whilst we have not modelled these potential payments for provision of system services directly, we have modelled variable prices for both import and export of electricity. These can be considered as a proxy for these payments for provision of system services since such payments would be directly linked to local supply and demand and so would be ultimately reflected in local market prices.

Peak demand typically occurs between the hours of 16:00 and 19:00 on weekdays and is most pronounced in winter; while renewable curtailment is likely to occur on windy nights amongst other times, with strong winds occurring more in winter.

Real time electricity pricing can be used as a proxy for the balance between supply and demand, although it is unlikely to capture local conditions under current market regulations.

This peak avoidance and surplus absorption – based on pricing – has been the focus of this modelling study.

It would, of course, be possible (as part of any future research) to expand the developed model to explore the possibilities and implications of providing other services (such as frequency response and balancing, in circumstances in which this might become viable on Eday.

2 Modelling Methodology

2.1 Overview

During the study a simple model was developed to simulate an energy management system (EMS) for the ITEG technologies, based on half-hourly electricity market prices. This enabled investigation of the impacts of various control strategies on the benefits which the ITEG technologies could offer to the whole energy system (locally and to the wider region).

The deployment and utilisation of the ITEG technologies to maximise the main system benefits listed in section 1.5 above, within a cost-optimal energy system for Orkney, was determined under a number of scenarios during the EPN whole-energy-system modelling (refer to Deliverable LT.4.2).

The model was therefore used to configure the EMS control strategies to contribute to supply and demand balancing (as described in section 1.5 above) and to match the optimised utilisation from the EPN modelling. This enables the maximum benefit for the whole energy system to be achieved.

Electricity prices and tidal generation profiles are both derived from real historical data (see sections 2.4 and 2.5 below).

2.2 EnergyPath Networks

Section 1.2 of this report introduces the whole energy system modelling and analysis which was carried out by ESC. Details of ESC's EnergyPath Networks (EPN) local area energy system modelling tool used, along with the scenarios and findings, are set out in Deliverable LT.4.2 titled "Whole Energy System Analysis: Long Term Impacts on the Orkney Energy System".

EPN uses a simplified representation of the timing of energy demands using representative seasonal days, each split into three time periods. The representative days are spring and summer, autumn and winter (average) and peak winter. The time slices are off-peak (23:00-06:00), midday (06:00-16:00) and peak (16:00-23:00). EPN therefore does not capture dynamics occurring at the half hourly timescale, since periods of multiple hours are modelled in a single step.

EPN then finds the lowest whole system cost configuration of available technologies to meet energy requirements and emissions targets, resulting in outputs detailing the capacity of each technology deployed in the future system, as well as various metrics such as cost and load factors (a measure of utilisation).

2.3 Model Overview

To represent the EMS control algorithm the EMS model calculates an electrolyser power level in each half-hour throughout a representative year. This algorithm can be based on time-of-day or other factors, but for the majority of the modelling study it was based on comparing the market price of electricity import and export in each half hour to user-adjustable price threshold settings. Depending on how the market prices compare to the threshold settings in each period, the electrolyser can use tidal energy only, or be turned up to use additional grid[2] energy or be turned down to free up tidal energy for grid export (see section 2.6 for more detail). The power level of the electrolyser is multiplied by its efficiency to calculate hydrogen produced in each period.

Electricity prices and tidal generation profiles are both derived from real historical data (see sections 2.4 and 2.5 below).

The model includes a simplified hydrogen store which is gradually filled by the production of the electrolyser. This store has a user-defined capacity and a user-defined time-of-day when it is collected and replaced (or emptied). If the store reaches its capacity, no further hydrogen production will occur until the store is collected and replaced (or emptied). At the time when the store is collected and replaced, the fill level is instantaneously reset to zero (i.e. no downtime is modelled for the process of swapping bottles / emptying). An example of the use of the hydrogen store is shown in Figure 3.

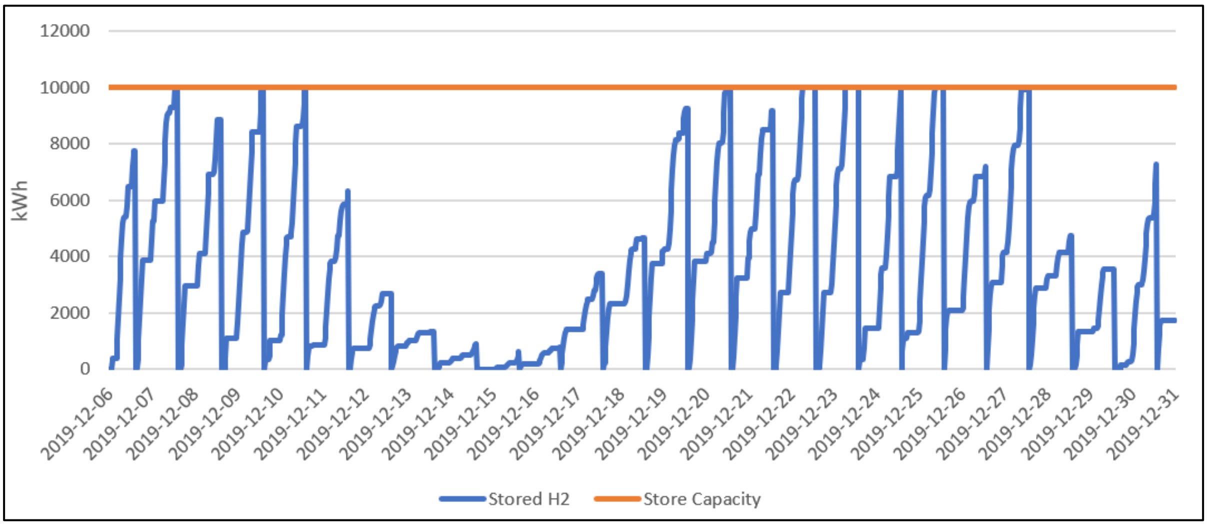

Figure 3 – Fill level of hydrogen store against maximum capacity over a sample period of several weeks

Power imported from and exported to the grid is then calculated for each period, based on available tidal power and electrolyser power consumption. These grid power flows are used to calculate cost and income from grid trading, while the hydrogen produced is used to calculate income from hydrogen sales.

2.4 Electricity Price Data

Historic, domestic half-hourly electricity price data is available to download by region. We have used data for Octopus's "Agile" time-of-use tariff, for both import and export, for North of Scotland; source: https://www.energy-stats.uk/octopus-agile/ .

While domestic rates would not be the most relevant rates for ITEG's medium-sized commercial connection, we consider them nevertheless to be indicative of the price curve shape over different times of day and different days of the year.

[2] The term "grid" is used here to represent either the national grid or the local distribution network, as appropriate, as the distinction is not material to the analysis.

The large price spread between import and export rates seen by domestic customers may be an artefact of the market which would be less pronounced for commercial connections, due to more of the non-energy costs being charged separately from the consumption tariff in commercial connections, leading to a lower import rate.

Should others wish to do so in future, alternative price data could be readily inserted into the model to explore its implications.

2.5 Tidal Generation Data

For consistency, historic tidal generation data has been taken from the same dataset used in Deliverable LT.4.2. This is based on a highly-granular, measured dataset (at 20 minute intervals) of 1996 tidal currents at EMEC's Fall of Warness site, Berth #5, with turbine characteristics as used in the EPN modelling (see Deliverable LT.4.2) used to produce power output data. This in turn was then converted into a fraction of maximum output at half-hourly intervals.

2.6 EMS Control Algorithm

As shown in Figure 4, the EMS model can choose to use energy from the tidal turbine only to supply the electrolyser (below left), or supplement tidal energy with energy imported from the network to supply the electrolyser (below middle), or export energy from the tidal turbine to the grid (below right).

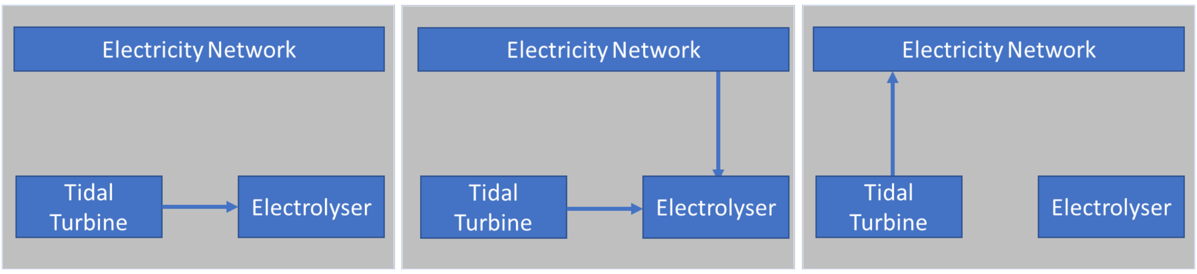

Figure 4 –Possible modes of operation chosen by the control algorithm

The decision is based on the comparison between real time market electricity prices (import and export) against the set threshold prices.

- When the price of electricity import drops below the set import threshold, electricity is imported from the grid to complement any generation from the tidal turbine, to run the electrolyser at maximum capacity (middle diagram above). In this state, grid electricity is cheap enough to justify its use to produce hydrogen.
- When the export price rises above the export threshold, the electrolyser is set to the minimum permissible power level, and any remaining tidal generation is exported to grid (right diagram above). In this state, the value available from exporting electricity justifies minimising hydrogen production to maximise tidal energy exported to grid.
- When neither of the above is true – import price is above the import threshold while export price is below the export threshold – all available tidal generation will be sent to the electrolyser, up to its maximum capacity (left diagram above). In this state, the cost of electricity import from the grid does not justify using it to produce hydrogen, while the value available from export does not justify sending tidal generation to grid. Use of tidal generation to produce hydrogen is maximised, while grid imports and exports are minimised.

Occasionally, further power flows may be required (as shown in Figure 5 below). If tidal generation exceeds the electrolyser's maximum capacity, surplus power will flow to grid (below left), and if a minimum electrolyser power level above zero is specified, there may be additional power flows at times to meet this requirement (below middle and right). The solid arrows show the control algorithm's "preferred" energy flow, and the dashed arrows show additional flows used to maintain these requirements.

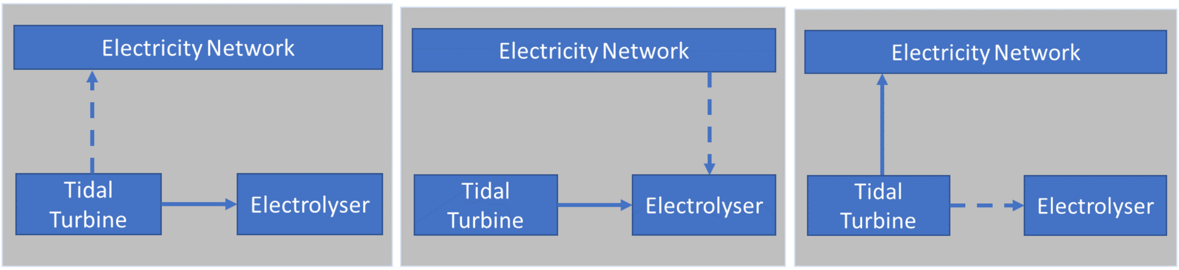

Figure 5–Possible modes of operation chosen by the control algorithm (including additional energy flows)

The algorithm decision matrix is summarised in Table 2 below.

Table 2 – EMS model algorithm decision matrix

Decision Inputs		Decision Outputs		Rationale
Half Hourly Import Price	Half Hourly Export Price	Electrolyser Function	Grid connection function	
Above set import threshold	Below set export threshold	Match electrolyser to tidal output (up to max capacity).	Any tidal output above electrolyser capacity exported. Any min. electrolyser requirement shortfall imported.	Electricity is too expensive to justify import for electrolysis. Export price too low to justify export.
Above set import threshold	Above set export threshold	Turn down electrolyser to minimum level.	Export all tidal output above min. electrolyser requirement – any shortfall imported.	Electricity is too expensive to justify import for electrolysis. Export is more valuable than electrolysis.
Below set import threshold	Below set export threshold	Run electrolyser at max capacity.	Import the difference between electrolyser capacity and tidal output.	Electricity is cheap enough to justify import for electrolysis. Export price too low to justify export.

Below set import threshold	Above set export threshold	Run electrolyser at max capacity.	Import the difference between electrolyser capacity and tidal output.	This condition shouldn't arise in a rational market. The behaviour described here is therefore arbitrary and could be revised.

2.7 Matching the EMS Model to EPN

EPN optimises the capacity and operation of each component of the energy system to find the arrangement with the least overall cost to society. We have therefore taken the ratio of tidal generation capacity to electrolysis capacity, and the load factor of the electrolysis, as deployed by EPN (based on scenarios modelled in EPN which have deployment of tidal turbines and electrolysers across Orkney at scale) as being representative of a cost-optimal deployment and operation strategy for the ITEG technologies.

The EMS model was adjusted (see section 2.3) so that the average electrolyser utilisation across each EPN time-slice matched the EPN value. If actions carried out by the EMS cause load factors to deviate from these optimum values produced by EPN, we take this as indicative of a loss of system benefit provided, since the behaviour of the ITEG technologies has strayed from the cost optimal.

Based on those scenarios modelled in EPN which have deployment rolled-out across Orkney at significant scale, EPN installs around 3.8 units (MWe) of tidal generation capacity for every unit (MWe)of electrolysis. The electrolysis load factors seen during each EPN time slice are shown in Table 3.

Table 3 – Electrolyser load factors from EnergyPath Networks for different times of day for different seasonal days

EPN Season (detailed in Deliverable LT.4.2)	EPN Time Slice	Electrolyser Load Factor (% maximum power)
Summer	Off-peak	3
	Midday	0
	Peak	63
Winter (average)	Off-peak	25
	Midday	8
	Peak	2
Peak Winter Day	Off-peak	41
	Midday	35
	Peak	8
Overall		**17**

Summer peak load factor stands out as higher than might be expected for this period. This is a result of the way the tidal generation profile was modelled in EPN. The maximum tidal output was aligned to occur during EPN's peak summer time slice as a test of network capacity when the highest tidal output coincides with low electricity demand. This utilisation factor for the summer peak period is therefore probably an over-estimate, on average but could be achieved on days with the highest tides.

The higher load factors on the peak winter day compared to the average winter day are also perhaps counter-intuitive, as electricity prices will be highest at this point – suggesting that electricity should be sold directly rather than used for hydrogen electrolysis. However, this can be attributed to the greater demand for hydrogen for heating in the coldest weather.

The load factors for the average winter day were deemed most suitable for matching the behaviour of the EMS model to the outputs of EPN. By contrast, the peak winter day is a rare occurrence, so will not capture typical market dynamics well, and the summer day sees a pattern of electrolyser behaviour which would be difficult to replicate using price-driven control logic (i.e. consumption is highest at peak time, when electricity prices will also be at their highest). The findings discussed in this report are therefore all based around EPN's representative average winter day.

Electrolysis Business Model

It is also worth noting that the overall electrolysis load factors are relatively low, and that this has implications for the business model for such units. Initially, these relatively low load factors may not appear commercially viable. However, it is important to remember that overall system cost drives the load factors in EPN, which are then used in this study. Equally importantly, other aspects such as plant ratings, operational control strategies, load factors, revenues, etc are considered during this study – and some of the results may seem counter-intuitive.

One could question, for example, whether the deployed electrolysis capacity is higher than it should be, or whether there is sufficient hydrogen storage. At first sight, making such adjustments might lead to a lower capacity of electrolysis, with an operating regime that has a more commercially attractive load factor. An explanation of the reasons for the load factors in EPN follows.

Drivers of Electrolysis Load Factor in EPN

EPN modelling is intentionally configured to provide optimum whole-system benefit rather than to generate maximum commercial revenue. The most cost-effective solution for the whole system is an electrolysis capacity greater than that required to provide just the mean hydrogen demand (even with an appropriate amount of hydrogen storage also deployed), and therefore to operate the electrolysis at somewhat lower load factors for most of the time with a few brief periods with much higher load factors.

The EMS model is also influenced, in a highly variable pricing regime, by the need to run when electricity is relatively cheap – in order to contribute to the whole system in a cost-competitive manner (when considering the whole-system costs and benefits of this and competing technologies). This approach provides maximum whole-system benefit through a combination of bulk energy production and provision of energy system services and allows the units to access a substantial part of their revenue from such services (given a sufficiently mature market structure for these services).

Finally, the load factor is influenced by one additional aspect of the EPN model which was intentionally configured to stress test the system under two key conditions:

1. maximum local electricity generation, with low local demand and maximum export (e.g. at summer peak, as explained above); and
2. minimum local electricity generation, with maximum local demand.

If the EPN model were to be reconfigured to adjust this final aspect, this might redistribute load factors somewhat, though it might not increase the total.

During this study of EPN control strategies, the EMS model has been used to assess the impact of several of these aspects, including (inter alia):

- varying the relative capacities of the tidal generation and electrolysis, in order to increase load factors
- increasing load factors to adjust the trade-off between revenue (to the operators of the ITEG technologies locally) and overall cost optimisation of the whole system (to society).

3 Findings

3.1 Timing Optimisation of Electrolyser Operation

There may be opportunities to deliver increased value by modifying the operation of the electrolyser at the seconds-to-hours timescale, while preserving the optimised load factors from EPN which split each day into three time slices.

A counterfactual case was modelled to mimic the low time step granularity of EPN, where the average electrolyser load factors reported by EPN were applied uniformly across those time periods (represented by the blue line in Figure 6 below). For example, the load factor in the time slice “winter off-peak” is 24%, so the electrolyser runs at 24% of maximum capacity constantly between 23:00 and 06:00 every day.

In contrast, the price threshold algorithm causes spikes of higher power, but shorter duration operation (represented by the orange line in Figure 6) in response to the electricity market, resulting in the same average load factors (calculated over the whole year – this figure shows a small part of the year data where infrequent operation between 6:00 and 23:00 can be seen).

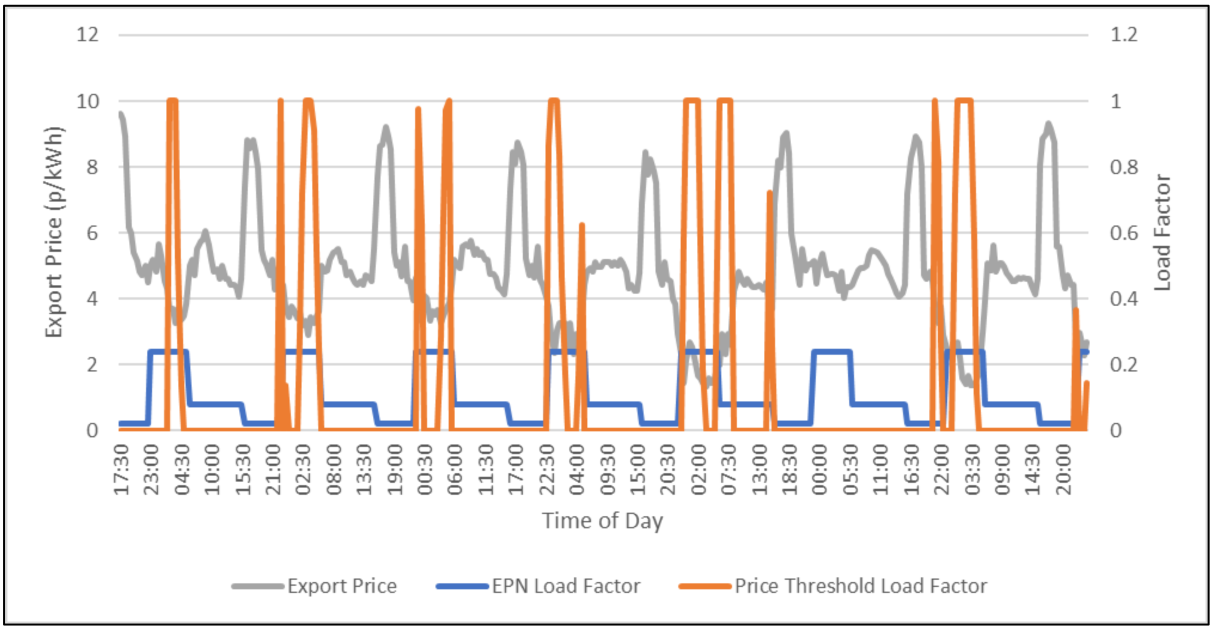

Figure 6 – Comparison of electrolyser operation when mimicking EPN’s time granularity against operation optimised at half-hourly granularity

However, the improvement to the sum cash flow (hydrogen sales, electricity import and export) is only 4% with the half-hourly time control (compared to the counterfactual using average EPN load factors).

3.2 Relationship between Price Threshold Settings and Load Factor

Unsurprisingly, a decrease in the import threshold price or an increase in the export threshold price both cause the electrolyser to run more, with more grid electricity and tidal electricity respectively used to produce hydrogen.

As explained in section 2.6 price combinations where market export price exceeds the set export threshold while market import price is below the set import threshold are likely to be invalid in the electricity market, and the model defaults to running the electrolyser at maximum capacity in these circumstances. This is likely to apply to areas of the plot where the set export price threshold is very low while the set import price threshold is very high.

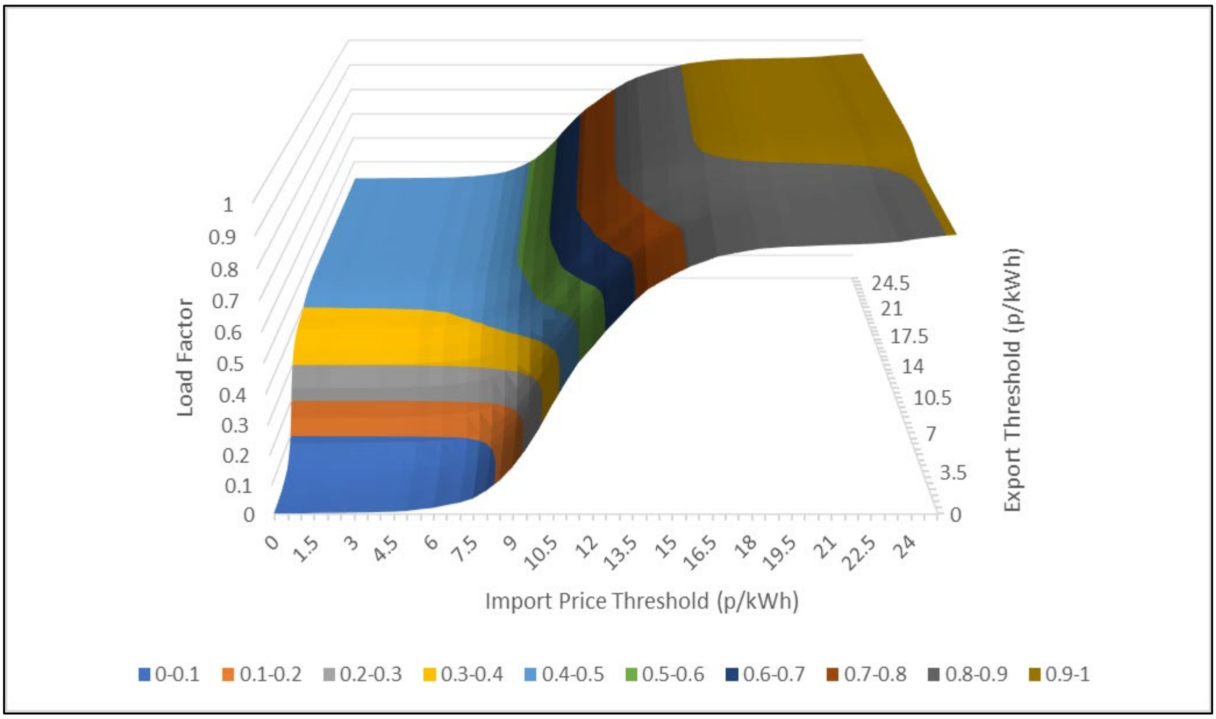

Figure 7 – Impact of varying import and export price threshold settings on electrolyser load factor

3.3 Relationship Between Relative Capacities and Load Factor

The capacity of the electrolyser relative to the capacity of the tidal turbine affects the electrolyser load factor under the price threshold control strategy described above. A relatively larger tidal turbine or smaller electrolyser will result in higher load factors, as the tidal turbine output will amount to a greater proportion of the electrolyser's capacity, and the load factor is driven by tidal output in certain price conditions. Figure 8 shows this relationship for fixed price thresholds matching those inferred from EPN load factors.

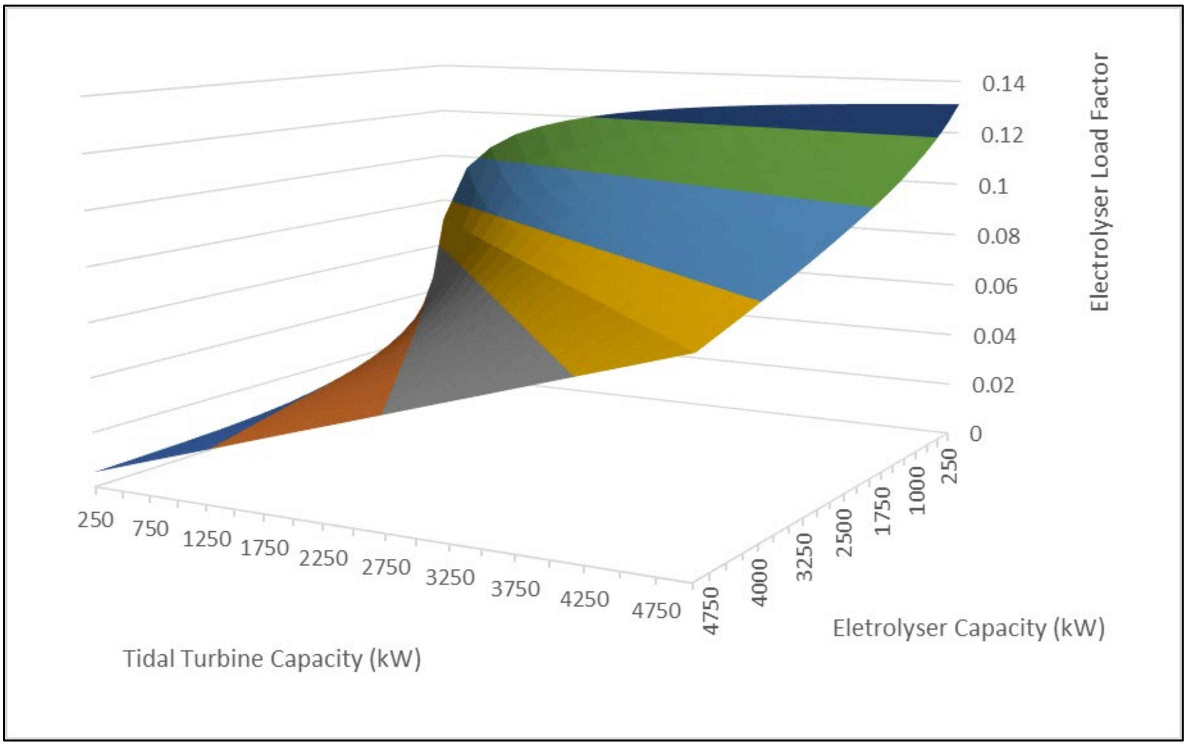

Figure 8 –Relationship of varying capacities of tidal turbine and electrolyser on electrolyser load factor

It is still notable, however, that even at the highest point – with largest tidal turbine and smallest electrolyser – the electrolyser average annual load factor in this example remains below 14%, which is comparable to the overall load factor of 16.9% from the EPN optimisation (see section 2.7).

3.4 Hydrogen-Electricity Price Differential

For a fixed profile of electricity prices, in order to maximise the ITEG revenue the load factor of the electrolyser increases with increasing hydrogen price, as shown in Figure 9 below. This is unsurprising, as the benefit of producing hydrogen increases when its value rises relative to the value of electricity, so it is operated more of the time.

Naturally, the viability of producing hydrogen from electrolysis is very sensitive to the price differential between hydrogen and electricity, which would be the primary source of value (as bulk energy). The electricity import / export price threshold required to make hydrogen production viable at each hydrogen market price is also shown. As expected the market price threshold for electricity increases as the hydrogen price increases. In Figure 9 if the electricity market price is below the price threshold at any given hydrogen price then hydrogen production at that price is viable at the capacity factor given. If electricity market price is above the price threshold then it is better to export the electricity than to produce hydrogen.

Figure 10 shows the frequency distribution of electricity import and export prices used. This shows that export prices are rarely above 10p/kWh and import prices are rarely above 15p/kWh implying that if the objective is to maximise revenue for the combined tidal turbine and electrolyser pairing then electrolyser capacity factors are likely to be significantly higher than if the objective is to minimise whole system costs. This is explored further in section 3.5.

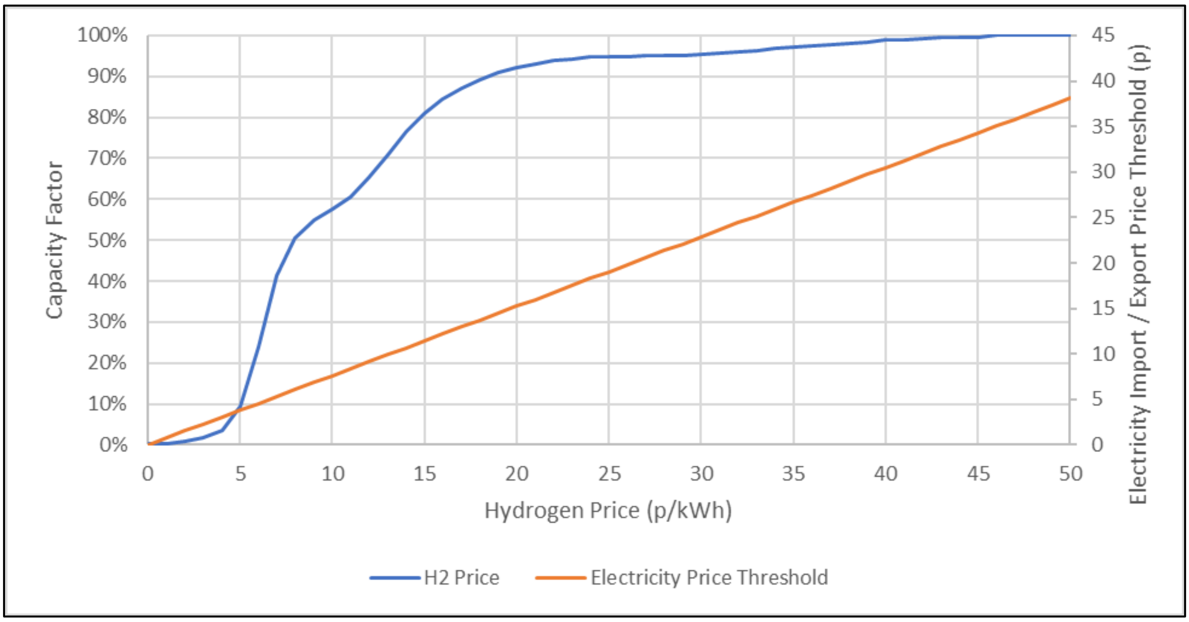

Figure 9 – Influence of varying hydrogen export price on electrolyser average annual load factor

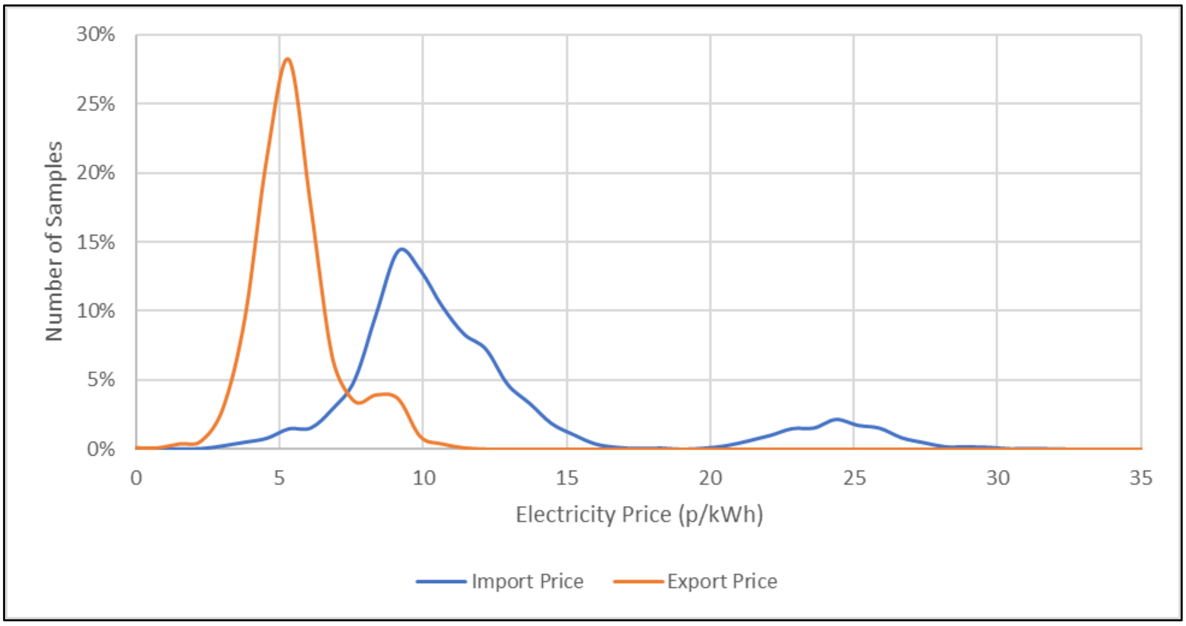

Figure 10 – Frequency Distribution of Electricity prices used

3.5 Local Benefits vs Whole System Benefits

Using the cash flow calculations, it is possible to adjust the price threshold settings to maximise overall cash flow to the operator of the combined tidal turbine and electrolyser. The sum of the value of hydrogen produced and electricity sold to grid, with the cost of electricity purchased from the network subtracted, gives the overall cash flow figure. This figure is found to reach its maximum value when both the import and export price threshold settings are set to the price of hydrogen divided by the efficiency of the electrolyser. In other words, it is worthwhile to use electricity to produce hydrogen when the cost, or export opportunity cost, of electricity required to produce a unit of hydrogen is less than the value of that unit of hydrogen.

Setting the price thresholds to maximise cash flow to the tidal turbine and electrolyser operator causes an increase in electrolyser load factor compared to the EPN mimicking settings (an increase from 11% to 51% overall, and from 3% to 38% at peak times). From this we infer that whole system value has reduced, because the load factors have deviated from those of the EPN whole system optimisation, and so there is a trade-off between maximising cash flow to the local technology operators and the total societal cost of the energy system. The sum of cash flow to the turbine and electrolyser operator increases by 6% in this configuration, suggesting costs are displaced to other actors within the energy system.

It should be noted that the significant change in load factor for the electrolyser actually results in quite a small change in overall cashflow to the turbine-electrolyser owner/operator (accounting for both hydrogen sales and electricity sales and purchases all together). Thus, although there is a trade-off between societal and operator benefits, it is less stark than it would first appear.

3.6 The Impact of Minimum Power Setting

Regularly switching off an electrolyser for short periods of time is likely to have an adverse effect on its lifetime. Therefore, to accommodate this, the model includes an input which allows the user to set a minimum electrolyser power level (expressed as a percentage of the full rated capacity) below which it will not operate. When the price-driven controls would switch the electrolyser off, or adjust the power level below this minimum, it instead continues to run at the minimum level. To explore the impact of this feature, the minimum level has been set to 10% (based on advice from Elogen).

The impact is that the load factor of the electrolyser increases overall from the EPN-mimicking values. This is most pronounced over the peak period, when electricity is most expensive and the price-driven controls would tend to switch the electrolyser off for the greatest amount of time; and it is least pronounced at off-peak periods when the inverse is true. The load factor at any time can be no lower than the minimum allowable power level set, regardless of the optimum load factor for whole-system or local cash flow optimisation. For example, the whole-system optimisation results in a winter peak load factor of 2%, whereas a minimum turn-down value of 10% increases the winter peak load factor to 13%.

Overall, a 10% minimum turn-down value causes the average daily load factor to increase from 11% to 20%. The sum cash flow for the combined technologies drops 2% due to a 4% reduction in electricity exported to grid, and a 23x increase in electricity imported from the distribution network, partly offset by a 79% increase in hydrogen produced. The use of a battery to store energy from the tidal turbine or from the grid at off-peak times could reduce the need to import energy at peak times.

4 Conclusions

The combination of a tidal turbine and electrolyser presents the opportunity to provide additional benefits to the energy system, beyond bulk energy provision, such as reducing the need for electricity network reinforcement or curtailment of renewable generation due to existing network constraints.

An energy management system could be designed to operate the combined tidal turbine and electrolyser pair so as to capture that value. This study has focused on its ability to turn load up when renewable curtailment is occurring locally, and down during peak demand times, by varying the power setting of the electrolyser.

The modelling primarily focussed on a larger scale roll out of the combined technology (see section 1.2) using half-hourly price signals and load factors as a proxy for these system benefits. An EMS which makes decisions based on those price signals could increase the value created by the combined solution, and the revenue it creates for a commercial owner/operator as a result.

However, there appear to be trade-offs between providing whole energy system (societal) benefits and maximising turbine-electrolyser owner/operator income, with system benefits being maximised at lower electrolyser load factors than those seen when revenue is maximised.

To maximise revenue for the tidal turbine and electrolyser operator, electrolyser load factors increase from 11% to 51% overall, and from 3% to 38% at peak times, yielding a relatively modest 6% increase in revenue. Additional system costs associated with higher hydrogen production are likely to include increased hydrogen distribution costs, and may include additional electricity network costs depending on the precise timing of electricity import for electrolysis and of turbine-generated electricity export compared to wider system supply and demand.

It should be noted that the significant change in load factor for the electrolyser actually results in quite a small change in overall cashflow to the turbine-electrolyser owner/operator (accounting for both hydrogen sales and electricity sales and purchases all together). Thus, although there is a trade-off between societal and operator benefits, it is less stark than it would first appear.

The optimum quantity of hydrogen to produce is sensitive to the price differential between electricity and hydrogen. When electricity prices are high the value of selling electricity directly can be higher than the value of hydrogen that could be created from that electricity. This trade-off will be closely related to the electrolyser efficiency with higher efficiency resulting in hydrogen production at higher electricity prices. From the perspective of maximising revenue to the commercial owner/operator it is worthwhile to use electricity to produce hydrogen when the cost, or export opportunity cost, of electricity required to produce a unit of hydrogen is less than the value of that unit of hydrogen.

A minimum turn-down value for the electrolyser significantly increases its hydrogen production relative to the whole-system cost optimal value. For example, a minimum turn-down of 10% of maximum power results in electrolyser load factors increasing from 11% to 20%. Battery energy storage could be explored as a means to mitigate this loss of system benefit by providing the whole system benefits achieved through managing energy flows between generation and electrolysis, in order to manage electricity import and export from the combined technology site – although this would carry additional capital and operational costs.

This analysis has shown that it is possible to adjust control strategies to suit priorities for particular locations and to optimise the benefits to the operator and to society dependent on those priorities. This can have significant impacts on the operation of the ITEG technologies (including notably the electrolyser load factors) and on the societal whole system benefits.

If control strategies are optimised for whole system societal benefits, then the impact on the plant operator’s cash flow is relatively modest, though in some cases it may be necessary for this shortfall to be made up by other means (potentially including financial arrangements with other parties).

5 Potential Future Studies

The simple EMS model developed for this study, focusing on peak avoidance and surplus absorption, has been made available to EMEC.

It has been designed with the intention that it could be modified and built upon at a later date by others, should they wish to investigate further questions around the impacts of various EMS control strategies. Input variables are highlighted for user adjustment, and alternative data for electricity prices or tidal generation could be imported. Using relatively simple cell formulae in a spreadsheet, the model is transparent and straightforward to alter or add to.

As one example, additional value streams from other system services (such as Dynamic Containment or participation in the Balancing Mechanism) could be integrated into the model to study the possibilities and implications of providing these types of services in a less constrained context and in circumstances in which this might become viable.

6 Appendix 1: User Input Values

The following variables can be set in the model by the user:

- Maximum capacity of tidal turbine (electrical output, kW – set to 2 MW in this study)
- Maximum capacity of electrolyser (electrical input, kW – set to 528.5 kW in this study to match EPN ratio to tidal capacity)
- Efficiency of electrolyser (dimensionless – set to 0.762 in this study)
- Electrolyser minimum permissible power level (percentage of maximum capacity – set to 0 except where stated otherwise, see section 3.6)
- Capacity of hydrogen store (kWh – set to 10,000 in this study)
- Time of day of store swap (hours and minutes, set to 12:00 (midday) in this study)
- Hydrogen price (p/kWh – set to 8 in this study). This can be differentiated by EPN time slice or entered directly for every half hour period. When bottles are collected daily, it is assumed that the price would be constant across time slices.
- Electricity import price threshold (p/kWh, set to 0 in this study except where stated otherwise) – the electricity import price below which grid electricity will be used to run the electrolyser
- Electricity export price threshold (p/kWh set to 3.94 in this study, except where stated otherwise) – the electricity export price above which all tidal energy will be exported to grid

Note that for the purposes of this analysis, hydrogen is modelled in units of kWh. This can be readily converted to kg or tonnes of hydrogen if desired, using the calorific value.

7 Appendix 2: Model Outputs

The model has the following outputs:

- Electrolyser load factor (broken down to match EPN time slices) – a measurement of how much the electrolyser runs, as a proportion of running at maximum capacity continuously
- Hydrogen produced over modelled period (MWh)
- Value of hydrogen produced, based on input price (£ thousands)
- Electricity imported from grid over modelled period (MWh)
- Cost of imported electricity based on historic price data (£ thousands)
- Electricity exported to grid over modelled period (MWh)
- Value of exported electricity based on historic price data (£ thousands)
- Sum cash flow: value of hydrogen produced, plus value of electricity exported, with cost of electricity imported subtracted.