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The potential for hydrogen to reduce curtailment of renewable energy in Scotland

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Executive summary

In Scotland, wind energy is sometimes significantly higher than the transmission network's capacity to transport the electricity to the rest of Great Britain. When this happens, payments are made to wind farms operators to compensate them for having to reduce their site's power output to the level the network can absorb. This is known as curtailment. Electricity system balancing is normal for all sources of electricity, but in the case of renewables it means that zero-carbon renewable energy goes unused.

Curtailed energy provides a potentially attractive source of electricity which can reduce the overall cost of hydrogen production, through installing electrolyser units which can utilise this power that would otherwise be curtailed. The hydrogen produced can then be used for a variety of applications, including industry, heat and transport.

This report looks at whether future volumes of curtailed energy from large-scale renewables in Scotland could be used to produce hydrogen economically.

1.1 Key findings

- The deployment of electrolysis in line with the British Energy Security Strategy (1GW by 2025, 5GW by 2030) [1] will potentially lead to a significant decrease in curtailment of renewable energy due to increased electricity load behind network constraints. This will depend on the location of deployment and revenue mechanisms. However, this growth in capacity is unlikely to be stimulated purely by the use of curtailed energy alone and a competitive cost of hydrogen production is only likely in specific locations and timeframes, subject to high uncertainty and business risk.
- The potential time lag between the growth of wind generation in Scotland and network reinforcement is likely to lead to a significant volume of curtailed energy in the late 2020s. Depending on the pipeline of offshore wind and the rate at which the Scottish Government's policy target for onshore wind is achieved, this

imbalance may continue into the 2030s. It implies load factors for network-embedded electrolysis, or facilities co-located with electricity generation, which may make the production of hydrogen from curtailed energy cost-competitive with other sources.

- These volumes of curtailed energy may, however, be transitory in both timing and location due to expansion of the transmission network. As transmission network reinforcement increases in response to the projected pipeline of new generators, the volume of network-related curtailment will reduce on an overall basis. Curtailment will also reduce in specific locations as discrete network reinforcements (such as the proposed Eastern Link sub-sea cables) come into operation. Generally, the frequency of curtailed energy is higher in northern Scotland due to additional network constraints, so electrolysers used for hydrogen storage located further north will have potentially higher load factors and a lower cost of hydrogen production, at least in the near-term.
- Cost-competitive production of hydrogen also requires that electrolysers are installed and dispatched in preference to other options for utilising curtailed energy or managing network imbalances. For example, one new pumped hydro scheme, or additional interconnector, will significantly reduce how often curtailed electricity is available and therefore how much energy would be produced by an electrolyser. Current lead times of 24-36 months on electrolysers will also mean curtailment-only hydrogen production would not be operational at scale until the late 2020s.
- Substantial hydrogen storage will be needed to buffer between production and demand**.** Near-term hydrogen electrolysis deployments are likely to be dependent on individual customers such as local heating systems or transport providers, which require either constant or seasonally-variant hydrogen supplies. In the absence of a wider hydrogen network, hydrogen will need to be stored either by the supplier or the customer, to mitigate the temporal imbalances.
- By the early 2030s, transmission-connected wind capacity is likely to significantly exceed off-peak electricity demand, meaning that curtailment will likely remain an ongoing feature of system operation. The availability of curtailed energy will depend on the wider context for energy system management and electrolysis will compete with a broad range of options, such as interconnection, battery storage, demand-side response and new pumped hydroelectricity capacity. The business case for using electrolysis for hydrogen storage will depend on the general growth of the hydrogen economy, transition of gas networks and broader market mechanisms that may be implemented across Great Britain's electricity and gas systems. The near-term use of curtailed energy for electrolysis can generate significant learning and preparation for a future where hydrogen may be used as a large-scale energy vector for system balancing.

1.2 Recommendations

- Market mechanisms, incentives and contracts for the deployment of electrolytic hydrogen capacity identified in the British Energy Security Strategy should be structured to consider the value of electrolyser location and its relation to curtailed renewable energy. The opportunity cost of curtailment mitigation should be part of any project assessment, including proposals around long-duration energy storage. Geographical considerations are illustrated in Figure 1.

- Hydrogen stakeholders should be kept informed on the progress of the time lag between new generation capacity and network expansion in the Scottish networks. Quantitative volumes of forecast curtailment, which are detailed, disaggregated by location and with appropriate uncertainty bounds, should be published by the National Grid Electricity System Operator and Distribution Network Operators to assist in the development of business cases.
- Alternative mechanisms for mitigating the impact of delays in commissioning new networks should be explored, including investment in local curtailment mitigation technologies, which might include the ability to locally deploy temporary, mobile electrolysis capacity to absorb excess energy, particularly for island networks.
- The potential for curtailed energy to accelerate near-term electrolysis deployment for hydrogen storage should be explored. For example, developers wanting to co-locate electrolysis capacity with new wind generation might be able to begin commissioning the electrolyser component before construction of the wind farm starts, with the facility using curtailed network energy prior to operating on wind turbine exports.
- The regulatory principles for low-carbon hydrogen to be produced from network-embedded or co-located electrolysis should be explored further. Electrolysis connected to electricity networks will require a robust accounting mechanism to correctly determine the carbon emissions from hydrogen production and to prevent double-counting of zero-carbon energy within the electricity system. This should be encapsulated within the Electricity System Operator's dispatch mechanisms and considered in how electrolysis is dispatched against renewable generators, storage systems and demand-side flexibility.

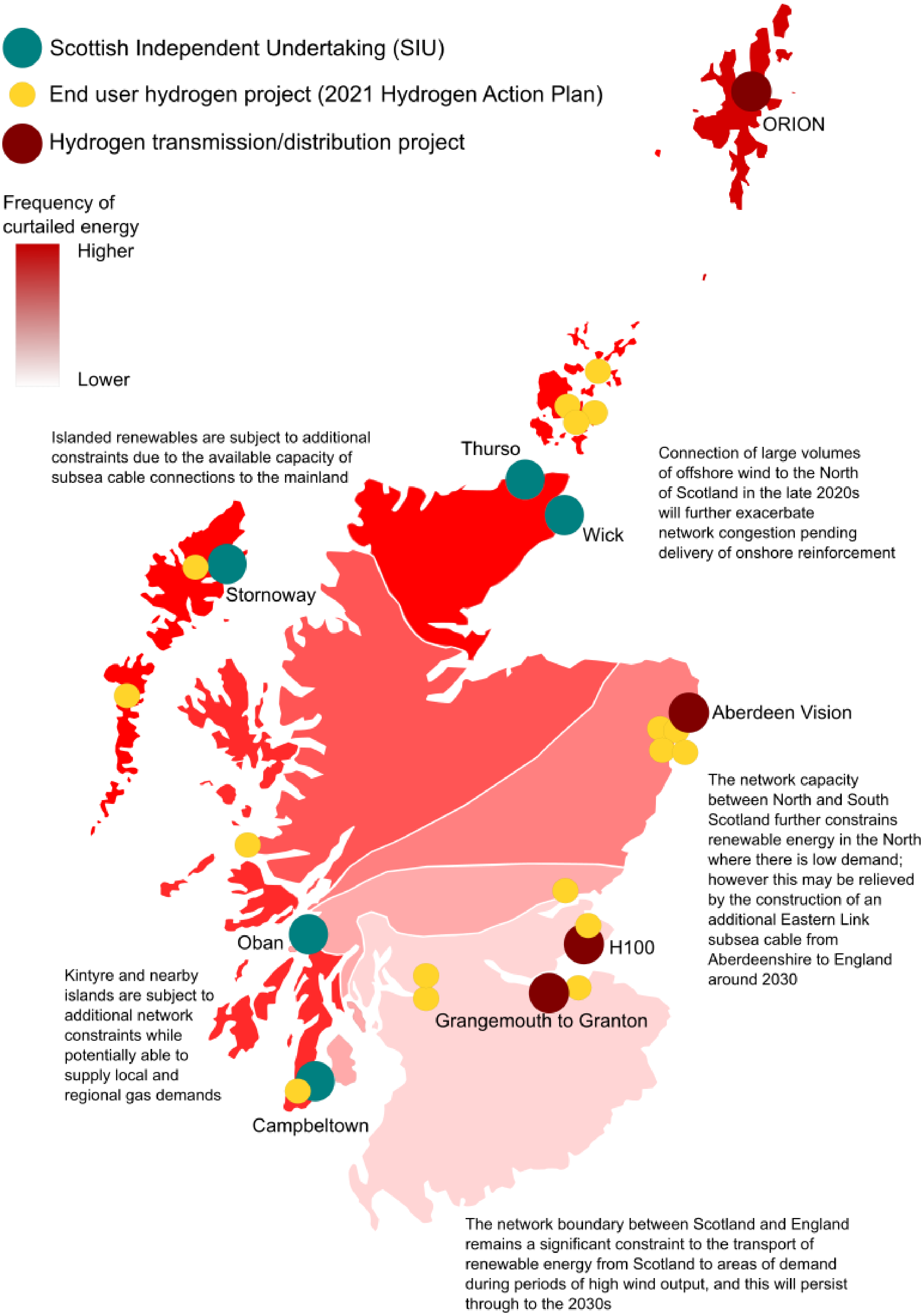

Figure 1 - Summary of future curtailment volumes in relation to current hydrogen demand and network projects. A Scottish Independent Undertaking is a local gas network not connected to the national gas network.

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Curtailment of Renewables

The Electricity System Operator (ESO), National Grid ESO, has responsibility for operational management of the electricity transmission networks across Great Britain (GB). Market dispatch ahead of time does not consider network capacities. In real-time operation NGESO must utilise the Balancing Mechanism - a pay-as-bid market - for increasing and decreasing the export/import of generators, energy stores and large demand [2]. This is undertaken to ensure that total energy supply meets total energy demand to maintain system frequency within statutory limits; and to ensure transfers of energy across components of the network does not exceed secure limits, as governed by the Security and Quality of Supply Standard [3].

2.1 Causes of Curtailment

Curtailment occurs when the network is unable to deliver the level of power that has been contracted in the market ahead of time.

Within the Balancing Mechanism, renewable generators connected to the transmission network (or large generators connected to the distribution networks) receive payments in return for any reduction in output necessary for the secure operation of the electricity network, under a pay-as-bid market mechanism. These payments are approximately equivalent to the value of the lost energy and subsidies that would otherwise have been received by the owner of the generation asset for the energy they have not been permitted to export.

Renewable generators are subject to curtailment for 4 reasons:

1. Under the 'Connect and Manage' framework [4], renewable generators are permitted to connect to the transmission network ahead of there being sufficient network capacity to absorb their full output, in order to maintain progression of renewable deployment ahead of long planning and construction timescales for transmission network assets. The result is that network capacity lags significantly behind the growth in renewable capacity, and curtailment acts as a bridging mechanism, pending the necessary transmission reinforcements being commissioned.
2. A small volume of curtailment is a feature of the economically optimal level of network investment. Broadly, it is cheaper to slightly undersize network and face some level of curtailment costs, than to build network capacity that has a very low utilisation rate (see Figure 2).
3. Maintenance of local network security by the System Operator, such as to keep energy transfer across key network boundaries within secure limits, and to manage stability in renewable-dominated areas of the network.
4. System-wide balancing, where the total amount of non-synchronous generation on the system exceeds a proportion of total demand and output must be curtailed to maintain system security. System-wide balancing occurs irrespective of the level of network capacity available to transport energy to areas of demand. To date this has not been a significant feature of the GB system[1], but is likely to

[1] In May 2020 NGESO contracted with Sizewell B to reduce reactor output through to September 2020 [5] in order to manage low demand volumes against non-dispatchable generation during lockdown; this gives a snapshot view of the conditions which may be expected as normal operation once non-dispatchable renewables are a significant proportion of electricity demand, in the absence of demand management strategies.

become so as the total installed wind capacity reaches or exceeds minimum electricity demand.

While network-related constraints (reasons 1-3 above) are the predominant cause of curtailment in today's system, these volumes may decrease as new network assets are deployed and 'catch up' with the rate of renewable deployment. However, as the total volume of renewables on the system increases, demand-related curtailment (reason 4 above) for the maintenance of whole system security may become the dominant cause, leading to different patterns of curtailment to those seen today. And in the long term, even once renewable generation has scaled to Net-Zero targets and network investment has provided a commensurate level of capacity, we will still expect curtailment to be a feature of the economically-optimal energy system (reason 2 above and Figure 2).

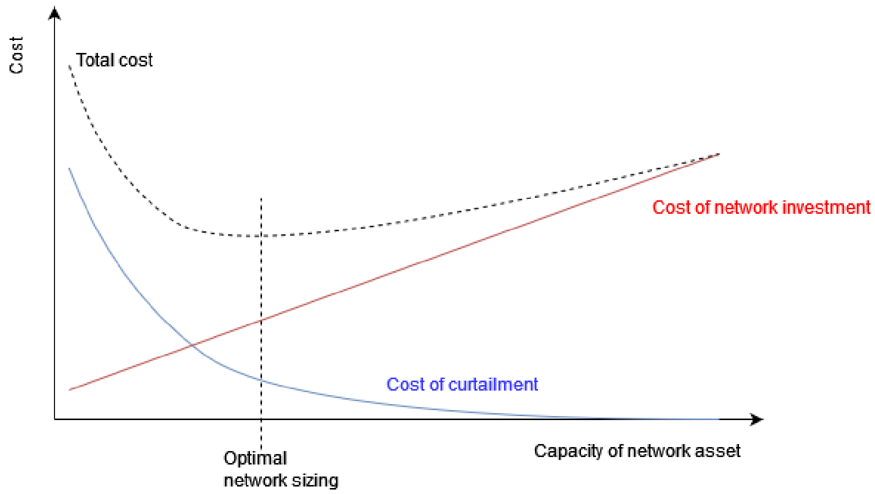

Figure 2 - Optimal network investment (idealised)

2.2 Historical curtailment

Historical monthly curtailment volumes for Scottish renewable generators is given in Figure 3, as determined from the Elexon BMRA archives [6]. Generally, the trend has been for this volume to increase over time as new renewable generating capacity is installed, with an additional peak in 2020 due to the reduced demand associated with the COVID-19 pandemic.

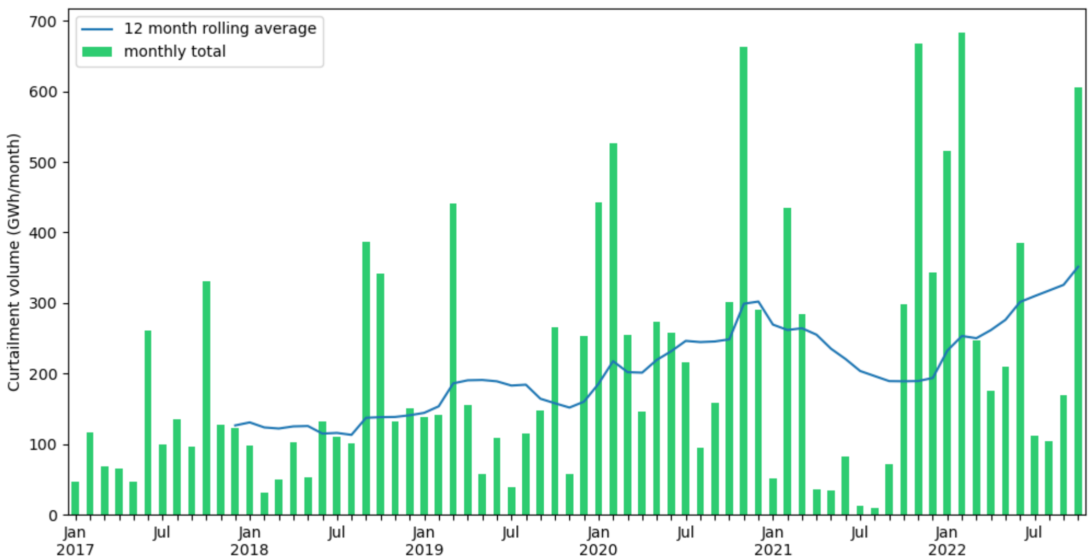

Figure 3 - historical curtailment volumes by month, all Scottish wind generators, with 12-month rolling average

As described above, the causes of historical curtailment volumes are not necessarily the same as for future scenarios. This means that today's level of curtailment – in duration, frequency, and location – potentially acts as a very poor proxy for predicting the availability of future curtailed energy for electrolysis, and to predict this requires assessment of the future growth of renewables against the planned level of network expansion in Scotland. We present results from this approach in the following sections.

Future scenarios

To evaluate the future volumes of curtailment expected on the Scottish transmission regions - operated by Scottish Power Energy Networks (SPEN) and Scottish and Southern Electricity Networks (SSEN) Transmission in the south and north of Scotland, respectively - the prospective growth in generation capacity is mapped onto a regional model of the Scottish electricity transmission networks, for a set of future scenarios. Broadly the 'Leading the Way' scenario of National Grid ESO's Future Energy Scenarios [7] is used as a baseline projection, with additional elements disaggregated to the Scottish context as detailed here. The model used is based on the OATS power system analysis toolbox [8], populating a zonal transport model representing the regional generation mix and inter-region network capacities

In this section a high-level overview of the generation and network elements of the selected scenarios is given; further background detail is provided in Appendix A: Scenario Assumptions.

3.1 Overview of network

Figure 4 shows a zonal network model for Scotland in use, representing the National Electricity Transmission System (NETS) network boundaries [9], corresponding power flow (FLOP) zones defined in the Future Energy Scenarios [10], and the connection to external areas (either rest-of-GB (rGB) or interconnection to Northern Ireland / Norway).

The topology of the transmission network can be visualised as a set of zones, as defined by the Electricity System Operator, with boundaries defined as divisions between those zones which have a certain capacity to transfer energy, representing the combined network capacity between them. Table 1 gives the transfer capacities for each boundary in scenario years, based on the economic pathway identified in the 2020/21 Network Options Assessment (NOA) [11].

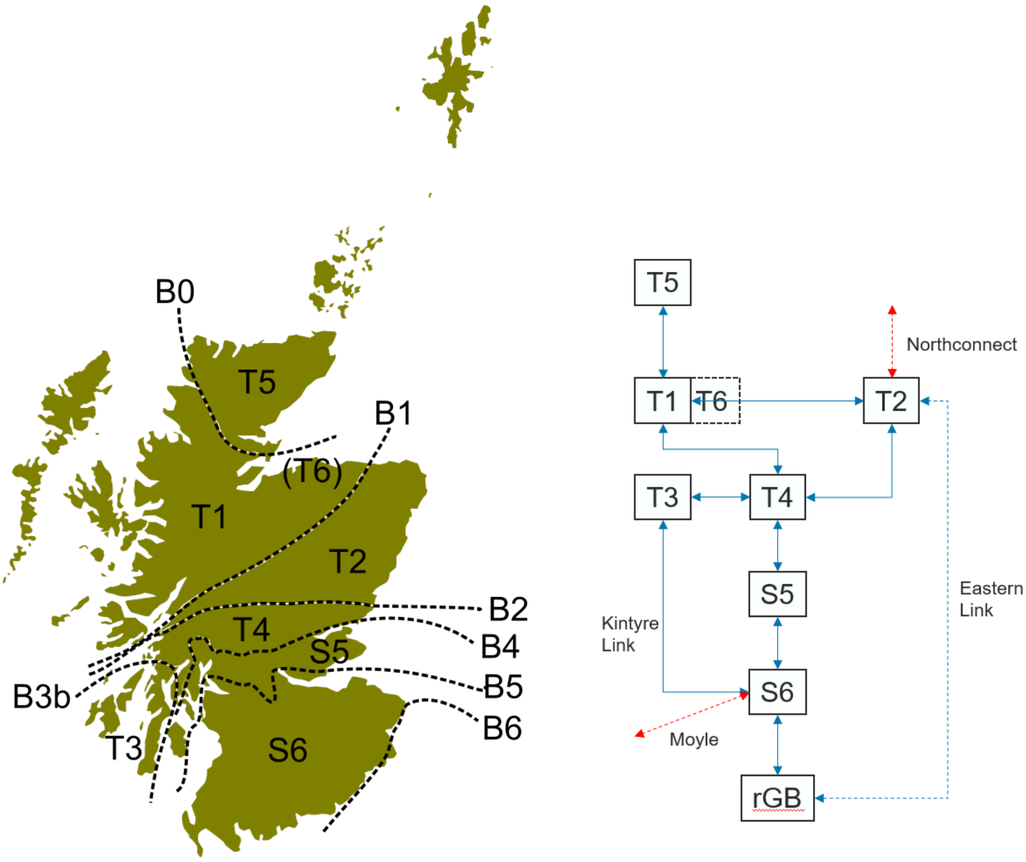

Figure 4 – Transmission System network zones for Scotland, indicating key transmission boundaries and defined FLOP Zones (left), alongside reduced network indicating representation in curtailment model (right). The B4 boundary acts as the dividing line between the Scottish Power Energy Networks (SPEN) and Scottish and Southern Energy Networks (SSEN) zones in the south and north of Scotland respectively. Moyle is the extant electricity interconnector to Northern Ireland, and Northconnect is the interconnector under development between Aberdeenshire and Norway. The Kintyre Link (extant) and Eastern Link (proposed) are explicitly included as they provide network capacity which bypasses other flow constraints between zones.

Table 1 - Network boundary capacities (MW) by scenario. Stated NOA capacities for B4/B5/B6 include the Eastern Link capacity (2000MW in 2030, 4000MW in 2035).

Boundary	Existing	2025	2030	2035
B0	1150	1944	2708	2708
B1a	2901	4882	5254	6710
B2	2600	4024	7314	9278
B3b	450	450	450	450
B4	3200	3677	7175	9123
B5	3600	4416	7004	9704
B6	6100	7278	10910	16900
Eastern Link	0	0	(2000)	(4000)
Kintyre	240	240	240	240

3.2 Overview of scenarios

Each scenario is proposed as a specific year of operation (based on half-hourly time series), with time series of demand and power output per generation type (wind/nuclear/gas etc.) per zone, along with a boundary transfer capacity for each identified boundary in Figure 4. Curtailment volumes are derived as the excess renewable generation within each zone which cannot be accommodated by the specified boundary transfer capacity, with the rest of the Great Britain transmission network acting as an effective 'sink' zone subject to this constraint[2] (i.e. able to use unlimited electricity).

The scenarios proposed correspond to points in time along a single pathway, chosen as the most aggressive expansion of renewables currently envisioned by Scottish policy. To correspond with this, the largest expansion of onshore transmission network currently identified by the Network Options Assessment (NOA) [11] is used in parallel.

The points in time are chosen to be 2021 (baseline), 2025, 2030 and 2035. This endpoint was selected as being the furthest horizon at which a consistent spatial picture of generation and network expansion could be identified from current published plans. The 2021 baseline provided a useful snapshot of current conditions, with energy demand having rebounded following lockdowns in 2020.

3.3 Expected growth of renewable capacity

An additional capacity of onshore wind of 10GW (from a current operational baseline of 8.4GW, giving a total of 18.4GW) is projected to 2030, in keeping with the Scottish Government's Draft Policy Statement of October 2021 [12]. A linear expansion of capacity is assumed through each scenario and extrapolated to 2035. To spatially disaggregate future expansion, currently identified pipeline projects have been extracted from the planning database and the regional growth extrapolated to this target total capacity.

The ScotWind 1 leasing results [13] of January 2022 gives a further pipeline of around 25GW of offshore wind, likely to connect to onshore locations across the transmission network. While the development timescales for these projects is currently uncertain, and would likely cause further onshore/offshore network development beyond the cases already identified in the NOA, we include some capacity as additional sensitivities in 2030 (+10GW) and 2035 (+20GW).

Growth in distribution-connected generation is already modelled and represented within the Future Energy Scenarios' representation of Grid Supply Point demand, so utilisation of demand time series as represented within the 'Leading the Way' scenario is considered inclusive of projected growth in small-scale distributed generation and storage. All growth in solar PV capacity in Scotland is assumed to be included within this (i.e. there are no transmission-level solar PV projects).

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[2] In the future, curtailment volumes in Scotland as a whole may be sensitive to the overall generation/demand balance for the whole of GB, or boundary transfer capacities within rGB. Within the time horizon evaluated it is considered that the given NETS boundaries will remain the binding constraints on exports from Scotland to rGB. This will also depend on the preferential curtailment of Scottish vs rGB generators to manage system-wide constraints; under current market arrangements this will depend on relative bid costs, in turn dependent on differentials in transmission costs and capacity factors. For these reasons, we keep demand-related balancing out of scope.

Three additional factors identified as of key importance are:

- The currently undetermined nature of the Eastern Link HVDC, which comprises three individual reinforcements: an offshore cable array between S6 and rGB (i.e. reinforcing the SPT/NGET boundary at B6) and 2 offshore cable arrays between T2 and rGB (creating a novel direct link between the North of Scotland – SHETL - and England/Wales – NGET - transmission areas). As the latter has the potential to significantly impact the volumes of curtailment in the SHETL zones, this particular network option is added as an additional sensitivity to be explored via sub-scenarios for 2030 and 2035.
- The development rate and deployment of the ~25GW of offshore wind options within the ScotWind 1 auction announced in January 2022.
- The growth in technologies other than hydrogen electrolysis which may also serve to reduce curtailment actions on the network, including new pumped hydroelectricity capacity, interconnection, battery storage and demand response.

The first two factors are explored through additional sub-scenarios for the 2030 and 2035 scenarios. The last is evaluated externally to the curtailment model by assuming different proportions of modelled curtailed energy are available for use by electrolysers and determining the impact this effective competition between balancing technologies will have on the electrolysis business case.

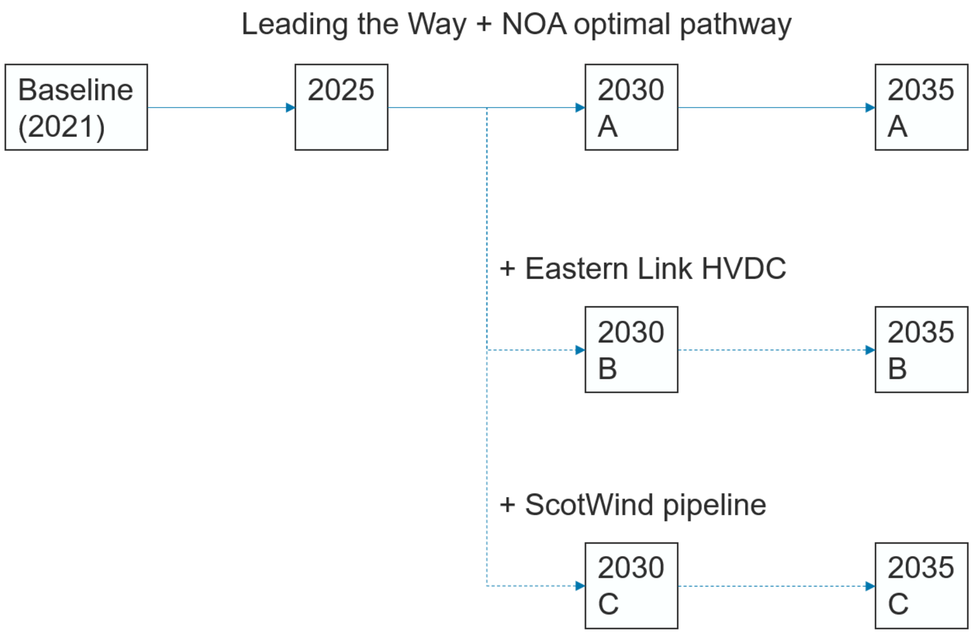


Figure 5 - Summary of scenarios

3.4 Impact of electrolyser capacity on curtailment

The British Energy Security Strategy of April 2022 [1] indicates the following support for the deployment of electrolysers:

- “doubling our ambition to up to 10GW of low carbon hydrogen production capacity by 2030, subject to affordability and value for money, with at least half of this coming from electrolytic hydrogen.

- aiming to run annual allocation rounds for electrolytic hydrogen, moving to price competitive allocation by 2025 as soon as legislation and market conditions allow, so that up to 1GW of electrolytic hydrogen is in construction or operational by 2025"

The addition of electrolytic capacity in Scotland would locally increase electricity demand. It would reduce the flows across network boundaries during periods of high renewable output, reducing the volume of curtailment. To evaluate this impact, electrolyser volumes of 500MW, 1.5GW and 5GW are added to each scenario and assumed to make priority use of curtailed energy.

Figure 6 indicates a potential substantial reduction in curtailment and a cost saving to the ESO of this electrolyser capacity if situated within Scotland. This indicates that in the near-term, electrolysis capacity avoids the negative consequences of the delay in network expansion. The value reduces as network capacity increases by 2035. In turn, this means that electrolysis may be evaluated as a potential alternative to reinforcement, especially for cases where network projects may be delayed by financing, approval or planning. However, under the scenarios with a large volume of additional wind capacity from the ScotWind pipeline is included (2030C, 2035C), it is evident that electrolysis provides great value in overcoming the substantial imbalances between generation and demand that will occur within the Scottish networks.

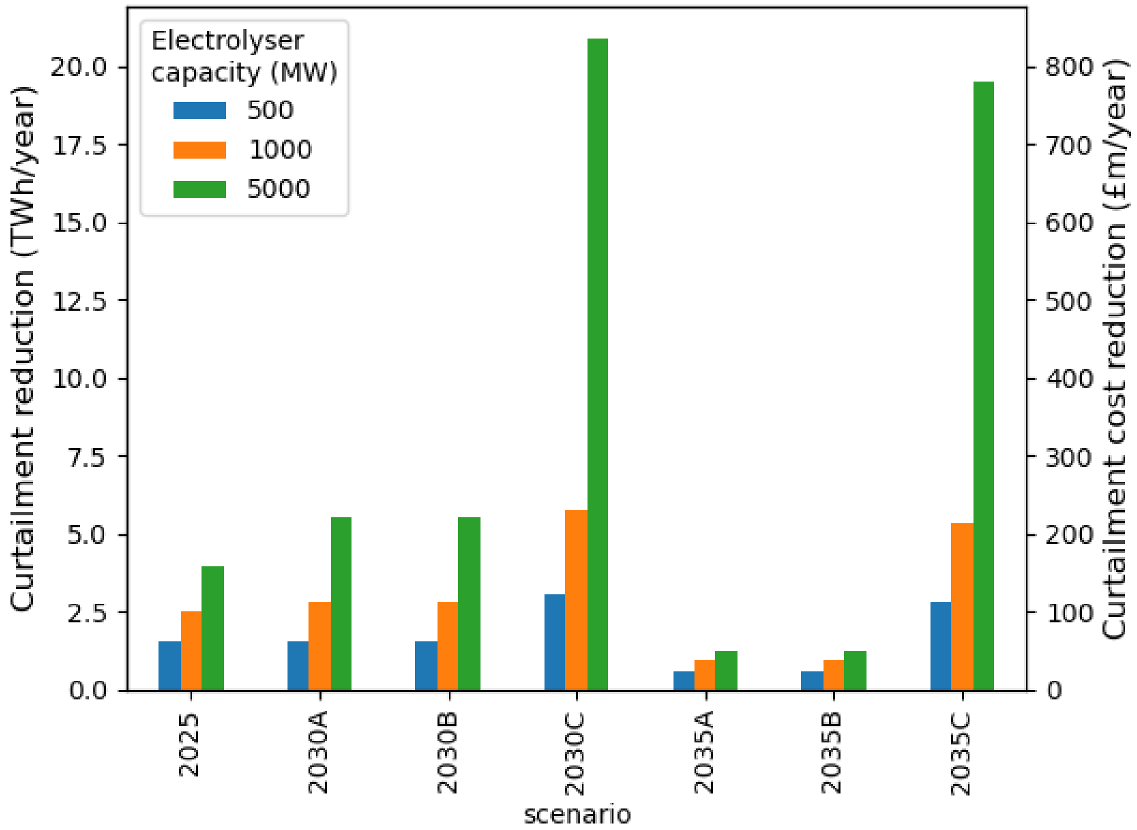


Figure 6 - Reduction in curtailment volumes and indicative curtailment cost savings to the ESO with installed capacities of electrolysis in Scotland. Curtailment cost reductions assume a flat rate of £40/MWh for wind curtailment (based on recent Contract for Difference delivery values [14]), and a zero bid price for electrolysis

This analysis assumes that no other constraint relieving technologies are commissioned within the same period. New pumped hydro capacity, interconnection, storage and demand-side management added to the system will also reduce the volume of curtailed energy on the system. The residual value offered by electrolysis will reduce as a consequence.

The impact will be dependent on the exact mixture of mitigating technologies, and the market arrangements under which they are dispatched. To illustrate this impact a secondary analysis is shown in Figure 7, with an additional 1500MW of flexible demand included and dispatched in preference to the electrolysis. This approximately corresponds to the proposed capacity of, for example, the Coire Glas pumped hydro scheme (1500MW) or the Northconnect Interconnector from Aberdeenshire to Norway (1400MW).

These results show that in 2035, without further growth of renewables, the combination of network reinforcement and this flexible demand leaves zero residual curtailment. Under the future scenarios with a substantial ScotWind pipeline, network constraints still produce a residual volume of curtailed energy which leaves a substantial benefit to the presence of electrolytic capacity.

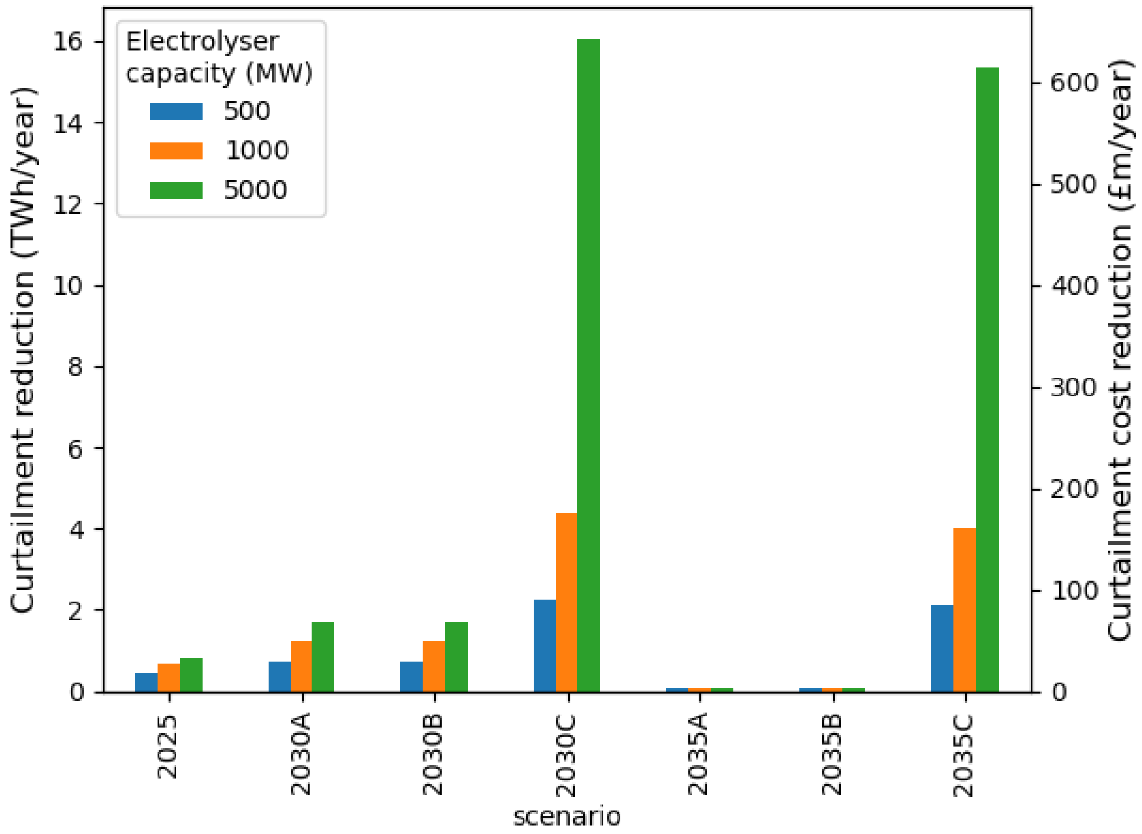


Figure 7 - Reduction in curtailment volumes and indicative curtailment cost savings to the ESO with installed capacities of electrolysis in Scotland, alongside an additional 1500MW of curtailment-mitigating technologies. Curtailment cost reductions assume a flat rate of £40/MWh for wind curtailment (based on recent Contract for Difference delivery values [14]), and a zero bid price for electrolysis

In these analyses the exact business case and market arrangements for electrolysers are not evaluated, it is assumed that the electrolysers are funded under a mechanism to be decided and will preferentially make use of curtailed energy over other sources. In the next section we evaluate the potential load factors implied by the use of curtailed energy, as a first step to assessing the potential business case for this mode of operation.

3.5 Evaluation of electrolysis using avoided curtailed energy

In Figure 8, a baseline view is given of the locational volumes of renewable curtailment seen within the specified network zones in 2021. The figure plots the following values against each other:

Capacity – The total volume of electrolysis (or other curtailment-absorbing technologies) connected to the network

Load Factor – The proportion of time any additional electrolysis capacity would be expected to operate at full load, if using only available curtailed energy

The normal flow of energy during times of high wind production is from North to South. It is assumed that an electrolyser within a specific network zone will also be able to relieve curtailment – and hence access the corresponding curtailment volumes - in any zones to the south. For example, it is assumed that an electrolyser located in the T2 zone will be able to access curtailed energy within T2, T4, S5 and S6. For this reason, the curtailed energy volumes are treated as additive, as indicated by the stacked plot. For the same reason, it is not necessarily the case that curtailment experienced within a region is caused by constraints on the boundary associated with that zone – for example a wind farm curtailed in the T4 zone may have been dispatched to relieve curtailment on the B6 boundary, but was selected due to having a lower cost of curtailment than wind farms in the S6 zone closer to the constraint.

Figure 8 indicates that an electrolyser located in the North of Scotland (T5/T1), by potentially being able to relieve curtailment across any transmission boundary in Scotland, could achieve a load factor as high as 25% or 30%. These load factors are sufficiently high that they would be considered potentially cost-competitive with other forms of hydrogen production in the recent BEIS report [15] (see Figure 12 below). However, these load factors would only relate to a small amount of electrolyser capacity, with load factors rapidly reducing past the first 50MW or 100MW of installed capacity. This also assumes there are no other competing technologies seeking to access the same volumes of curtailed energy; if, for example, 500MW of additional pumped hydroelectric capacity were commissioned in these zones then this could push the load factors of electrolysers down below 15%.

Figure 9 projects these load factors by zone to future scenarios under the pathway which maximises the extent of network investment. The total volume of curtailment could be expected to increase through the decade, particularly in the Northern (T5/T1/T2) zones as wind generation capacity connects ahead of network expansion. However, the commissioning of new network capacity greatly relieves this internal congestion, with little curtailed energy in 2030 beyond the volumes experienced at the B6 boundary, as shown in Figure 9. With the commissioning of the second component of the Eastern Link by 2035, and similar reinforcement of the B6 boundary, curtailment volumes are significantly reduced with electrolyser capacity operating at nominal load factors.

This scenario assumes no additional offshore wind capacity is installed beyond that identified in the current pipeline, which is unlikely to be the case. The scenario illustrates the potentially transitory nature of curtailment as an outcome of generation connecting ahead of network reinforcement. If the pipeline of new renewable energy connections reduces, then internal congestion on the networks similarly will be expected to reduce. Cost-competitive load factors may be achievable for electrolysis capacity connecting in the latter part of this decade. However, the duration of this business case is strongly dependent on how far into the future the growth in renewable capacity extends, and the commissioning rate of new infrastructure intended to accommodate it.

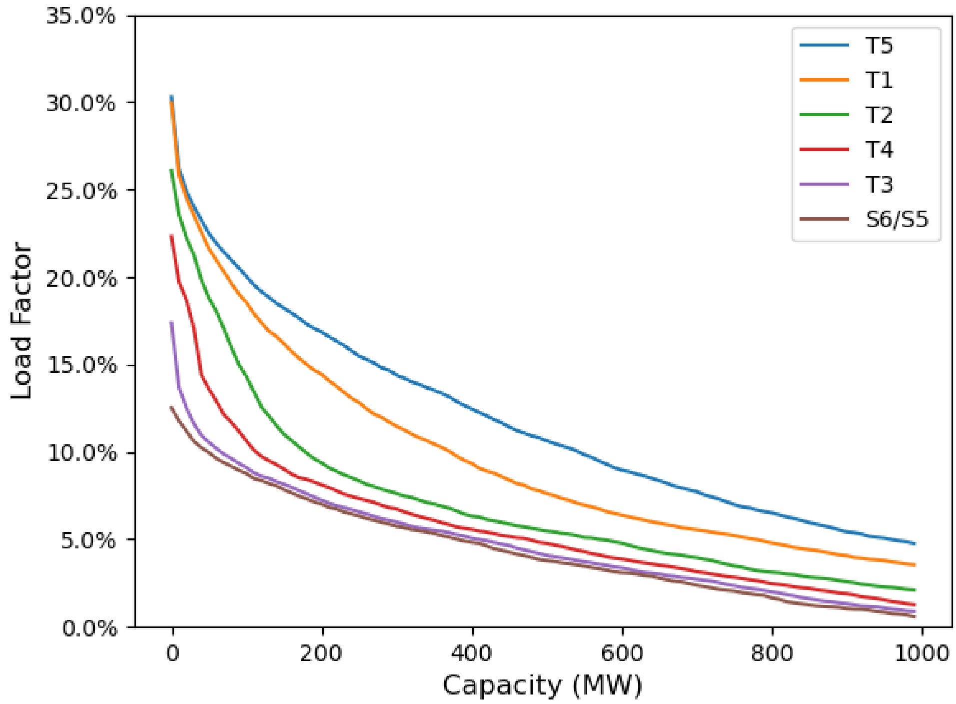


Figure 8 - Electrolyser load factors by zone, by installed capacity of electrolysis, using 2021 actual curtailment volumes/locations. Zones are ordered north to south in the legend.

To contrast, Figure 10 looks at the ScotWind pathway, with an additional 10GW and 20GW of offshore wind capacity connected to the appropriate NETS zones as described in Appendix A: Scenario Assumptions. This indicates that substantial growth in wind capacity has the potential to greatly increase both the frequency and duration of curtailment. This would push up potential electrolyser load factors and the capacity which may profitably be deployed. However, these are entirely illustrative scenarios which contain no further network expansion. In reality, it would be expected that further onshore network reinforcement would be scoped in response to a pipeline of new connection applications at this scale. The extent of network congestion under such a scenario would also likely lead to alternative uses of the output from new offshore capacity, such as co-located electrolysis.

To give context to the above load factors, Figure 11 illustrates the implied levelised cost of hydrogen for a Proton Exchange Membrane (PEM) electrolyser commissioned in specific years running at a specific load factor, using cost assumptions given in [15]. Figure 12 compares this cost projection to other sources of hydrogen. This indicates that an electrolyser commissioned in 2025, using curtailed electricity at a 25% load factor (solid green line, Figure 12), could potentially produce hydrogen under £50/MWh. This cost would make it competitive with other sources of hydrogen production such as methane reformation (solid dark blue line, Figure 12). However, a relatively small decrease in load factor would remove this competitive advantage.

Full results for the 3 pathways in 2030/35 are given in Appendix B.

The addition of electrical storage to an electrolyser has the potential to further increase load factors, and reduce the headline electrolysis capacity required, by ‘smoothing’ the intermittent input from curtailed energy. However, as curtailment periods tend to span multiple hours, the capacity of such storage would need to be capable of storing energy across the same timeframes to have a significant impact. Assessment of the combined potential of electrical storage and electrolysis is similarly dependent on the uncertain evolution of storage costs, and not conducted within this study.

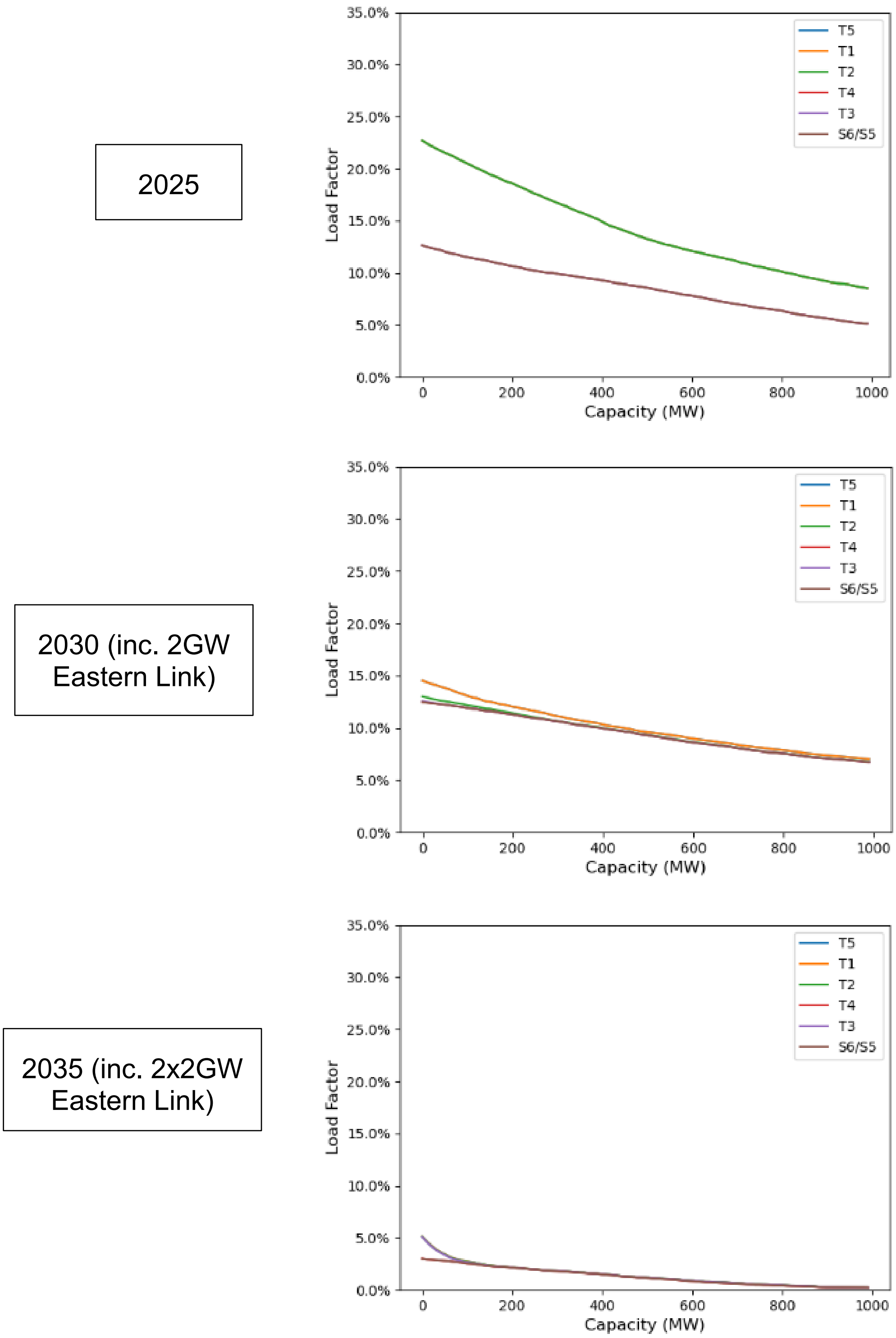
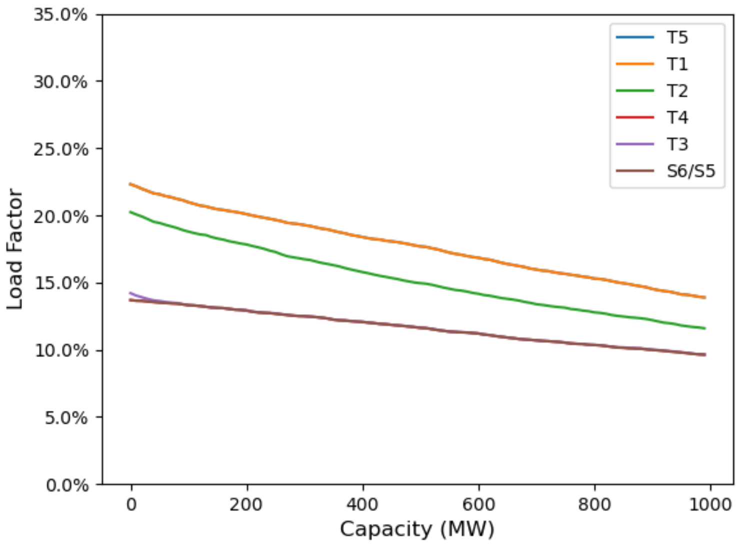
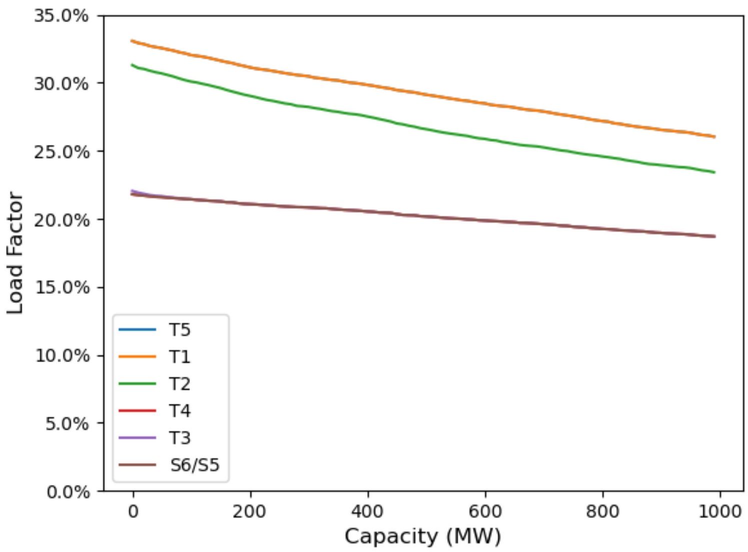


Figure 9 - Electrolyser capacity factors by NETS zone using scenario projections for 2025 (top), 2030b (middle) and 2035b (bottom). Zones are ordered north to south in the legend. Zones not visible have no additional curtailment beyond zones to their south and are collapsed to the next boundary in the direction of flow - for example, in 2025, S6/S5/T3/T4 have access to the same curtailment volumes as defined by the binding constraint at the B6 boundary



2030 (inc. 10GW of ScotWind)



2035 (inc. 20GW of ScotWind)

Figure 10 - Future electrolyser load factors by NETS zone, assuming additional ScotWind capacity and no further boundary reinforcement beyond NOA optimal pathway and Eastern Link.

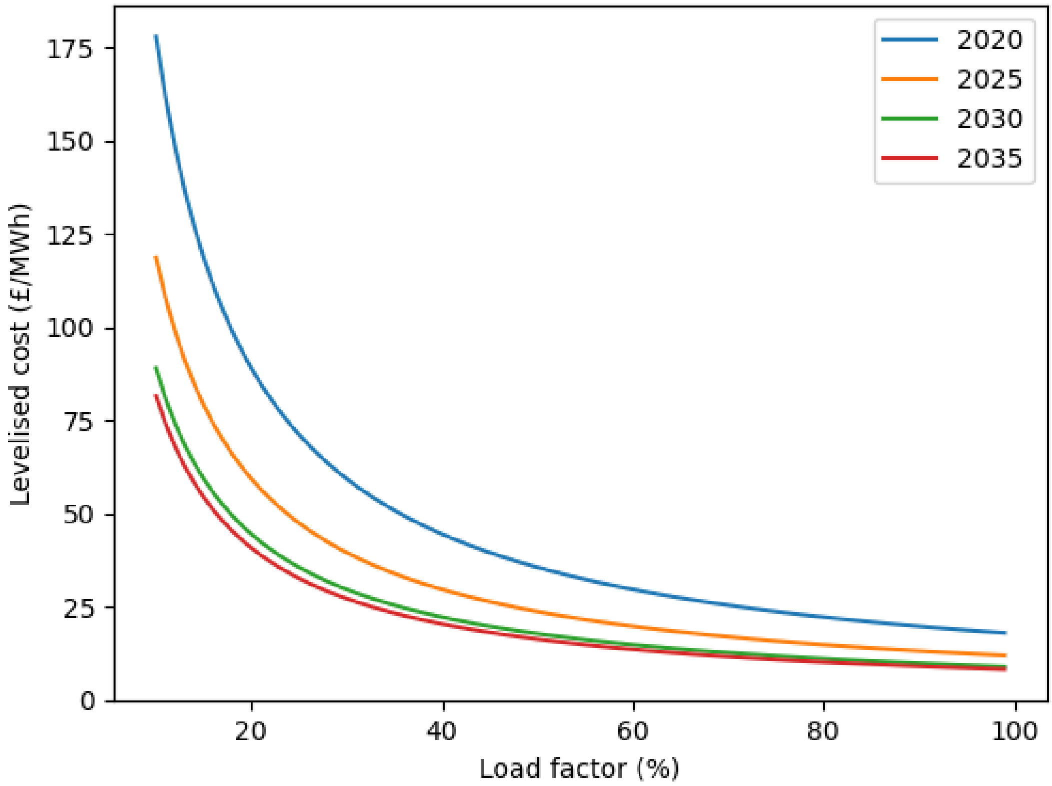


Figure 11 - Implied levelised cost of hydrogen for PEM electrolyser by commissioning year, assuming zero electricity cost, 70% efficiency and 11-year payback.

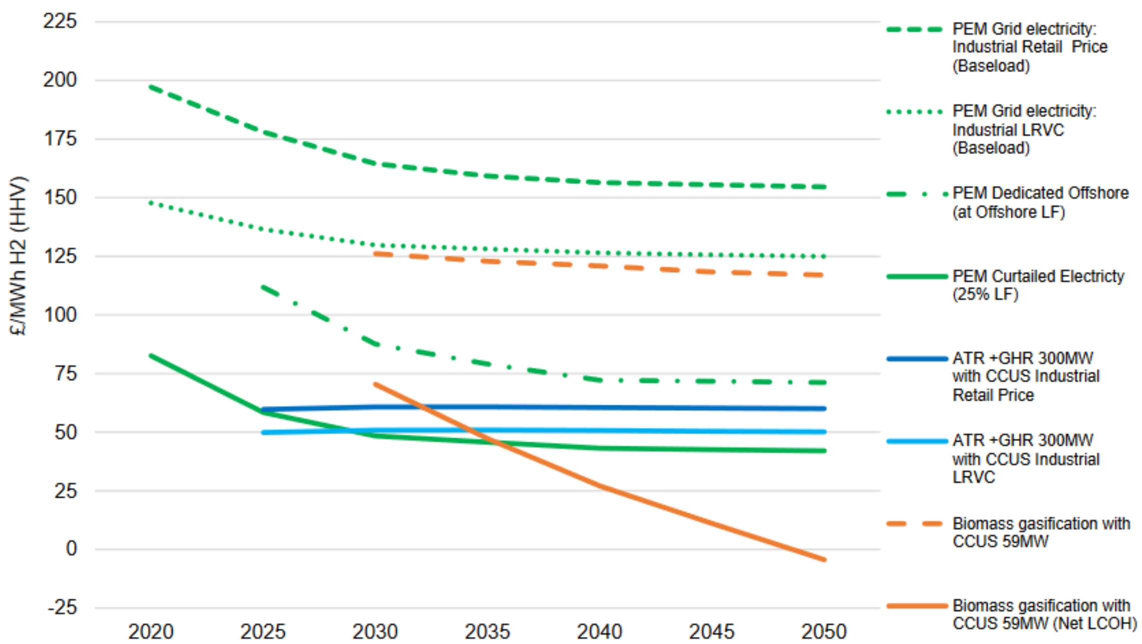


Figure 12 - Comparison of hydrogen levelised cost by source, reproduced from [15]. “PEM Curtailed Electricity” is the case under evaluation in this study

Electrolyser business cases

The preceding section analysis suggests that available curtailed volumes of electricity are significant at least in the period to 2030. The business case for use of this electricity to produce hydrogen is considered further in this section, including CAPEX/OPEX assumptions and manufacturing capacity.

Capital and operating cost assumptions have been aligned with previously published data by the UK government Department for Business, Energy and Industrial Strategy (BEIS) [15]. The methodology for calculating levelised cost of hydrogen (LCOH) is set out in the same reference and used for consistency of approach.

This analysis views the main role of any hydrogen production via curtailed electricity as a means of supporting wider grid management. For this reason, Proton Exchange Membrane (PEM) electrolysers are the focus of analysis given their faster response (start-up) time relative to alkaline or Solid Oxide Electrolyser Cell (SOEC) designs. The PEM design is the most efficient of these designs when operating at part load.

Operating costs incorporate both fixed (e.g. labour costs, insurance, maintenance) and variable (e.g. stack replacement) costs, but exclude any consideration of storage capacity or transport of output hydrogen.

While a commissioning time of 3 years is assumed, consistent with the BEIS cost assumptions [12], it is recognised that this can be seen as optimistic given current production capacity and scale of market demand. Longer commission times would severely impact the ability of any project to make optimal use of late-2020s curtailment volumes.

4.1 On-site vs network-embedded

Two development cases are considered:

1) A stand-alone, network-embedded electrolyser which exists only to utilise curtailed electricity. The electrolyser operates at low capacity factor without any supplementary power (either from local or grid-connected supply).
2) An on-site solution where an existing renewable generator extends operating the plant to include green hydrogen production[3]. The electrolyser operates at a higher capacity factor than the stand-alone case, using on-site generation to supplement curtailed supply.

In both cases output hydrogen is sold on to an undefined end user. The means of transport to consumer and any storage requirements are not prescribed.

4.2 Competition with other technologies

Hydrogen production using curtailed electricity volumes is only one possible action to support grid balancing activities. Network embedded batteries, demand side management and pumped hydro storage are all other options that could be deployed. The relative contribution of each of these options can't be predicted with any certainty. For this reason, these are considered qualitatively as a single impact on the availability of curtailed volumes for use in hydrogen production.

[3] Green hydrogen production is defined here as the use of electrolysis for the production of hydrogen. All power requirements are met from renewable generation sources.

The load factor data presented in Figure 9 and Figure 10 show a decrease in achievable load factor as greater electrolysis capacity is installed. First mover advantage (obtaining highest load factor of 0.25 – 0.30) is rapidly reduced by electrolyser capacity of 50 – 100 MW (load factor 0.15 or lower). Other assets could equally well draw on these curtailed volumes and therefore reduce the scale of hydrogen production achievable. For example, one single pumped hydro scheme (given 100+ MW scale) will readily disrupt the opportunity that stand-alone network embedded electrolysers could offer. A small number of grid-scale battery projects would have the same impact.

4.3 Use of curtailed energy by existing generators

Historic Balancing Mechanism payments to wind operators, as derived from the BMRA archive [6] are shown in Figure 13. This suggests a typical price of around £70/MWh. This offers a threshold revenue point when considering the benefit of curtailed electricity use by an existing generator (i.e. hydrogen would have to be worth at least equivalent to £70/MWh to be competitive). Given the current terms of participation in the Balancing Mechanism process, generators can either retain payment for curtailment or use the curtailed generation volume to produce hydrogen; potential revenues are not cumulative. A significant increase in use of curtailed volumes will also impact the revenue available to those generators not using curtailed volumes.

This bid price is expected to reduce in the future as more offshore wind farms with Contracts for Difference (CfDs) come online, with an approximate contract price of £40/MWh for projects commissioning in 2023/24 [14]. Under the Transmission Constraint Licence Condition, generators are required to provide bid prices which reflect the lost value of energy. In this future position, the net benefit of hydrogen production might be more favourable than curtailment (i.e. net revenue from hydrogen production could be higher than the default revenue of £40/MWh).

This analysis has considered curtailed volumes within a given half hour period. In practice, there would be potential system balancing requests at minute timescales within a given half hour period. This is a further challenge to the use of hydrogen production as a network balancing contributor, given the response time of even the fastest PEM electrolyser designs starting up from cold is 5 to 10 minutes [16].

Offshore generators entering the market from 2030 onwards may incorporate dedicated green hydrogen production as a means of minimising electrical infrastructure costs (co-located offshore) or at landfall. This assumes the availability of cost-effective routes to transport output hydrogen to consumers. The business case for hydrogen production is therefore driven by optimising the value of generation output (and associated systems of supply delivery) rather than as a network balancing service. In this situation, available volumes of curtailed electricity are minimised since offshore generators are co-locating loads that use the increased generation. While direct network investment specific to offshore wind capacity is uncertain in the period 2030 – 2035, it is reasonable to presume some level of investment if generation volumes far exceed existing network capacity in specific regional areas. This would lead to an evolving position in terms of network management - less concern about matching demand and supply; more focus on managing supply. This would not offer any certainty to operators of hydrogen production looking to support network balancing services. Other large-scale competing options (such as battery storage or pumped hydro) may be prioritised depending on the scale of challenge between generation volumes and demand.

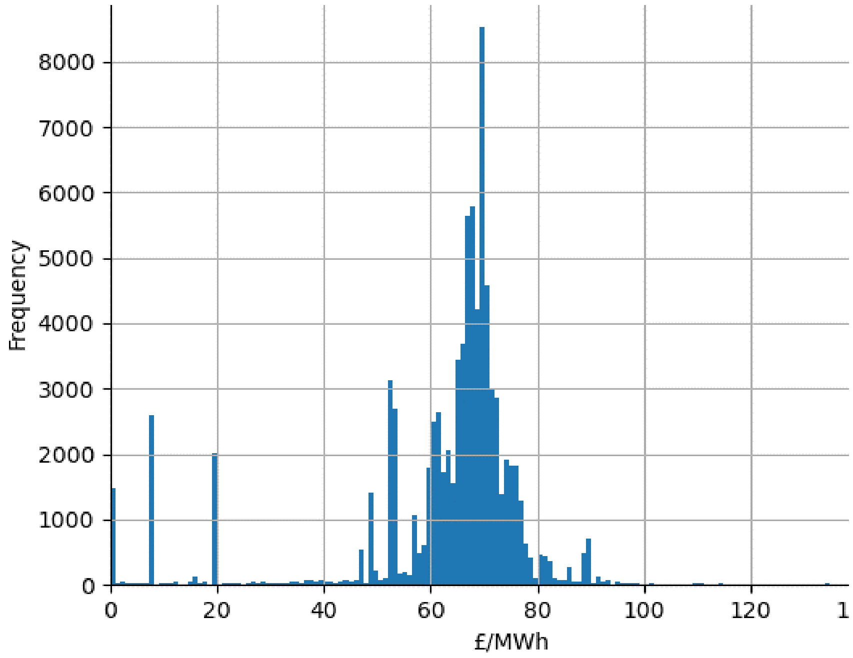


Figure 13 - Distribution of accepted wind balancing bids (i.e. price paid to wind generators to reduce power output), Jan 2020 - Dec 2021

4.4 Water availability

The reliable availability of a water supply is a crucial element in hydrogen production (an indicative range of 18 – 24 kg of water per kg of hydrogen is used here as an initial benchmark [17]). In the case of onshore production this means managing potentially competing abstraction licences from other users (such as distilleries or agriculture). In the case of offshore production, it will rely on additional desalination processes for the input feed to the electrolyser.

Scottish Water continually monitor drought conditions across each supply zone in Scotland and liaise with the Scottish Environment Protection Agency to manage water stress and prolonged drought conditions. Medium and long term projections suggest that Scotland will be increasingly vulnerable to periods of dry weather [18].

Recent work has looked at regional vulnerabilities to drought conditions in Scotland and the extent to which abstractions further contribute to water stress. Projected drought hotspots in the near term (2020 – 2049) include regions around the Spey and Tay rivers, as well as other areas in the Highlands. This could act as a constraint on proposed hydrogen production in the more northerly FLOP Zones where the greatest aggregate curtailed volumes are available. It is an additional factor that could make pumped storage more favourable in a given region due to net abstraction rates linked to environmental permit requirements [19].

4.5 End user demand

The business case analysis presented focusses on use of curtailed electricity volumes as a means of system balancing. In practice, transmission level embedded hydrogen production will need a firm end user for output hydrogen. While transport costs of shipping hydrogen are not explored in this study, transporting large volumes of hydrogen over any significant distance (whether by tube trailer, marine vessel or pipeline) would not be cost-competitive. It also ignores practical issues associated with environmental permitting, not least in respect of on-site storage volumes and related regulations such as Control of Major Accident Hazards (COMAH) [20].

The Scottish Government's Hydrogen Assessment [21] provides a guide to projected end use demand for hydrogen out to 2050. For the purposes of this study the snapshots of end use demand in 2025 and 2032 are useful, with predominant sources of demand being industrial applications, domestic heating (specifically via blending into the existing national gas transmission network) and transport. To explore the relationship of renewable energy and hydrogen demand, Figure 14 provides a view of wind and solar generation sites across Scotland overlaid with potential sites of largest hydrogen demand linked to industrial users.

Domestic heat demand could be met in part through transformation of the existing natural gas system to use of hydrogen. For this purpose, the most suitable locations of hydrogen production are heavily linked to access into the gas transmission network, rather than availability of curtailed electricity for use in production. Locations in northerly FLOP zones (to take advantage of the greatest curtailed electricity volumes) will be further from gas transmission infrastructure (notwithstanding the small number of stand-alone gas networks discussed below). It is possible that transportation costs of hydrogen for such applications would be prohibitive.

Industrial demand for hydrogen is heavily weighted to the East of Scotland including the Grangemouth industrial cluster, Aberdeen and St Fergus and other major industrial sites. Work looking at repurposing existing infrastructure to support twin objectives regarding hydrogen production and carbon capture storage will use blue hydrogen production[4] as a transition step to wider adoption of green hydrogen. The investment case for blue hydrogen, relative to a specific green hydrogen project based solely on use of curtailed electricity volumes, will look stronger, given the short period in late 2020s and early 2030s before uncertainty arises around diminishing availability of curtailed volumes. In addition, the transport costs of moving large hydrogen volumes from curtailed generators to end consumers in the East of Scotland will be prohibitive (when compared with blue hydrogen opportunities).

There is potential for more distributed demand associated with distilleries. Solutions for hydrogen production to meet these needs may be either aggregated e.g. meeting collective demand in locations such as Islay. Otherwise they could be be localised and therefore better suited to hydrogen production solutions embedded in the distribution system (rather than the transmission scale considered in the current study).

Another potential source of hydrogen demand could be the Statutory Independent Undertakings (SIUs) - stand-alone gas networks managed by SGN and currently using LNG as the primary fuel[5]. The largest of these is in Oban, with the others in Thurso, Wick, Stornoway and Campbeltown. SGN's investment case [22] suggests a future use of biomethane and hydrogen as a pathway to decarbonising these networks. It is possible that network embedded hydrogen production could support the networks in Thurso, Wick and Campbeltown given the projected curtailment volumes available in these FLOP zones. Any such capacity would likely have to compete with larger scale production volumes of biomethane/hydrogen produced within SGN's wider supply chain. However, it would have potentially lower transport costs due to the SIUs being unconnected to the wider network. It is also possible that distribution network level

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[4] Blue hydrogen production is defined here as the use of steam methane reform (SMR) or similar production methods where process emissions are captured via carbon capture and storage

[5] With the exception of Stornoway, which uses LPG, and where biopropane would be the alternative biofuel

electrolyser production (tied to locally curtailed smaller scale community wind assets for example) would be a more effective means of offering resiliency of supply within SGN's operations.

Transport applications (road, rail or marine) will rely on secure supply of smaller volumes than industrial or heat applications. These are better suited to localised solutions at distribution scale, utilising community-scale generation assets. Road transport applications are likely to see Original Equipment Manufacturers (OEMs) wrap hydrogen supply into purchase agreements (i.e. vehicles will come with both a fuel supply agreement and ongoing maintenance support as a single deal), further complicating (and potentially reducing) the revenue benefit to hydrogen produced using curtailed electricity.

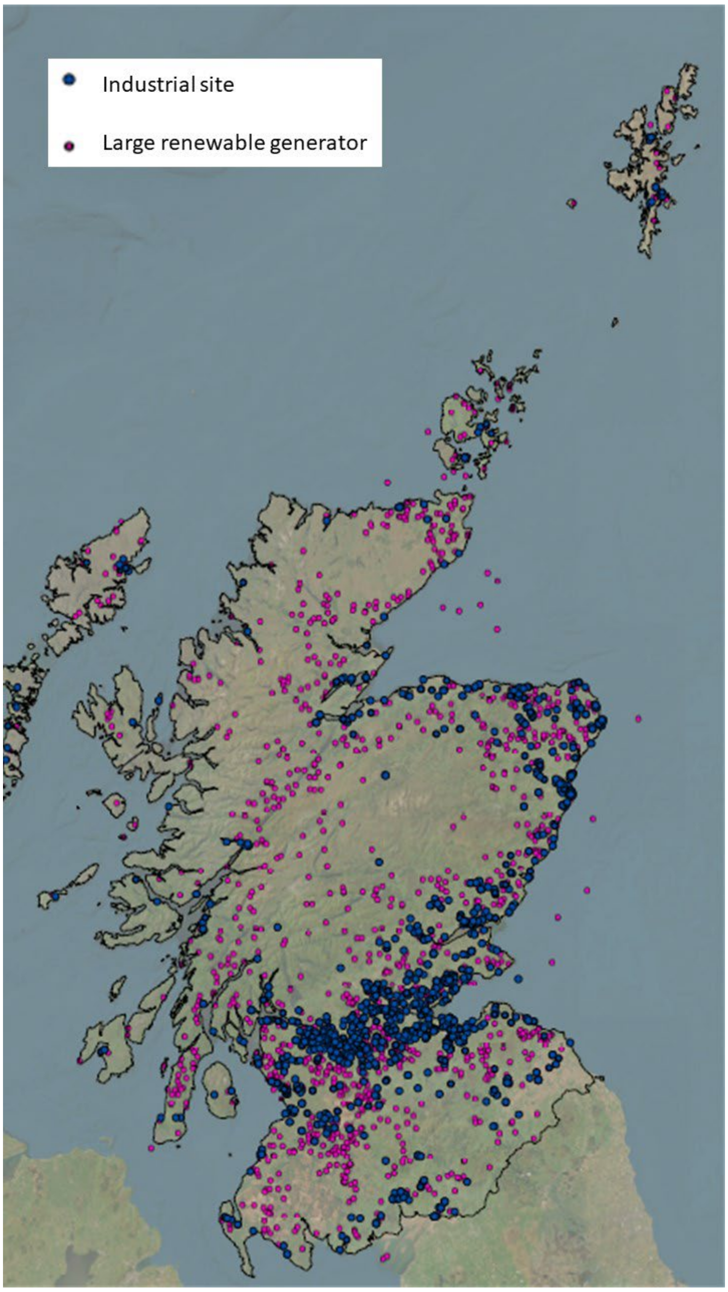

Figure 14 – Location of renewable generation and commercial energy users (Figure reproduces data from [23] and [24])

4.6 Relation to growth in hydrogen demand

The Scottish Hydrogen assessment provides three potential pathways for hydrogen market development in Scotland. It provides an envelope of potential demand at two snapshots in time relevant to the current study – 2025 and 2032.

Aggregate demand ranges from ca. 0.4 – 1.7 TWh in 2025, rising to between ca. 8 – 25 TWh in 2032 (Figure 15).

If the entire curtailed volumes modelled for 2025 were utilised for hydrogen production this would amount to the order of 1 TWh; the hydrogen production in 2030 would be 1.3 TWh. In this context, while the 2025 production rate is theoretically significant in respect of overall demand in Scotland, this theoretical rate of production is unfeasible in practice given blue hydrogen competition on production cost (as noted in Figure 12).

By 2030 there is considerable uncertainty regarding the availability of curtailed electricity, dependent on the ScotWind expansion of renewable energy and as network infrastructure investment is realised, which could result in even the theoretical maximum volume of production being a small fraction of projected demand. Additionally, there is uncertainty over whether the use of electrolysis could be deployed as a stopgap pending electricity network upgrades, or if the increase in localised demand associated with electrolysis would defer those upgrades indefinitely.

In practice, we expect that wider sources of demand are likely to drive hydrogen production sites, increasingly focussed on eastern sites, both on and offshore.

Figure 15 – Projected hydrogen demand and supply in 2025 (left); projected hydrogen demand and supply in 2032 (right) [16]

Conclusions and recommendations

The results of the initial analysis were presented to a roundtable of stakeholders on 1 December 2021, including representatives of network companies, electrolysis project developers and local agencies with an interest in hydrogen deployment. The results presented were iterated based on their feedback and this is further incorporated into the conclusions presented here.

5.1 Business case for curtailment-only operation of electrolysis

The results indicate that within some locations and timeframes, the load factor of an electrolyser utilising only curtailed energy may be high enough to produce cost-competitive green hydrogen. However, this is subject to several constraints:

- Depending on the pipeline of new wind energy volumes connecting to the transmission network, these volumes may be transitional and reduce as network reinforcement grows to meet installed generator capacity.
- In particular, these volumes are dependent on the projected growth of onshore wind meeting stated policy targets, which will be constrained by planning restrictions as the volume of onshore sites available for development reduces.
- The electrolyser must either be network-embedded or co-located with a wind farm that is bidding aggressively within the Balancing Mechanism to be dispatched preferentially over other sites.
- The volumes of curtailment available will be dependent on the growth of other curtailment-mitigating technologies, such as new pumped hydroelectric capacity, grid-scale batteries, demand-side flexibility and interconnector capacity (such as the proposed NorthConnect link between Scotland and Norway).
- Optimal network zones for exploiting curtailed energy may be constrained by the availability of water.
- The intermittent nature of the available electricity will cause a variable rate of hydrogen production, and in the absence of any significant hydrogen networks this implies a need for storage (at increased total cost) when providing hydrogen to customers - such as transport or heat systems - with a particular constant or seasonal demand profile.

This points to the curtailment-only pathway for the installation of new electrolysis capacity as a highly uncertain business case when assessed in isolation.

5.2 Potential for service stacking

Curtailed energy provides a potentially attractive source of zero-cost electricity which can reduce the overall cost of production of hydrogen. However, the business case in delivery is not straightforward.

For example, an electrolyser co-located on a wind farm might be dispatched to use both the output from that wind farm as well as any curtailed energy available from other wind farms behind the same network constraint, to maximise the utilisation of the electrolyser. However, as wind speeds are highly correlated between nearby locations, at any point where curtailed energy is available, the electrolyser will likely already be dispatched to utilise energy from the local site.

For a network embedded electrolyser, the only alternative means to generate hydrogen would be from grid electricity at times when renewable output is not at a surplus, i.e. the increased demand from the electrolyser will be met by average carbon intensity grid supply from elsewhere on the network. This would mean that the output of the electrolyser will be more expensive, and potentially at least as carbon-intensive as hydrogen directly reformed from natural gas.

The remaining potential case for electrolysis that utilises curtailed energy in addition to other sources is where co-located electrolyser capacity is over-sized with respect to the co-located renewable production facility (e.g. a 150 MW electrolyser installed on a 100 MW wind farm, with the excess capacity able to import curtailed energy from the grid connection). The potential advantage of this arrangement would be to benefit from an economy of scale – if that additional capacity could be realised at a significantly lower cost than a standalone electrolyser facility of the same capacity. However, the cost components of electrolysis capacity mean that this economy of scale is not expected to exist to the extent required.

Similarly, there may be the potential for co-located electrolyser capacity to be installed ahead of the corresponding generation asset, with the electrolyser initially operating from curtailed energy imported from the network prior to absorbing output from the local facility. As an example, a ScotWind project aiming to commission in 2030 with some component of co-located electrolysis could potentially access heightened curtailment volumes in the late 2020s, pending the Eastern Link HVDC commissioning. This would be the case if the onshore grid connection/electrolyser capacity could be planned and commissioned ahead of the offshore components.

5.3 Comparison to other options for mitigating curtailment

Other options for mitigating curtailment in Scotland include:

- New pumped hydroelectricity capacity (such as the Coire Glas scheme proposed by SSE Renewables).
- Increased interconnection, such as via the NorthConnect link proposed from Aberdeenshire to Norway.
- Demand-side flexibility, such as through EV charging management or dispatchable heating systems.
- Electricity storage technologies, such as grid-scale batteries.

One advantage that electrolysis may possess over these alternatives is the potential modular and mobile nature of electrolyser capacity. In the results from this work, there is potential for curtailment to be transitory pending network reinforcement. This may mean that there is a case for local deployment of electrolysers where particular network constraints are temporarily increasing curtailment volumes.

As an example, failures of the Western Link HVDC temporarily increased curtailment associated with the B6 boundary in January 2020 and February 2021, as well as initial project delays increasing curtailment in 2017 through to 2019 [25]. If electrolyser capacity were available as a potentially mobile/rapid response capability, this would enable a potentially 'opportunistic' business case with the ability to reduce the impact of a lack of export capability. The analysis presented in this study assumes that all network projects are delivered on time to the pathways identified in the NOA [11]; experience demonstrates this is not always the case. A potential alternative to seeking financial redress from asset developers due to such delays might be to impose a duty to prepare 'plan B' mitigations, which might include seeking alternative uses for energy which is curtailed as a result.

5.4 Regulatory issues

The exact mode of participation of electrolytic capacity in the Balancing Mechanism is not clear. In particular, if a wind generator has co-located electrolyser capacity (i.e. connected behind the meter) it is unknown if the bid placed by the operator to the Electricity System Operator could continue to reflect the operating cost of the wind generator in isolation. This would be stacking revenue from balancing services and hydrogen production. The alternative could be a requirement to consider the potential revenue of the hydrogen produced during curtailment periods. This is because the output of the wind generator is effectively being re-routed to hydrogen production rather than actually curtailed.

Similarly, the role of network-embedded electrolysis is not clearly established: whether this should be regulated as a form of storage or demand; which network costs it would be subject to; and in which ancillary service markets it would be permitted to offer services. In the case of hydrogen production, there are also parallel regulatory arrangements for potential entry into gas markets and networks. If the operation of electrolytic capacity in these markets requires warm-starting and/or part-loading of the electrolyser (to accommodate potentially lengthy start-up times), this potentially increases the notional carbon intensity of the hydrogen produced. Clarity is then required on the range of carbon intensities permitted for electrolytic hydrogen, which may be subject to separate incentives from other hydrogen production methods based on being a low/zero-carbon energy vector. The UK Low Carbon Hydrogen Standard [26] provides current guidance on emissions accounting and compliance for hydrogen production from electrolysis.

None of these issues are prohibitive to the technical basis for hydrogen electrolysis as a means for reducing curtailment, but may restrict the revenues and extent of service stacking that developers may assemble to generate a business case for investment.

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Appendix A: Scenario Assumptions

This appendix provides additional detail on the assumptions used in the scenarios modelled.

Future Offshore Wind Development

Table 2 – timeline of regional offshore wind deployments in Scotland

Name	Status	MW	Zone	2020	2025	2030	2035
Robin Rigg	Operational	174	rGB	174	174	174	174
Beatrice + extension	Operational	598	T5/T1	598	598	598	598
Aberdeen Bay / EOWDC	Operational	93	T2	93	93	93	93
Levenmouth (Firth of Forth)	Operational	7	S5	7	7	7	7
Hywind (Aberdeenshire)	Operational	30	T2	30	30	30	30
Kincardine (Aberdeenshire)	Operational	48	T2	48	48	48	48
NNG	Under construction	448	S6		448	448	448
Seagreen 1	Under construction	1075	S6		1075	1075	1075
Seagreen 1a	Consented	360	S6		360	360	360
Inch Cape	Consented	1080	S6		1080	1080	1080
Moray West	Consented	900	T2		900	900	900
Forthwind	Consented	30	S5		30	30	30
Berwick Bank	Seabed lease	4150	S6/rGB			4150	4150
Pentland FOW	Seabed lease	100	T5/T1			100	100
Morven	ScotWind	2907	B6/rGB			?	?
SSE/CIP/Marubeni FOW	ScotWind	2610	B6/rGB			?	?
Falck/BlueFloat FOW	ScotWind	1200	B6/rGB			?	?
CampionWind	ScotWind	2000	B2/B6/rGB			?	?
Vattenfall/Fred Olsen FOW	ScotWind	798	B2/B6/rGB			?	?
Cluaran Deas Ear	ScotWind	1008	B2/B6/rGB			?	?
Cluaran Ear-Thuath FOW	ScotWind	1008	T1/T5			?	?
Falck/Orsted/Bluefloat FOW	ScotWind	1000	T1			?	?
Ocean Winds	ScotWind	1000	T1			?	?
Falck/BlueFloat FOW	ScotWind	500	T1			?	?
MarramWind FOW	ScotWind	3000	T1			?	?
Floating Wind Alliance FOW	ScotWind	960	T1			?	?
West of Orkney	ScotWind	2000	T5			?	?
Northland Power	ScotWind	1500	T1/T5			?	?
Magnora/Technip	ScotWind	495	T1			?	?
Northland Power	ScotWind	840	T1			?	?
MachairWind	ScotWind	2000	T3			?	?

Other Generation Capacities

Thermal Generation. Based on the current plans for nuclear plant operating life, Hunterston is included in the baseline scenario only. Torness is included in 2025 but assumed to close by 2030. Peterhead is maintained throughout all scenarios and is assumed to operate as per today. While it is expected that Peterhead will either be operating with CCS or converted to hydrogen ahead of a ban on unabated gas generation by 2035[6], this will not impact its operating schedule. While there is some expectation that additional peaking thermal plant may be constructed in Scotland, this is not expected to affect curtailment volumes (as it would not be dispatched in preference to renewable output) so is not considered. This is similarly assumed to be the case for new baseload plant which may be deployed e.g. at Hunterston and Torness (such as BECCS), which is assumed to have sufficient flexibility to be re-dispatched by the System Operator in preference to curtailment of renewables.

Hydroelectric Generation. Current volumes of run-of-river and pumped hydro capacity is considered to persist throughout all scenarios. Additional small-scale hydro is assumed to be included in distributed generation as below. Additional pumped hydro capacity (e.g. Coire Glas) is not assumed to be built – this is treated as an alternative technology to hydrogen electrolysis which would in effect be acting as a competitor in the market if utilising arbitrage.

Other Sensitivities

Baseline scenario. While there was a particularly high level of curtailment in 2021 compared to previous years, this is still seen as a suitable baseline for analysis due to the overall increasing trend over time. There has also been significant new wind capacity commissioned in 2021 after a hiatus in 2019/20.

Island-specific constraints are not represented in the model, as island links are at distribution voltages therefore curtailment is subject to distribution network management rather than transmission-level balancing actions. It is acknowledged that there are multiple joint reinforcement projects that may be co-developed with wind generation that may be active in the Balancing Mechanism:

- Orkney connected to Thurso GSP – 220kV subsea cable from Dounreay to Finstown to be approved if 135MW of generation ready to proceed by end 2021
- Shetland– 600MW HVDC Viking link (contingent on CfD for Viking Wind Farm)
- Western Isles – Lewis-Beauly link

In order to correctly represent the inflows from these particular large concentrations of wind generators in areas of particularly high wind resource, these are modelled as comparable to single offshore wind installations connected to the relevant transmission area.

Interconnection. Future flows along the Moyle interconnector are assumed to follow a similar pattern to today. A key aspect is that, due to the capacity of wind generation at the Irish end of the link, Moyle is not assumed to relieve curtailment in Scotland.

The proposed NorthConnect interconnector between Norway and the SSEN transmission zone is currently highly uncertain and is excluded from this analysis. However, it is highlighted that NorthConnect, if commissioned, is likely to be a significant sink for excess renewable output in North Scotland, and should be treated as a potential competitor option to utilisation of electrolysis to relieve curtailment.

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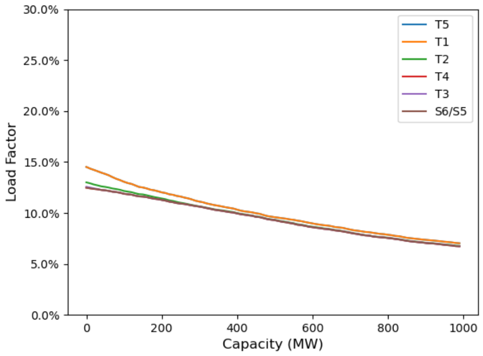
Non-balancing constraints. A thermal group constraint is required which represents secure dispatch for Scottish transmission areas (i.e. a volume of dispatchable plant online to ensure regional electricity security in the event of transmission outages). This is evaluated from the baseline scenario data for which existing dispatch levels are available, to determine the proportion of dispatchable thermal plant left online during curtailment periods. This is then be applied as a fixed % of demand met by dispatchable generation in Scotland (i.e. Peterhead + pumped hydro).

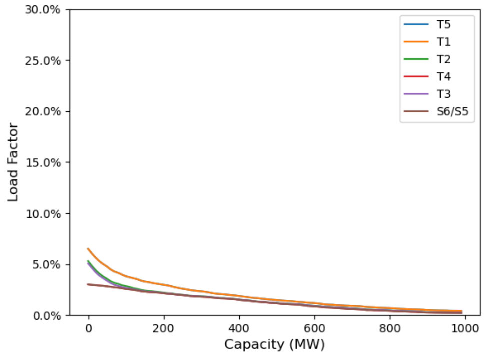
Appendix B: Load Factors for 2030/35 by Scenario Pathway

Load factors for the baseline and 2025 scenarios are given in the results section above.

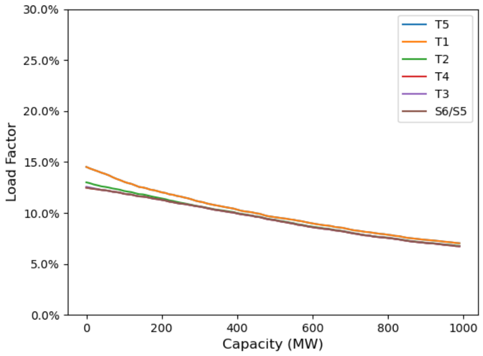
2030 | 2035

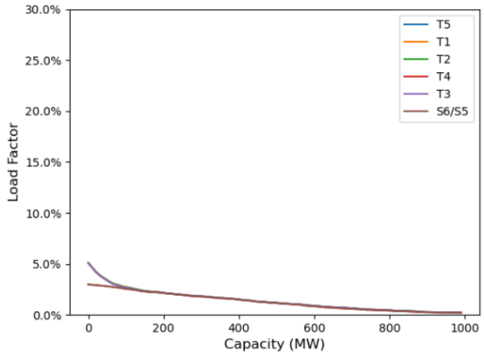
A





B





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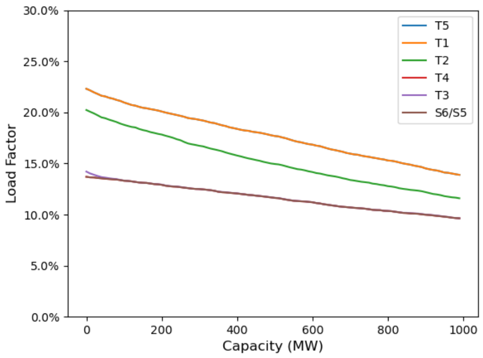

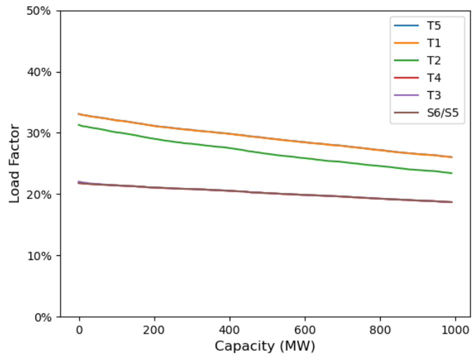

A: Current policy pathway for onshore/offshore renewables in Scotland, with NOA optimal pathway for network reinforcement

B: As Scenario A but with additional Eastern Link HVDC capacity linking T2 to England

C: As Scenario B but with additional ScotWind capacity (10GW in 2030, 20GW in 2035) and no additional network capacity (note adjusted y-axis scale in 2035C)

climate change

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