Methilltoune Phase 1
Feasibility Design
Public Summary Report

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Your gas. Our network.

Contents

Table of Abbreviations

Abbreviation	Meaning
ALK	Alkaline
BEIS	Department for Business, Energy & Industrial Strategy
Capex	Capital Expenditure
CCS	Carbon Capture and Storage
CO2	Carbon Dioxide
FEED	Front End Engineering and Design
FID	Final Investment Decision
FOAK	First of A Kind
GSMR	Gas Safety Management Regulations
GSR	Gas Safe Register
IGEM	The Institute of Gas Engineers and Managers
OEM	Original Equipment Manufacturer
Opex	Operational Expenditure
OREC	Offshore Renewable Energy Catapult
PEM	Proton Exchange Membrane
QRA	Quantitative Risk Analysis
WESLID	Whole Energy System: Levenmouth Integrated Demonstrator
WP	Work Package

Executive Summary

This report describes the feasibility of the first ever green hydrogen production facility that utilises offshore wind for hydrogen production. The proposed end use of the hydrogen produced is through a purpose-built hydrogen gas distribution network capable of supplying domestic properties with zero carbon heat. This delivers a world first end to end system for delivering zero carbon heat, using hydrogen as an energy vector. Discussed is a proposed demonstration system for installation in Levenmouth, Scotland, as well as the options for the UK to employ this concept at a larger scale.

The report collates the findings of a multi-disciplinary study by SGN, Arup, Kiwa Gastec and the Offshore Renewable Energy Catapult (OREC).

The work carried out included assessing the potential hydrogen demand and renewable energy capacity to determine the scale of hydrogen production required. This design was then used to calculate system costs for both construction and operation. An analysis of how the cost reduction of this method of hydrogen production could be achieved. Finally, the project's development and delivery plans were created.

During the Phase 1 feasibility study SGN have successfully delivered on the outcomes we set out including:

- System design for the hydrogen production facility
- Agreement in principle for renewable electricity supply to the electrolyser
- Local support for the project
- Suitability of the proposed site
- Confidence in the safety case
- Options for commercial models and regulatory arrangements
- Engagement with the supply chain, and;
- An updated project cost estimate.

As a result, we now have confidence that this project is technically and regulatory feasible, safe and can be delivered on time and to budget and is ready to progress to the next phase.

The study concludes that there is a technically and regulatory feasible solution for a hydrogen production system to supply a 100% hydrogen distribution network in the Levenmouth area.

Introduction

This report describes the feasibility of the first ever green hydrogen production facility that utilises offshore wind for hydrogen production. The proposed end use of the hydrogen produced is through a purpose-built hydrogen gas distribution network capable of supplying domestic properties with zero carbon heat. This delivers a world-first end to end system for delivering zero carbon heat, using hydrogen as an energy vector. Discussed is a proposed demonstration system for installation in Levenmouth, Scotland, as well as the options for the UK to employ this concept at a larger scale.

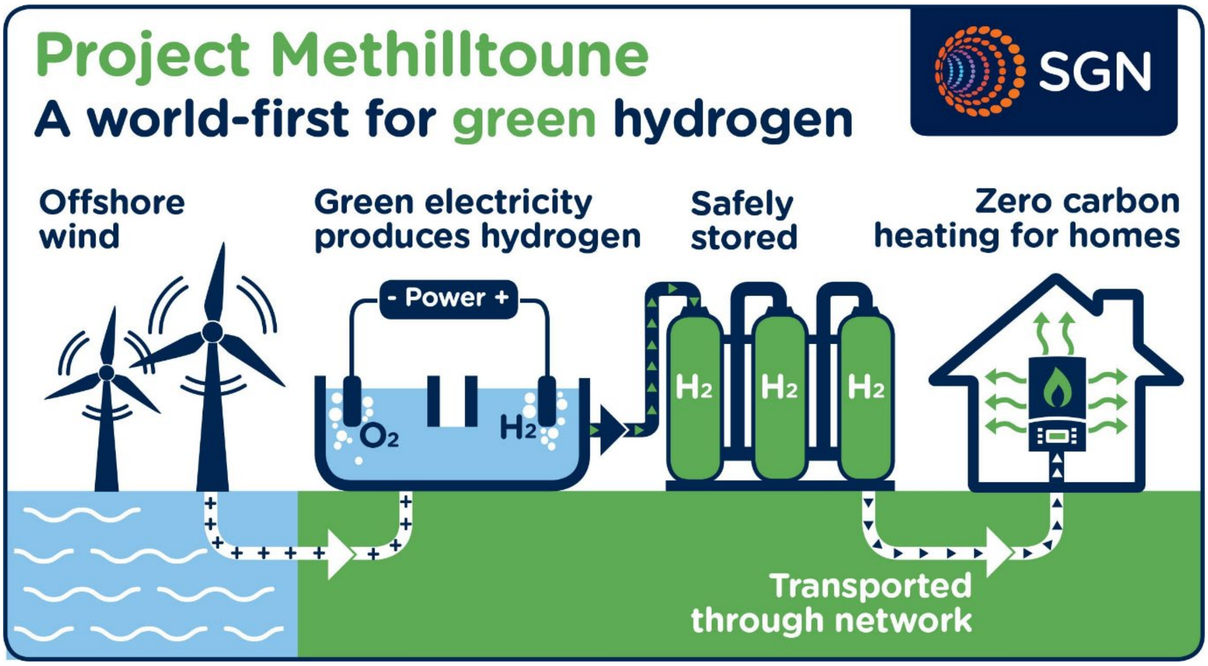


Figure 1: Project Methilltoune concept diagram

The use of renewable energy sources to generate zero carbon hydrogen from electrolysis and use it within the gas distribution network offers a potential route to decarbonise heat within the UK and take full advantage of the natural resources at a local community level without the need for major investment in upgrading transmission and distribution networks. In order for this to become a widely deployed zero carbon heat solution, it must be demonstrated that the hydrogen can be supplied with the same level of resilience and consistency as the existing network standards and costs must be significantly reduced.

The UK has committed to reaching net-zero carbon emissions by 2050 and reducing the carbon emissions arising from the UK's current natural gas (NG) consumption is, arguably, a necessary step in the path towards the goal of net-zero. This is particularly relevant in winter because, from November to March, the energy consumed in the form of NG is 300-400% that consumed in the form of electricity.

This project will seek to maximise energy from renewables through the supply of green hydrogen providing a model and the supporting arrangements that will enhance the business case for the connection of the growing and significant pipeline of offshore wind[1] whilst reducing the impacts of grid constrained curtailment or expensive and disruptive infrastructure upgrades.

However, it is critical that a roadmap for bulk supply allows for a scalable ramp up in production, while the highest potential cost reduction opportunities are identified and implemented. Local 100% hydrogen gas heating networks offer that scalable, replicable model to bulk supply. They will allow penetration in the gas networks in locations where large-scale Steam Methane Reformation (SMR) plus Carbon Capture and Storage (CCS) may not be practical to implement, or the least cost solution.

[1] 'An innovator's guide to the offshore wind market', ORE Catapult, 2018

Figure 1 shows the overall concept of Project Methilltoune, i.e. offshore wind generation interfacing with an onshore electrolyser for producing hydrogen gas to be stored in pressurised tanks. This hydrogen gas can then be distributed through SGN's gas network to nearby homes. Whilst this feasibility report does discuss the two concepts, the distribution and consumption of this hydrogen gas is the addressed more closely in H100 and Hy4Heat (respectively), two distinct but related projects.

This report collates the findings of a multi-disciplinary study by SGN, Arup, Kiwa Gastec and the Offshore Renewable Energy Catapult (OREC) to assess the feasibility of a hydrogen production facility in the Levenmouth area to support the deployment of SGN's H100 domestic hydrogen distribution network.

The project was split into eight Work Packages (WP):

- WP1 – Production System Design
- WP2 – Controls and Systems
- WP3 – Renewable Energy Interface
- WP4 – Heat Demand Characterisation
- WP5 – Cost Reduction Pathways
- WP6 – Techno-economic System Model
- WP7 – Development Plan
- WP8 – Delivery Plan

The study concludes that there is a technically and regulatory feasible solution for a hydrogen production system to supply a 100% hydrogen distribution network in the Levenmouth area.

Basis of Design

The basis of design defines the known performance requirements, the system inputs and assumptions for the Methilltoune feasibility stage. The scope of this study begins with assessments of the future hydrogen gas demand from the H100 network and the potential energy input to the system from the Offshore Renewable Energy Catapult (OREC) Levenmouth Demonstration Turbine (LDT). These inputs will allow the production system and controls to be designed.

The hydrogen that is produced through Project Methilltoune is intended for use in the H100 hydrogen distribution network. The key design criteria for the H100 project are:

- system safety is paramount;
- ensure security of supply to customers under current standards and Licence obligations – agreed to be through storing five peak days of demand in H100 feasibility;
- minimise grid imported electricity;
- ability to fit within budget constraints considering Capex, Opex and lifecycle costs; and
- ability to fit within timescale constraints and deliver by the BEIS 2021 deadline.

Other design parameters include the following.

- An N(100%) +1 redundancy design approach will apply throughout.
- The maintenance and spares strategy will need to be considered to ensure security of supply.

It is acknowledged that there are no standards specific to the supply of hydrogen gas, but that the system shall be designed to meet the security of supply requirements as defined in:

- SGN's Ofgem licence conditions;
- IGEM guidance; and
- GSMR & GSR.

The distribution network for H100 is being designed to pass 1000 homes, with the intention that at least 300 homes connect. Connection to the hydrogen network will be voluntary for customers through an opt in process. The Project Methilltoune production system has been designed to ensure that if there is greater uptake than expected (i.e. more than 300 homes connect), there will not need to be a second electrolyser system installed on the site to cope with the extra demand on the network.

Heat Demand Characterisation

The necessary size of the system was determined by analysing data on heat demand. Heat demand characterisation was performed to establish the volume of storage required to provide security of supply for a given number of households. Using BEIS sub-national consumption postcode data on the gas demand specifically within the distribution network area, the average and peak gas demand levels were established.

The (adjusted) monthly gas demands for 300 homes and for 900 homes are shown in Figure 2, for both the average (median) year and the coldest year (which also resulted in the highest heat demand).

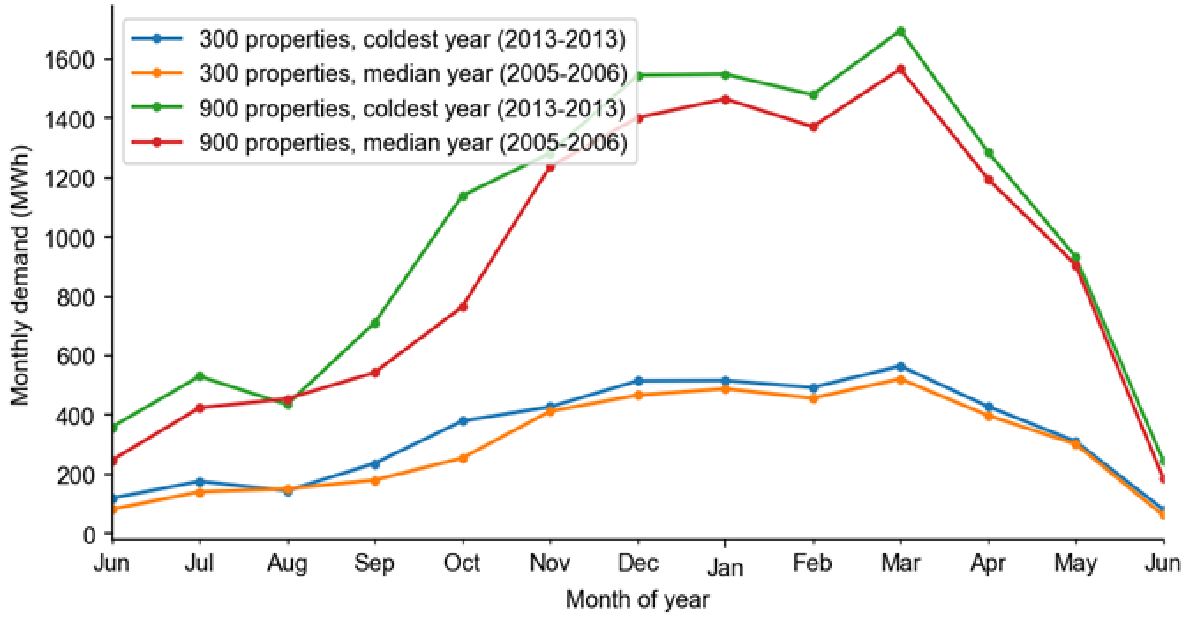


Figure 2: Monthly gas demand profile for 300 and 900 properties adjusted for degree days – median (2005-2006) and coldest (2012-2013) years.

The 5-day period of peak natural gas demand was found to be 374 kWh per home over five days during December 2010. This was used to determine that the projected gas storage requirement for the plant to ensure SGN can ensure security of supply for 300 homes is 112.3 MWh (2,850kg).

Renewable Energy Interface

This section details the outcome of WP3, the renewable energy interface. This primarily concerns the behaviour and power output of the wind turbine, and how this power provision links with electrolyser operation.

The following aspects have been completed through the delivery of WP3:

- acquiring appropriate wind data for the turbine location, and correcting appropriately;
- deriving power curve from empirical data;
- noticing other features of turbine operation;
- identifying reasons for turbine shutdowns;
- isolating incidents that are unlikely to occur in future running;
- building a model for turbine output, using the above analyses; and
- determining how the turbine output will connect to the electrolyser.

Project Methilltoune will utilise the existing 7 MW LDT to provide the electrical input to the hydrogen production system. The output of this turbine was analysed to determine how much hydrogen production it could support. There were four key data gathering processes:

- Analyse site wind data
- Analyse the turbine power curve based on empirical data
- Analyse how the turbine output ramps up and down on start-up/shutdown
- Analyse how often and why the turbine shuts down

From these data, a realistic model of it with 1-minute time resolution was created that simulated how the power output varied with wind speed considering its unique features.

Each June-June year in the historical data was put through the model, to determine the variation of power output from the turbine. The values for total electricity generated and capacity factor for each year can be found in Table 1.

Table 1. Power generation and capacity factor values as determined from the completed model. The equivalent values for the 2018-19 year using the measured power from the turbine is provided for comparison.

Year (13th June – 12th June)	**Total Electricity Generation (GWh)**	**Capacity factor (%)**
2013-14	17.1	27.9
2014-15	16.5	26.9
2015-16	15.1	24.5
2016-17	15.8	25.8
2017-18	17.1	27.9
2018-19	16.0	26.1
2018-19 (turbine for comparison)	*13.9*	*22.7*

The direct comparison between model and turbine output shows that the modelled power output for the 2018-19 year is higher than that seen in the turbine data. This is due to the differences in how turbine shutdowns are treated between the model and the real data. There was a significant, one-off, outage during 2018-19 that was removed from the modelling analysis because it was a one off.

Table 1 shows that the annual electricity generated by the turbine from this model was an average of 16.0 GWh (ranging from 15.1 GWh to 17.1 GWh for the six years modelled). Taking account of the variation in wind over a 20 year period, the generation in the least windy year is estimated to be approximately 13.6 GWh (15.1% less than the average).

Alternative renewable energy sources were investigated for the site. However, none of the explored options will be ready for connection prior to March 2021. They will therefore be the subject of future optimisation.

Following an assessment of the local electrical grid systems, including both the DNO and the LDT, a shortlist of four potential electrical connection methods have been produced for the site. These four options are:

1. Cable supply direct from the Shore Substation
2. One cable circuit each direct from the Shore and Grid Substations
3. Loop into the existing 11 kV cable between the Grid and Shore Substations
4. 11 kV switchboard between the Grid and Shore Substations

A more detailed design will be developed from the options once the electrolyser type and size have been confirmed.

Production System Design

This section seeks to understand and assess the feasibility and design details of a hydrogen generation and storage system. The proposed plant consists of the existing 7 MW wind turbine which will be utilised to produce hydrogen via electrolysis. The hydrogen produced is to be stored on site before being distributed through the H100 distribution network to between 300 and 900 domestic properties within the area of Levenmouth, Scotland; for use primarily as fuel for heating in participating homes.

A review of current electrolysers available commercially was carried out. Informed by these studies and the key design requirements, a list of 42 different alkaline and PEM electrolysers from 9 different companies was compiled. A selection of operational data such as system power requirement and hydrogen production rate were collected for these products.

Using these product data, four potentially suitable electrolysers were selected for further research in the form of a focused technical questionnaire. It was desired that a range of different technologies be investigated, covering a mixture of different outlet pressures and electrolysis technologies. It was decided that three technologies be represented: an atmospheric pressure alkaline unit; a medium pressure alkaline unit; and a high-pressure Proton Exchange Membrane (PEM). The three manufacturers chosen to represent well-known suppliers within the industry.

A demand-driven model of electrolyser performance was created to simulate how each of these different electrolysers would operate within the Project Methilltoune system, whilst ensuring security of supply for the H100 distribution network. This modelling determined the optimal electrolyser size and the electrolysers were compared in the context of this system model. The systems were modelled for both:

- A conservative year (low wind generation from the turbine and high hydrogen demand through the distribution network) to ensure that the designed system will remain compliant with SGN's gas licence conditions.
- An average year (median wind generation and median hydrogen demand through the distribution network) to ensure that the economic modelling is based on the longer-term average and not one extreme year.

Additional sensitivities were carried out on:

- Different grid import tariffs for electricity that the system needs in addition to that from the turbine (i.e. when the electrolyser requires electricity for standby or extreme case hydrogen production).
- A range of properties from 300 up to 900 connected homes on the distribution network.
- A potential option to reduce the grid import for the atmospheric electrolyser that included a hydrogen boiler to keep the system in a hot standby state.

The optimal electrolyser size was determined to supply a maximum of 900 homes domestic heat demand. A 900 homes target was selected to ensure that the system could be practically scaled up to meet increasing demand.

In addition, the most cost-effective form of storage for the required volume is low pressure (30bar), steel tanks. It was clear from the modelling that a small, medium pressure alkaline electrolyser would not meet the design requirements. A comparison of two system archetypes using key design criteria is shown below:

The 30-bar pressurised PEM hydrogen production system:

- Ensuring security of supply to customers – Having a minimum of two electrolysers ensures that there is no single point of failure and increases the ability of the system to ensure security of supply. However, there is a concern that, as a relatively immature technology, PEM electrolysers may potentially have a comparatively low overall availability.

- Minimising grid imported electricity – These electrolysers can respond quickly to variations in electrical input. This allows them to reduce the grid import below 10% for a 300-home system.
- Fitting within budget constraints – PEM systems are generally more expensive than alkaline systems. During Phase 2A, work will be conducted to determine how the costs of a PEM system can fit within the budget constraints.
- Fitting within timescale constraints – From discussions with manufacturers it is suggested that the lead time for these systems is 12-18 months.

The atmospheric alkaline hydrogen production system:
(including post production compressors to increase the pressure of the gas to 30 prior to storage):

- Ensuring security of supply to customers – Having a minimum of two electrolysers ensures that there is no single point of failure and increases the ability of the system to ensure security of supply. Alkaline electrolysers are a mature technology and their overall availability is believed to be very good.
- Minimising grid imported electricity – Atmospheric systems respond slowly, which results in a high-level of grid import (>35%) for 300 homes. This is a potential area of innovation within the project. Early design work has been conducted in Phase 1 that suggests the addition of the hydrogen boiler into the system could significantly reduce grid import.
- Fitting within budget constraints – Atmospheric alkaline systems are a mature technology with a low Capex cost. During Phase 2A, work will be conducted to determine whether there are any additional reductions in Opex that can be made for these systems, e.g. approaches to keeping the system warm during standby.
- Fitting within timescale constraints – From discussions with manufacturers it is suggested that the lead time for these systems is 9-12 months.

Further analysis indicates that the 30bar PEM systems are the superior system to use to supply 300 homes. However, there are several technical and commercial barriers associated with 30bar PEM systems compared to the atmospheric alkaline systems. During Phase 2A, we will engage with electrolyser Operational Equipment Manufacturers (OEMs) as part of a market assessment. A key area where we will gain a greater understanding is the reliability of each electrolyser type. Currently, it is believed that the more mature atmospheric alkaline systems will be significantly more reliable and additionally have a higher total availability. Anecdotal evidence of PEM electrolysers suggests a likely availability of below 95%.

Controls and Systems

This section aims to provide the control logic for the Project Methilltoune hydrogen production plant. It also investigates the potential safety systems required and the possibility of using additional electrical storage onsite.

The plant can be split into three key elements:

- gas production and electrical management
- hydrogen storage
- hydrogen distribution (including pressure reduction and odorisation)

Each of these areas will include packaged plant which will have their own (mainly passive) control systems. The overall control system will be used to control the hydrogen production and storage systems in a coordinated way and thus ensure that demand can be met.

Under the Methilltoune project, the wider gas distribution network is not included, but for the purposes of designing the control system, it is assumed that the production and storage facility supplies gas on consumer demand. It is foreseen that the final step of pressure reduction and odorisation would be self-contained units with no requirement for additional controls to respond to varying demand profiles and therefore do not form part of the production and storage control strategy detailed in this document.

The primary aim of the control strategy is to:

- ensure safe operation of the plant and storage facilities
- ensure security of hydrogen supply to consumers
- maximise the use of electricity generated through the wind turbine and minimise reliance on imported grid electricity
- system should be simple, reliable, and effective

Control of hydrogen production will be performed using pressure measurement throughout the system. Pressure measurements will be located:

- on the output of electrolyser and/or output of hydrogen gas compressor depending on system design
- on each storage tank
- on the pressure let-down unit
- on the network

Despite the relative simplicity of the control logic, controlling the input feed to an electrolyser system from the output of an offshore wind turbine in this manner is an innovative process. The variable nature of the wind output, compared to the continuous demand for hydrogen from the network, leads to a clear focus on security of supply. Hence, the simple, reliable structure of the control system.

We have performed two bow-tie analyses on the potential system design to identify critical safety considerations, their potential causes and consequences and any barriers or mitigations to these. This high-level hazard identification exercise focussed on loss of hydrogen containment as the “top event”, and enumerated design modifications to reduce the likelihood of the events occurring, and several mitigation factors to reduce the impact should they occur. The top events analysed were the loss of hydrogen containment and the loss of supply to the distribution network.

A potential plant layout for each electrolyser option was developed by investigating the ATEX zone classification and hazard ranges for the systems. Due to its low density, hydrogen has a high buoyancy in air. On release, hydrogen forms a high-pressure jet which acts in the direction of the release. As the momentum diffuses, the remaining hydrogen will ascend vertically. As hydrogen diffuses and mixes with air, the bulk density of the combined gas will increase, leading to small quantities hydrogen moving with the air creating a harmless mixture if in a well-ventilated area. The recommendation, given the buoyancy of hydrogen and the work carried out, would be to use the range to Lower Explosive Limit (LEL) for the horizontal separation distance between components and then the range to 25% LEL for the vertical separation distances. The horizontal distances were rounded up to 5 m to follow the British Compressed Gases Association guidelines.

Electricity storage offers an opportunity to smooth the variable nature of turbine power generation to reduce grid import. However, the costs of importing grid power over the project lifecycle are significantly lower than the increased Capex and Opex from including battery storage for the scale of production at Methilltoune. The inability to offset the capital and operating costs through offering additional services due to the restriction in how electrical storage could operate plays a key role in making this non-viable. The increased complexity and large footprint also create barriers to successful deployment in a pilot plant. However, these may be considered optimisation and cost reduction routes in the future if costs of battery technology were to significantly reduce. In the short term, and for the purposes of the pilot plant, it is suggested that the electricity grid is acting as the energy store for the turbine, which is then subsequently imported when the turbine cannot supply the demand.

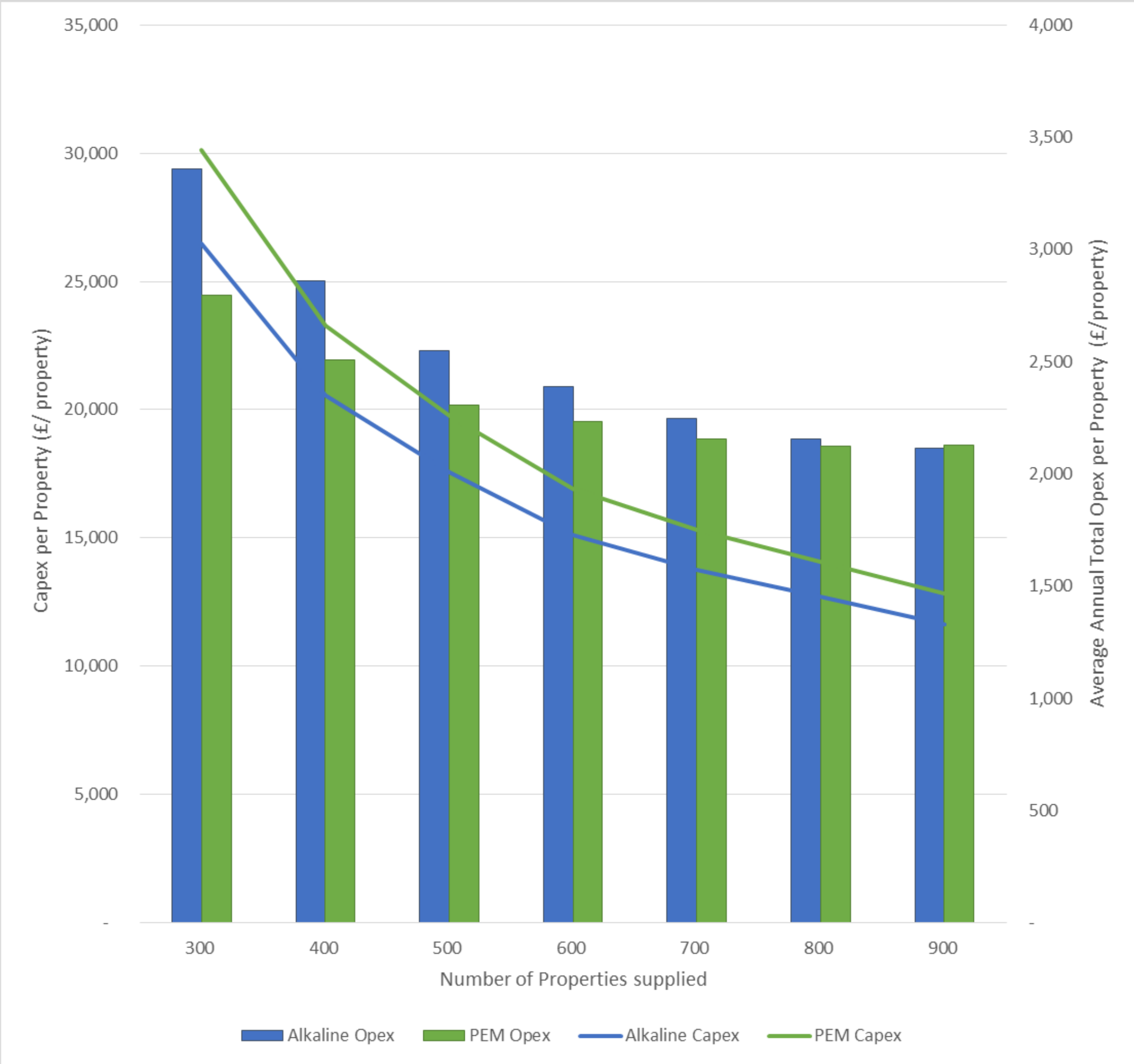
In future, the control system could be developed further by adding the ability to predict changes in output based on short term weather forecasting. This could be particularly beneficial to the less-responsive atmospheric alkaline system. Innovative controls, such as those examined by OREC’s Whole Energy System: Levenmouth Integrated Demonstrator (WESLID) project, could be integrated with the site control system to allow cross vector coupling of energy services. Based in Levenmouth, WESLID investigated the development of a smart local, multi-vector energy system. WESLID identified that hydrogen would play a crucial role in a local energy system that sought to integrate heat, power and transport, by providing potential for use in domestic and industrial heating, fuel for industrial transportation and as an energy storage option.

Techno-economic Modelling

A techno-economic model was produced to calculate the costs of the system in Methilltoune as per the design set out in previous chapters. This section presents the outputs of the modelling results, methodology for calculating these costs and the analysis of the economic performance of the different system options.

There are two key components to the system that have the highest impact on costs: the electrolyser unit and the amount of storage. As part of the system design and technical analysis, different levels of demand along with different types of electrolysers units, five electrolysers were chosen for cost examination.

The lifetime costs for the different types of electrolyser for various demand scenarios ranging from 300 – 900 homes have also been calculated. Following this modelling, the options were narrowed down to two systems. The full Project Methilltoune report shows the Capex and total annual Opex of both systems.



To capture uncertainty, risk in the outturn costs and to provide a confidence bound on likely outturn costs, probabilistic modelling has been undertaken. This modelling analyses the contributions of two potential sources of error, namely cost estimation (uncertainty) and chance events (i.e. risk). Estimating uncertainty and risk have been analysed using Monte Carlo simulation (also referred to as Quantitative Risk Analysis (QRA), which is an industry standard methodology to assess uncertainties.

Cost Reduction Pathways

This report discusses potential cost reduction pathways for the future bulk production and storage of hydrogen. A broad range of innovations, design & operational improvements have been considered in a future where a hydrogen economy has developed and therefore a significant order of magnitude of hydrogen is produced compared to today. Consideration is also made for potential types of funding to further develop the hydrogen economy and discussion on how the maturity of technology and robustness of supply chain impacts the type of investor and potential funding strategy.

For hydrogen production to make sense from a carbon reduction perspective, the electricity for production needs to be generated by a renewable source (e.g. wind, solar). Renewable energy generation through wind and solar is now entering a more mature phase. Nevertheless, further reduction in cost is still expected due to advances in technology and economies of scale across the supply chain. These reductions are expected to positively impact an electrolysis-based hydrogen system. Finding a suitable source and optimising the location of the electricity generation will be key in potential cost reductions in order to minimise the losses to the hydrogen production system.

There are currently two industrially mature technologies for production of hydrogen through electrolysis: alkaline (ALK) and proton exchange membrane (PEM). Two other main technologies exist, SOE and AEM, however, these are still somewhat experimental and not widely commercially used. ALK is the cheapest option, having historically been used in industry applications, whereas PEM is newer and more expensive. PEM has the ability to handle fluctuating power input (i.e. from wind production), which ALK currently struggles with. Both are expected to experience technological and supply chain cost reductions going forwards, with considerable potential for savings possible as electrolyser system sizes scale up. Large scale systems would be able to take full advantage of a hybrid system of ALK and PEM technologies to take advantage of established low cost ALK technology with the benefit of PEM providing flexible peak electricity production.

Hydrogen storage is essential to matching supply to demand for both intraday and inter-seasonal energy fluctuations. Both geological and non-geological storage are potential solutions. Geological storage provides high volume and low unit cost construction (although requires extremely high upfront capex), whilst non-geological storage provides cheaper and more flexible storage for small volumes, however, has a high unit cost of construction. Cost reductions to non-geological storage methods is expected in line with developing regulation and design standards which will lead to standardisation of design and construction, reducing the investment in bespoke hydrogen storage. However, these are not expected to be the key system cost reduction driver. Limited cost reductions are expected with respect to geological storage given that costs are heavily dependent project specific factors (i.e geology, size, pressure, depth, location, etc.). As a result, cost reductions to geological storage will be predominantly driven by overall growth in the hydrogen economy to allow large geological storage to be used to support larger inter-seasonal demand fluctuations.

Whilst cost reduction pathways exist for specific aspects of the hydrogen system, the key for maximising cost reduction potential of a hydrogen system is to consider the whole system cost reduction pathways. Whole system cost reductions will predominately be driven by an increase in the overall scale of the hydrogen network and economy as outlined below.

For local/regional networks, costs are likely to always be high since production systems cannot benefit from economies of scale, as well as the fact large geological storage will not be economically favourable. Therefore, tank storage will be required to provide security of supply. Material cost reductions will, however, be achieved once a full hydrogen economy is developed, as this will lead to supply chain reductions, standardisation of systems and the ability to utilise a mixture of geological and tank storage to meet both intraday and inter-seasonal security of supply. This will lead to significant unit cost reductions across the full hydrogen system.

From a financing perspective, as the technology, supply chain and system mature, investors will gain confidence in the expected returns and reduced risks for these types of projects. Investors may be able to gear their investment through the introduction of debt financing. This is commonly provided by banks or funds, and is cheaper than equity, however, providers require stable project cashflows. Subsidies, such as Contracts for Difference, could enable the product sale at a fixed price for a long-term period (e.g. 20 years in the energy sector). This has enabled the introduction of financing into other energy projects, such as offshore wind, enabling technology development to current mature and low cost levels. The completion of this pilot study will act as proof of a bankable concept, opening up cheaper and private financing options going forwards, enabling technology development to mature and low cost levels.

For current large-scale systems, the key cost driver is renewable power generation, which contributes to over 60% of the overall system cost. This is followed by electrolysis at c. 20 to 30% and the rest related to storage. Going forwards, in 2030, cost reductions are anticipated due to advancements in technologies, supply chain and cheaper financing as explored previously. It is anticipated that these will result in overall system cost reductions of between 15 to 25% for large-scale systems, predominantly driven by reductions in electrolysis (20 to 50% technology cost reduction) and renewable generation (c. 10 to 13% technology cost reduction).

Development Plan

Our proposed system will demonstrate a whole system solution to manufacturing hydrogen from electrolysis. The system we have put forward here is for demonstration purposes and will help inform how future electrolysis production systems look.

In a similar fashion to most process plant, bulk hydrogen systems offer substantial reductions in cost with increasing scale, but the discrete nature of hydrogen production from wind tends to introduce a series of step changes. We envisage that there will be three stages of hydrogen system development:

- Stage 1 - Smaller local systems, which then combine into
- Stage 2 - Regional systems, then eventually as hydrogen demand grows into
- Stage 3 - National scale systems.

This concept is a FOAK and may be replicated across different regions, in particular those where a hydrogen economy is forming, such as Australia, New Zealand, Japan, Korea and America. This pilot project could develop IP for export, creating market share for UK firms across the globe and drive forwards the UK as a hydrogen leader.

Levenmouth is ideally suited to expand local hydrogen usage from the proposed site out to the rest of Fife and eventually up the east coast of Scotland and into North East England with a number of potential sources of renewable energy and storage places.

All electrolysis production with grid systems will need to be designed to fit the particular power inputs and heat demands, there is not one size fits all. In our plan we identify what a potential ‘typical system’ for each type would look like, looking specifically at the East of Scotland.

Delivery Plan

The Project will be delivered in two phases, Phase 2A & 2B which will include several WPs to enable the activities and milestones to be realised.

Phase 2A will progress the project development activities which will culminate in the evidence base to enable a Final Investment Decision (FID) to be made by SGN’s board. Key areas that are critical to the success of the project, and will be addressed during Phase 2A include:

- Key consents and construction and operational permits are in place and/or appropriately progressed
- A preferred technology and infrastructure supplier that can meet the required safety, reliability and commercial criteria has been secured and the current sensitivities that apply to both capital and operational costs have been minimised
- Appropriate operational commercial support mechanism to be identified and agreed with the regulatory authorities

- All critical third-party agreements including landowner, access to grid and OREC turbine electricity, water/utilities etc have been secured on acceptable commercial terms
- That any other commercial and regulatory approvals including the Safety Case and licencing strategy have been appropriately managed
- That all risks including commercial, technical and safety are fully understood, quantified and appropriately managed
- Funding commitment to the full H100 programme

The completion of Phase 2A activities will provide both SGN and BEIS will full confidence that the construction and operation phases can delivery on time and budget while meeting the wider project objectives. Phase 2B will commence following approval by SGN and BEIS based on the successful outcome and appropriate risk management of construction and operation risks, addressed through Phase 2A.

The project will be delivered using the following Work Packages:
Phase 2A

- WP1: Project Management and Integration
- WP2: Planning, Environmental & Permitting
- WP3: Engineering & Technical Support
- WP4: Delivery of Procurement Process
- WP5: Commercial & Regulatory
- WP6: Third Party Agreements
- WP7: Safety Case Approval and CDM compliance

Phase 2B

- WP8: Project Management, Engineering Support and Integration
- WP9: Design, Supply and Construction of Hydrogen Production System

The Work Packages will include the following Milestones:
Phase 2A

- M1 Procurement strategy selected
- M2 Submit planning application
- M3 Launch procurement process with prequalification
- M4 Suppliers down select and issue invitation to tender
- M5 Potential to undertake preferred electrolyser OEM down select
- M6 Potential to commence electrolyser manufacture
- M7 Conclude third party agreements negotiations
- M8 Agreement in principle for operational commercial models with regulator
- M9 Approval of Safety Case
- M10 Agreement in principle for supply of hydrogen production system
- M11 Final investment decision (FID) BEIS & SGN board sign-off of Decision to Proceed - Stage gate

Phase 2B

- M12 Appointment of principle contractor
- M13 Commitment to other third-party agreements
- M14 Pre- construction consent conditions discharged
- M15 Commencement of construction works on site
- M16 Delivery and installation of electrolyser on site
- M17 Pre-operation consent conditions discharged
- M18 Operational permits in place
- M19 Commissioning and installation complete
- M20 Operations commence
- M21 Demonstration complete

Summary of Recommendations

The Phase 1 feasibility study of Project Methilltoune sought to develop the concept of a hydrogen production system that can deliver a bulk supply of hydrogen derived from offshore wind. Such a system demonstrates the use of a renewable resource that is available in abundance to the UK, and harness this to generate a zero carbon gas that can have applications in heating, power and transport. Faced with the UK targets of net-zero by 2050, tackling the decarbonisation of heat challenge is a primary focus for SGN and the wider gas networks. This project seeks to prove hydrogen as an energy vector and a viable solution for decarbonising heat at scale through at first of a kind demonstration.

During this Phase 1 feasibility study we have successfully delivered on several work packages.

The *Heat Demand Characterisation* work package calculated the hydrogen demand that the Project Methilltoune production facility will need to service. For 300 homes, this results in a requirement for the system to hold a minimum of 2,850 kg of hydrogen. The *Renewable Energy Interface* work package looked at the behaviour and power output of the wind turbine, and how this power provision links with electrolyser operation. The annual electricity generated by the turbine from this model was an average of 16.0 GWh (ranging from 15.1 GWh to 17.1 GWh for the six years modelled). A shortlist of 4 potential electrical connection methods have been produced for the site. The *Production System Design* work package further considered the electrolyser model design where the optimal electrolyser size was determined to be between 4 MW – 4.6 MW to supply a maximum of 900 homes domestic heat demand. The hydrogen storage solution that was considered optimal was steel bullets (cylindrical tanks) at low pressure with an operable range of 3 to 30 bar. The *Controls and Systems* work package investigated the control logic required for Project Methilltoune. Control of hydrogen production will be performed using pressure measurement throughout the system. The variable nature of the wind output, compared to the continuous demand for hydrogen from the network, leads to a clear focus on security of supply. Hence, the simple, reliable structure of the control system that has system safety as a primary objective. The *Techno-Economic Modelling* work package used modelling to calculate costs of the Methilltoune system. The model has calculated the lifetime costs of running a system over a 20-year period (considered to be the asset life of the electrolyser) including capital expenditure, operational expenditure and an estimated levelised cost of energy. The electrolyser model and storage were the two key components that impact significantly on overall cost. The *Cost Reduction Pathways* work package identified location and scale of production as key criteria for mobilising cost reduction of hydrogen production. Geological storage will be required to realise the cost reduction solutions to meet bulk supply of hydrogen, while storage bullets offer flexibility of location for small scale provisions. The *Development Plan* work package examined the commercialisation of green hydrogen and considered three stages to this development; short-term, long-term and 10TWh and beyond. The *Delivery Plan* work package addresses the key deliverables the are required to bring this project through to the next phase construction and operation.

As a result, we now have confidence that this project is technically and regulatory feasible, safe and can be delivered on time and to budget and is ready to progress to the next phase. We are proposing a two-stage approach for Phase 2, which is in keeping with most construction projects;

- Phase 2A - Front End Engineering and Design (FEED), leading to a Final Investment Decision (FID), and then
- Phase 2B - Construction

The deliverables at the end of Phase 2A are outline planning consent, a land agreement, other third party agreements including a commercial agreement with OREC, appointment of a construction contractor, completed qualitative safety risk assessment reviewed by the HSE, agreed commercial model, funding commitment for the H100 gas network and appliances and tender prices from the supply chain. These deliverables have value to BEIS in confirming arrangements for hydrogen for heating community trials, and as an essential evidence gathering step in the heat decarbonisation policy work. They will also support future work on cost reductions for bulk hydrogen production, based on real tender prices.

Based on the results of Phase 1, we can be confident that a positive outcome to the FID at the end of Phase 2A will lead to the construction of the world's first end to end whole system hydrogen project for domestic heating. At the end of Phase 2B, Project Methilltoune will have moved the TRL level of integrated hydrogen production facilities from 5 to 7 and as a result:

- Demonstrated that intermittent renewables can be used to generate gas grid reliable hydrogen, providing confidence that this is a technically achievable solution.
- Developed the necessary control systems required to manage the hydrogen production and supply.
- Produced a design methodology and repeatable detailed design for a hydrogen production facility from renewables.
- De-risked future commercial investments and at scale demonstrations by proving a regulatory model and integrated supply chain that can be repeated and optimised in subsequent projects.
- Enabled a whole system solution which is essential to determining consumer response to hydrogen and build wider confidence in 100% hydrogen for heating as a large-scale solution to decarbonising heat.
- Provided real data on the costs of bulk hydrogen production both in facility construction and maintenance and operation that can be used to help value engineer future solutions to optimise the proposed cost reduction pathway.
- Demonstrated the best of British engineering, supporting export potential of consulting, design, manufacturing and construction expertise.

Hydrogen projects are by their very nature complex and to be successful, must achieve the significant collaboration and coordination efforts. The BEIS funding of this project is an essential component of overcoming those challenges and ensuring critical learning is developed to support the cost reduction of zero carbon hydrogen production and the wider role of hydrogen in the urgent and essential need to decarbonise the UK's energy system. Project Methilltoune offers a solution that can inform decisions on the role of hydrogen in the future of heat.