Low Carbon Hydrogen Supply 2 Competition Stream 1 Phase 1 Nuclear Hydrogen Cogeneration

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Executive Summary

The UK Government has set an ambition for a 10 GW production capacity of low-carbon hydrogen by 2030 [1], increased from the initial target of 5 GW set two years before [2]. The vision is that a large ramp up in low-carbon hydrogen production will follow in order to meet ambitious future hydrogen economy scenarios which are integral to achieving 2050 Net Zero goals and improved energy independence and security.

This report details a feasibility study, undertaken by Frazer-Nash Consultancy and Nuclear AMRC, of one potential credible solution to support these goals, which is not yet commercially viable for market entry: hydrogen cogeneration from nuclear power. The work sought to examine both the feasibility of nuclear hydrogen cogeneration and what impact a demonstrator (in a second phase of work) could have. The chosen technologies for this review examined hydrogen production from water, and nuclear power; both of which are inherently low-carbon technologies offering significant benefit to Net Zero goals.

A detailed review of the potential technologies has shown that hydrogen cogeneration with ANT is feasible, and, indeed desirable, as there is the potential for this to contribute to a significant proportion of the 2050 low-carbon hydrogen goals. There are clear synergies between the technologies both from thermal and electrical energy production and requirement, offering improved efficiencies for low-carbon hydrogen production in comparison to current commercial alternatives. Importantly, there is also considerable interest within the industry for cogeneration between these technology types (from both hydrogen and nuclear technology developers). Examination of the potential mechanisms for coupling the two technologies has highlighted that ideal coupling arrangements are dependent on the specific technologies. Cost modelling shows the potential for costs to be competitive with current other low-carbon alternatives, and indeed with conventional fossil-fuel based methods, helped in part by the current spike in gas prices. The largest uncertainties in these costs are typically driven by the hydrogen technologies, which aligns with their current Technology Readiness Levels (TRL).

The most developed of the technologies reviewed was High Temperature Steam Electrolysis (HTSE) and Pressurised Water Small Modular Reactors (PWSMR), and it is credible that, assuming supply chain challenges can be overcome these could start producing hydrogen by nuclear cogeneration in the 2030s. Development of these supply chains within the UK would further support the social feasibility of these cogeneration technologies. The cost modelling estimated the LCOH for this coupling to be in the range of 2-6 £/kg H_2 (at production pressure), which has the potential to be cost competitive with fossil fuel-based technologies utilising carbon capture. Further development of lower TRL technologies may offer further cost reductions and social benefits from different hydrogen nuclear cogeneration coupling arrangements in the longer term.

Optioneering analyses for a demonstration facility identified two potential designs (a larger central facility and a smaller mobile facility); the larger central facility, which offers the most flexibility and greatest opportunity for growth of the hydrogen technologies is presented in this report. The proposed facility has been shown to be feasible (when considering the above criteria against which it was assessed), offering significant opportunities to support the UK’s Net Zero goals, not only by the accelerated development of the hydrogen technologies, but also value, IP, skills and capabilities to the UK.

Glossary

AMR	Advanced Modular Reactor
ANT	Advanced Nuclear Technology
CAD	Canadian Dollar
CAPEX	Capital Expenditure
CCUS	Carbon Capture Utilisation and Storage
Cu-Cl	Copper Chlorine (a type of thermochemical cycle)
Gen III	Generation III (advanced), or Generation III+ (evolutionary) are water-cooled nuclear reactors (Boiling Water Reactor, PWR, Pressurised Heavy Water Reactor) which are more advanced than the older Gen II nuclear reactors.
Gen IV	Generation IV nuclear reactors are a group of six different reactors either thermal reactors (HTGR, Very High Temperature Reactor, MSR, Super Critical Water Reactor) or fast reactors (Gas-cooled Fast Reactor, Sodium-cooled Fast Reactor, Lead-cooled Fast Reactor)
H_2	Hydrogen
HHV	Higher Heating Value
HTE	High Temperature Electrolysis
HTGR	High Temperature Gas nuclear Reactor
HTSE	High Temperature Steam Electrolysis
HTTR	High Temperature Test nuclear Reactor
IHX	Intermediate Heat Exchanger
ITE	Intermediate Temperature Electrolysis
ITSE	Intermediate Temperature Steam Electrolysis
ITWE	Intermediate Temperature Water Electrolysis
JAEA	Japan Atomic Energy Agency
kh	Kilo hours (1000 hours)
kt	Kilo tonnes (1000 tonnes; 1,000,000 kilograms)
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Hydrogen
LHV	Lower Heating Value
LTE	Low Temperature Electrolysis
MSR	Molten Salt Reactor
OPEX	Operating Expenditure
PEM	Polymer Electrolyte Membrane or Proton-Exchange Membrane
PWR	Pressurised Water Reactor
PWSMR	Pressurised Water Small Modular Reactor
R&D	Research and Development
S-I	Sulphur Iodine (a type of thermochemical cycle)
SMR	Small Modular Reactor
TC	Thermochemical Water Splitting
TRL	Technology Readiness Level

Contents

1 Project Overview

The UK Government has set an ambition for a 10 GW production capacity of low-carbon hydrogen by 2030 [1], increased from the initial target of 5 GW set two years before [2]. The vision is that a large ramp up in low-carbon hydrogen production will follow (up to 55GW [2]) in order to meet ambitious future hydrogen economy scenarios which are integral to achieving Net Zero goals and improved energy independence and security.

The BEIS Low Carbon Hydrogen Supply 2 competition aims to support the development of innovative low carbon solutions for future hydrogen supply. Stream 1 of the competition directs effort to identify, support and then develop credible innovative supply or enabling technologies that are not yet commercially viable for market entry: solutions at a Technology Readiness Level (TRL) of 4-6 at start of project. The competition is split into Phase 1 and Phase 2:

- **Phase 1** focuses on an initial feasibility study, including developing a core understanding of the technologies under investigation, potential technical and market performance, and highlighting probable market routes.
- **Phase 2** will support a physical demonstration of supply solution.

This report details the findings and conclusions from the Phase 1 feasibility study for a “Nuclear Hydrogen Cogeneration” solution for low carbon hydrogen supply, as well as outlining the plans for the Phase 2 demonstration facility.

The feasibility study has been independently undertaken by Frazer-Nash, Nuclear AMRC and their supporting partners. The Phase 1 work sought to examine both the feasibility of nuclear hydrogen cogeneration and the impacts a Phase 2 demonstrator could have on the solution’s development. This led to the following mission statement [3]:

> “To determine if it is financially, economically, socially, technologically, environmentally and commercially feasible & desirable, to develop a demonstrator test facility for nuclear hydrogen cogeneration replicating the performance of Advanced Nuclear Technologies (ANT) in order to integrate with hydrogen technologies.”

The study builds on the recommendations of [4], considering the feasibility of a new small-scale demonstrator, for development and construction in the near-term. The hydrogen and nuclear technologies assessed were based on the recommendations of [5] considering the synergy of the likely timing of the respective technology’s commercialisation. The technologies considered have been limited to:

- Nuclear Reactors falling in the category of ANT; Gen III Small Modular Reactors (SMR) and Gen IV Advanced Modular Reactors (AMR);
- Hydrogen technologies in the TRL 4-6 development stage which offer cogeneration potential; that is electrolysis in the intermediate and higher temperature operating conditions (Intermediate Temperature Electrolysis (ITE) and High Temperature Electrolysis (HTE)) and Thermochemical Water Splitting (TC) technologies.

It should be noted that the boundary of our assessment has excluded consideration of hydrogen storage; the impact of different output hydrogen pressures of the different technologies has not been taken into account.

1.1 Background and Context

The hydrogen production industry is currently dominated by 'grey' hydrogen from fossil fuels yielding high carbon emissions (responsible for ~98% of global hydrogen production in 2019 [6]). Commercially available Low Temperature Electrolysis (LTE) technologies are both established and proven for low carbon hydrogen production, producing hydrogen electrochemically from water. However, the cost of LTE has prevented wider uptake of this technology. The drive to Net Zero offers a timely opportunity to examine the potential increased efficiencies of ITE, HTE and TC technologies that also produce hydrogen from water and remove the dependency on fossil fuels and associated requirement for Carbon Capture Utilisation and Storage (CCUS) technology in a low carbon future.

When combining these higher temperature hydrogen generation technologies with nuclear power, multiple advantages are realised, including the potential for use of both heat and electricity produced by the nuclear reactor for cogeneration, improved efficiencies and flexibility in energy use which may offer the potential to be used to balance electric supply and demand to the grid. The key advantages of the various higher temperature hydrogen production methods and how they compare to commercially available LTE and their significance for cogeneration are summarised in Table 1.

Feature	Advantage relative to Commercial LTE	Significance for cogeneration with AMR & SMR
Lower electrical demand	Electricity requirement for electrolysis decreases with increasing temperature in the gas phase. Furthermore, TC (S-I TC cycle in particular) requires minimal electricity.	Potential cost savings if high temperature process heat (such as from an AMR) can be used. It also reduces the dependency on the cost of electricity.
Direct use of thermal energy	Direct use of thermal energy from reactors to heat the feed input or reaction chambers reduces the overall process energy demand and costs, and increases process efficiency due to lower electrical conversion losses. Waste heat from reactors, at lower temperatures, may also be available as free or low-cost thermal energy sources.	New AMR designs generate heat at high enough temperatures to be utilised for this, increasing overall process efficiency and reducing costs. If waste heat is used, there is the potential for no costs for heat, yielding further cost reductions.
Process Efficiency	Overall hydrogen production system efficiency can reach over 50% when paired with higher efficiency ANT, in comparison to <40% for LTE systems [7] [8].	Operating temperatures can be met directly by the high temperature outputs of AMRs. Also, higher temperature reactors offer improved electrical generation efficiency.

Table 1: Advantages of High Temperature Hydrogen Production Processes for Nuclear Cogeneration

Electricity generation has been the main focus for nuclear reactor operators, however, there is opportunity for utilisation of process heat to support areas considered hard to decarbonise and unlike intermittent sources such as wind and solar power, nuclear can provide continuous, baseload production capacity. As nuclear power is one of the lowest carbon methods for electricity generation [9], it is a key component for Net Zero targets [2]; when coupled with hydrogen cogeneration there is further potential for positive change in the early 2030s. Colocation of nuclear hydrogen cogeneration systems within population centres and industry is more practical with the smaller size ANTs, and offers diversity in supply of electricity, district heat and hydrogen.

The aim of the Phase 1 feasibility study described in this report was to build upon previous work [4], [5] to the benefit of BEIS and industry. The strategic rationale and the potential impacts the proposed demonstration facility may have can be summarised as follows:

- Increase technology maturity enabling the ability and effectiveness of nuclear hydrogen cogeneration and its value as part of a wider Net Zero local and national energy system.
- Increase policy certainty and confidence in demand for both green hydrogen and heat.
- Contribute to increasing confidence of the timing related to market formation for use of both hydrogen and heat.
- Help inform a route to deployment through a more robust business case for ANT route to market incorporating cogeneration.
- Support the UK to be a future hydrogen economy leader.

1.2 Methodology

The work breakdown for this feasibility study was broadly split into three separate complementary areas described below, which are further broken down into a number of complementary work packages:

1. Understanding (data gathering) – Outcome to define a set of “generic” technologies to feed into areas 2 and 3 below;
2. Feasibility Assessment of Cogeneration (cost, practicality, market assessments) – Outcome to determine the Levelised Cost of Hydrogen (LCOH), flexibility and impact of the nuclear and hydrogen coupling arrangements, and a small market assessment;
3. Test Facility Assessment (design, cost, impact) – Examination of the technical requirements of a test facility, projected costs and its projected impact for driving forward development for nuclear hydrogen cogeneration.

The generic technology types have been used to define input data and coupling scenarios for the LCOH modelling, as well as practicality and market assessments, together with the initial concepts for a test facility. The initial stages of these later packages of work began in parallel with the literature research and industry engagement. This ensured that the data and knowledge requirements for the assessment and modelling work packages were sufficiently understood to focus literature searches and discussions with the vendors to align with the goals of the feasibility study.

2 Results & Conclusions

2.1 Generic Technical Specifications

The initial focus of the feasibility study was to define “generic” technologies which would be the key data on which the feasibility assessment was based. In order to define these "generic" technology types, the range of technologies under development were assessed through both industry engagement and a literature review. A total of five generic hydrogen production technology cases [10] and three generic ANT [11] were derived, see Table 2 and Table 3 respectively.

Generic Case	Technology Used	TRL	Main Requirements from Nuclear Reactor
Case 1	High Temperature Steam Electrolysis (HTSE)	6	Electricity, High Temperature Heat or Steam
Case 2	Intermediate Temperature Steam Electrolysis (ITSE)	5	Electricity, High Temperature Heat or Steam
Case 3	Intermediate Temperature Water Electrolysis (ITWE)	4	Electricity, High Temperature Heat
Case 4	Sulphur-Iodine (S-I) cycle TC	4	High Temperature Heat
Case 5	Copper-Chloride (Cu-Cl) cycle TC	3	High Temperature Heat, Electricity

Table 2: Generic Hydrogen Production Technology Cases

Generic Case	Technology	Maximum Temperature for Cogeneration (°C)	Efficiency (%)	Power Range (MWe)
Case 1	Gen III SMR: PWR	300	33-35	70-470
Case 2	Gen IV AMR: MSR	600-800	35-45	16-200
Case 3	Gen IV AMR: HTGR	900-1000	45	4-300

Table 3: Generic Nuclear Reactor Technology Cases

These final technologies chosen for review, were down selected based on available data, level of vendor engagement, development within the UK and likely time to generation, as well as consideration of the range of potential ANT and hydrogen technology operating temperatures. Clear synergies were identified between the final selection; some almost perfect potential matches.

2.2 Key Considerations from Industry Engagement

The key findings from the vendor engagement activities are as follows:

- All showed significant interest in the concept of nuclear hydrogen cogeneration. The readiness of data sharing however varied significantly dependent on technology maturity and their availability to support the programme given the evolving energy markets and interest in their technologies. As a result, unfortunately, no vendor input was obtained for the HTGR and TC technologies.

- The maturity of the technologies ranged, typically, between the TRLs of 4-6.
  - Of the hydrogen vendors, HTSE was the most mature, with small scale (<5MW) systems already demonstrated, near term aims of demonstrating systems of 20-25MW and larger ~100MW systems currently in design; ITSE were in the process of demonstrating small scale systems (~1MW); ITWE were demonstrating the fundamental technology rather than at the system level.
  - Of the ANT vendors, the Gen III SMR was the most mature in the UK, with the first operational plant expected 2030. The Gen IV AMR designs were less well developed and are demonstrating fundamental aspects of their core and primary circuits.
- Operating parameters and conditions highlighted a number of clear synergies between the technologies.
- Some areas of commonality between different vendors were highlighted:
  - Electrolysis designs with a steam phase reaction were developing their Balance of Plant (BoP) to take an input feed of low temperature (≤200°C) steam. Heat recovery within the system allowed cooling of exit gases and heating of inlet steam thereby improving system efficiencies. The largest efficiency gains from use of nuclear heat would be the phase conversion of the input feed from water to steam; further heating to operating temperature would only yield marginal improvements.
  - Nuclear vendors noted the following options they had for their technology outputs:
    - Reactors could supply heat only, negating the need and expense of turbines and grid connection for electricity generation. The heat supplied could vary dependent on which reactor coolant loop the heat was taken from.
    - Reactors could supply electricity by a private wire concept, negating the need and expense of connection to the grid. This would offer a cheaper supply of electricity to a hydrogen production facility, with potentially longer fixed prices reducing the cost volatility on hydrogen production costs.
- Commercial operating options were discussed, whereby a common operator would be in charge of both hydrogen and nuclear facilities, allowing optimum electricity and hydrogen supply (and price) to be managed. Without this arrangement the hydrogen vendors would essentially be buying electricity at a market sale price which could be volatile and would increase risk and uncertainty to the LCOH of the hydrogen facility.
- With a few notable exceptions, minimal engagement between hydrogen and future nuclear developers had occurred. This project hoped to bridge some of these gaps and nuclear developers noted this to be a key reason for their support to the study.

2.3 Process Practicalities

This section explores the key practicalities of the proposed cogeneration solution, and additional influencing factors and efficiencies of system processes to allow comparison against alternatives [12]. This involved reviewing how each of the generic nuclear cases align with the generic hydrogen production processes as defined in Section 2.1. The outcomes of this review fed into the LCOH assessment (Section 2.4) to provide additional detail on plant design and operation and deduce what impact these have on cogeneration.

2.3.1 Coupling

There are many different parameters which can impact the cogeneration designs. Nuclear plants can produce both heat and/or electricity to support hydrogen production. Although electricity comes as a “one size fits all”, the process heat temperature available from ANTs is dependent on reactor type and design. The hydrogen production processes require vast ranges in the amount of electricity and thermal heat. Therefore, when reviewing which hydrogen process best aligns with a reactor type, the applicability of process heat needs to be at the forefront, as extracting this heat from a nuclear plant requires further equipment and potentially a reduction in the capacity for electricity generation.

To some degree, each of the five generic hydrogen production processes assessed require electricity and heat, however the relative demand can vary significantly for each technology. Electrolysis technologies require more electric energy than heat energy, whilst for the TC technologies process, the converse is true. As such, hydrogen cogeneration with electrolysis would favour the ANT being configured to produce electricity as its primary function, and if some of the heat could be tapped off this could benefit the higher temperature processes’ heat input requirements. TC processes, on the other hand, would favour a configuration where heat extraction is the primary focus of the ANT.

Conventionally, a nuclear plant consists of transfer of heat generated in a primary circuit to the secondary circuit (via boiler / steam generator heat exchangers) which drives turbines for electricity production. When extracting heat for hydrogen production, the primary circuit is not affected, and so rather than basing design on turbine requirements, more flexibility is achieved by use of an Intermediate Heat Exchanger (IHX) separating the primary and secondary circuit (for which a range of coolant fluids can be considered). This secondary circuit would then transfer the process heat to the hydrogen facility via another, or multiple (tertiary) heat exchanger(s). This allows a direct means of utilising heat from an ANT, and an example of this is illustrated at the left had side of Figure 1, and in detail in Figure 2, for hydrogen cogeneration by S-I TC. Alternative configurations would also direct a portion of the primary circuit to steam generators for electricity production, shown by the two configurations in Figure 1.

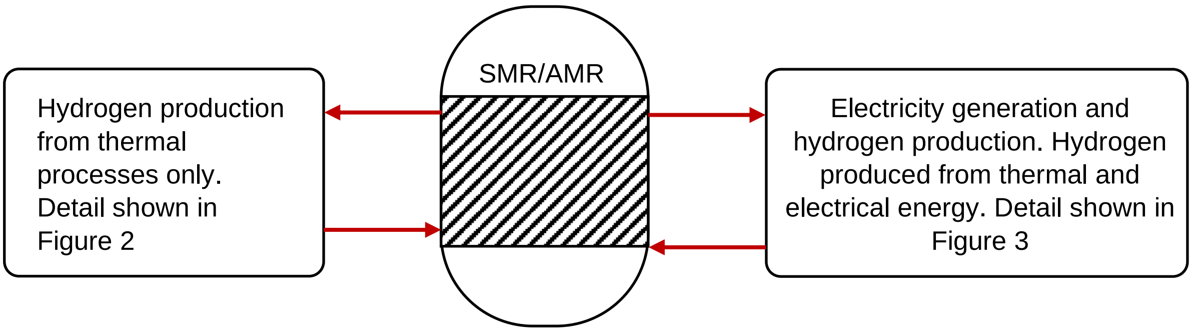

Figure 1: Illustration of Nuclear Hydrogen Cogeneration Plant Configurations

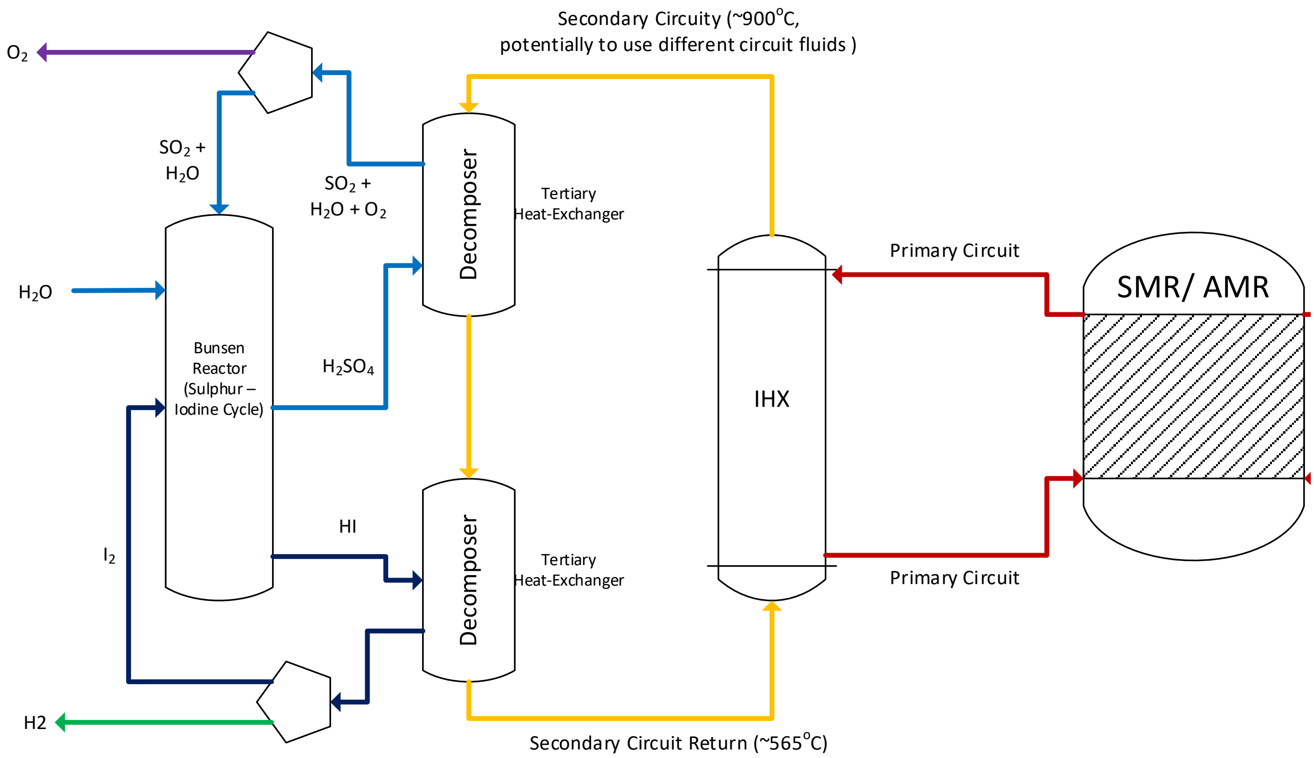

Figure 2: Illustration of Nuclear Hydrogen Cogeneration Plant Configuration to support Thermal Processes (Provision of heat only, no electricity production)

Where O_2 = oxygen; H_2 = hydrogen, H_2O = water, HI = hydrogen iodide, or hydroiodic acid when dissolved in water, H_2SO_4 = sulphuric acid, SO_2 = sulphur dioxide

Although the configuration shown in Figure 2 is the most direct and potentially largest scale set up for utilising heat from a nuclear plant, other arrangements are illustrated in Figure 3, which include:

- Offtake after all the turbine cycles; utilisation of waste heat [offtake T4 in Figure 3];
- Offtake between turbine cycles [offtake T2 and/or T3 in Figure 3].

The secondary circuit offtake heat location will dictate its potential thermal energy for the hydrogen facility. For instance, the greatest and least available heat will be from the offtakes T1 and T4 respectively in Figure 3. Additionally, if heat is extracted from offtakes T1-T3 the electrical generating capacity of the plant (and potential revenues) is reduced, whereas utilising the waste heat (offtake T4) should have minimal impact on the plant.

Hydrogen production processes for which the main input requirement is electricity (such as electrolysis) align well with cogeneration arrangements with heat offtake at the turbine stages, particularly where input temperatures support the use of waste heat (after all turbine cycles). In these scenarios an IHX would not be required, however a tertiary heat exchanger would still be required to transfer the offtake heat from the secondary circuit (Figure 3).

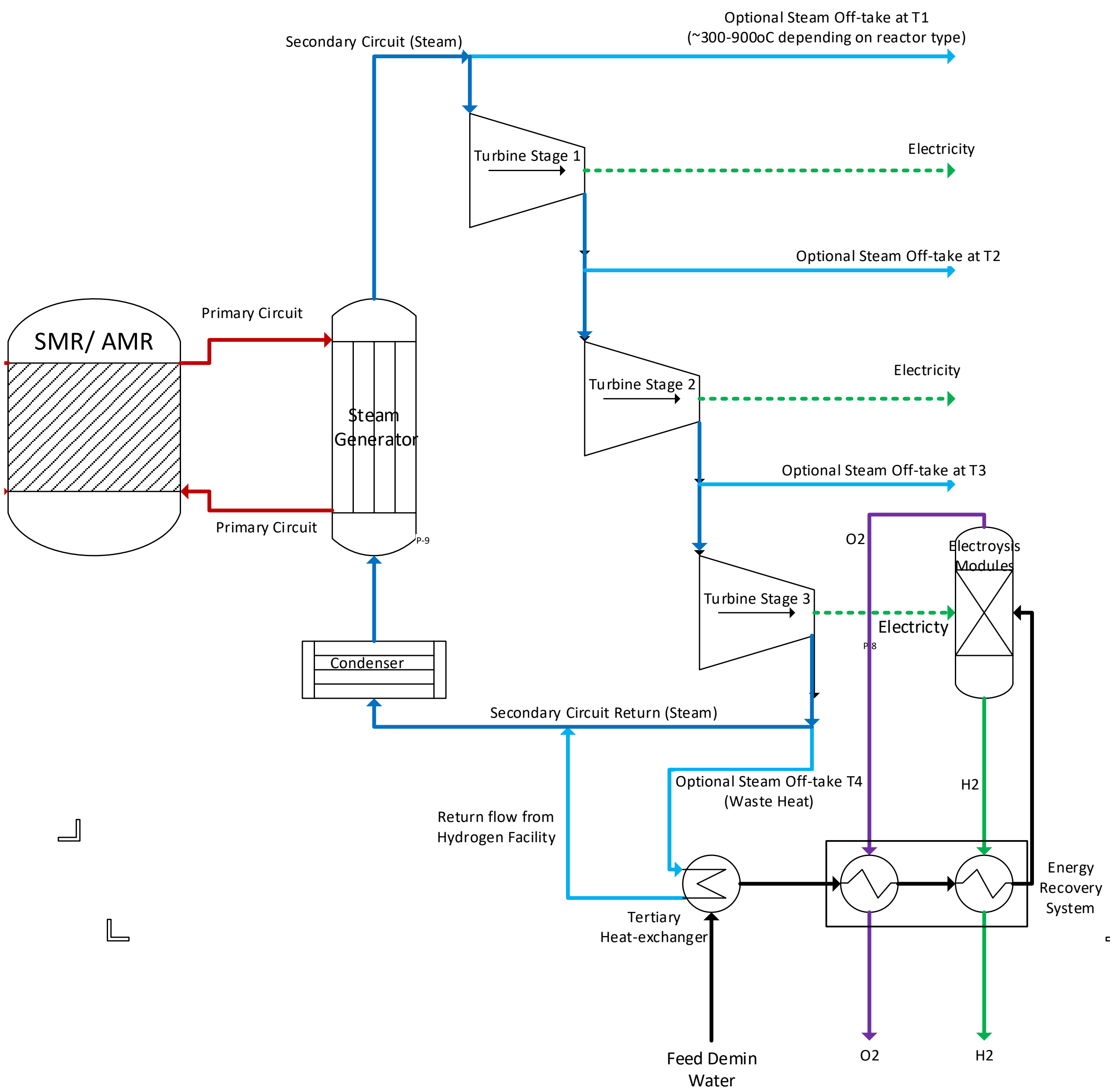

Figure 3: Illustration of Nuclear Hydrogen Cogeneration Plant Configuration to support Combination of Thermal and Electrical Processes (provision of heat and electricity)

The key finding from HTSE and ITSE hydrogen developers (Section 2.2) was that high grade heat is not required to support these systems; large efficiency gains are made by utilising waste heat (from other industries) to evaporate the feed demineralised water, further heating is achieved by separate integrated electrical heating systems with heat recovery. Utilising available excess heat is expected to reduce power consumption by 10-15% compared with no waste heat, whilst a 30% reduction on power consumption is expected when compared with low temperature electrolysis (these values were obtained from the vendor engagement). This equates to a preferred reactor design coupling that focuses on electricity generation (Figure 3).

2.3.2 Safety Practicalities

Given the safety requirements and legislation associated with building and operating a nuclear platform there are numerous reasons why there should be separation (by the secondary circuit) between the nuclear island and the hydrogen production facility, which is discussed in depth elsewhere [8]. This is particularly pertinent to the system arrangement shown in Figure 2, where an option might be to directly couple the primary circuit to the tertiary circuit rather than by the inclusion of an additional (secondary) circuit. The clear physical separation between the primary circuit and hydrogen production facility allows the tertiary heat management facility to be independently designed; it allows operation, maintenance and repair work to be conducted under non-nuclear conditions, reducing costs; and a secondary circuit with the specific sole purpose of provision of heat (as opposed to electricity production as shown in Figure 3) is attractive, since it gives flexibility in the design and allows the use of a range of different fluids.

The employment of this additional loop (secondary circuit), however, does have some disadvantages, such as:

- Requirement of an IHX as an additional component increases the overall capital costs and may require substantial development for a bespoke design.

- The temperature of heat transferred to the hydrogen production facility will be reduced due to additional heat losses by the additional needs of an intermediate heat cycle (i.e., efficiency losses, potential compression requirements). This reduces the overall plant efficiency.

2.3.3 Design Considerations

If a nuclear platform is configured to support thermal processes, the IHX will need to be designed and operated for the life of the plant (over 60 years, in line with ANT design life) whilst working under the harsh conditions of high temperatures and pressures, and temperature and pressure gradients, which put stringent requirements on the material selection. Their limitations are principally dictated by the available materials, whereas the optimal choice is defined by economics. Peculiar to nuclear applications in an HTGR are the aspects of helium as a coolant, low pressure differential across the IHX, operating times in excess of 500 kh, the assumption of abnormal operational or accident states, the presence of process gases and the limitation of activation of product gases [8]. For lower temperature and pressure operations (both hydrogen and nuclear technologies), material selection will have great flexibility and should be more cost effective. This incentivises the lower temperature hydrogen production processes including ITSE, ITWE and Cu-Cl TC cycle albeit their overall process efficiencies maybe lower than those achievable in HTSE and the S-I TC cycle.

A lot of R&D has been dedicated to the design of components at HTGR temperatures. Currently, no technology can meet the anticipated requirements in terms of long-life performance, pressure drop and mechanical resistance, requiring further work. The final choice will be made according to criteria such as local stress/strain conditions, corrosion, dust susceptibility, in-service inspection, qualification and, of course, cost and for nuclear systems appropriate material selection is essential. The main challenges for IHX development are the choice of structural materials that can be operated over long times at temperatures up to 1000°C.

The proposed Phase 2 testing facility could also support the development of high temperature nuclear components including heat exchangers, given its ambitions to mimic the outputs of future ANTs. This offers an additional function of the facility after the demonstration of cogeneration and development of hydrogen production processes.

The above design and safety requirements (focused on the higher temperature ANTs) are equally applicable to heat exchanges used in SMR and MSR cogeneration designs. SMRs operate at lower temperatures than HTGRs and already have examples in operation (submarines). Therefore, their technological philosophy is already well developed and understood. Component development for SMRs will of course continue, but reduced development and costs (relative to HTGR requirements) is expected, especially considering the less harsh operating conditions and so material selection for the IHX and/or tertiary heat exchanger, should be easier and far more flexible.

There are still further developments to be made with regards the heat integration loops of MSRs given the limited use of molten salt in industry. Developers are currently in the test and development phase (Section 2.2) to demonstrate whether component designs meet the equipment qualification requirements for a nuclear plant.

2.3.4 Practicalities Case Study Conclusions

The three generic ANTs examined in this report each have the capability to provide heat and electricity in a hydrogen cogeneration capacity. The outcomes of the practicalities review concluded the following:

- The design of the heat exchanger requires particular focus. It will be the primary part of any coupling system that allows heat transfer between the reactor and the hydrogen plant. Separation of the nuclear and hydrogen systems will allow the hydrogen plant to be built without the need to conform to nuclear regulatory safety standards. However, increasing the number of heat exchanger systems will lower the maximum potential temperature and energy available for the hydrogen plant.

- Higher temperature heat will likely require more expensive heat exchangers and additional coupling equipment, due to the material requirements of these systems in these harsh conditions. The coupling may entail the design of new types of heat exchanger, or refinements of traditional designs with more advanced materials. The proposed Phase 2 testing facility could also support this, given its ambitions to mimic the outputs of future nuclear facilities and would allow testing of new heat exchanger designs.

- SMRs are the most developed of the three ANTs considered, with plans for a functioning reactor by 2030. It utilises similar technology to existing UK reactors at a smaller scale, which allows for direct electrical power supply to potential hydrogen production facilities. However, the operating temperatures of these types of reactors (up to 300°C, Table 3) are too low to supply direct thermal power at the required operating temperatures of ITE, HTE, and TC processes (ranging from 300°C – 1000°C depending on the specific technology) beyond initial heating of the feed water.
  - For HTSE and ITSE technologies, the evaporation of the electrolyte feed stream via the utilisation of waste heat from an ANT (after all the turbine stages) will still equate to 10-15% overall hydrogen production process efficiency as the latent heat to evaporate the electrolyte equates to approximately 66% of the total process heat requirements. This arrangement presents the most favourable set up for an SMR hydrogen cogeneration plant as there would be no impact to the electric generating capacity of the nuclear plant and the hydrogen production efficiencies are increased via use of waste heat. Equally all HTE and ITE vendors engaged with (including ITWE) have already designed their heat recovery systems so that they only require low grade

waste heat. This cogeneration solution will be possible with existing heat exchangers, potentially reducing research and design costs.

– The potential to use electrical heating for TC processes, using supply from SMRs, will require further investigation and modelling to determine the economic viability.

- MSRs with a high operating temperature and potential utilisation of long-distance molten salt loops, may offer a reliable, safe source of thermal energy to meet the thermal requirements for all but the highest temperature hydrogen production processes (HTSE, S-I TC cycle), as well as electrical power if linked to generating equipment and suitable heat exchangers. The higher temperatures and corrosive nature of the salts make the heat exchanger designs more complex than those of current reactors. Power generation or external heat supply requires at least a tertiary loop, limiting the maximum temperature. However, the potential for these reactors to provide heat and electricity to both the electrolysis and TC hydrogen production processes is evident with numerous potential arrangements, noting, as with the SMRs the potential for utilisation of waste heat.

- HTGRs are able to provide heat at a suitable temperature for all the hydrogen production methods examined, assuming appropriate heat exchangers are designed. The high temperatures increase heat exchanger material requirements and cost. However, the higher efficiencies possible using thermal energy directly as well as the higher potential electrical generation efficiency would enable more efficient hydrogen production. As the MSRs, the potential to provide heat and electricity to both electrolysis and TC hydrogen production processes is evident with numerous different potential arrangements.

2.4 Levelised Cost of Hydrogen (LCOH)

Levelised cost metrics enable straightforward comparisons between different technologies as they consider all relevant costs over the entire lifetime of the technology [13]. The LCOH metric is used to compare the costs of different hydrogen production methods and is a measure of the total cost of hydrogen production per kilogram of hydrogen produced by the plant over its lifetime. In this report, the LCOH is used to compare the different potential cogeneration options against each other. A similar metric, Levelised Cost of Electricity (LCOE), is used to compare electrical power generation methods. The calculations used in this study follows that of [13]. Further details of the model method and capabilities are included in [14].

Each of the three generic nuclear plant technologies and five generic hydrogen plant technologies required a full set of parameter inputs. The nuclear reactor heat rating, construction time, design life and decommissioning time were set as constants for each reactor, while all other parameters had a range of values, defined by upper and lower bounds. The information received from hydrogen and nuclear vendors formed the base inputs to the modelling, whilst open-source literature data created a wider range of potential values (and fill any data gaps). These were increased by 10% (upper value) and 5% (lower value) to cover any uncertainties.

The LCOE used in the modelling calculations were those provided by nuclear vendors based on expectations and were not calculated independently from the nuclear reactor CAPEX and OPEX values. These were based on nuclear vendors own internal research and are therefore likely to be an accurate assessment of potential sale costs of electricity.

The coupling of the different technologies was as recommended in Section 2.3.1, and two coupling configurations were modelled as follows:

1. Nuclear reactor supplies all heat and electricity requirements to the hydrogen technology. The heat supplied is sufficient to bring the feed water/steam to operating temperature, and is supplied at the sacrifice of electricity production. No optimisation in terms of waste heat recovery was made, and so this would provide a conservative LCOH.

2. Nuclear reactor supplies all the electricity requirements to the hydrogen technology, and only waste heat from the reactor is provided (T4 off-take from Figure 3). In this case, an additional electricity burden would be required to bring the feed water/steam to operating temperature, however the nuclear reactor would generate optimum electricity levels. Some hydrogen facility waste heat recovery is assumed, and provides more realistic LCOH values. This was only performed for electrolysis technologies due to the alignment with their current system development.

The main assumptions of the model are as follows:

- All data was assumed to be accurate, and assumes the designs are proven (that is, development costs are not included). The detail of the information provided by each technology vendor was significantly variable and specific cost and technical data was not provided for either TC technologies or HTGR. Assumptions based on HTSE data were made to fill in cost gaps for ITSE and ITWE plants, this is assumed to be reasonable as they are all electrolysis-based technologies. Realistic values for missing parameters were assumed to be represented by those found in the open literature.

- Costs were scaled linearly e.g., it was assumed that a 400MW reactor would be double the CAPEX and OPEX of a 200MW reactor. This assumption will likely be valid for first in class type plants, but it is expected that over time economies of scale will reduce these costs; this aspect is not modelled at present. This is assumed to also be true for whatever hydrogen technology the reactor has been paired with. As yields will also increase linearly within the model, the LCOH values predicted are for the reactor hydrogen technology pairings at any scale.

- The input data values for the heat exchangers are based on [15], where separate costs were given for electrical generation infrastructure. It is assumed that these costs would include any heat exchangers required to provide heat to hydrogen processes, and these have been scaled appropriate to each reactor modelled. For any electrical heating required in addition to thermal energy from a reactor, efficiencies of >95% were assumed. This was based on a wider literature review.

2.4.1 Key Findings

The results for the various potential cogeneration arrangements are shown in Table 4, Table 5 and Table 6, and the calculated LCOH values are compared with those of other commercial hydrogen production methods [13] in Figure 4. The following can be noted:

- Indications are that each hydrogen nuclear cogeneration system modelled can provide tens of kilotonnes (kt) of hydrogen per year. Reducing the hydrogen yield, and therefore increasing the electrical yield of the nuclear plant can slightly reduce the LCOH if the sale of electricity can be used to offset the production costs of hydrogen. However, the yield of hydrogen is lowered, as less power is available for the hydrogen plant.

- Of all the methods examined, these results indicate that the Cu-Cl cycle has the potential for the lowest LCOH value, as well as the highest potential hydrogen yield per MW input power, as this technology has the lowest total energy requirements. However, as it is still at a TRL of ~3-4 (laboratory-based process), there is quite a large variance in potential costs and yields, due to the uncertainty in energy requirements. Processes requiring AMRs also have more varied potential LCOH values, due to the uncertainty in potential AMR costs.

- A wide range of values for LCOH and yields is noted for each cogeneration system. The uncertainty involved is almost always dominated by the CAPEX and OPEX of the hydrogen facilities in the case of the electrolysis technologies, which is likely due to the low TRL of the technologies, coupled with the fact that for the electrolysis technologies, current and projected costs were obtained, whereas for the other technologies, only projected costs were provided. It is likely that these costs will become more defined in future as the technologies progress, allowing more accurate predictions of LCOH. The key factors contributing to uncertainty of the cogeneration with TC technology were not as clear and varied dependant on reactor type.

Hydrogen Technology	LCOH (£/kg)	Yield (kt/year)	Largest Uncertainty Factors
HTSE	3.29 – 6.91 (3.00 – 6.30)	75 – 94 (82 – 103)	HTSE’s OPEX, CAPEX and electricity requirement
ITSE	4.91 – 8.78 (4.34 – 7.77)	57 – 66 (65 – 75)	ITSE’s OPEX and CAPEX, and PWSMR’s CAPEX
ITWE	4.50 – 11.99 (4.18 – 11.20)	69 – 94 (74 – 102)	ITWE’s OPEX, CAPEX and electricity requirement

Table 4: Modelling Results of 470 MWe, 1200 MWth PWSMR Cogeneration, Configuration 1. Figures in brackets correspond to Configuration 2, use of waste heat only.

Hydrogen Technology	LCOH (£/kg)	Yield (kt/year)	Largest Uncertainty Factors
HTSE	2.62 – 6.11 (2.34 – 5.46)	30 – 38 (33 – 42)	HTSE’s OPEX and CAPEX, and MSR’s OPEX
ITSE	3.96 – 7.94 (3.39 – 6.83)	22 – 26 (26 – 31)	ITSE’s OPEX, MSR’s CAPEX and OPEX
ITWE	3.75 – 10.25 (3.43 – 9.42)	28 – 38 (30 – 41)	ITWE’s OPEX, CAPEX and electricity requirement
Cu-Cl	1.30 – 3.12	35 – 63	Cu-Cl’s heat requirement, MSR’s OPEX and CAPEX
S-I	2.70 – 6.00	19 – 30	MSR’s OPEX and CAPEX, S-I’s heat requirement

Table 5: Modelling Results of 195 MWe, 400 MWth MSR Cogeneration, Configuration 1. Figures in brackets correspond to Configuration 2, use of waste heat only.

Hydrogen Technology	LCOH (£/kg)	Yield (kt/year)	Largest Uncertainty Factors
HTSE	2.62 – 6.11 (2.34 – 5.46)	30 – 38 (33 – 42)	HTSE's OPEX, CAPEX and electricity requirement
ITSE	3.96 – 7.94 (3.39 – 6.83)	22 – 26 (26 – 31)	ITSE's OPEX and CAPEX, and HTGR's Turbine Efficiency
ITWE	3.75 – 10.25 (3.43 – 9.42)	28 – 38 (30 – 41)	ITWE's CAPEX, OPEX and electricity requirement
Cu-Cl	0.94 – 1.90	51 – 94	Cu-Cl's electricity and heat requirements, and HTGR's OPEX
S-I	1.88 – 3.77	28 – 43	S-I's CAPEX, OPEX, and heat requirement

Table 6: Modelling Results of 275 MWe, 600 MWth HTGR Cogeneration, Configuration 1. Figures in brackets correspond to Configuration 2, use of waste heat only.

Comparison of the calculated LCOH values for TC, ITWE, ITSE and HTSE with those of other commercial hydrogen production methods [13] (Figure 4) shows:

- All nuclear cogeneration options modelled have the potential to be cost competitive with current electrolyser production methods utilising baseline grid electricity.
- HTSE and TC nuclear cogeneration further have the potential to be cost competitive with fossil fuel-based technologies utilising carbon capture.

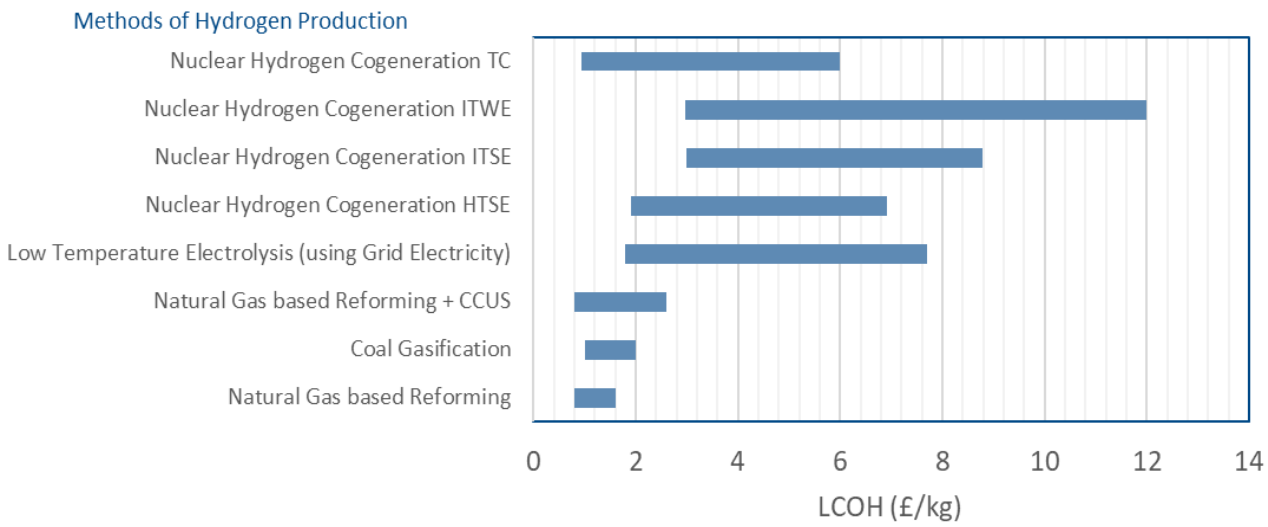

Figure 4: Comparison of LCOH of hydrogen production methods

However, in comparing these values, it should be noted that the data in [13] uses input data from 2020 and so does not take into account the recent increase in UK energy costs (natural gas and electricity). Fossil fuel based methods are highly dependent on the cost of natural gas and electricity, and so whilst steam methane reforming and coal gasification methods of hydrogen production are shown to yield the cheapest LCOH in Figure 4, this does not reflect current market trends; indeed electrolytic hydrogen has recently been able to undercut fossil fuel based hydrogen [16].

3 Description of Demonstration Project

For Phase 2 we developed a proposal to construct a Nuclear Hydrogen Cogeneration Demonstrator that will mimic the heat & electricity output of the generic ANT platforms (Section 2.1) that allow coupling of electrolysis and/or TC systems, to demonstrate cogeneration capabilities. It could physically prove that the heat and electrical outputs from an ANT can be effectively used to produce hydrogen via these higher temperature processes. The key benefits would be:

- Hydrogen developers with technologies at TRL 4-7 (specifically HTE, ITE and TC) gain an opportunity to develop, demonstrate and showcase their technologies. The facility could provide a platform for developers to increase their technology TRL by demonstration of their systems, bridge the gap to commercialisation and demonstrate coupling potential with a range of ANTs, expanding their future market potential.
- ANT developers will see how their platform outputs could produce hydrogen more efficiently than current processes and explore the practicalities of this cogeneration.

The feasibility study has shown that providing this technology agnostic development facility for hydrogen developers would be technically and financially viable. The flexibility of the facility also offers the potential as a valuable R&D asset for the UK to bridge the gap from low to mid TRL technologies and beyond, much called for throughout the industry (see for example [17]). The facility would allow UK (and potentially international) based companies to advance the development of higher efficiency but (currently) lower TRL hydrogen production processes to the point of full industrial deployment.

The facility would also offer value to existing ANT developers in the optimisation of their own cogeneration capability. It would also offer an environment where both technology sectors could work collaboratively to optimise the synergies between the two technologies and so fully exploit available efficiencies and maximise potential hydrogen production capacities. This would give the UK supplier base a significant advantage over international competitors and would allow IP generation that could be licenced around the world.

The facility could also enable the creation and delivery of a funded hydrogen technologies R&D programme (with a focus on those hydrogen production methods that align with the next generation of nuclear reactors) to enable the national coordination of low carbon hydrogen production related R&D. Stimulating R&D activity in this way would bring forward commercially deployable hydrogen technologies that need to use a national facility of this type to create UK value, IP, skills and capabilities. The facility will ensure that the development of critical local supply chains for hydrogen related technologies takes place and will enable the leveraging of cross sector expertise and capabilities.

The optioneering activities undertaken for the Phase 2 demonstration have identified two potential options:

- A large, multi-output static plant, with potential to demonstrate systems up to approximately 6 MW, or multiple smaller systems at a range of temperature inputs;

- A smaller, mobile based facility which could be transported to hydrogen developer premises and would best suit smaller scale hydrogen generation systems and the lower end of the TRL 4-6 technologies.

These both offer different advantages, however, the static plant concept offers a broader development opportunity and it is this design which will be discussed further in this report; further details of both design options are included in [18]. The report recommends that further work is undertaken to iteratively develop the Phase 2 demonstrator design, whilst at the same time defining potential siting requirements. This will then enable a suitable site to be identified that minimises any potential technical, environmental, social, or economic constraints; supports value for money; and optimises potential impact and opportunities for exploitation.

4 Design of Demonstration

The demonstration plant (see [18] for full design details) operates as a steam raising plant, i.e., it will have several stages of heat and reheat to produce superheated steam outputs that simulate those of an ANT. It is comprised of a closed loop recirculating system with 3 boiler stages (with an option of a 4th), the output of each boiler going either to the next stage boiler for further heating, to a heat exchanger coupled to the hydrogen technology or to a cooler before recirculation. Detailed schematics of the Phase 2 plant layout is shown in Figure 5, with a summary of the steam temperatures at each stage shown in Table 7.

Demonstration Plant				Generic ANT Represented	Most Applicable Coupling for the Generic Hydrogen Technologies (Maximum System Size)
Boiler Stage	Maximum Output Temperature (°C)	Mass Flow (kg/h)	Heat Input (kW)		
4	900	not specified[1]		HTGR	HTSE, S-I Cycle TC
3	800	600	81.6	HTGR	HTSE, ITSE, (3 MW) S-I Cycle TC (180kW)
2	600	1180	271	HTGR & MSR	ITSE, ITWE (5MW) Cu-Cl Cycle TC (300kW)
1	300	1780	1360	HTGR, MSR & PWSMR	HTSE, ITSE (6MW) (waste heat coupling)

Table 7: Static demonstration plant output stages and temperatures

[1] The materials required to survive prolonged and sustained use at the higher temperatures may prove to be cost prohibitive or be immature in development and understanding, and so it may not be viable to provide the stage 4 outputs. Analysis and postulation on the development of suitable materials for such high temperatures is beyond the scope of this study; if the boiler and heat exchanger manufacturer market analysis show that such vessels are not readily available or require exotic and expensive alloys, then these stages will be marked as potential upgrade options, should the market position change within the lifetime of the plant.

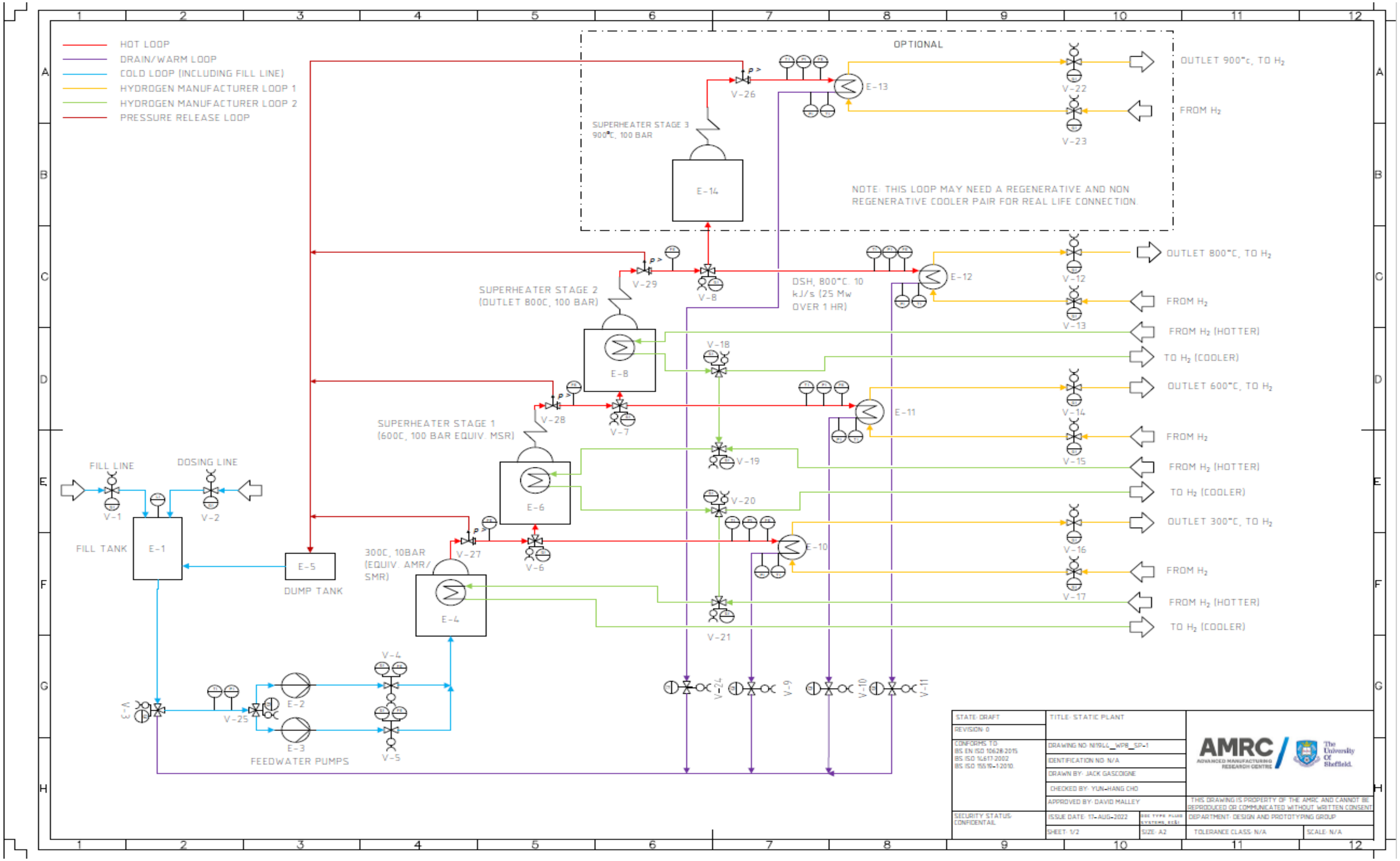

Figure 5: Detailed Plant Schematic. Note, some sensors are omitted for clarity.

The boiler output temperatures have been selected to simulate (as close as is practicable) the minimum and maximum generic ANT coolant temperatures available for cogeneration (noting the potential coupling arrangements described in Figure 2 and Figure 3, Section 2.3). The design also incorporates some flexibility for potential additional ANT development.

The most applicable hydrogen technology and maximum system size which can couple to the various stages of the design is also illustrated in Table 7. It should be noted that heat exchanger design and/or flow rates may impact the applicability of the coupling, for example ITSE typically operates <700°C, so coupling with the output from boiler stage 3 will require careful consideration of operating parameters.

5 Benefits and Barriers

5.1 Benefits of Nuclear Hydrogen Cogeneration

It is well known that the UK will need to dramatically increase its low carbon hydrogen production capacity to both follow government strategies and to meet legally binding net zero targets (discussed further in Sections 1 and 7). The low carbon ITE, HTE and TC technologies each generate hydrogen from water and offer increased efficiencies relative to the commercially available alternative. When coupled with nuclear power, renewable energy or biomass, these methods are not dependent on fossil fuels, so are independent of fossil fuel prices. The application of a nuclear power source to provide energy would also reduce the variability of energy costs, due to the generally stable and reliable cost of nuclear power [19].

HTE and ITE are promising alternative electrolysis technologies to LTE and are recognised leading technologies towards large-scale, low-cost clean hydrogen production [20]. ITE and HTE both require the water feed to be heated to significant temperatures (300-850°C) and can use electricity to provide the required heat as well as electrical power to drive hydrogen production. It is possible to significantly increase these efficiencies by using thermal energy directly, reducing the total energy demand. Utilising "waste" thermal energy for example at ~200°C to convert feed water to steam, as required for ITSE and HTSE technologies, achieves the majority of this efficiency increase (Section 2.2). These increased efficiencies offer the potential for these processes to be operated at much lower cost than LTE, as well as higher overall process efficiency (in terms of energy provided to hydrogen production). Nuclear reactors offer the potential to provide a steady supply of either high grade thermal energy (to reach operating temperatures) or "waste" thermal energy (to convert the feed water to steam) in addition to the low carbon electrical energy required to drive the reaction of these technologies (Section 2.3). Consequently, nuclear energy is widely considered to be very good match for these technologies.

TC technologies have also been identified as another potential method for producing large amounts of hydrogen using nuclear heat. These cycles have the potential for high energy efficiency, and lower overall energy demand when compared with electrolysis technologies and hence promise to reduce the hydrogen production cost. The high thermal energy requirement of these cycles also reduces the dependency on the conversion efficiency of turbines, if the thermal energy can be supplied directly. Higher temperature Gen IV reactors are ideally suited for this, and AMR designs should be directly compatible with hydrogen production facilities. However, a number of technical hurdles and barriers must be overcome, mainly relating to the durability of materials used in the processes.

5.2 Benefits of Facility

The TRLs of some of these promising, increased efficiency low carbon hydrogen production technologies, are still at the point where system prototyping at scale, in a relevant environment, has not been consistently achieved. Some of the less well-developed hydrogen alternatives require investment to move them up the TRL scale and enable commercially viable technologies to be deployed at scale. If further development focussed on supporting these mid-TRL technology alternatives, then they could be used to increase the production of hydrogen within the UK, as well as develop innovative technologies for wider exploitation. The concept behind the proposed facility (Section 3) was to provide simulated thermal outputs a range of ANTs. The fact that some of these technologies (such as HTGRs) are considered to be technically immature is not of concern, as the output conditions can be simulated to allow for design and testing of different cogeneration coupling arrangements. The Phase 2 facility would be a full scale, factory sized plant, with the ability to operate for long durations at a time.

Hydrogen vendors would be able to investigate the practicalities of integrating their technology for use with the thermal outputs of ANTs. Connection of their demonstration units to the simulated heat outputs would allow experimentation of the impact of multiple different heat outputs and steam conditions and determination of optimal efficiencies. The high functionality and multiple heat outputs of the facility would ensure flexibility in use and would lead to potentially increased development of cogeneration technologies, at a faster rate than present. It may also allow for higher nuclear hydrogen paired production efficiencies.

The simplification of design (in that high temperature steam would be used to simulate all nuclear thermal outputs) reduces technical and safety risk, complexity and cost. For nuclear designs which incorporate a steam loop, the facility offers additional advantage, where nuclear vendors could equally experiment on heat exchanger designs, in a safe and radiation free environment, that allows access to the heat energy whilst minimising the impact on electricity generation. There is also potential for nuclear and hydrogen vendors to work collaboratively and use the demonstrator plant to optimise the synergies between their technologies.

The facility would provide opportunities for jobs and skills training within the nuclear and hydrogen sectors. It would promote UK Small Medium Enterprises (SME) development of advanced nuclear and hydrogen technologies, which would in turn lead to wider economic investment, skills development and job creation.

A further potential benefit is that the facility could be used as a research facility for thermohydraulic test rig for components.

5.3 Challenges of Facility

The main risk is the lack of demand from developers, who may not have (or wish to provide) the capital necessary to utilise the facilities. They may also have reservations around IP protections for their technology, or may simply not see the benefit of this cogeneration concept, for example if the hydrogen technology has been optimised to operate without integration with nuclear reactor technology, or vice versa for nuclear technologies. There is a high associated CAPEX and OPEX, as well as complex safety justifications. There is the potential that specialised control and instrumentation systems will be required, which may prove difficult to implement. The facility location may prohibit vendor access, especially with larger equipment or travel distances. The need for planning consent and land rent or purchase has not been fully scoped at this stage, and it may fail to find a suitable location and willing community to host the plant, which would result in the project failure.

5.4 Potential Hydrogen Production Capacity and LCOH

The primary aim of the facility is to aid the development of cogeneration partnerships and technologies, rather than to generate hydrogen. However, utilising the same LCOH model from Section 2.4, and replacing the “nuclear CAPEX value” with the Phase 2 test facility cost (detailed in Section 6) estimates have been generated for the production capacity of the Phase 2 facility, when paired with all five TRL 4-6 generic hydrogen production technologies investigated. The operating assumption for both plant designs is full utilisation of the facilities for 8 hours a day, 300 days a year. The range of potential values and LCOH for each technology facility pairing are shown in Figure 6. The estimated LCOH of the different hydrogen technologies when using the facility show opposite trends to the estimated LCOH presented in Section 2.4 (Table 4 to Table 6) when coupled with an AMR (i.e., the lower LCOH of TC technologies when coupled with an AMR give the higher LCOH when using the test facility and vice versa for the electrolysis technologies). This is because the limited thermal capacity of the test facility (when compared to an AMR) significantly limits the potential yield of the TC technologies which rely on thermal energy as the main (or only) driver for the hydrogen generation. The electrolysis technologies on the other hand, rely predominantly on electricity to drive the hydrogen generation (with a relatively small thermal energy input requirement); as the electricity requirement is met by supply from the grid, the yield is not impacted to as great an extent. Consequently, the CAPEX of the facility has a greater relative impact on the LCOH for the TC technologies.

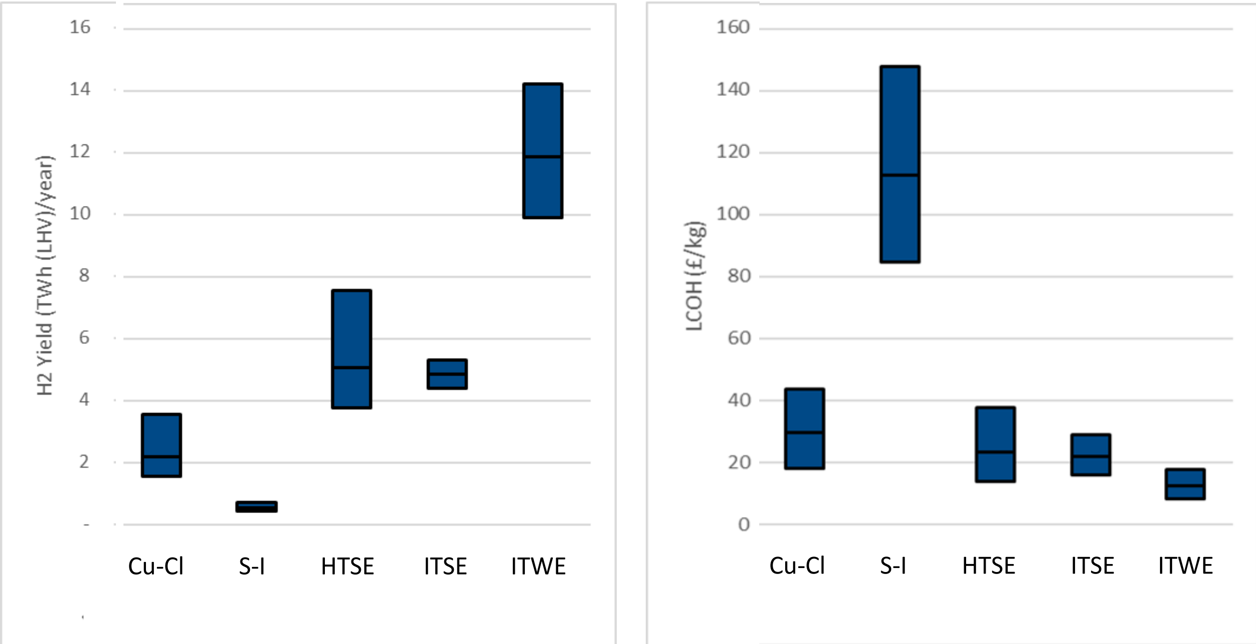

Figure 6: Hydrogen Yield and LCOH for the Phase 2 Facility with Hydrogen Production Technologies

6 Costed Development Plan

6.1 Capital and Operating Costs

The capital cost for the facility is £4.9 million (excluding VAT) which includes a 20% contingency and decommissioning costs; this is within the planned budget for Phase 2. A detailed breakdown of the facility costs is included in [18]. Additional design work is still required for the Phase 2 facility, including finalising sizing of the plant and determining a suitable location for the facility, the cost of which has been incorporated into the estimated build cost. The contingency has been added to the final facility costs to account for the level of uncertainty in some of the costings, such as specialised design for some of the higher temperature boilers and heat exchangers. The plant will provide electricity and thermal energy (via high temperature steam through heat exchangers to which the hydrogen technology will couple) to hydrogen vendors.

Annual facility operating costs (excluding VAT) have been split into staffing and utilities costs at £506k and £300-£4,400k respectively. The variation in utility costs arises due to hydrogen technology type, and operation configuration (described in Sections 2.3 and 2.4), however these costs have been conservatively estimated to be at an upper bound of £970k for the Phase 2 period. Full details are included in [18]. The staffing and utilities costs are based on the assumption of the plant operating for 8 hours per day, for 300 days per year. These costs were used to generate the LCOH model, with the total costs (except energy costs) acting as the AMR OPEX values. Costs for electricity and gas were added into the model as additional parameters.

6.2 Phase 2 Facility Development and Business Plan

The primary purpose of the Phase 2 plant is to allow hydrogen producers to develop, optimise and characterise their technologies to exploit the energies and synergies available from ANTs. The plant is targeted at companies intending to develop processes and plants for larger scale hydrogen but will offer the ability for academic research to be conducted. This will enable the development of hydrogen production technologies and shorten the time to commercial deployment. The plant does not have a target for hydrogen production volume. However, the plant must demonstrate the symbiosis of the two technologies and so hydrogen must be produced.

Additional uses of the plant could include allowing nuclear plant designers to develop and test the interfacing systems that will be required for hydrogen cogeneration and enables research to be conducted on thermohydraulic systems.

The estimated running costs for the plant are between £810k to £4.9m per year. The range is due to expected variability in the cost and quantity (dependent on the type and size of hydrogen system under test) of electricity required. While this is a significant annual cost, it is assumed that much of this will be borne by the facility user, so these costs can be recovered by commensurate billing for facility use. Inclusion of a modest profit within these charges would allow a contingency fund for unplanned events, and is considered prudent. Foreground IP created would be owned by the facility user, or would be agreed separately in the case of collaborative projects. The energy costs could be mitigated if dedicated power generation, such as wind turbines, were constructed as part of the facility. This may allow power provision at a discounted rate to users, lowering the barriers for facility use. However, the cost and practical implementation of this has not been investigated.

The facility is assumed to be operational for 3 years for the purposes of deriving the LCOH and its cost will be amortised over that period. However, the facility would be designed and constructed to operate for a much longer time period if an appropriate operating mechanism could be found or if the demand for its use exists beyond the end of this period. This requires further investigation, as well as the likely involvement of partner organisations. Government intervention may be required to incentivise the use of a facility, such as grant funding and facilitating legislation.

7 Rollout Potential

As the focus of this work is low carbon hydrogen production by nuclear power cogeneration, it is necessary to examine the roll out potential of both hydrogen production technologies and ANTs.

Sources suggest the UK produces around 27 TWh (mass equivalent ~700 kt) of hydrogen annually [21], with a demand in the region of 500-600 kt H_2 [22]. It is likely that future hydrogen demand will increase, due to the need to decarbonise the wider energy sector, and industries (such as steel production and freight transport) are highly likely to require hydrogen based fuels to reduce their carbon footprint, due to the lack of suitable low carbon alternatives [30]. The UK Government Hydrogen strategy estimates that 20-35% of Energy Sector demand could be met by hydrogen by 2050, potentially as energy storage mediums or as fuels [32].

Currently, 96% of hydrogen produced in the UK comes from fossil fuel based production methods [21]. A significant increase in demand for low carbon hydrogen technologies is therefore envisaged as a transition from fossil fuel based to low carbon sources by 2050 takes place. This may be achieved by switching to alternative production methods (electrolysis and/or TC technologies), by applying CCUS technologies to current fossil fuel derived methods [23], or a combination of the two.

The hydrogen technologies discussed within this report require electricity and/or heat inputs, both of which can be provided by nuclear power. Significantly, the high operating temperatures of AMRs are well placed to meet the high-grade heat requirements of the higher temperature hydrogen production technologies. When low-grade heat is utilised instead (e.g., with HTSE) greater electricity capacity will be required to allow for further electrical heating.

Hydrogen production by electrolysis is the most developed of the TRL 4-6 technologies examined. If ambitions are met, HTSE in particular has the potential to scale-up systems to 100+ MW size by 2030. Critically, electrolysis is inherently scalable, based on module “building blocks” of ≤3MW size. This is similar to a number of ANTs, where the vision is to encompass a number of small scale reactors on one site. TC technologies are less well developed and the scalability of these system is unknown at present.

The UK currently produces approximately 6 GW electricity from nuclear power, which meets the need of ~15% of its electricity needs [24], however, ~80% of this current capacity will be retired by the end of the decade. The UK government has ambitions for up to 24GW of new nuclear powered electricity to be installed by 2050, potentially suppling

25% of electrical power needs [24]. Two new Gen III+ reactors are under construction at Hinkley Point, with a further two planned at Sizewell by EDF [24] which will provide an additional 6.5GW. It is expected that some of the 24GW capacity planned will be met by ANTs.

8 Route to Market Assessment

By 2050, the UK aims to have met its Net Zero targets, with 20-35% of energy requirements needing to be met by low carbon hydrogen. Using estimates obtained as part of this work, a potential scenario for cogeneration by 2050 could be 28 RR-SMRs (assuming ramped up production capacity in the 2040s), two MSRs and two HTGRs dedicated to hydrogen production, providing an output of 2.5 Mt H_2 per year (>10% of UK hydrogen requirements by 2050). This is not including the potential of the hydrogen export market, which is estimated to cover 25% of global hydrogen demand.

Japan is likely to be one of the world leaders in hydrogen, as they were the first country in the world to announce a hydrogen strategy in 2017 [25] [26]. Their aims include increasing the Japanese current production capacity from 2 Mt per year to 3 Mt by 2030 and 20 Mt by 2050 [25]. Japanese market demand is expected to increase dramatically with 10 Mt H_2 per year needed for power generation [25].

Canada has also developed a hydrogen strategy planning for Net Zero by 2050. It is estimated that Canada will require production rate of 20 Mt H_2 per year, meeting 30% of energy needs [27]. The Canadian Strategy also focusses on the potential export market for hydrogen, which could provide 50 billion CAD to its economy by 2050 [27].

The EU is a potential large export market for the UK. The EU has a current hydrogen demand of 339 TWh per year (~8.5 Mt), of which 95% is generated from fossil fuel based production [28]. Similar to the UK, there is a desire to switch to low carbon hydrogen for both current demand and predicted future feedstock requirements, such as steelmaking, transport and heating. This is expected to increase demand sevenfold [28], with European countries likely to become net importers of hydrogen.

Production methods for LTE are progressing, alongside the government hydrogen strategy ambition of reaching 10 GW of production capacity by 2030 [1]. Energy companies (such as EDF [29] and Scottish Power [30]) are investing in hydrogen production facilities and projects.

Of the higher temperature hydrogen production technologies examined in this report, HTSE technology is currently the most advanced; some European developers already offer multi MW facilities [31]. Within the UK, prototype ITWE and demonstrator level ITSE plants are under development, with an ITSE 1MW electrolyser demonstration plant planned for 2022 [32].

8.1 Main Challenges

The main issue facing low-carbon hydrogen production methods is cost competitiveness with current production methods. BEIS estimates [13] (from 2020 data) show fossil fuel produced hydrogen at an LCOH of less than £2/kg. While this has risen dramatically in recent months due to wider global market issues [16], LTE LCOH values are also predicted to fall [13], especially when coupled with renewable electricity, which makes the future hydrogen market extremely competitive. Hydrogen cogeneration with nuclear power using HTE or ITE technologies (or LTE technology) requires a large proportion of electricity, which would have to be relatively cheap to allow for cost effective hydrogen production.

One potential challenge for hydrogen cogeneration from nuclear power is that the focus of the majority of vendors we engaged with was not considering this type of cogeneration when developing their specific technology. The coupling of the two technologies will require some consideration and development. Electrolyser developers in particular had not previously considered cogeneration with nuclear power in detail, suggesting limited market awareness of this coupling. Similarly, some of the newer AMR design developers saw a number of different potential markets for their technology (using electricity, heat or both), of which hydrogen cogeneration was just one.

Development to hydrogen production supply chain infrastructure is required to allow electrolysis and TC technologies to scale up to meet market demand fast enough. Some European HTSE developers have plans for increased production capacities of 500 MW per year (minimum) by 2024 [33], and up to GW scale once suitable supply chains are established. This should mean that a rapid ramp up of production and expansion of facilities is possible once the suitable production infrastructure is in place. Scale up of supply chain infrastructure in one electrolyser technology may positively impact the other electrolyser technologies. The establishment of these supply chains is the main barrier to the creation of GW scale electrolysers. Supply chains also will need to be established for ANTs. PWSMR technology within the UK is currently being designed by the Rolls Royce SMR, with a prototype reactor operational by 2030, at a cost of £2.2 billion [34]. 20% cost reduction are expected by the 5th reactor, meaning that reactors could be produced for £1.8 billion [34]. The planned production capacity is to be able to build two full sets of reactor modules per year by three Rolls Royce production factories. There are up to 10 initial 470 MWe reactors planned by 2035 [35] [36], with more possible if additional production factories are built. It is likely that production capacity may increase to meet both UK internal and international export targets [37].

The main challenge for TC and AMRs in the UK is the risk around the unproven nature of the technologies. The Japanese Atomic Energy Agency (JAEA) is leading the way with hydrogen cogeneration from HTGRs. They have been operating a 30 MW High Temperature Test Reactor (HTTR) since 1998, which has been used to design and test many different future HTGR technologies. They also plan to construct commercial HTGRs by 2050 (with the potential for a TC hydrogen production demonstrator cogeneration plant) [38], however, it has not yet been optimised for hydrogen production [39].

- TC methods are currently still at laboratory scale, with prototype plants being designed with dedicated AMRs, such as with the HTTR in Japan [38], or with a SCWR in Canada [40]. The JAEA currently has plans to pair large scale S-I cycle TC demonstrator plant with HTTR in the 2030s, with potential for private sector demonstrators in the 2040s. Both the S-I and Cu-Cl TC cycles are expected to move from laboratory to demonstrator level in the 2030s, but are currently still facing challenges with continual production, due to the harsh chemicals and temperature requirements of the process [41] [42].

- For HTGR design, in addition to the lead by the JAEA in Japan, China has had two operational pebble bed reactors that have been generating electrical power since December 2021 [39]. Development of HTGRs is also underway in the US [43]. Within the UK, the UK Government Department for Business, Energy and Industrial Strategy have an ongoing AMR Research and Development programme, to provide funding to HTGR technology demonstrator programmes. National Nuclear Laboratory (NNL), Springfield Fuels Limited, USNC UK, U-Battery Developments Ltd and EDF have all been approved for funding to develop HTGR technologies for potential deployment to aid in Net Zero goals, including for hydrogen generation [44]. NNL are partnering with JAEA, who are world leaders in this area.
- MSRs were initially developed during the 1960s but are currently being researched as potential AMRs in several countries, including the UK. Demonstrators at the multi MW level are planned for the 2030s. Commercial MSRs are also in development in Europe, Japan and United States.

The emphasis on modularity and smaller sizes in the new ANT designs may prove more difficult to implement, despite both PWSMR and MSR being based on existing nuclear reactor technologies. However, as well as PWSMR development in the UK, other countries, such as the US and China, also have their own SMR technologies based on existing Gen III technologies [45]. The first plant is planned for operation by 2030, with 16 reactors planned initially [46]. There has been significant foreign investment as well, with the potential for export of modules and technology to the Netherlands, Czech Republic, Estonia and Turkey [37] [47]. Additionally, it is unclear what issues Gen IV reactors would face in the UK from a regulatory standpoint.

There is also a public perception issue around nuclear technology in general, which could be a barrier to low carbon hydrogen cogeneration from nuclear technology. Nuclear power is not perceived to be a low carbon energy source and is seen as less suitable than other technologies for Net Zero [48].

8.2 Future Trends and Market Analysis

The main driver for the future hydrogen market is the drive towards net zero. To meet Net Zero climate change targets, decarbonisation is required across the energy sector. In particular, some areas which are difficult to decarbonise would be ideally suited for substitution with low carbon hydrogen as an energy source. These include:

- Heating (industrial and domestic);
- Energy storage;
- Small scale electrical generation;
- Transport fuel.

The committee on Climate Change estimates demand for hydrogen may increase up to 20 times by 2050, equating to around 13.5 Mt H_2 per year worldwide [21], with other estimates ranging as high as 18.75 Mt H_2 [49].

The UK Government's current UK Hydrogen Plan [1], sets goals towards 2050 including:

- 1 GW of low carbon electrolytic hydrogen production and 1 GW of CCUS enabled hydrogen production under construction or operational by 2025;

- 10 GW of low carbon hydrogen production, at least 50% with electrolytic methods, by 2030 and rapid increases expected towards 2050;
- Decarbonisation of industry using low carbon hydrogen;
- 20-35% of Energy Sector demand met by hydrogen by 2050.

Within the UK, hydrogen production targets also feature as part of the Energy Security Strategy [50], with planned investment in renewable and nuclear power to provide sufficient generation capacity to produce hydrogen in off peak times. From an energy security standpoint, the main aim of producing hydrogen is for electrical energy storage and blending with natural gas supply, to reduce the peak costs of both [50].

In the wider world economy, many countries are also looking at hydrogen to meet decarbonisation and climate targets. It is estimated that 25% of world demand will be traded internationally, with European countries likely to be net importers of hydrogen [51]. There is therefore an opportunity for the UK to take advantage of this large external market.

8.2.1 New Use Cases

A potential implementation strategy for hydrogen cogeneration from nuclear power in the UK is given below. Cogeneration offers potentially higher efficiency generation of hydrogen, as well as electrical supply if needed more than hydrogen during peak times. Furthermore, utilisation of waste heat, rather than dedicated reactor thermal output, could allow for decreased hydrogen production and sale costs, as well as efficiency gains.

In the 2030s, following the UK Hydrogen Strategy [23], it is assumed that the necessary distribution and storage infrastructure for a hydrogen economy would either be in place, or be in the process of being set up. This may include utilising current gas supply networks. By this point, it is expected that multi-MW scale HTE and ITE plants are being manufactured and RR-SMR nuclear plants will be under construction. This could offer a large cogeneration potential, utilising the waste heat and some electricity capacity from the SMR capacity to facilitate hydrogen production either during off peak demand, or alternatively, dedicated hydrogen production in multi MW HTSE systems. It is expected that the UK will have HTSE plants actively contributing to hydrogen economy using grid electricity, potentially with industrial waste heat as a source of thermal power. The UK Hydrogen Strategy anticipates large scale up of hydrogen technology, with over 9000 new jobs supported by a hydrogen economy by 2030 [23]. Construction of the new Rolls Royce SMRs will provide 40,000 regional jobs by 2050, contributing around £52 billion to the UK economy [34].

In the 2040s, there is potential for a scale up of production capacity of these technologies, including building more production factories, allowing more reactors to be built in the UK faster, and export of modules abroad. This may allow more dedicated hydrogen production or cogeneration plants to be built, utilising HTE or ITE technologies. By this point, it is likely that demonstrators and commercial plants will have been built for MSRs and HTGRs worldwide, of which some may be available in the UK, producing electricity, industrial heat, or as part of hydrogen production facilities. TC hydrogen production plants are expected to be at prototype or first-of-a-kind stage.

9 Dissemination

During the course of this project, dissemination activities have focused solely on the vendors who contributed to the project, through their time and/or provision of data specific to their technologies. These activities have taken the form of either email correspondence and meetings, to indicate project progress, and our findings in relation to their technology and have been based on the level of engagement and interest of each particular vendor. Over the course of these activities, a greater understanding of the cogeneration potential has been achieved through both the project team and individual vendors. It has also facilitated "introductions" between different companies and technology types, highlighting the potential for lower temperature operating nuclear technologies (for example PWRs) to be linked with higher temperature operating technologies (for example HTSE); a coupling which had previously not been considered advantageous. Following completion of the project, a final set of meetings are planned (in September 2022) with the vendors to provide the final results of the feasibility study, with a particular focus to their technologies.

Additionally, Frazer-Nash are hosting an event "Hydrogen Cogeneration – will nuclear rise to the challenge?" in 2023 (postponed from original date of 20 September 2022). At this event, we will present the findings of this feasibility study to a wider range of industries, academia and supply chain interested in both nuclear power, hydrogen production and the cogeneration potential.

10 Conclusions

A detailed review of the potential technologies has shown that the concept of hydrogen cogeneration with ANT is feasible, and, indeed desirable, as indications show that the cogeneration examined has the potential to contribute to a significant proportion of the 2050 low-carbon hydrogen goals. The technologies reviewed are all inherently low-carbon technologies offering significant benefit to Net Zero goals. There are clear synergies between the two technologies both from thermal and electrical energy production and requirement, offering improved efficiencies for low carbon hydrogen production in comparison to current commercial alternatives. Potential mechanisms for coupling the two technologies are varied, and examination of the options has highlighted that ideal coupling arrangements are dependent on the specific technologies. Cost modelling shows the potential for costs to be competitive with current other low-carbon alternatives, and indeed with conventional fossil-fuel based methods, helped in part, by the current spike in gas prices. The largest uncertainty in these costs typically surrounded the CAPEX and OPEX of the hydrogen technologies, which aligns with their current TRLs.

Importantly, there is considerable interest within the industry for cogeneration between these technology types (from both hydrogen and nuclear technology developers). Of the vendors engaged with over the course of this work, the nuclear vendors were particularly interested to gain insight into the different hydrogen technologies and were keen to make new industry contacts in this field by their participation with the feasibility study; this was met with positivity from the hydrogen developers.

The most developed of the technologies reviewed was High Temperature Steam Electrolysis (HTSE) and Pressurised Water Small Modular Reactors (PWSMR), and it is credible that, assuming supply chain challenges can be overcome these could start producing hydrogen by nuclear cogeneration in the 2030s. Development of these supply chains within the UK would further support the social feasibility of these cogeneration technologies. The cost modelling estimated the LCOH for this coupling to be in the range of 2-6 £/kg H_2 (at production pressure), which has the potential to be cost competitive with fossil fuel-based technologies utilising carbon capture. Further development of lower TRL technologies may offer further cost reductions and social benefits from different hydrogen nuclear cogeneration coupling arrangements in the longer term.

Optioneering and Strengths, Weakness, Opportunity and Threat (SWOT) analysis for a Phase 2 demonstration facility identified two potential designs (a larger central facility and a smaller mobile facility); the larger central facility, which offers the most flexibility and greatest opportunity for growth of the hydrogen technologies is presented in this report. The proposed facility has been shown to be feasible, with significant potential opportunities to support the low-carbon hydrogen UK Government goals, not only by the accelerated development of current TRL 4-6 technologies, but also value, IP, skills and capabilities to the UK.

Despite the conclusion that a Phase 2 demonstrator facility is feasible when considering the technical, environmental, social, financial, economic and commercial criteria against which it was assessed, the project is unlikely to progress to a Phase 2, in the BEIS Low Carbon Supply Stream 1 competition. The main identified hurdle was that no hydrogen technology developer approached to date has been able to commit to supporting the project. The reasons for this were different for particular developers; but typically, those who were at higher TRLs were looking for opportunities to demonstrate larger systems (≥20MW) than could be undertaken within the budgetary constraints of the competition, and those at lower TRLs were fully committed to other projects (running concurrently to the proposed Phase 2) resulting in resource constraints in the competition timescales.

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Topsoe

Ultra Safe Nuclear Energy

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