THE IRISH ACADEMY OF ENGINEERING

ENGINEERING & TECHNOLOGY

THOUGHT LEADERSHIP IN A TIME OF GREAT CHANGE

A Commentary on the Medium Term Prospects for **Ireland's Hydrogen Economy**

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THE IRISH ACADEMY OF ENGINEERING

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The Irish Academy of Engineering
22 Clyde Road
Ballsbridge
Dublin D04 R3N2
Ireland.
Registered in Ireland: CRO 439234, CHY18046, RCN 20068455

President: Seamus McKeague FIAE
Chief Executive: Dr. Gabriel Dennison

Telephone: +353 1 665 1337
academy@iae.ie
www.iae.ie

Contributing Academy members:

Gerard Hurley
David Timoney
Gerry Duggan
Kieran O'Brien
Terry Nolan
Tim McGloughlin
Don Moore

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CONTENTS

EXECUTIVE SUMMARY

Following the example of several other countries, Ireland has recently produced a National Hydrogen Strategy.[1] This strategy recognises that **green hydrogen** *"is still very much a nascent technology with great uncertainty on the future costs, potential end-uses and the infrastructure, skills and supply chains needed to deliver on it."*

This commentary by the Irish Academy of Engineering looks at the use of green hydrogen gas - produced by the electrolysis of water and powered by renewable electricity - to assist in the decarbonisation process in Ireland

It is feasible to produce green hydrogen using variable renewable energy sources in Ireland. The resources to do this will increase as Ireland expands its renewable energy capacity but the following issues need to be considered.

- Global decarbonisation will require a vastly expanded use of electricity as an energy vector.
- The main focus of international green hydrogen strategies will be on hard-to-decarbonise sectors where direct electrification is not feasible or where low energy efficiencies preclude cost-effective solutions.
- The Irish Strategy envisages green hydrogen being used to provide back-up electricity when variable renewable energy is not available.
- This Strategy also suggests a large hydrogen export potential based on the expansion of Irish wind generation.
- The technology for large scale green hydrogen production is not yet available and is unlikely to be available on an unsubsidised commercial basis before the late 2030s.
- Large storage capacity will be required for green hydrogen if it is to play a back-up role in the Irish power system. However, hydrogen is difficult to store and the only proven storage arrangements anywhere in the world are in salt caverns. Ireland (Republic) does not have any known salt caverns onshore which might be suitable for this purpose.
- Consideration is being given to using depleted gas fields at Kinsale to store green hydrogen. This technology is unproven and is unlikely to be suitable, The cost of "cushion gas" at Kinsale would be considerable and the production capacity of the field would likely be insufficient to provide the power requirement for the level of back-up generation that will be needed.
- Producing green hydrogen by electrolysis, transporting it, storing it and combusting it to generate electricity (in an open cycle gas turbine) is an extremely inefficient process. This inefficiency stems from the laws of physics rather than any unnecessary process waste. In the order of 80% of the initial electricity input into the system is, inevitably, lost.
- The winning bids in the recent ORESS1 offshore wind auction had an average wholesale electricity price of €86 per MWh. Assuming this cost for the electricity used to produce green hydrogen, the final cost of the electricity produced from open cycle gas turbines could well exceed €500 per MWh when the cost of these large energy losses are considered. .
- Whereas a low marginal cost of hydrogen may be assumed for pilot projects (based on the use of curtailed wind generation), the full price of electricity will have to be paid for the large-scale production of back-up electricity using green hydrogen. This may well lead to very high electricity prices under current market arrangements.
- This issue could, potentially, be addressed by redesigning the electricity market and the EU is currently looking at this possibility. However, any move away from current market rules and structures could create a perception of political risk for investors in energy infrastructure projects. This, in turn, could negatively impact critical investment in renewables.

1 https://www.gov.ie/en/publication/624ab-national-hydrogen-strategy/

- The option of using green hydrogen to back up renewables should be explored further on a pilot scale. However, a definitive decision on adopting this option should not be taken until reliable evidence-based analysis is available. Until then, all options for backing up variable renewable electricity generation should remain open.

- Much discussion is currently taking place on establishing Ireland as an export source of green hydrogen or of an appropriate chemical derivative such as ammonia. The Academy does not see potential for a hydrogen export industry to be developed in Ireland for the foreseeable future because of the high pre-tax price of Irish electricity. It is difficult to see Irish green hydrogen production competing on a cost basis with green hydrogen produced in the many other countries worldwide which have significantly cheaper electricity.

1. INTRODUCTION

Ireland is one of many countries that have pledged to decarbonise their energy sectors by 2050.

- Targets have been set for large scale deployment of variable renewable energy sources, notably wind and solar.
- Incentive schemes have been put in place to encourage a switch away from fossil fuels to heat pumps for heating.
- Transport is slowly, but inexorably, shifting from oil-based fuels to battery electric vehicles (BEVs).
- Various interventions are being tested on farms to reduce greenhouse gas (GHG) emissions from Ireland's agriculture industry.

Even if all the interim 2030 targets for the various sectors are met in Ireland, a recent report from the Environmental Protection Agency (EPA) concludes that Ireland will, at best, achieve a reduction in GHG emissions of 29% (compared to 2018 levels) instead of a targeted reduction of 51%. This assumes that all planned actions are implemented on or ahead of schedule – a very challenging outcome.[2]

The effectiveness of the Irish emissions reduction programme in terms of meeting interim 2030 targets is now questionable and will be addressed in future Academy reports.

This report is focussed on the use of green hydrogen gas produced by electrolysing water using renewable electricity to assist in the decarbonisation process in Ireland.

2 https://www.epa.ie/publications/monitoring--assessment/climate-change/air-emissions/irelands-greenhouse-gas-emissions-projections-2022-2040.php

2. BACKGROUND

Hydrogen produced from fossil fuels is termed black, brown or grey, depending on whether the fossil fuel used is hard coal, lignite or natural gas.

In total, approximately 90 million tonnes of hydrogen are produced annually worldwide. This is used primarily in oil refining and in chemical processes and is equivalent, in energy terms, to less than 2% of global energy supply.

Given that less than 1% of this production is green, the starting point for the green hydrogen industry is vanishingly small.

Hydrogen is difficult to manage, and it is currently used on a relatively small scale in oil refining and in some other chemical processes such as ammonia production.

Hydrogen is the simplest of all molecules and is known to occur naturally in a few locations. Recent commentary suggests some potential for exploration to identify large sources of naturally occurring hydrogen.[3]

The key to the global energy transition is a major expansion of electricity as an energy vector, but there are certain applications where electricity is not appropriate:

- High temperature processes such as steelmaking from iron ore are not suited to electricity use.
- Chemical processes such as those used for the manufacture of plastics and for fertiliser production require fossil fuels and these cannot be easily replicated using electricity directly.
- Battery electric technology is unlikely to be economically viable for shipping, commercial aircraft and other similar heavy transport applications.

Hydrogen is being held out as the answer to overcoming many of the barriers to complete decarbonisation. Discussions about a future "Hydrogen Economy" first surfaced about 50 years ago but it is only recently that many countries and regions (including the EU, USA and Japan) have prepared hydrogen strategies and roadmaps.

Because the current cost of producing green hydrogen is very high - as are the costs associated with the infrastructure needed to transport, distribute and store it - large government subsidies are necessary to attract investors in the short term.

While the Academy acknowledges and is supportive of policymakers exploring the role that hydrogen could play in the overall energy transition, it is concerned that the barriers to using hydrogen as an energy vector are not sufficiently appreciated and, particularly, that the timescales suggested for large scale adoption of green hydrogen are unrealistic.

This report aims to summarise these issues and present them in a useful format to assist policymaking.

In July 2023 the Department of the Environment, Climate and Communications (DECC) published a National Hydrogen Strategy.[4] The Academy is pleased to acknowledge the timeliness of this document and welcomes government's observation that:

> *Renewable hydrogen is still a nascent technology. Global research and innovation over the coming years will be essential to future competitiveness and scale up.*

The Academy will, separately, publish a detailed report on the current status of the emerging green hydrogen industry in the near future (**Hydrogen as an Energy Carrier in the Irish Context**). It is evident that the issues to be considered are complex and that much work remains to be done in Ireland and elsewhere to chart a way forward.

3 https://www.renewablematter.eu/articles/article/natural-hydrogen-a-geological-curiosity-or-the-primary-energy-source-for-a-low-carbon-future

4 https://www.gov.ie/en/publication/624ab-national-hydrogen-strategy/

3. HYDROGEN AS AN ENERGY VECTOR

Hydrogen as an energy vector appears, at first sight, extremely versatile and it can be used in many applications. However, there are problems which limit the potential uses of hydrogen - notably the economics of its application in areas such as transport and heating - and there are challenges in handling and storing hydrogen gas.

The following Case Studies highlight the challenges of using hydrogen for transport or heating.

Case Study 1 – Hydrogen for Land Transport

Take the example of a car powered by a hydrogen fuel cell (a proven technology). Starting with 100 units of electrical energy generated renewably and allowing for the inevitable energy losses in producing, storing and transporting hydrogen and in converting it back to electricity in a fuel cell to use in the car motor – at most 28 units of electricity would remain to power the car.

In contrast, the corresponding figure for the energy available for the motor in a Battery Electric Vehicle (BEV) is approximately 68 units.

BEVs are more than twice as energy efficient as fuel cell vehicles. That is why Toyota, which has spent three decades developing fuel cell cars, has yet to successfully market these vehicles at any significant scale. That is also why the three hydrogen refuelling stations which Shell opened in the UK between 2017 and 2019 have already been closed.

Lithium Ion (Li-Ion) battery technology has improved to such a degree over the past decade that hydrogen fuel cell vehicles will only be required in very restricted circumstances. These could include heavy goods vehicles, long distance coaches and, perhaps, construction machinery. But continuing battery improvement - both in performance and cost terms - means that many heavy transport applications look more likely to be battery powered rather than hydrogen fuelled in the long-term.

In July 2021, Bus Éireann purchased three hydrogen buses for routes in the Greater Dublin Area at a cost of €2.4 million. That is approximately double the cost of equivalent diesel buses. This pilot approach to hydrogen bus transport is welcomed by the Academy. It is very important to experiment with emerging technologies - and to do so at a small scale and over a significant test period - before major investment decisions are made.

By way of example, the city of Montpelier in France cancelled an order for fifty one hydrogen buses in 2022 when the authorities recognised that battery powered buses would be far cheaper for city transport and hydrogen could not compete.

Hydrogen for most land transport is unlikely to be an option for Ireland in the foreseeable future, if ever.

Batteries are already superior, and research and development continue to improve the technology.

Case Study 2 – Hydrogen for Home heating

There have been several efforts to justify hydrogen as a replacement for natural gas for home heating. It is technically feasible to replace up to 20% of the natural gas supply with hydrogen without much difficulty. Beyond 20%, boilers would require major modifications.

In Britain, plans to convert two thousand homes from natural gas heating to hydrogen heating were recently abandoned when residents objected on both safety and cost grounds. At the time, the UK Energy Secretary said that it now appeared unlikely that UK homes would use hydrogen boilers in the future.

The electricity used to produce hydrogen could instead be used to operate a heat pump delivering at least three times the amount of heat to the home per unit of electricity used. The differences in efficiency are striking. Because of this, the Irish Government has, correctly, implemented policies favouring heat pumps to replace fossil fuel fired boilers.

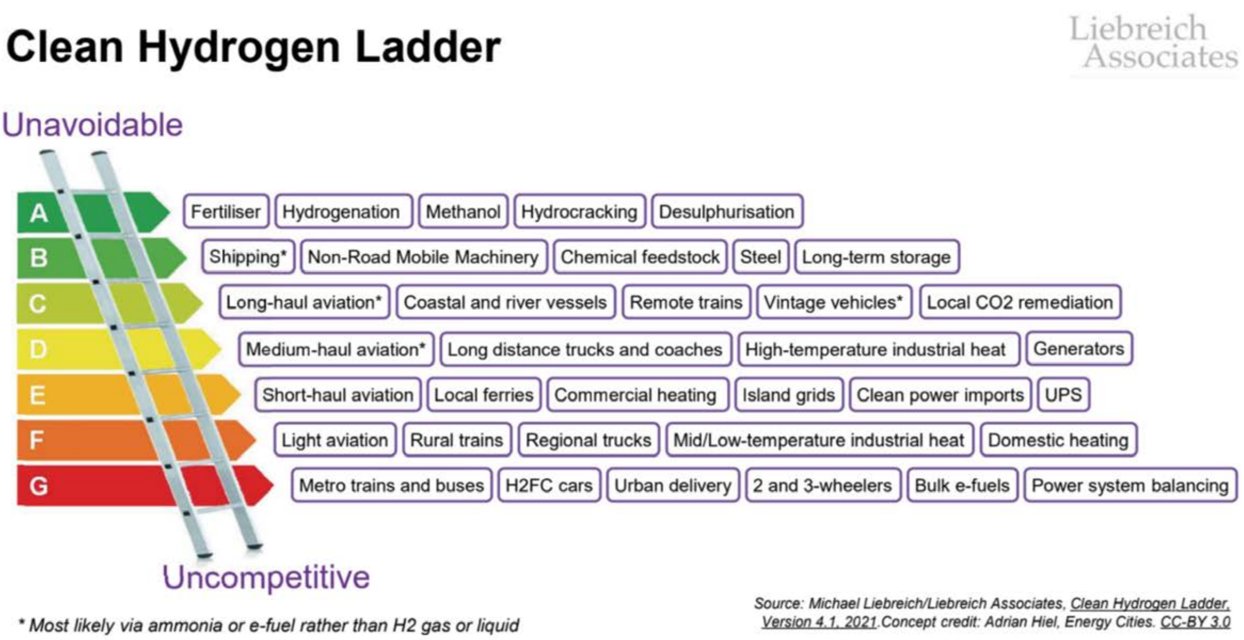
However, the widespread adoption of heat pumps for domestic heating will create significant challenges for both electricity generation and distribution and will necessitate major and possibly disruptive investment in the electricity sector, particularly in urban areas. It will also need to be accompanied by a major programme of deep retrofitting for residential buildings.

The phasing out of fossil fuel for heating generally has already commenced and heat pumps are the obvious alternative for this application.

4. WHERE MIGHT GREEN HYDROGEN BE USED IN IRELAND?

A useful, if somewhat simplistic, matrix of possible hydrogen utilisation is provided by Liebreich and Associates - the so called *Clean Hydrogen Ladder* (**Fig 1**).

Fig 1: Liebreich and Associates' Clean Hydrogen Ladder



The top lines of the ladder (Row A and Row B) list areas where green hydrogen is "unavoidable" for decarbonisation. The bottom line (Row G) lists applications where the technology is "uncompetitive". Much of the applications listed in the in-between rows remain to be explored in technological terms.

The "unavoidable" applications include:

- Fertiliser manufacture
- Steel making
- Use of hydrogen as a feedstock to produce chemicals such as plastics and synthetic fuels.

These industries are not located in Ireland and there is, therefore, no requirement to decarbonise them locally.

Hydrogen is identified as a possibility for long term energy storage (Row B) in support of stable electricity power supplies. Hydrogen storage could provide an energy buffer for periods when variable renewables are not available. Storage could additionally offset the country's security of supply exposure.

The Irish Government has recognised the need for backing up variable renewables but has yet to produce a detailed techno-economic plan for this. Hydrogen appears as an "aspirational target" by 2030 and is projected to answer all back-up difficulties after this date.

It is the Academy's view that the commercial development of large-scale green hydrogen production is unlikely before 2035 and possibly may not occur until 2040. Until then, Irish variable renewable generation will be backed up, primarily, by natural gas fired generating plant.

5. BACKING UP VARIABLE RENEWABLE POWER

The planning required to ensure sufficient margin to meet future demand peaks requires complex statistical analysis (usually based on Monte Carlo simulation of half hourly dispatch for the next decade) and is carried out by EirGrid subject to regulatory approval from the Commission for the Regulation of Utilities (CRU) (see **Appendix 1**).

There are four major variables to be considered:

1. Growth in electricity demand.
2. Reliability of back-up generation at times of low wind or solar generation.
3. The security of fuel supplies for back-up generation.
4. The huge variability of wind and solar generation depending on the weather.

The last factor is a particularly difficult problem for a small, isolated power system like Ireland's. There are times, particularly in winter when demand is high, when high pressure weather systems become stationary for weeklong periods over Western Europe. At these times, wind generation can be as low as 5% of actual electricity demand and, since the same conditions apply in neighbouring countries, electricity imports over interconnectors may not be available.

In addition, experience since the Russian invasion of Ukraine highlights the essential requirement for secure fuel supplies for back-up generation, and the desirability of holding adequate stocks of these fuels within our own jurisdiction.

Against this background, back-up generation is currently provided by fossil fuel fired plant. This includes, for the moment, coal fired generation at Moneypoint. Most of the back-up is supplied by gas fired plant, both combined cycle and open cycle. It is almost certain that up to 2040, Ireland will rely primarily on gas or distillate-fired plant for back-up generation. Indeed, an "emergency programme" is currently underway to compensate for earlier failures to install sufficient back-up capacity.

Post 2040, there are other alternatives that may be considered for this back-up - including green hydrogen - but the only available policy option now under consideration is to continue to install new open cycle gas turbines and aim to convert this plant from natural gas to green hydrogen in the future. In this context, the Government's recent National Hydrogen Strategy envisages that *A 2 GW target of offshore wind, for the production of renewable hydrogen, to be in development by 2030, will help to provide greater certainty for investors and create the volumes needed to scale up the sector.*

Prior to this 2 GW of offshore capacity being available, the National Hydrogen Strategy envisages that some hydrogen could be produced for generation purposes using wind generation that is surplus to system requirements whenever this occurs. In 2022, 3.4% of wind output (401 GWh) was curtailed off and would, potentially, have been available for hydrogen production (see **Appendix 2**).

While the Academy is supportive of using marginal hydrogen production for pilot projects, it remains highly unlikely that large scale green hydrogen volumes will be available before the late 2030s.

When they do become available, costs will not be based on marginal electricity production - when plant is constrained off the power system - but rather on the full production cost of power due to the volume of green hydrogen required.

In addition to green hydrogen, there are other back-up options the Academy believes should be considered, and these will be outlined in a separate report later in the year.

The remainder of this report focuses on green hydrogen production and its use for back-up power generation purposes in Ireland post 2030.

6. PRODUCING AND FINANCING GREEN HYDROGEN

Most secondary school students will have seen hydrogen produced in a science class using a beaker of water, wire and a small battery.

Demonstrating a scientific principle is one thing; scaling this up to industrial production at the scale required to provide large-scale renewable energy at a competitive cost is an enormous and difficult challenge.

For example, **Fig 2** shows a 100 kg per hour capacity electrolyser which completed proof of concept testing in Q4 2022. If such an electrolyser could operate around the clock for a year, it would produce 876 tonnes of hydrogen with an energy content of 29,000 MWh. This is equivalent to the energy which two large (6 MW) modern onshore wind turbines would produce in a year.

Fig 2: Large electrolyser tested by HydrogenPro in Q4 2022[5]

There are several competing technologies which may be used for hydrogen production using electrolysis. All are characterised by low levels of energy efficiency (see **Appendix 3**).[5]

Much research is going on at present into scaling up the production of green hydrogen and some large projects have been announced.

- The Omani authorities have announced a 25 GW plant at Al Wusta. Construction will commence in 2028 and full capacity is planned for 2038.
- China has announced a large project at Ordos, but no commissioning date has been identified.
- In Germany, the Aquaventus consortium has announced a 10 GW project at Heligoland aiming to deliver a pilot capacity of 30 MW in 2025 and reach completion in 2035.

5 https://hydrogen-pro.com/wpcontent/uploads/2023/02/HydrogenPro_Q4_2022_presentation.pdf

- In The Netherlands, Shell plans to bring into operation what it describes as *Europe's largest renewable hydrogen plant* in the Port of Rotterdam in 2025. It will include a 200 MW electrolyser to produce hydrogen at a rate of up to 60,000 kg per day for local consumption at its refinery plant.

Globally, the pipeline for green hydrogen projects exceeds 250 GW. It all looks very promising. But these are all plans and remain conditional on advances in the technology and on the conclusion of finance for the projects.

In 2022, The European Investment Bank (EIB) published a report on investor perspectives on the risks associated with investing in green hydrogen projects.[6] This was prepared at the request of the European Union which is actively supporting the development of the technology. It lists, in detail, the many reasons why investors are wary of committing major funds to large projects including, for example:

> *Financing conditions for hydrogen infrastructure projects remain challenging because of the many risks associated with such projects, including a paucity of demonstrations from which lenders can draw experience. For demonstration projects, large capital expenditure requirements relative to the risk profile are a further constraint.*

The report refers to the *ramp-up* required and points to the experience of wind generation which took decades to reach its current level of acceptable financial risk. In particular, the report identifies the difficulties of obtaining non-recourse project finance for such large investments.

Investors' ability to finance hydrogen projects on a senior, non-recourse basis - which is essential for the scale-up of the sector - is constrained by the perception of significant residual risks. In the case of project finance for demonstration projects, early-stage investors are particularly constrained by the large capital expenditure requirements and their perception of better investment opportunities in other areas - such as the bioeconomy, renewables or electrification - where investment requirements may be more modest.

The definitive take away from the EIB report is summarised in this extract:

> *Overall, project promoters have announced more than €130 billion of investment in hydrogen in the European Union to date. However, out of the 23 gigawatts of electrolyser capacity to be installed by 2030, only 350 MW (less than 2%) are linked to projects that are currently underway or for which a final investment decision has been made.*

The clear message from this important EIB report is that green hydrogen technology is slowly making progress but that investors are extremely cautious and large-scale deployment will take time. Moreover, experience suggests that the lead times for green hydrogen projects in Ireland will be long, based on the experience of many other infrastructure projects in negotiating their way through the Irish planning and courts systems.

It is important to understand what it means when a power generation technology reaches commercial maturity. At commercial maturity:

- Technical risk has been largely removed from the project and is carried, instead, on the balance sheet of the Original Equipment Manufacturers (OEMs) by way of performance guarantees.
- Commercial and construction risk is perceived as being acceptable by the financial community based on the experience accumulated over many projects.
- Financiers are typically willing to lend in excess of 70% of the project capital cost on a non-recourse basis, meaning they have no recourse for repayment of loans other than income from the project itself.

It took two decades for the wind generation industry to reach this level of maturity. It is unlikely that green hydrogen technology will be financeable at scale in Ireland by 2030. While the EU will undoubtedly provide funds to accelerate this development, the Irish Government should be cautious about providing taxpayer funds at scale or structuring projects in such a manner that residual risks fall on the electricity consumer.

6 https://www.eib.org/en/publications/unlocking-the-hydrogen-economy

This does not mean that Ireland should ignore green hydrogen as an option for decarbonisation but rather that it should accept that a realistic date for the earliest implementation of this technology at scale in Ireland is post 2035 and, quite possibly, not until 2040. In some ways, the recent National Hydrogen Strategy recognises this.

However, other viable, and possibly better, alternatives may arise in the next decade, and these deserve equal consideration.

Ireland will likely have to continue to back up its variable renewable generation with natural gas until 2040. At that time alternative generation technologies will, hopefully, be available and can be adopted to eliminate the use of natural gas for electricity generation by 2050 as an important step to the country's energy sector becoming net zero.

7. TRANSPORTING HYDROGEN

Producing hydrogen is only the start of the journey. It must then be transported and stored before it can be used. Transporting hydrogen by pipeline is problematic. As a result of its very small molecule size, hydrogen may leak from containers and fittings which are gas tight for natural gas. Thus, when hydrogen is used in industries - such as the pharmaceutical industry in Ireland - all fittings must be certified as being hydrogen suitable. It also means that many valves and fittings on the natural gas grid may not be suitable if use of high concentrations of hydrogen is envisaged.

Moreover, in contrast to natural gas, hydrogen is a highly reactive gas. It reacts with the carbon steel pipes used for natural gas transmission causing hydrogen embrittlement. Because of the interest in using hydrogen in the future and the extensive existing natural gas transmission and distribution networks in many countries, there is significant research being undertaken to determine whether existing pipeline systems could be repurposed to carry hydrogen.

For example, Gas Networks Ireland has carried out a study of the suitability of its gas transmission and distribution networks for use with hydrogen, blended with natural gas and with 100% hydrogen.[7] The study analysis concluded that:

- The distribution system is suitable for use with 100% hydrogen.
- The material used in half of the gas transmission steel pipeline network is suitable for use with 100% hydrogen at design pressure.
- The other half would require additional testing to determine its suitability.
- Additional study is required to determine the suitability of equipment such as valves, meters and compressors used in above ground installations.

To date the analysis indicates that it may be possible - if pipeline flows and, consequently, pressures are held stable - to minimise variations in pipeline stresses. This, however, would not be feasible in Ireland where very large variations in hydrogen flow rates would occur if hydrogen was to be extensively used for back-up generation.

Hydrogen has an extremely low liquefaction temperature of -253°C. This is just 20 °C above absolute zero, the lowest temperature that can theoretically be achieved. Liquefying hydrogen is extremely energy intensive, typically using up to 30% of the energy content of the gas. Because of the very low liquefaction temperature and the low calorific value of liquid hydrogen, storing hydrogen in the liquid state is both extremely rare and expensive. The largest such facility in the world is at Cape Canaveral. Its capacity is 4,730 m^3 and its energy storage capacity is approximately 51 GWh (or 4,350 tonnes of oil equivalent).

There are, at present, no liquid hydrogen shipping tankers in service of any significant scale and the development of such carriers is now at the same state that LNG carrier development was 65 years ago. One small prototype vessel has been constructed in Japan.

Converting green hydrogen to ammonia, methanol (or some other chemicals) and shipping that as a fuel is technically feasible but has not yet been attempted at any scale. The transport of ammonia (which is a highly toxic gas) is, however, well established. Because of its toxicity, ammonia was generally withdrawn from use in refrigeration systems decades ago.

In the event of the emergence of an international green hydrogen market, it is possible that Ireland, far from being a producer, would in fact be an importer of green hydrogen delivered from locations where renewable energy resources are more predictable and stable - and, thus, more suited to process use - and where renewable electricity costs are lower.

Given that Ireland's electricity prices (pre-tax) are among the highest in Europe (see **Appendix 4**), it is difficult to see Ireland becoming an exporter of green hydrogen. Production costs in Ireland will, most likely, be internationally uncompetitive.

7 https://www.gasnetworks.ie/docs/renewable/Hydrogen-Feasibility-Study.pdf

8. STORING HYDROGEN

If Ireland is to transition to using green hydrogen for back-up generation, then it will be necessary to store large quantities of the fuel for use during low wind periods. This is a major challenge.

Various parties have proposed storing hydrogen in depleted gas fields.

Hydrogen has the potential to adversely react with the pore structure of depleted gas reservoirs or saline aquifers were these to be used for hydrogen storage. Because of its very small molecule size, hydrogen also has the potential to migrate through structures in a manner different from natural gas and to leak from existing well boreholes. Thus, very extensive investigation, analysis and testing is required.

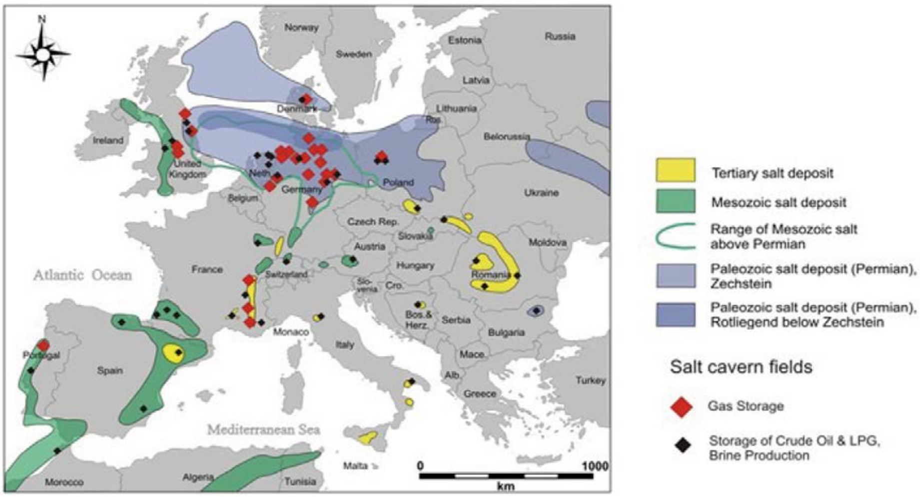
In addition, if either the main Kinsale Field or the Corrib Field were to be developed to store green hydrogen, a very large investment would be required to produce the "cushion gas" which would have to be injected to restore the pressures required for high volume delivery.[8] This cost would be many multiples of the price paid for the natural gas produced from those fields.

Attention to date has focused on smaller fields like SW Kinsale, which was previously developed for natural gas storage purposes. However, all the equipment at the Kinsale complex has been decommissioned and removed. Furthermore, if redeveloped for hydrogen storage, the withdrawn hydrogen would contain traces of natural gas, which could poison the catalysts used in fuel cells, thus potentially limiting its use for transport applications.

Because of these considerations, there are only four locations, worldwide, where the storage of hydrogen has been undertaken in geological formations. All of those have been in salt formations, where a salt cavern was first created by pumping water into the formation to dissolve the salt.

There are potentially suitable salt formations in Britain and Northern Ireland (**Fig 3**). However, no such formations are known to exist in Ireland (Republic).

Fig 3: Location of salt cavern fields used for energy storage in Europe and North Africa[9]



The Sustainable Energy Authority of Ireland (SEAI) commissioned a study to examine seismic data generated when the Kish Bank area was being explored for hydrocarbons to determine whether suitable storage possibilities could be identified. This analysis found that there were multiple small structures with storage potential. However, extensive drilling and testing is required to prove that capability. In addition, developing multiple structures, for storage purposes would require extensive subsea infrastructure.

8 Cushion gas is the gas that is permanently stored in a gas storage reservoir in order to maintain sufficient pressure in the storage reservoir to allow for adequate injection and withdrawal rates at all times

9 https://www.neuman-esser.de/en/company/media/blog/hydrogen-storage-in-salt-caverns/

9. HYDROGEN FOR GAS TURBINES

Hydrogen has been used in many locations to fuel gas turbines but mainly as an addition to natural gas. While there is no fundamental reason why pure (100%) hydrogen cannot be used to fuel gas turbines, some technology development will be required, and significant modifications to existing gas plant will be necessary.

Of all the challenges to implementing a green hydrogen back-up strategy, this is probably the easiest to overcome and the technology required will almost certainly be available by 2030.

In addition to the option of using green hydrogen to fuel gas turbines, research is taking place into burning ammonia directly in gas turbines and this technology may well be available during the next decade (see **Appendix 5**).

10. RECOVERING STORED GREEN HYDROGEN FOR STANDBY GENERATION

Storage facilities for green hydrogen must not only have the required energy storage capacity, they must also have the capacity to deliver the gas in the required quantities and at the required rate to the back-up generation plant required when renewables cannot meet demand.

This challenge is all the greater for hydrogen (compared to natural gas) because hydrogen has only one-third the calorific value of natural gas on a volumetric basis.

At present Ireland has 6,752 MW of thermal generation.

If it is assumed,

- firstly, that 4,000 MW of hydrogen powered back-up generation would be required in the future and,
- secondly, that all the hydrogen required to fuel that generation would be supplied from storage during periods of low wind speeds,

then the hourly hydrogen production rate from whatever storage facilities that might be used would be,

- 18 times the peak flow rate from the SW Kinsale reservoir when it was used to store natural gas, and
- 6.6 times the peak flow rate from the Corrib Field (2017).

Achieving the required flow rates from storage would be a considerable challenge.

11. THE ECONOMIC CHALLENGE OF USING GREEN HYDROGEN TO BACK-UP RENEWABLES

Even at this stage, the scale of the economic challenge of using green hydrogen to generate back-up electricity during periods when renewables are not available appears daunting as shown by the analysis presented in **Appendix 3**.

Taking the recent results of the ORESS1 auction - where the average bid price accepted was €86 per MWh – to provide a base cost for renewable electricity, this analysis suggests that back-up electricity produced using green hydrogen could cost between €377 and €516 per MWh.

This analysis is based on the use of Proton Exchange Membrane (PEM) technology which seems most suitable at present for large scale electrolysis.

The cost inefficiencies arise because between 77% and 83% of the renewable energy initially produced would be lost in producing, transporting, storing and, ultimately, combusting green hydrogen in an open cycle gas turbine.

Moreover, this cost estimate makes no provision for the recovery of the capital cost of the equipment involved nor of the indirect operating and maintenance costs of the electrolyser and gas turbine. These costs would be in addition.

Based on optimistic projections, it would seem that a mean cost in excess of €500 per MWh might well be typical for electricity produced from green hydrogen.

It is important to bear in mind that, under current market conditions, this would be the marginal production price for electricity in Ireland and would, therefore, set the price for *all* power sold on the Irish electricity market (see **Appendix 6**).

12. INTERNATIONAL EXPERIENCE

It is worthwhile briefly considering how Ireland's National Hydrogen Strategy compares to that of other countries.

Most industrialised countries perceive green hydrogen as essential to decarbonising important industries and heavy transport, and have published strategies to reflect this view.

Britain, for example, is proceeding with a major expansion of offshore wind capacity and has earmarked some of the electricity produced from this source for hydrogen production. It has not, however, produced any plans to use this hydrogen for significant power system back-up. Instead, a major programme of nuclear investment has been published and the UK Government is actively encouraging investors in this industry.

France - which is also proceeding with large offshore wind installations - will rely primarily on its extensive nuclear capacity to meet electricity demand for the foreseeable future.

Major greenhouse gas (GHG) emitters such as the US and China seem to be embarking on similar programmes.

In contrast to Britain, France, the US and Canada, Germany is shutting down its nuclear capacity and is faced with the challenge to eliminate its large dependence on coal and natural gas at the same time as it closes its nuclear plants. In this context, Germany published its National Hydrogen Strategy in 2020.

Germany's strategy focusses on hydrogen for use in industrial processes and in advanced transport applications. Although the strategy does consider the use of hydrogen to back-up power generation it does not address this challenge in detail.

However, the feasibility of using green hydrogen in Germany for back-up power generation was considered in a paper published by the Max Planck Institute in 2021.[10]

This paper reached a very negative conclusion as follows:

> *In summary, the balancing of fluctuations of renewable energy through green hydrogen seems feasible only up to a level of several GWh per day. However, the German government's idea of replacing a significant share of conventionally produced electric energy in the order of TWh with hydrogen does not stand up to scientific analysis.*

This conclusion highlights the gap that can open between Government policy objectives and reality when novel and as yet unproven solutions to backing up renewables are proposed.

Unlike Ireland, Germany is at the centre of the largest synchronous power system in the world and is well positioned to import back-up generation from numerous neighbouring countries when it is required.

In July 2023, the German Government published a more sober update of its hydrogen strategy. The aspirational targets in this update include the following:

> *The 2020 strategy identified green hydrogen made from renewable electricity as the only sustainable form in the long-term. The strategy update says that in order to ensure a rapid ramp-up of the hydrogen market and to meet the expected demand, "other colours of hydrogen will also be used, at least until sufficient green hydrogen is available." This would especially be low-carbon hydrogen from waste or natural gas in combination with CCS (Carbon Capture and Storage).*
>
> *The country will have to import 50-70 percent of this by 2030, later an even higher share.*
>
> *Intensify cooperation at EU level to make use of potential to produce hydrogen in southern Europe, the North Sea, Baltic Sea, Mediterranean and Black Sea.*
>
> *Auctions for 4.4 GW hydrogen/ammonia "sprinter power plants" from 2023-2026, and other hydrogen power plants.*

It is notable that Ireland is not included in the list of regions from which green hydrogen might be imported.

10 https://link.springer.com/content/pdf/10.1140/epjp/s13360-021-01585-8

SUMMARY AND CONCLUSIONS

It is feasible to produce green hydrogen using variable renewable energy sources in Ireland. The resources to do this will increase as Ireland expands its renewable energy capacity but the following issues need to be considered.

- Large scale electrolysers are not yet available, and the technology is still at an early stage of development. It is unlikely that there will be large scale and economic hydrogen production before 2035 and possibly not until 2040.
- One major constraint in scaling up the technology is the availability of finance for projects that are perceived to have high technical risk. Large scale commercial electrolysers are unlikely be available on a non-recourse finance basis before 2035 and possibly not until 2040.
- Hydrogen is very difficult to handle and to store. The only way of storing it on a large scale, currently, is under pressure at normal temperatures in salt caverns. Ireland does not have any known suitable geological storage. The salt deposits at Islandmagee in County Antrim, Northern Ireland might offer storage opportunities, albeit at a considerable distance from the power stations requiring it.
- Exploration of Ireland's offshore geology with a view to storing green hydrogen is being undertaken by SEAI but there are, as yet no proven sites. It is quite possible that no suitable sites exist.
- Consideration is being given to using the depleted SW Kinsale Gas field for storage. This type of storage for hydrogen is unproven and technically challenging. In addition, much of the infrastructure for gas production at Kinsale has now been removed.
- SW Kinsale would also require cushion gas. If the electricity costs to produce this green hydrogen were at levels close to those accepted at the recent ORESS1 offshore wind auction, then this would require a large financial investment.
- Moreover, if production levels for hydrogen from storage were similar to past production levels for natural gas, then the SW Kinsale Gas field could only supply a very small fraction of the hourly hydrogen required to meet standby generation fuel requirements in 2030.
- Given the enormous challenge posed in finding a suitable location to store green hydrogen in Ireland, it is important that no short-term commitments are made to the technology for power system back-up and that other options continue to be investigated.
- An initial estimate indicates that the cost of electricity produced from green hydrogen could exceed €500 per MWh. Since this could establish the marginal generating cost on the system, overall prices would tend towards this level.
- Given the large inefficiencies involved in using green hydrogen as a back-up for variable renewable generation, the Academy recommends that the CRU undertake a financial modelling exercise to estimate its impact on Irish electricity prices which are already among the highest in Europe (pre-tax).
- The green hydrogen option should be explored further on a pilot scale while a definitive decision is deferred until an evidence-based decision can be taken on its future development.

APPENDIX 1 - PEAK ELECTRICITY DEMAND AND SUPPLY

In 2021, peak demand for electricity in the Ireland reached 5,500 MW. This was estimated to have increased to 5,700 MW in 2022 and is projected to reach 7,500 MW by 2030.[11]

In 2022, Ireland had 4,890 MW of so called non-dispatchable generation. Wind turbines accounted for 4,500 MW (over 90%) of this total. At times of low wind speeds, only a small proportion of this generation capacity may be available.

In addition to non-dispatchable generation capacity, Ireland had 6,752 MW of conventional (dispatchable) generation. This is mainly gas fired but includes 820 MW of coal fired generation at Moneypoint. This plant is called on to meet the gap between variable renewable generation and the instantaneous demand on the power system.

At times of peak demand, certain power users - Demand Side Units (DSUs) - have entered into agreements to reduce their demand, effectively providing extra capacity to the system. The total DSU capacity available in 2022 was 604 MW and is projected to rise to 632 MW in 2030.

Additionally, Ireland has an interconnector with Great Britain - the East-West Interconnector (EWIC) with an import capacity of 530 MW - and Northern Ireland has the Moyle Interconnector with Scotland - with a rating of 432 MW.

In the first half of 2023, extensive use was made of these interconnectors and six times more energy was imported than was exported. Indeed, the level of electricity imports to Ireland equated to 28% of the wind and solar generation in the same period.

The effective capacity of these interconnectors in periods of high demand and low wind speeds, in both islands, can be substantially lower than their rated capacities. In assessing the capacity of the system to meet demand, EirGrid (Republic) and SONI (Northern Ireland) apply an External Market De-Rating Factor (ERDF) of 60% and an Interconnector Outage Rate of 7.5%. Based on this, these interconnectors (with an aggregate rated capacity of 962 MW) are assessed as being able to deliver 534 MW in periods of constrained wind output and high demand.

In addition, further interconnectors are currently under development:

- the 500 MW Greenlink Interconnector to Wales, due in 2024; and
- the 700 MW Celtic Interconnector to France, due in 2027.

EirGrid's and SONI's planning assumption in 2022 was that these would be subject to similar ERDFs.

However, there is uncertainty as to what an appropriate ERDF will be in the future due,

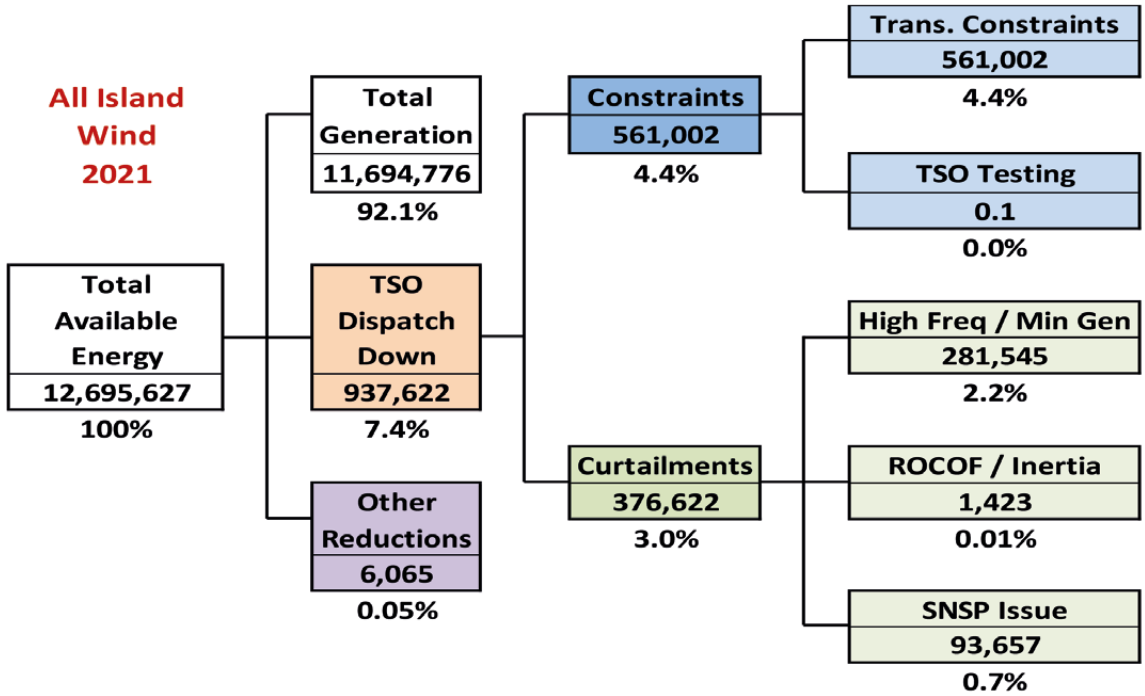
- firstly, to Britain's increasing dependence on wind, and
- secondly, because half of the French nuclear fleet - the 900 MW units constructed between 1977 and 1988 - will be almost 50 years old by 2030, and thus increasingly exposed to faults such as those experienced in the past year.

Finally, government recently approved the development of additional interconnectors to Britain, France, Spain, Belgium and the Netherlands. No timeframes have yet been established for these developments and each will require agreement at the other end. Also, no financing mechanism has yet been specified.

11 For clarity, Ireland refers only to the Republic and does not include Northern Ireland notwithstanding that there is a single all-Island electricity market

APPENDIX 2 - ELECTROLYSIS USING DISPATCH-DOWN WIND GENERATION

EirGrid's *Annual Renewable Energy Constraint and Curtailment Report 2022* contained the following graphic:[12]



In 2022, 8.3% of wind generation - equivalent to 988 GWh - could not be utilised. (The equivalent figures in 2021 were 7.3% and 752 GWh).

Based on the data in **Appendix 3**, this 988 GWh of dispatch-down wind energy could, theoretically, yield about 18,000 tonnes of hydrogen. Assuming a round-trip efficiency of 22.8% (electricity-to-hydrogen-to-electricity), the net energy yield from 988 GWh would be about 225 GWh of back-up electricity, when fuelling open-cycle gas turbines. This represents approximately 0.7% of system demand (31,622 GWh in 2022) or about 62 hours of average supply if no other sources were available.

This calculation demonstrates that marginal low cost electricity would be entirely insufficient for the large scale production of hydrogen required for back-up power generation. Moreover, the above example does not differentiate between constraints and curtailments. Whereas the latter could be used for electrolysis, the former might not be available to be used depending on the location of the electrolysis plant in relation to the curtailed wind generation plant.[13]

12 https://www.eirgridgroup.com/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2022-V1.0.pdf

13 The 988 GWh of dispatch-down energy is very much a high-side estimate of what could have been used in 2022 to produce green hydrogen on a marginal basis. A more realistic assumption would be that only the 401 GWh of generation curtailed due to *High Frequency or Minimum Generation* requirements could have been used

APPENDIX 3 - THE IMPACT OF ENERGY LOSSES ON THE ECONOMICS OF USING GREEN HYDROGEN TO FUEL BACK-UP GAS TURBINES

The economics of using green hydrogen to provide back-up capacity for renewables are challenging and the scale of this challenge can be seen by considering the efficiency loss at each stage of the hydrogen supply chain.

The growth in demand for green hydrogen is stimulating competition among four competing electrolysis technologies:

- Alkaline Water Electrolysis (AWE)
- Proton Exchange Membrane (PEM)
- Solid Oxide Electrolysis (SOE)
- Anion Exchange Membrane (AEM)

At present, most focus is on AWE and PEM as the most suitable technologies for large scale electrolysis associated with variable renewable energy sources. The efficiency figures for both these technologies are similar.

Using data for PEM technology, the table below estimates the aggregate impact of the inescapable inefficiencies along the chain from using renewable electricity to produce green hydrogen all the way through to producing back-up electricity by burning this green hydrogen in open cycle gas turbines.

Taking the recent results of the ORESS1 auction - where the average bid price accepted was €86 per MWh – to provide a base cost for renewable electricity, the back-up electricity subsequently produced using green hydrogen could cost between €377 and €516 per MWh.

This is the result of between 77% and 83% of the renewable energy initially produced being lost in producing, transporting, storing and, ultimately, burning green hydrogen in an open cycle gas turbine.

It is important to understand that this cost estimate makes no provision for the recovery of the capital cost of the equipment involved nor of the running cost of the electrolyser and gas turbine. These costs would be additional.

	Most Optimistic Estimates	More Realistic Estimates
Rectifier Efficiency (%)	95.0%	93.0%
PEM Electrolyser Specific Energy Consumption (kWh per kg of H2)[14]	55.0	70.0
PEM Electrolyser Hydrogen Production Efficiency (to LHV)	60.6%	47.6%
Storage Round Trip Energy Efficiency (%) Including any Compression Losses Incurred	99.0%	97.0%
Hydrogen Transportation efficiency (% of LHV)	100.0%	95.0%
Open Cycle Gas Turbine Efficiency (% of LHV)	40.0%	40.0%
Estimated Overall Round Trip Efficiency (%)	22.8%	16.7%
Ratio of Input Electrical Energy to Output Electrical Energy	4.4	6.0
Assumed Cost of Input Electricity per MWh	€86	€86
Calculated Cost of Output Electricity per MWh	**€377**	**€516**

Under current plans, this excess cost would apply to 20% of Irish generation (assuming an 80% renewable target is reached). This 20% would constitute the marginal system production for most, if not all, of the time and would, under normal market conditions, be reflected in the market price of Irish electricity.

Finally, it is not conceivable that the green hydrogen that would be required to provide back-up power generation could be produced using only low cost marginal constrained renewable generation capacity. There just is not enough production under these conditions. See **Appendix 2.**

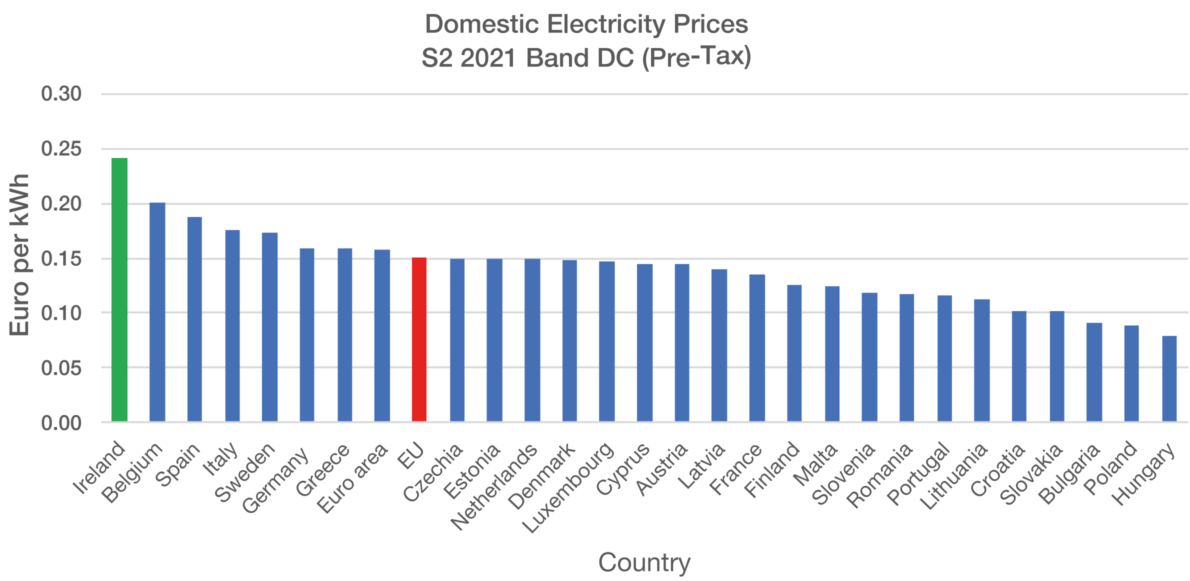
14 For reference the lower heating value (LHV) of hydrogen is 33.3 kWh per kg

APPENDIX 4 - ELECTRICITY PRICES IN IRELAND

The challenge of the *energy trilemma* is to balance the requirements for our energy to be secure, sustainable and cost competitive. Unfortunately, Ireland's electricity prices are already among the highest in Europe (pre-tax). Pre-tax prices reflect the actual economics of electricity production.

The chart below shows that typical domestic consumers in Ireland - with an annual consumption between 2,500 kWh and 5,000 kWh - had the highest pre-tax price in the EU in 2021. Prices in Ireland were 61% higher than the EU average and 63% higher than in Denmark. This analysis is based on data from Eurostat.

Irish domestic electricity prices (Band DC pre-tax), Semester 2 2021[15]

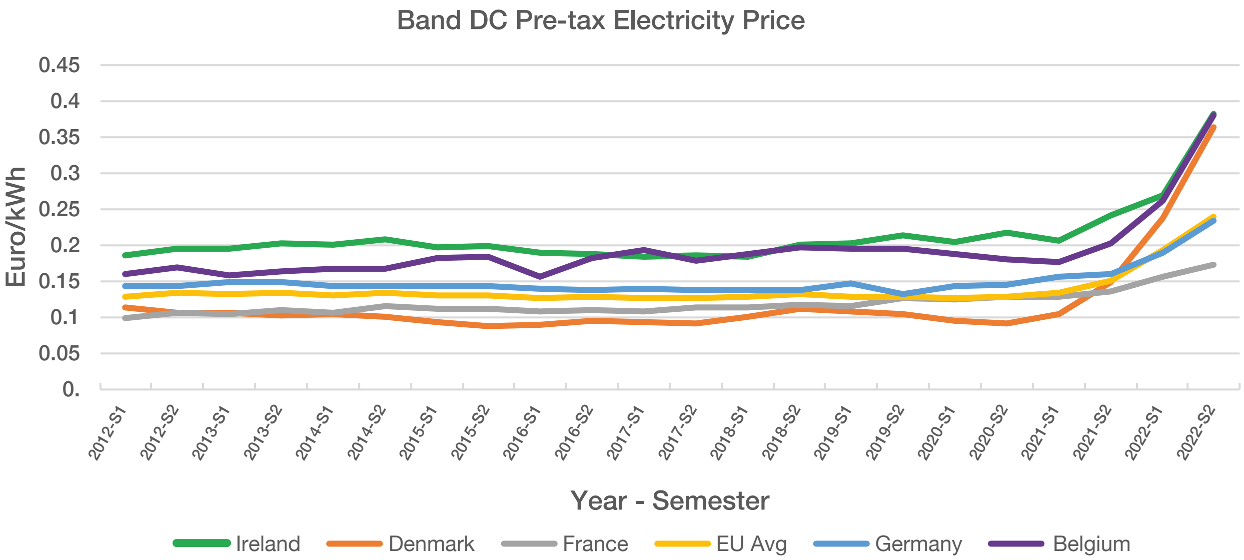


Consumers in Ireland do, however, benefit from having some of the lowest taxes on electricity in the EU. It is possible that taxes on energy will increase in Ireland to compensate, for example, for the loss to the Exchequer of taxes on petrol and diesel as the number of EVs in the country increases.

The high level of the price of electricity for domestic consumers has been a fixture for some time as shown in the chart below from 2012 to 2022. The effect of the Ukraine war on prices post-2021 is evident.

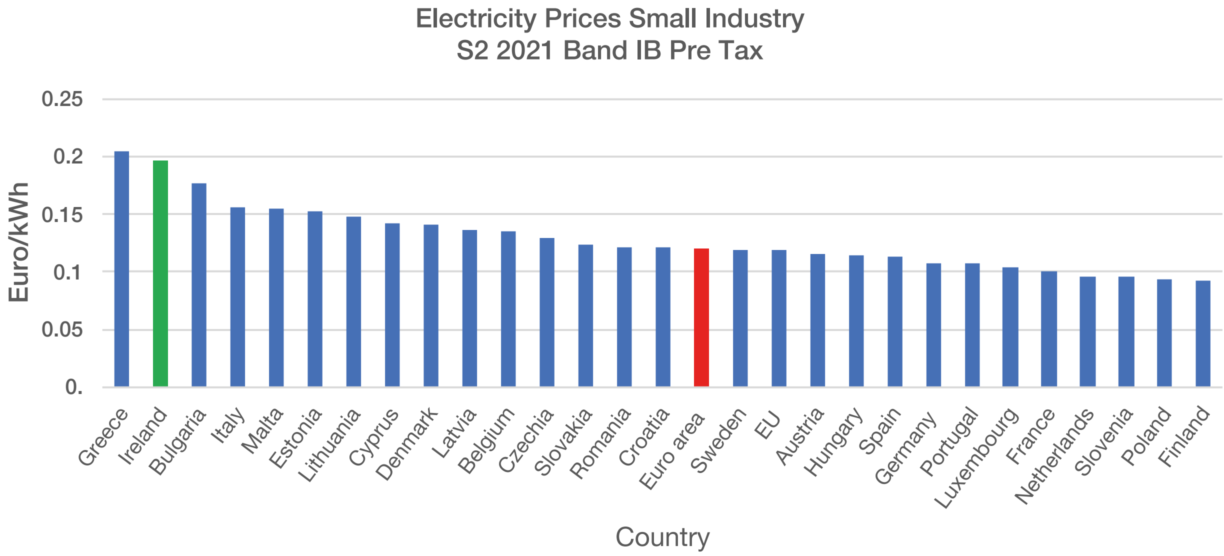
15 Band DC: 2,500 kWh < Consumption < 5,000 kWh

Trends in Band DC domestic electricity from 2012 to 2022



The situation for other consumption bands is broadly similar. For medium size industrial consumers in 2021 - with an annual consumption of between 20 MWh and 500 MWh - pre-tax electricity prices were 65% above the EU average and 39% higher than in Denmark.

Irish industrial electricity prices (Band IB pre-tax) for medium sized[16]



Against the above background, the Academy sees an urgent need for detailed financial modelling to estimate how a green hydrogen back-up strategy for Ireland would impact Irish electricity prices.

16 Band IB: 20 MWh < Consumption < 500 MWh

APPENDIX 5 - AMMONIA AS A BACK-UP FUEL FOR POWER GENERATION

The only means of storing hydrogen in Ireland which is technically proven and potentially capable of delivering the very high hourly flow rates required is in the form of ammonia.

The production of ammonia (NH_3) from hydrogen is already the second largest use of the gas, after oil refining, and was undertaken at Marino Point by NET for twenty years, following the discovery of the Kinsale Field.

Ammonia can be liquefied by increasing its pressure to 7.5 bar or by cooling it to -33°C. In its liquid form, ammonia can be readily stored and transported (whether by ship, rail, truck or pipeline).

Onshore liquified natural gas (LNG) storage facilities could potentially be reused for ammonia storage provided the metallurgy of storage tanks pipework and fittings was ammonia compatible. The boil off rates would be much lower for ammonia than for LNG.

However, ammonia is a poisonous gas. Any large scale storage site would be subject to COMAH Regulations and would require a significant sterilisation zone around the site. In practical terms the leading options for storing ammonia would appear to be in Ballylongford on the Shannon Estuary or in or adjacent to the Whitegate Oil Refinery. Its large scale storage in Dublin Bay appears highly unlikely.

While ammonia is not used to power gas turbines at present, two companies - GE and IHI - have announced their intention to develop the technology to enable ammonia to be used in new and existing gas turbines by 2030.[17]

17 https://www.ge.com/news/press-releases/ge-and-ihi-sign-memorandum-of-understanding-to-develop-gas-turbines-that-can-operate

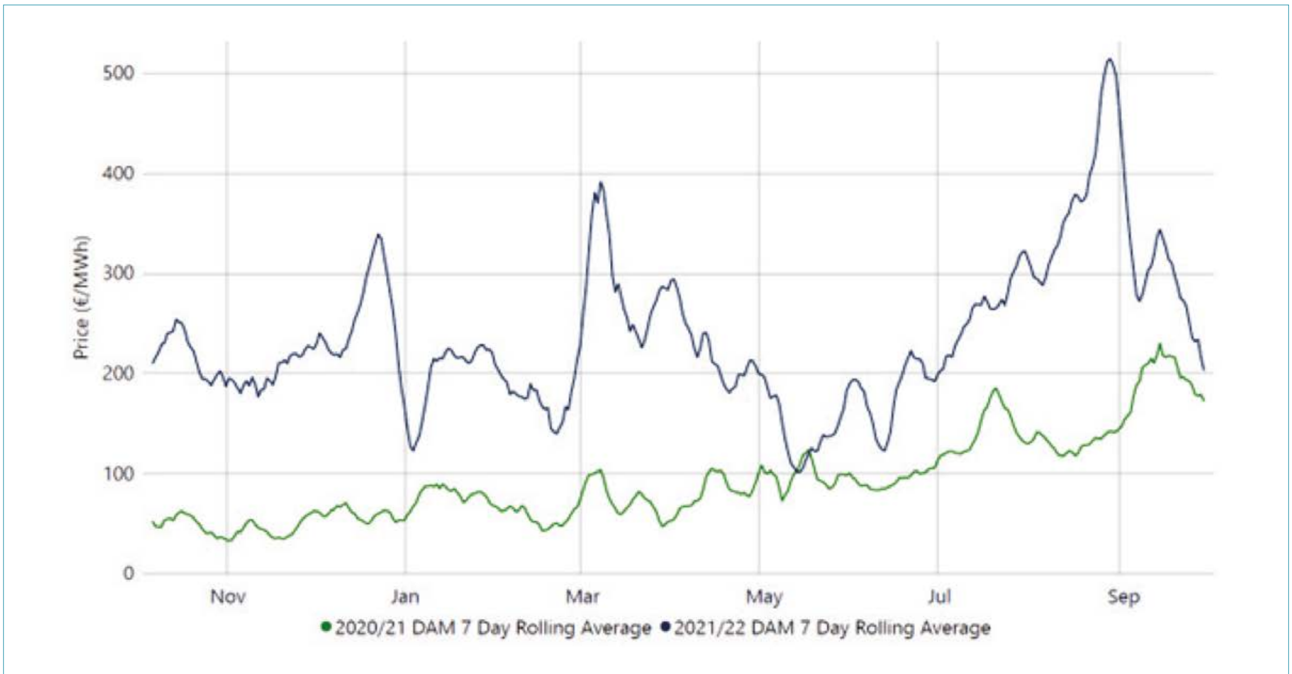
APPENDIX 6 - EFFECT OF HIGH MARGINAL ELECTRICITY PRICES

The effect of high marginal prices was vividly illustrated in the Irish market over the past two years following Russia's invasion of Ukraine in February 2022. This led directly to a rapid rise in the price of natural gas used for power system back-up.

Prices in the Irish electricity market are set primarily in the so-called *Day Ahead Market* or DAM. In early 2021, electricity prices in this market were well below €100 per MWh. Then, on the 24th of February 2022, when Russia invaded Ukraine, gas prices began to increase, and this drove general electricity prices up because these are based on the marginal production cost arising from gas fired generation.

This trend is evident in the graphic below taken from the Single Electricity Market Committee (SEMC) annual report covering the period October 2021 to September 2022. [18]

Comparison of trends in SEM DAM electricity prices 2021 and 2022



At the highest point during 2022, DAM prices exceeded €500 per MWh.

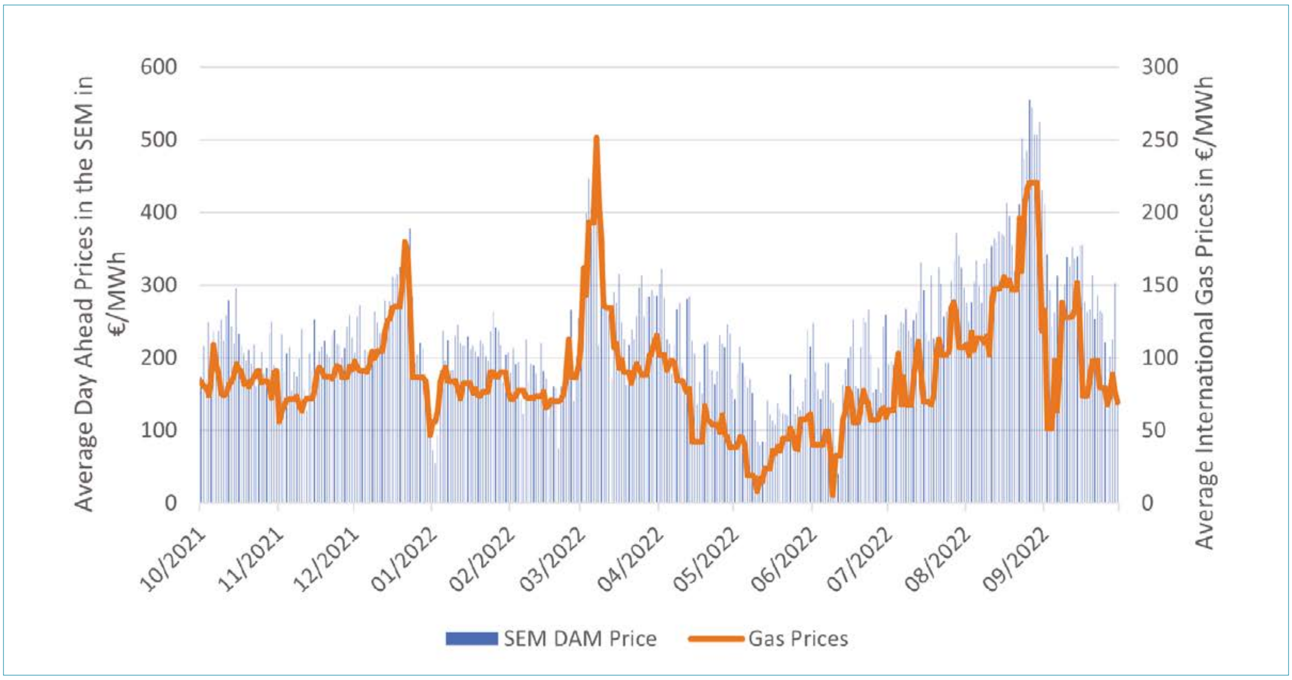
For most of the year the average price was of the order of €250 per MWh.

This price represented an increase over pre-war prices of approximately 300% and caused enormous hardship to electricity consumers. It also resulted in significant windfall profits for producers (including some wind generators) who benefited from these high prices.

18 https://www.semcommittee.com/publications/sem-23-019-semc-annual-report-october-2021 september-2022

The close tracking of electricity and gas prices is immediately evident in the diagram below also produced by the SEMC.

Comparison of trends in SEM DAM prices and international gas prices, October 2021 to September 2022



During this period of market turmoil, there were calls on governments to introduce a tax on windfall profits or, indeed, for wholesale change in the structure of electricity markets. Most governments resisted such pleas for fear that interference in the market could discourage future investment. The concern is that any increase in "political risk" could encourage potential investors to go elsewhere. The importance of this factor is emphasised by Ireland's need to attract in the order of €20 billion of private investment for the renewables expansion programme planned over the next decade.

The Irish Government chose the option of compensating electricity users at the general taxpayers' expense and the EU undertook to revise electricity market structures.[19]

To date, the proposals emerging from the EU are more concerned with reducing price volatility and discouraging fossil fuels.

Were "normal" market rules to apply in the context of green hydrogen being used to back-up Ireland's power system during periods when renewables were not available, then market prices for electricity could increase to very high levels.

This issue has not been addressed in the recent National Hydrogen Strategy.

19 https://ec.europa.eu/commission/presscorner/detail/en/IP_23_1591

Disclaimer

The members of the Taskforce and the contributors participated in extensive discussions in the course of a series of meetings, and submitted comments on a series of draft reports. Its contents convey the general tone and direction of the discussion, but its recommendations do not necessarily reflect a common position reached by all members of the Taskforce, nor do they necessarily reflect the views of the organisations to which they belong.

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The Irish Academy of Engineering
22 Clyde Road, Ballsbridge, Dublin D04 R3N2
Telephone: +353 1 665 1337
academy@iae.ie
www.iae.ie
Registered in Ireland: CRO 439234, CHY18046, RCN 20068455

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