The Basis for Hydrogen in Ireland's Energy System Transition

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Declaration

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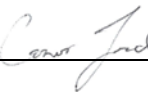
Sign:  ID No: 13465398 Date: 22/10/2020

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List of Acronyms

ALK Electrolyser:	Alkaline electrolyser device used to split water into hydrogen via an electrical current.
BEV:	Battery electric vehicle.
BNEF:	Bloomberg New Energy Finance.
BOP:	Balance of plant costs are those associated with piping, pumps and electrical installations.

Btoe:	Billion tonnes oil equivalent, unit of measurement for fuel consumption.
Capacity Factor:	The wind capacity factor gives the amount of energy actually produced in a year relative to the maximum that could have been produced had the wind farm been generating at full capacity all year.
CAPEX:	Capital costs/expenditure.
CCUS:	Carbon capture utilisation and storage.
CHP:	Combined Heat and Power, plant designed to produce both heat and electrical power from a single source.
CNG:	Compressed natural gas.
Controllable Generator:	Electricity generators that can automatically act upon a remote signal from the TSO to change it's active power output.
CSO:	Central statistics office, Ireland.
Data Centres:	Large buildings used to store data.
DCCAE:	Department of climate change action and environment, Ireland.
EirGrid:	State-owned electricity transmission system operator in the Republic of Ireland; plans, develops and operates the electricity transmission system in the jurisdiction.
EV:	Electric vehicle, a vehicle that incorporates a battery to power an electric motor for propulsion.
FCEV:	Fuel cell electric vehicle, zero emission vehicle powered by hydrogen.
Floor Price:	The lowest preconceived price that a seller will accept.
GNI:	Gas Networks Ireland builds, develops, and operates Ireland's gas infrastructure.
GoO:	Guarantees of Origin, certificates which provide proof that electricity has been generated from renewable sources as defined in the renewable energy directive (RED).
GW:	Gigawatt; 1,000,000,000 watts (unit of power).
Heat Pump:	A device that provides heat energy from a source of heat to a destination called a "heat sink".
Hydrogen Valley	A geographical area where several hydrogen applications are combined together into a hydrogen ecosystem that consumes a significant amount of hydrogen, improving the economics behind the project.

HRS:	Hydrogen refuelling station.
HVDC Interconnector:	Connects the transmission system of one independently supplied transmission system to that of another using high voltage direct current cables.
IEA:	International energy agency.
IMF:	International Monetary Fund.
IRENA:	International Renewable Energy Agency.
IRR:	Internal Rate of Return, measure of the rate of return expected from an investment.
I-SEM:	Integrated Single Electricity Market, where electricity is traded on the island of Ireland.
kV:	Kilo volt, unit of electrical potential or electromotive force.
LCOE:	Levelized cost of electricity, expressed in euro/MWh; represents the average price of electricity that each type of RES-e generator would have to earn in its lifetime at a given capacity factor in order to cover its capital costs and operating costs.
LNG:	Liquefied natural gas.
MEC:	Maximum export capacity, is the maximum capacity that a generator can export to the electricity distribution system.
Mtoe:	Million tonnes oil equivalent, unit of measurement for fuel consumption.
MVA:	Mega Volt Ampere; 1,000,000 Volt Amperes. Volt Ampere is the unit used for the measurement of ‘apparent power’ in an electrical circuit.
MW:	Megawatt; 1,000,000 Watts (unit of power). Watt is the unit used for the measurement of ‘real power’ in an electrical circuit.
MWh:	Megawatt hours; 1,000,000-Watt Hours. Measure of energy over time.
O&M:	Operation & maintenance.
OPEX:	Operational expenditure.
PEM Electrolyser:	Polymer Electrolyte Membrane, electrolyser device used to split water into hydrogen via an electrical current.
PHEV:	Plug-in hybrid electric vehicle.

PPA:	Power Purchase Agreement; contractual arrangement between electricity generators and purchasers (off takers).
Primary Energy	Energy in the form that it is first accounted for in a statistical energy balance, before any transformation to secondary or tertiary forms of energy.
PSO Levy:	Public Service Obligation: a government subsidy charged to all electricity consumers in Ireland. The money collected is used to subsidise renewable energy generation.
RES:	Renewable Energy Source: a clean form of energy production that is harnessed from natural resources.
RES-E:	Renewable energy sources for electricity generation.
RESS:	Renewable Electricity Support Scheme in Ireland.
SEAI:	Sustainable Energy Authority Ireland.
Simulation:	Is usually recursive; where the model is run year after year and the hypotheses and parameters can evolve over time.
SONI:	Electricity Transmission System operator for Northern Ireland; plans, develops and operates the electricity transmission system in the jurisdiction.
TCO:	Total Cost of Ownership.
TER:	Total electricity requirement.
TLAF:	Transmission Loss Adjustment Factors allocated to generators. These are calculations of the losses and are calculated jointly by EirGrid/SONI and approved by the Regulatory Authorities on an annual basis.
TSO:	Transmission System Operator; responsibility of managing the bulk electricity supply in the jurisdiction.
TUoS:	Transmission Use of System Charge is the system of charging for transporting power in bulk across the transmission system (110kV,220kV and 400kV network).
VRES:	Variable renewable sources of energy, which include wind and solar.

Abstract

The Irish Governments ‘Climate Action plan 2019’ includes the target for 70% renewable electricity by 2030. This will involve Ireland more than doubling its renewable generation capacity in the coming decade to account for a growing electricity demand. The renewable capacity is planned to come from wind and solar energy resources. These sources by their nature are intermittent and variable, and there are challenges associated with their efficient integration onto the electricity system. In recent years, Ireland’s existing renewable generation fleet (primarily onshore wind) have had their output constrained/curtailed due to inefficiencies of the electricity system. Addressing these inefficiencies will be key to Ireland realising its climate ambitions.

Long term energy storage facilities are part of the solution as they can capture excess renewable electricity during periods of an oversupply. Hydrogen is a long-term storage option that can be deployed to absorb surplus renewable electricity. The major benefit of hydrogen is its versatility as a fuel, which has end uses across the energy system. In addition, hydrogen produced from renewable electricity can be referred to as ‘green hydrogen’ and is a zero-emission fuel in hard to decarbonise sectors such as heat and transport.

Green hydrogen is the focus of this research study, with the primary objective of determining a business case for the production of green hydrogen. To determine this, it was necessary to analyse the entire value chain of green hydrogen from the production source to the end user/consumer. This included a review of hydrogen delivery methods and applications in the heat and transport sectors in Ireland. The analysis concluded that green hydrogen production from renewable electricity requires financial support and policy mechanisms to encourage its uptake in the heat and transport sectors. The potential socio-economic benefits arising from the provision of supporting policy for green hydrogen were also explored as part of the study.

1 Introduction

The large-scale integration of variable renewable electricity sources (VRES) into the current electricity grid is limited by a variety of technical issues that can affect reliability, affordability, sustainability, emissions, and economics of the generated electricity. Several actions can be taken to mitigate the effect of intermittency to enable a higher share of VRES into electricity/energy system. One of these actions is developing long-term energy storage technologies. Hydrogen offers a long-term energy storage option that could be vital to both Ireland's and the European Union's plans to achieve a 100% renewable electricity supply to help decarbonise our society and combat climate change.

Excess renewable electricity can be converted to "green hydrogen" via electrolysis using an electrolyser. High levels of surplus renewable electricity and falling costs in renewable power have recently focused attention on green hydrogen production and storage. Capital costs for electrolyser equipment have decreased significantly over the past number of years and it is expected that they will continue on a downward trend in the next decade as large markets such as China, Japan, USA and Germany scale up their electrolyser capacity.

Green hydrogen has applications in transport, industry and heat sectors and provides an opportunity to decarbonise the entire energy system. Both China and the USA have targets for at least 1 million hydrogen powered fuel cell electric vehicles (FCEVs) by 2030. As production volumes increase and economies of scale improve, it is expected the cost of FCEVs will decrease to provide an alternative but complimentary zero emission option to battery electric vehicles.

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2 Literature Review

2.1 Policy

The European Union has taken major steps towards reducing carbon emissions emanating from fossil fuel use. Binding targets set out in the Renewable Energy Directive (RED) 2009/28/EC for Ireland in 2020 included zero carbon renewables accounting for 16% of the national energy consumption, a 20% reduction on greenhouse gas (GHG) emissions based on 2005 levels and a 20% efficiency improvement based on the energy use between 2000 & 2005. In its National Renewable Energy Action Plan Ireland proposed to meet its 16% Renewable energy target by implementing [1]:

- 40% share of renewable electricity.
- 12% share of renewable energy in the heat sector.
- 10% of renewable energy supplying the transport sector.

The Department of Communications, Climate Action and Environment (DCCAE) in the 2015 Energy White Paper set a specific target of reducing Ireland's greenhouse gas (GHG) emissions by 85% to 90% compared to 1990 levels by 2050 [2].

In 2016, the EU's Clean Energy Package committed EU members to increase RES share from 20% in 2020 to 32% by 2030. The energy package also comprised a new energy rulebook under which each Member State drafts National Energy and Climate Plans (NECPs) for 2021-2030 setting out how to achieve their energy union targets, and in particular the 2030 targets on energy efficiency and renewable energy. The package is also designed to create a smarter and more efficient electricity market.

As part of the Clean Energy Package, the EU agreed to the updating recast of the Renewable Energy Directive (Directive (EU) 2018/2001) [3]. This may be also referred to as "RED II". Under RED II, key changes were introduced to facilitate the integration of gas including hydrogen from renewable energy sources into the gas system. Some of the key changes include:

- Guarantees of Origin (GoOs) are extended to cover renewable and low-carbon gases. This enables greater cross- border trade in such gases.
- Ensure consistency between the different GoO systems for electricity, hydrogen and gas.

- Annual increase of 1.3 % of renewables' share in heating and cooling starting from the level achieved in 2020.
- The Member States, where relevant, shall assess the need to extend the existing gas network infrastructure to facilitate the integration of gas from renewable energy sources.

The Irish Governments 'Climate Action Plan 2019' outlines decarbonisation strategies across key sectors including Electricity, Transport, Built Environment, Industry and Agriculture [4]. For Ireland to achieve necessary CO_2 emissions reductions, the plan sets out key targets in each sector for 2030:

- 70% Renewable Electricity Sources (RES-E): Reduce CO_2 eq. emissions from the electricity sector by 50–55% relative to 2030 Pre-NDP projections, by developing at least 3.5 GW of offshore wind and up to 1.5 GW of solar energy and up to 8.2 GW of onshore wind capacity.
- 1 million electric vehicles (EVs): Reduce CO_2 eq. emissions from the transport sector by 45–50% relative to 2030 pre-NDP projections. There are also plans to prohibit the sale of new petrol and diesel Vehicles by 2030.
- 600,000 renewable heating sources: Deploying renewable heating sources including heat pumps to decarbonise residential buildings.

In July 2020, the European Commission (EC) unveiled the EU's roadmap for hydrogen development out to 2050 in a report titled 'A hydrogen strategy for a climate-neutral Europe' [5]. During the timeframe 2020-2030, the report details investments of between €24-42 billion for 40 GW of electrolyser capacity and €220-340 billion to scale up and directly connect 80-120 GW of wind and solar energy to the electrolysers.

The roadmap is split into three phases and each has a strategic objective.

Phase 1: 2020-2024

Policy: Phase 1 lays out the regulatory framework required for a well-functioning hydrogen market. This includes incentivising both supply and demand in lead markets e.g. bridging cost gap between conventional solutions and renewable and low-carbon hydrogen, state aid rules. Enabling framework conditions will push concrete plans for large wind and solar plants dedicated to gigawatt-scale renewable hydrogen production before 2030.

Technology Scale and Funding: Phase 1 aims for up to 6 GW of renewable electrolyser capacity installed in the EU by 2024. With this capacity, producing up

to 1 million tonnes of Green hydrogen annually. To achieve this European electrolyser manufacturing needs to be scaled up. Green hydrogen projects will be able to access funding through the European Clean Hydrogen Alliance, Next Generation EU, Strategic European Investment Window (InvestEU) and the ETS Innovation Fund.

Applications: electrolysers could be installed next to existing demand centres in larger refineries, steel plants, and chemical complexes. It is envisaged that they would be powered directly from local renewable electricity sources. In addition, hydrogen refuelling stations will be needed for the uptake of hydrogen fuel-cell buses and trucks.

Phase 2: 2025-2030

Policy: Phase 2 is designed to ramp up the EU's financial support and stimulate investments to facilitate hydrogen becoming an intrinsic part of an integrated energy system. EU-wide logistical infrastructure will be required, and steps will be taken to transport hydrogen from areas with large renewable potential to demand centres located possibly in other Member States. The existing gas grid could be partially repurposed for the transport of renewable hydrogen over longer distances.

Technology Scale and Funding: Phase 2 plans for up to 40 GW of renewable electrolyser capacity installed in the EU by 2030. With this capacity, producing up to 10 million tonnes of green hydrogen annually. In this phase, renewable hydrogen is expected to gradually become cost-competitive with other forms of hydrogen production.

Applications: "Hydrogen Valleys" will develop, relying on local production of hydrogen based on decentralised renewable energy production and local demand, transported over short distances. Dedicated demand side policies will be required for industrial demand to gradually include new applications, including steelmaking, trucks, rail and some maritime transport applications, and other transport modes. Renewable hydrogen will start playing a role in balancing a renewables-based electricity system. providing flexibility by transforming electricity into hydrogen when renewable electricity is abundant. Hydrogen will also be used for daily or seasonal storage, as a backup and enhancing security of supply in the medium term.

Phase 3: 2030-2050

Policy: In the 3rd phase, from 2030 onwards and towards 2050, policies implemented in phase 1 and 2 allow renewable hydrogen to reach maturity.

Technology Scale and Funding: It is expected that renewable hydrogen technologies reach maturity and be deployed at large scale to reach all hard-to decarbonise sectors where other alternatives might not be feasible or have higher costs.

Applications: Hydrogen and hydrogen-derived synthetic fuels, based on carbon neutral CO_2, could penetrate more largely across a wider range of sectors of the economy, from aviation and shipping to hard-to-decarbonise industrial and commercial buildings. Sustainable biogas may also have a role in replacing natural gas in hydrogen production facilities with carbon capture and storage to create negative emissions.

2.2 Historical Energy Consumption and Emissions

2.2.1 Global Energy Consumption & Emissions

Since the industrial revolution, fossil fuels have been the main sources for the global primary energy supply. In addition, fossil fuels have acted as a fundamental driver for technological, social and economic development. Unfortunately, these fuels have been the dominant source of air pollution and emitter of CO_2 and other greenhouse gases (GHGs). Figure 1 shows that in the last 30 years, coal, natural gas and oil have been the major contributors to the global primary energy supply. Primary and secondary oil consumption has jumped from 3.23 Btoe (billion tonnes oil equivalent) to 4.35 Btoe in this timeframe, with natural gas and coal seeing similar hikes in the same period.

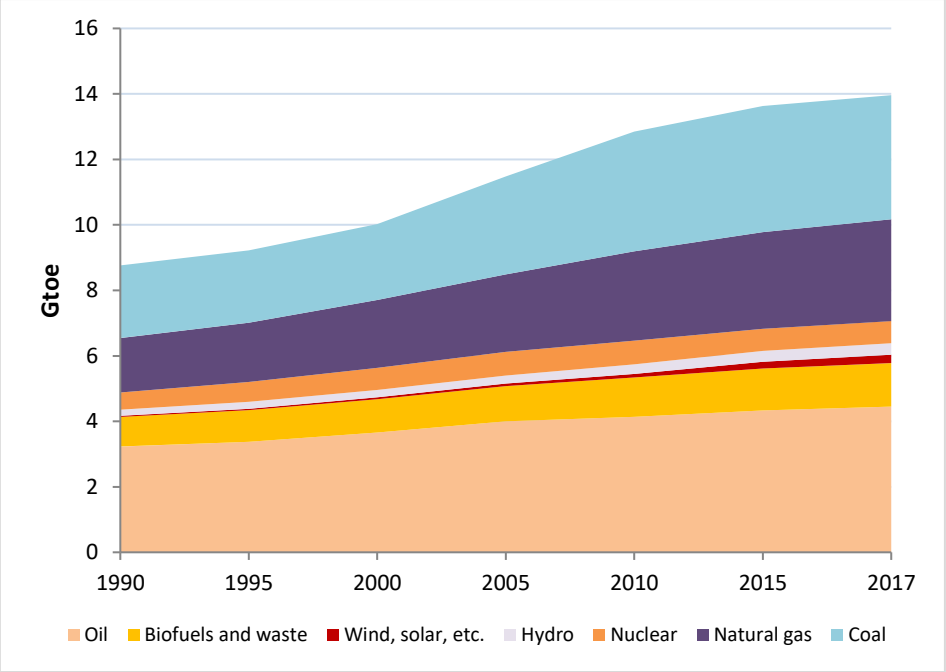

Figure 1 Global Total Primary Energy Supply 1990-2017 [6].

Since 1990, the use of renewable fuels as a primary energy supply has grown exponentially as a product of a shift in policy towards clean energy production. Figure 2 demonstrates this growth. The percentage increase between 1990 and 2017 was over 600% for renewable technologies such as geothermal, wind and solar. Hydro power grew by 90%, while Nuclear and Biofuels/waste also increased by over 29% and 47% respectively.

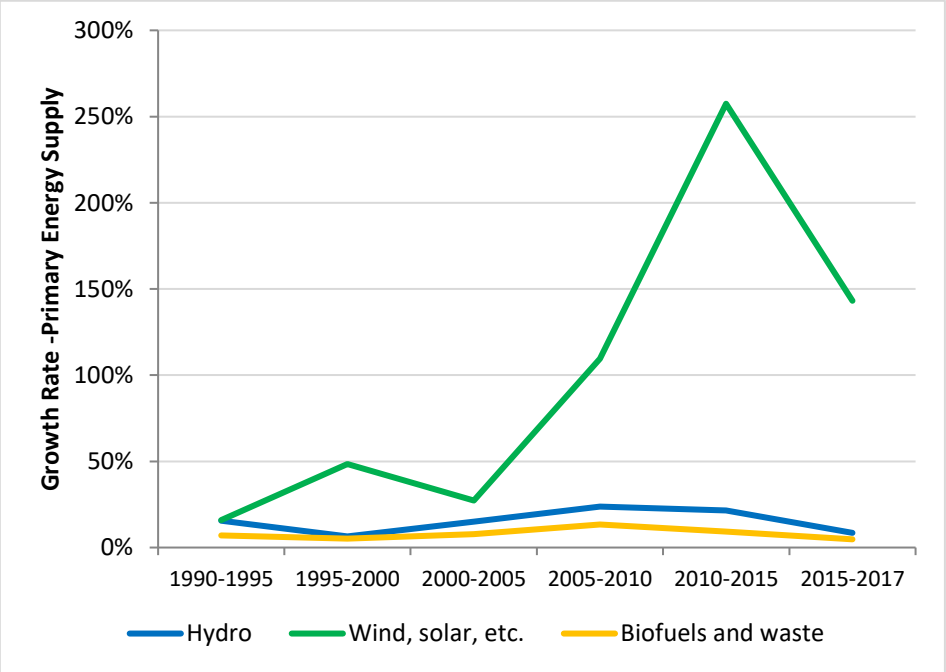

Figure 2 Growth in Renewable Energy Sources Use in Primary Energy Supply [6].

The European Union has made significant progress in reducing the reliance on coal; however, the growth in GDP and population in China and India and other developing countries has contributed to a rise in the use of coal as a primary energy source. While the use of fossil fuels is continuing to grow, the rate of growth has slowed down since the turn of the century (See Figure 3).

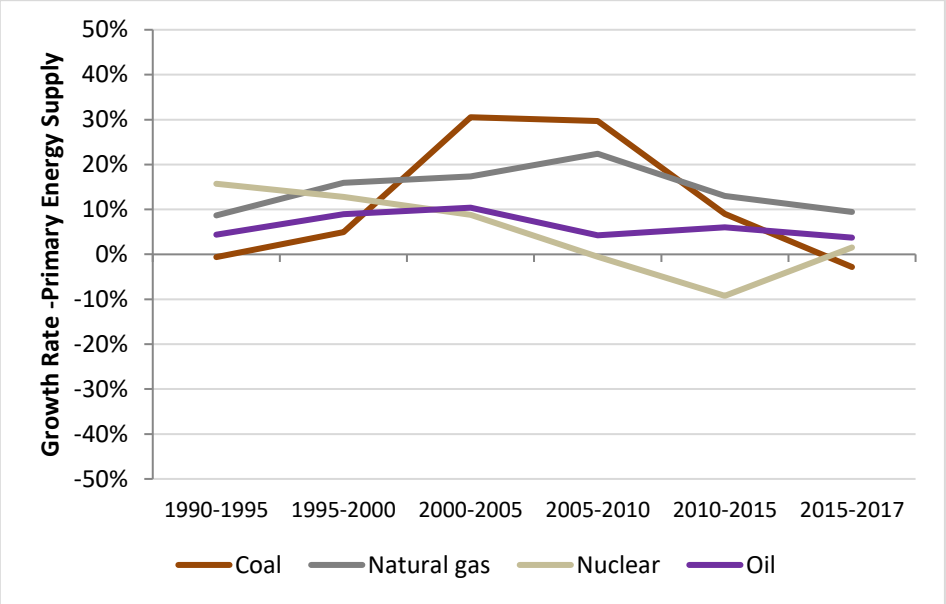

Figure 3 Growth Rate in Fossil Fuel Primary Energy Supply Use [6].

The continuing rise in CO_2 emissions globally is a cause for grave concern. In 1990, just over 20 billion tonnes of CO_2 were emitted into the atmosphere. The amount of CO_2 released in 2010 surpassed 30 billion tonnes (See Figure 4).

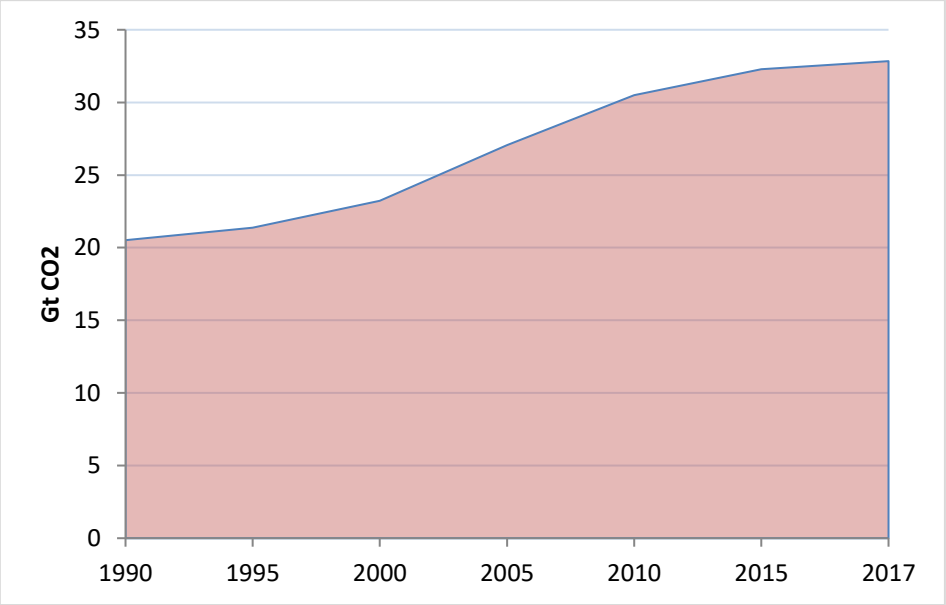

Figure 4 Global CO_2 Emissions 1990-2017 [6].

The breakdown of global CO_2 emissions in 2017 is illustrated in Figure 5. The Electricity generators and heat producers (combined heat and power and heat plants) combined were the highest emitters accounting for 41%, with transport and industry contributing 25% and 19% respectively.

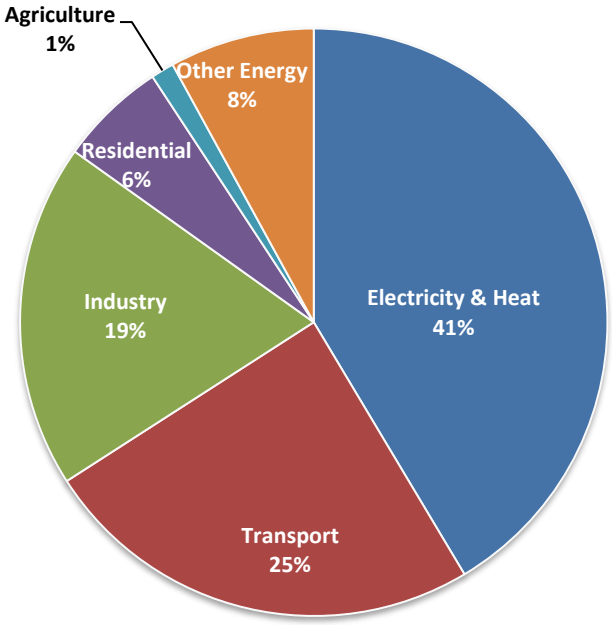

Figure 5 Share of Global Emissions By Economic Sector 2017 [6].

2.2.2 Ireland's Energy Consumption & Emissions

Consumption & Emissions by Sector

Analysing data obtained from the central statistics office (CSO) in Figure 6, it is clear that the transport, industry and residential sectors have been the highest consumers of energy over the last the 15 years. The transport sector is the highest consumer at present. Demand for energy in Ireland has been on an upward trend since 2012 as Ireland's economy emerged from a recession. In 2018, transport energy consumption amounted to over 5.2 Mtoe (42% of the final energy consumption). The residential sector was the next highest consumer at 2.8 Mtoe (23% of the final energy consumption), followed closely by industry requirements totalling 2.6 Mtoe (21% of the final energy consumption).

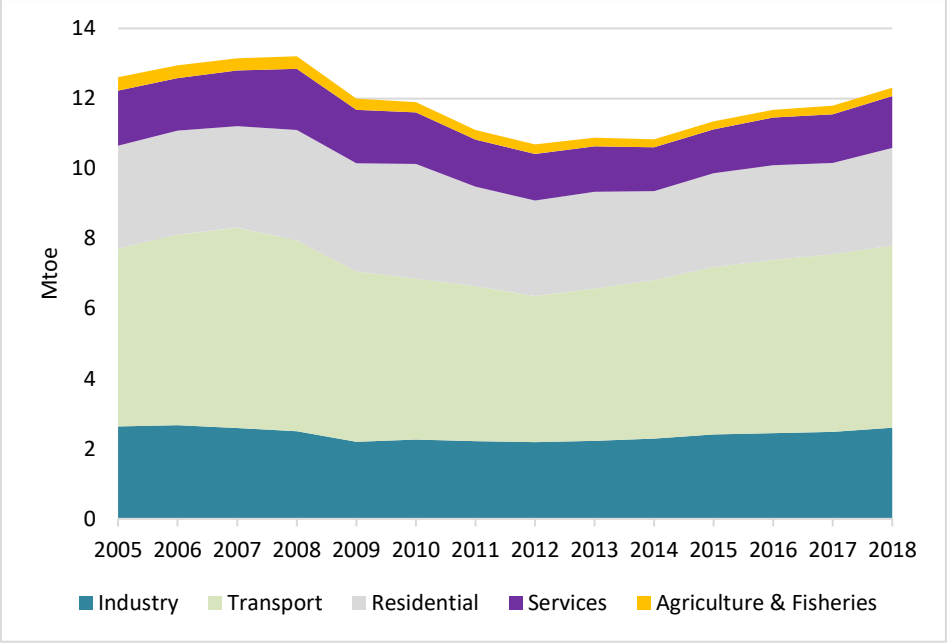

Figure 6 Ireland's Final Energy By Sector 2005-2018 [7].

Since 2005, the transport sector has contributed to the highest levels of emissions (See Figure 7). Industry and the residential sectors are the next largest emitters. It is noted that for both of these sectors and the services sector there have been decreasing trends in terms of emissions over the past 15 years. While emissions from the agriculture and fisheries sector have also seen a drop over the same period but at a lower rate of reduction.

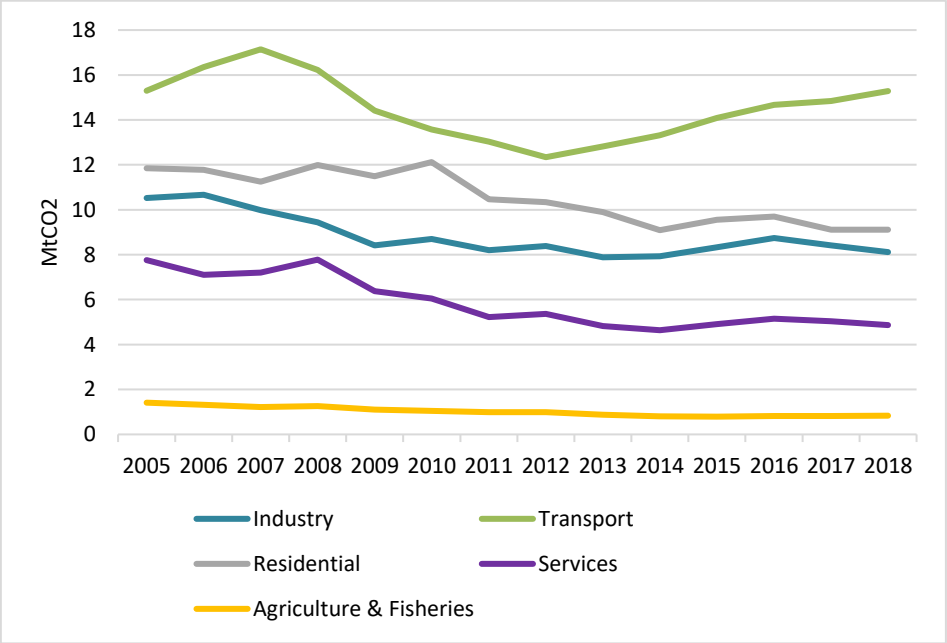

Figure 7 Ireland's CO_2 Emissions By Sector 2005-2018 [8]

Transport Sector

When comparing the demand for energy in the transport sector in 2005 and more recently 2018 it appears that there has been no significant change. However, in this period there has been a changing landscape in terms of the consumption by fuel type. The increase in demand for diesel has contributed to the rising transport emissions. Demand for petrol has halved in the same timeframe while the demand for electricity has been negligible. It is evident from Figure 8 that demand for fuel in the transport sector is highly dependent on the performance of the economy.

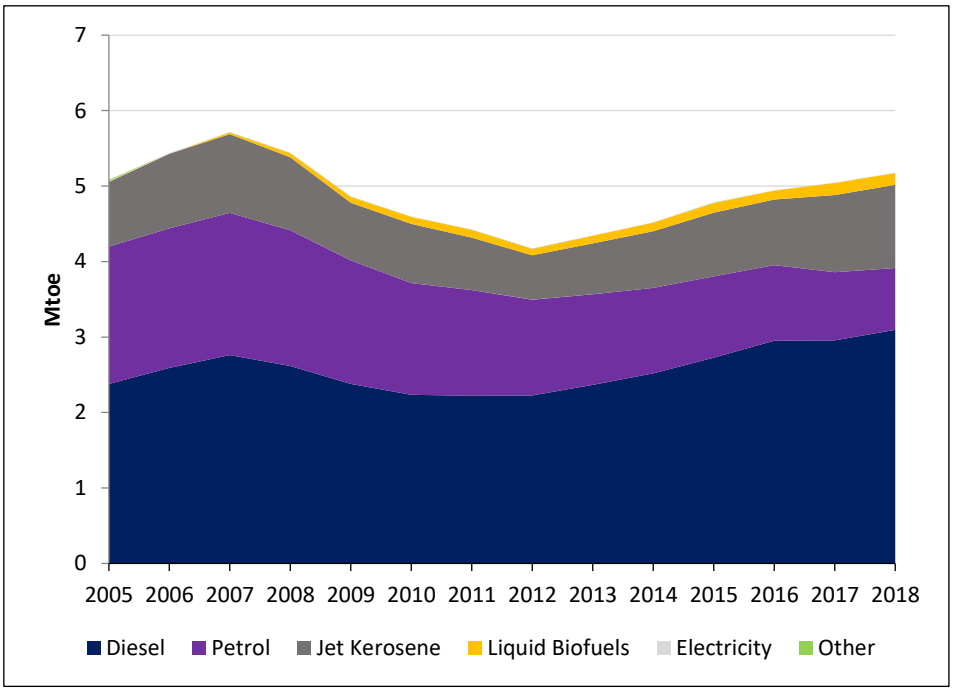

Figure 8 Transport Final Energy Consumption By Fuel Type 2005-2018 [9].

From Figure 9, when comparing the share of final consumption in the transport sector by category it is clear that road private cars are responsible for the highest share with over 35% since 2005. Road freight/ Heavy goods vehicles and international aviation have been the next largest consumers. Fuel consumption from rail transportation remained relatively unchanged. However, consumption in light goods vehicles has grown significantly over the past 15 years to 6.4%.

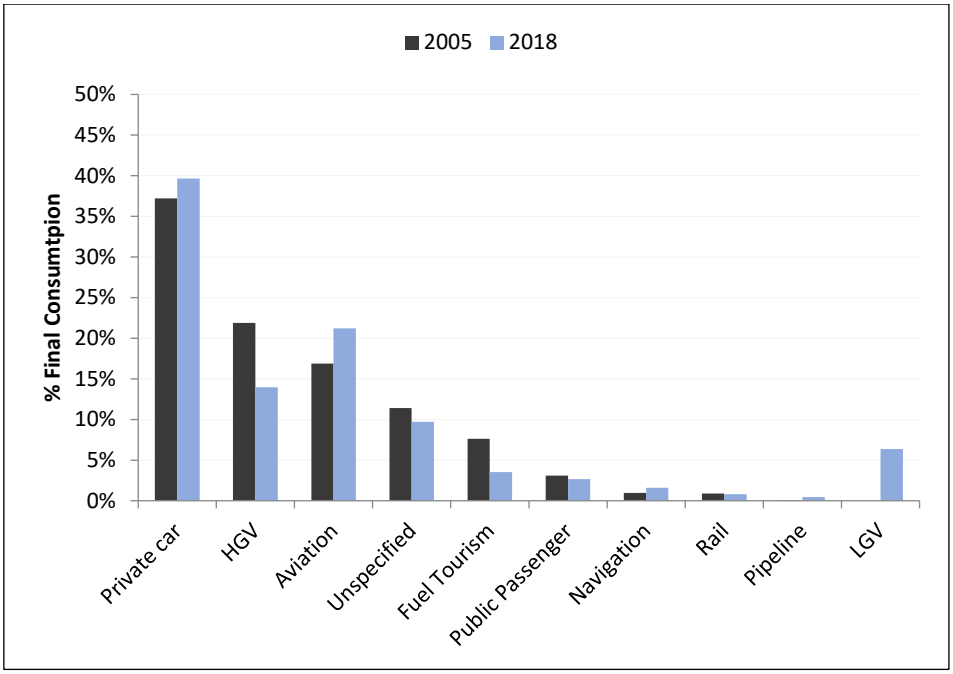

Figure 9 Share of Final Consumption in Transport By Category [9].

The bulk of CO_2 emissions in the transport sector over the past 15 years have been associated with road transportation. Figure 10 displays the CO_2 emissions in this sector since 2005. In 2018 road transportation accounted for over 95% of emissions in the transport sector.

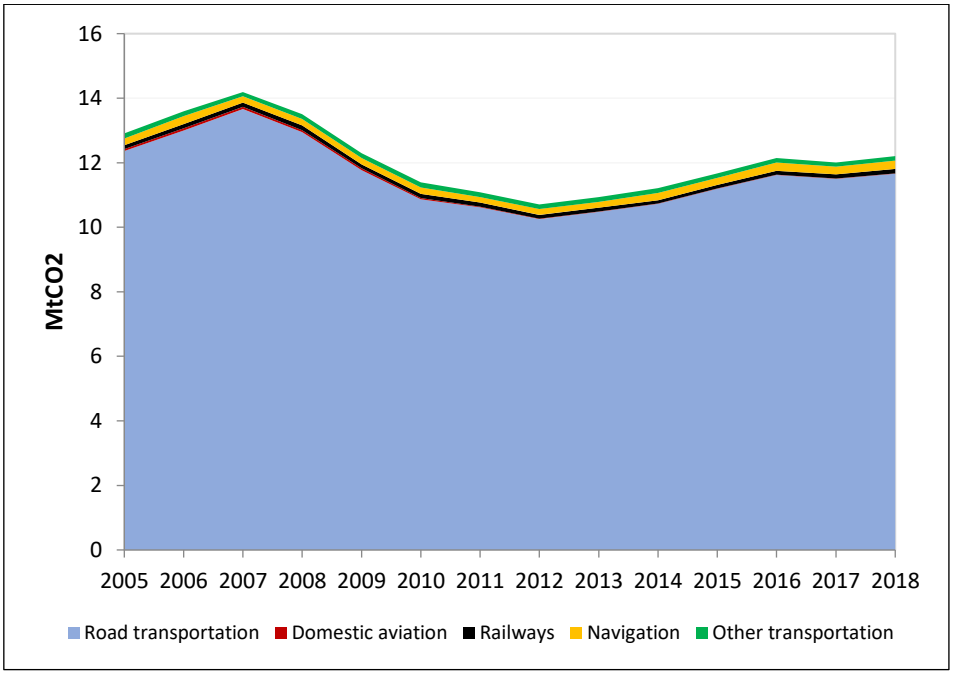

Figure 10 Contribution to CO_2 Emissions in Transport 1990-2016 [8].

Industry Sector

From Figure 11, the demand for fuel in the industry sector increased by approximately 18% when comparing the demand in 2009 and 2018 following a drop off in demand on the back of the economic downturn in 2008. Fuel oil was a major contributor in the industry until 2010, however its usage has tailed off in recent years. Electricity and natural gas have become the main fuel source for industry since 2005 – overtaking fuel oil. The consumption of renewable fuels has remained relatively low since 2005 with a total of 0.198 Mtoe consumed in 2018.

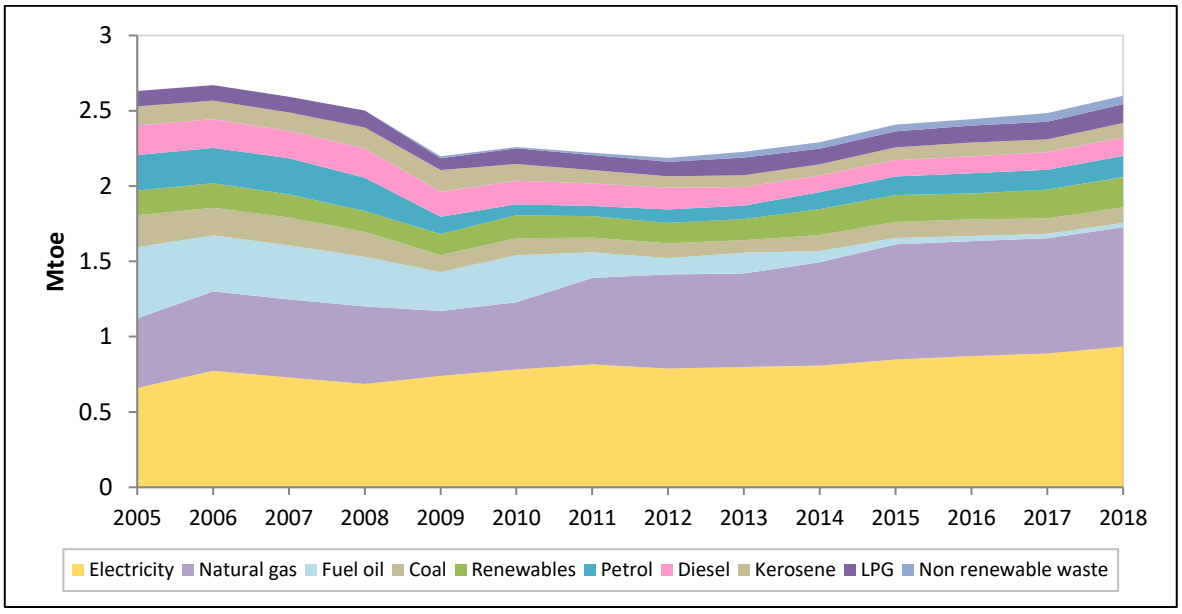

Figure 11 Industry Final Consumption By Fuel Type 2005-2018 [7].

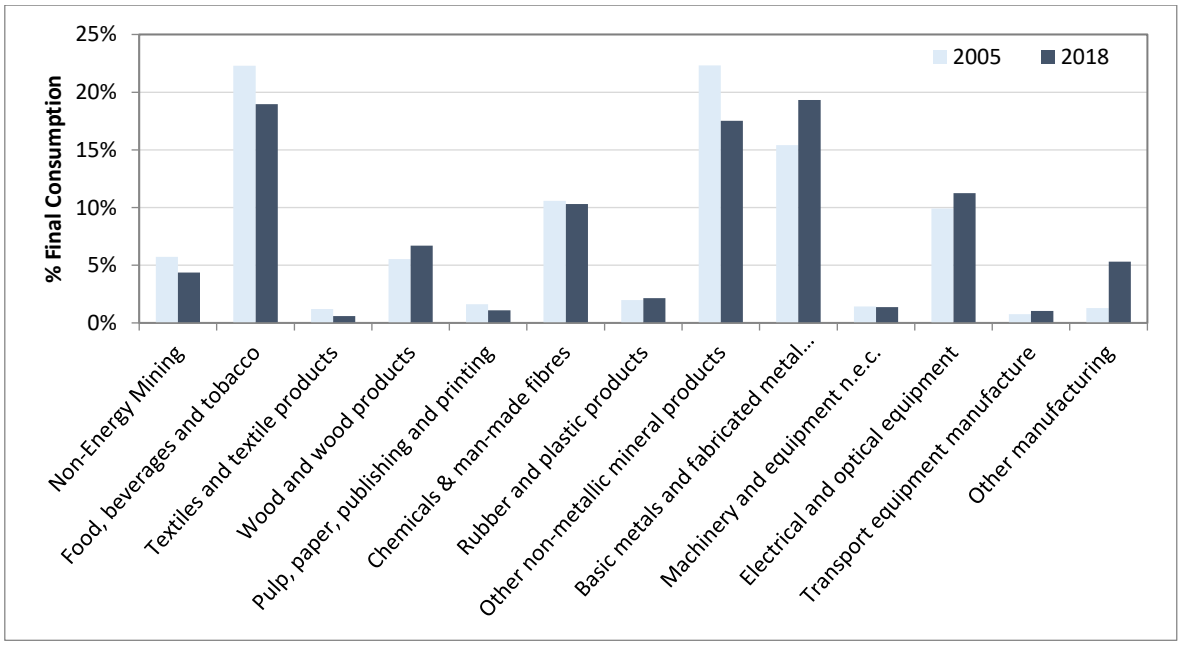

Figure 12 Share of Final Consumption in Industry By Category [7].

In terms of CO_2 contribution, the mineral industry has historically been the highest contributor as shown in Figure 13. The mineral industry includes the manufacturing of cement, asphalt and other aggregate products. The CO_2 emissions arising from the use of non-energy products such as lubricants and paraffin wax have remained at similar levels to 2005.

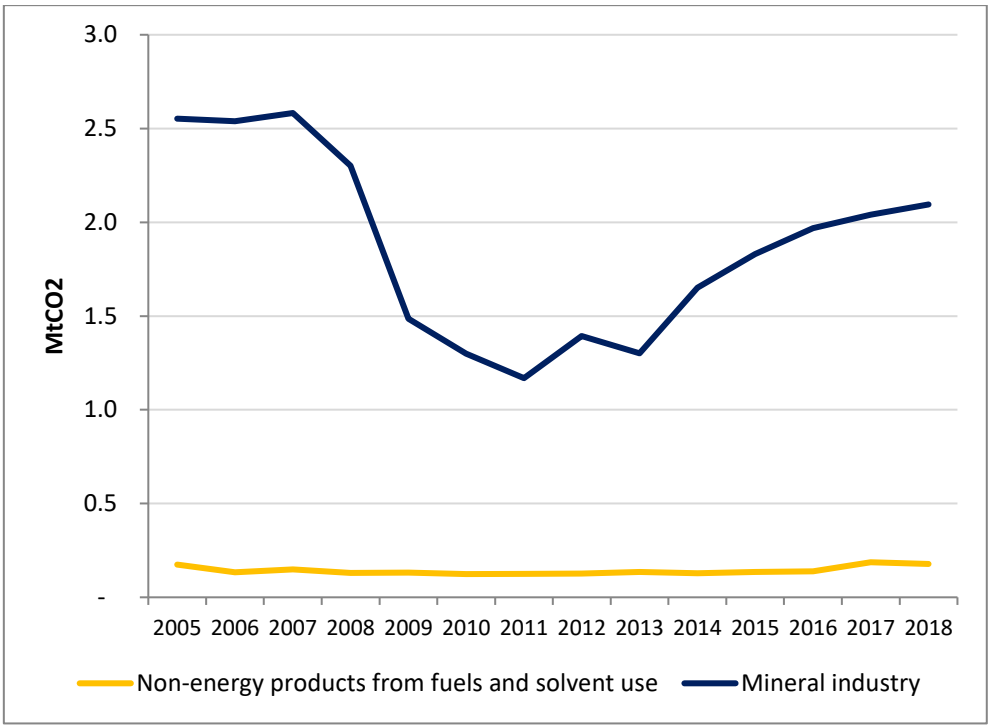

Figure 13 Contribution to CO_2 Emissions in Industry 2005-2018 [8].

Heat Sector

Natural gas, oil and electricity are the main energy sources currently used for heating in the sector. In 2018, the sector was responsible for a quarter (24%) of the energy-related CO_2 emissions. From 2006 to 2014 there were significant reductions in the energy used in homes and the resulting CO_2 emissions [10]. This may be partly due to the economic downturn in 2008. Since 2014 this trend has reversed, energy use in households was 9% higher in 2018 than in 2014. Despite an increase in energy use, CO_2 emissions did reduce slightly between 2016 and 2018, mainly due to a reduction in the carbon intensity of electricity generation.

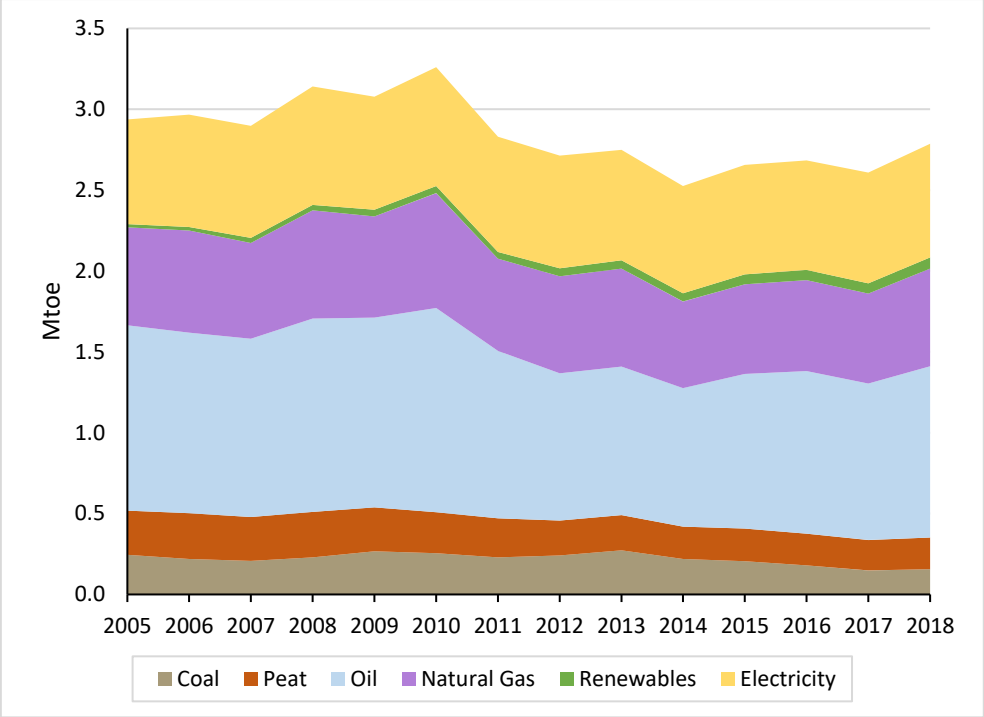

Figure 14 Residential Final Consumption by Fuel Type 2005-2018 [10].

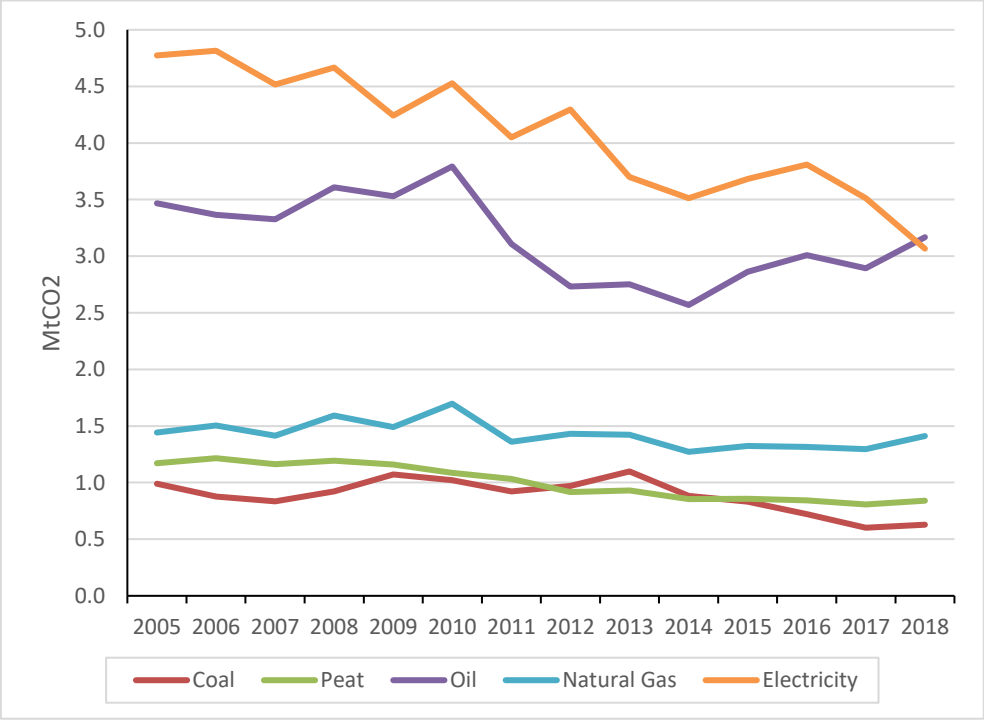

Figure 15 Residential CO_2 emissions by Fuel Type 2005-2018 [10].

2.2.3 Ireland's Progress Towards Meeting 2020 Climate Targets

According to the Sustainable Energy Authority of Ireland (SEAI) [11], Ireland is not on track to achieve its climate targets set out under the RED 2009/28/EC and the National Renewable Energy Action Plan. The heat and transport sectors are not expected to meet their respective targets of 12% and 10% renewable energy by the end of 2020. However, the electricity sector is on track to achieve a 40% share of renewable electricity (RES-E). (See Figure 16).

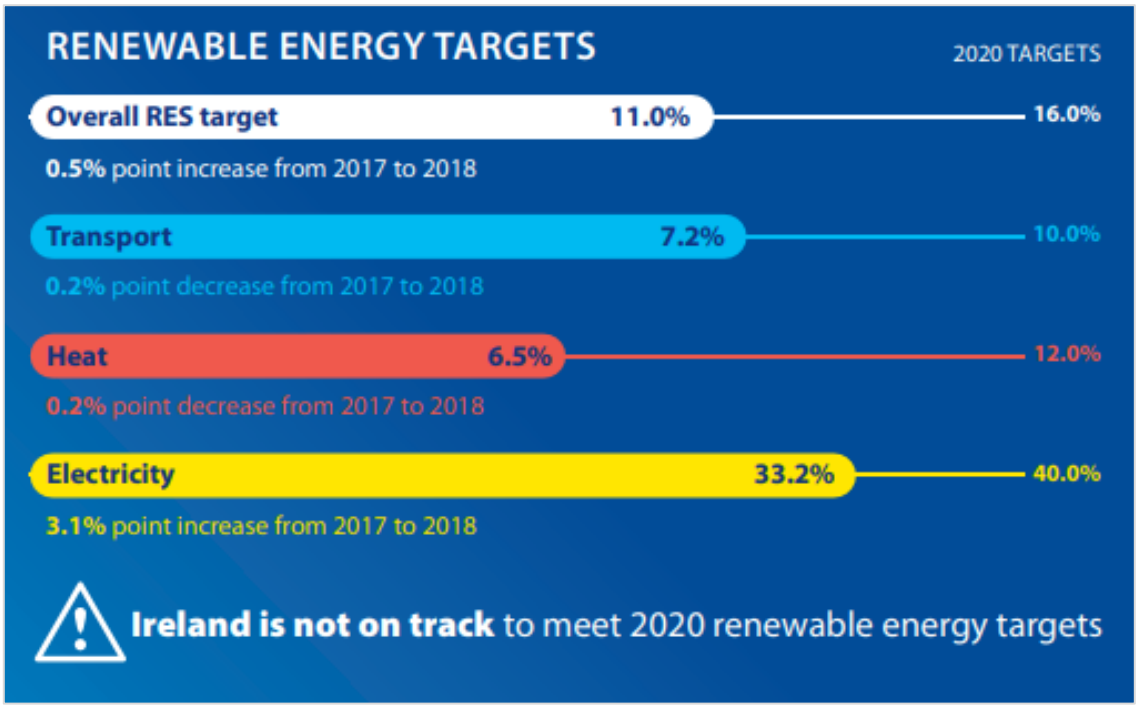

Figure 16 SEAI Ireland's progress towards 2020 climate targets [11].

2.3 Ireland's Transport Sector

2.3.1 Current Technologies

Ireland heavily depends on oil in transport. The majority of vehicles are fuelled by petroleum products. Ireland has no domestic commercial oil production and is therefore 100% dependent on petroleum product and crude oil imports. While the majority of oil imports into the state are in the form of refined product, significant volumes of crude oil are also imported. Crude oil is imported into Ireland by a single refinery, located at Whitegate, in Co Cork [12].

Table 1 illustrates the number of vehicles by fuel type and vehicle category in Ireland for 2018. Figure 17 shows the share of fuel type by vehicle category and demonstrates the reliance on fossil fuels for the transport sector.

Table 1 Ireland Number of Vehicles by Fuel Type 2018 [13].

Vehicle Category	Petrol	Diesel	Other	Total
Private cars	946,864	1,129,397	41,202	2,117,463
Goods vehicles	664	353,571	223	354,458
Motorcycles	39,747	52	52	39,851
Tractors and machinery	328	85,445	47	85,820
Small PSVs	2,500	17,468	1,351	21,319
Large PSVs	11	10,684	0	10,695
Exempt vehicles	6,372	22,123	545	29,040
Other vehicles	22,387	47,847	120	70,354
Subtotal	**1,018,873**	**1,666,587**	**43,540**	**2,729,000**

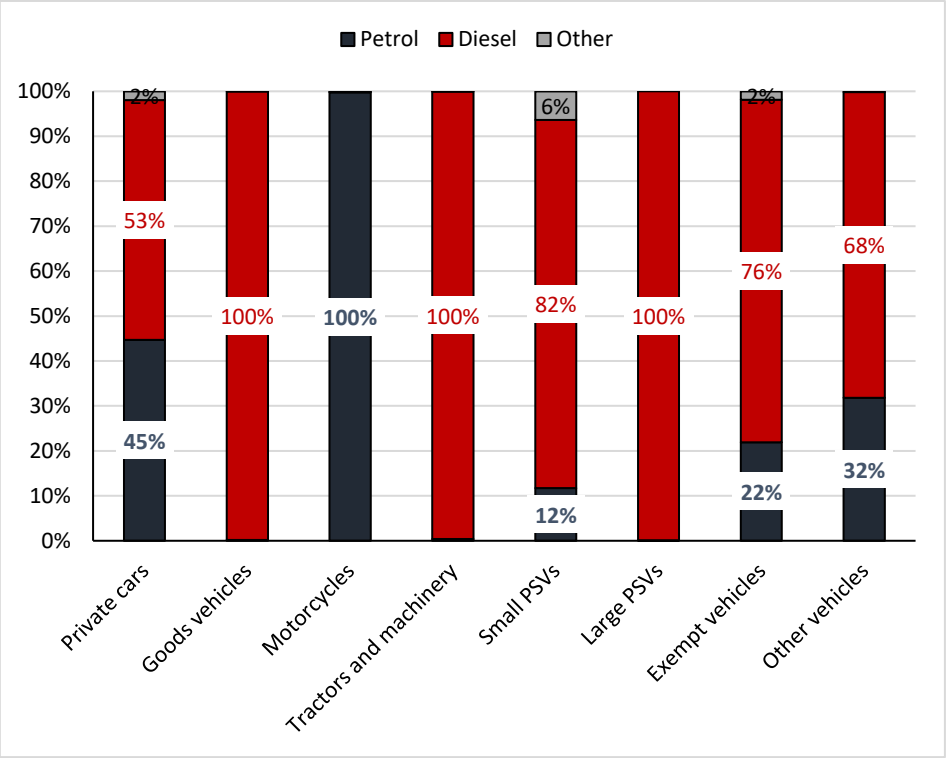

Figure 17 Ireland Breakdown of Vehicle Fuel Type by Transport Category 2018 [13].

2.3.2 Decarbonising Transport

Electric Vehicles

The Climate Action Plan 2019 set a target to have 936,000 EVs (including battery EVs and plug-in hybrid EVs) on Irish roads by 2030. This is equivalent to one-third of around 2.8 million vehicles that are currently on the road in Ireland. The government committed significant funding to support electric vehicles (EVs) through the National Development Plan which includes an allocation of €200 million for the period 2018-

2027 [12]. DCCAE provides the following supports which are delivered by the SEAI [14]:

- Purchase grant of up to €5,000 for new battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs).
- Home Charger Grant Scheme.
- Public Charge Point Scheme.
- Current Government incentives to support EV purchases also include:
    - VRT relief of up to €5,000 for the purchase of BEVs and up to €2,500 for PHEVs.
    - Benefit-in-Kind tax relief for battery electric vehicles.
    - Grants of up to €10,000 for EVs for the taxi sector (plus an extra €2,500 if taxi is made wheelchair accessible), administered by the National Transport Authority (NTA).
    - Accelerated Capital Allowances for businesses.
    - Low rate of annual motor tax.
    - Tolling reductions of 50% for battery electric vehicles and 25% for plug-in hybrid electric vehicles.

Biofuels

Biofuels are renewable liquid or gaseous fuels used in transport and are created from biomass material. Typically, biofuels are deployed blended with fossil fuels in Ireland with bioethanol blended with gasoline in petrol (up to 5% volume) and biodiesel blended with fossil diesel (up to 7%). Bioethanol is typically produced from crops including barley, wheat and sugar cane with biodiesel produced from oil crops such as rapeseed as well as from wastes such as used cooking oil and animal fats [12].

The Biofuels Obligation Scheme was introduced in 2010 and is administered by the National Oil Reserves Agency (NORA). This is a certificate-based scheme which sets out an obligation that suppliers of road transport fuels must include a certain percentage of environmentally sustainable biofuels across their general fuel mix. The scheme ensures that each supplier fulfils their requirement by having the necessary number of biofuel certificates required.

Hydrogen, CNG, LNG and Biogas

Hydrogen can be used to power vehicles through either combustion or fuel cell technology. Recent developments are predominately focused on fuel cell electric

vehicles (FCEV) whereby a fuel cell converts chemical energy into electricity allowing vehicles to operate similar to EVs. Storing energy as hydrogen is significantly lighter and utilises less space than battery technology, making hydrogen a suitable alternative for heavier vehicles operating over greater ranges. Hydrogen FCEVs have zero carbon emissions with only water vapour and warm air emitted, contributing to greenhouse gas emission reduction and improved air quality.

The second phase of the low-emission task force established by DCCAE focuses on the stimuli and planning legislation to support low emission vehicle types including hydrogen, Biogas, compressed natural gas (CNG) and liquefied natural gas (LNG). The vehicle support recommended by the low emission task force include to expand the supports available for battery electric vehicles to hydrogen vehicles such as purchase grants, vehicle registration tax relief, benefit-in-kind tax relief, a low rate motor tax, accelerated capital allowances and reduced tolls. Additionally, the low emission task force recommend any new vehicle supports put in place for CNG/LNG HDVs should be extended to include hydrogen vehicles [15].

In the transport budget 2021 [16], the government announced €12 million in funding allocated to a number of carbon reduction measures including:

- Supports for a new vehicle purchase grant to help freight and commercial bus operators to buy electric, gas or hydrogen fuelled vehicles
- Funding to trial hydrogen fuelled buses as well as supporting the further transition of Local Link services to zero-emission vehicles in rural Ireland

In parallel to the second phase of low emission task force, a new industry-led group was established seeking to develop a strategy for use of hydrogen in the transport sector in Ireland. Hydrogen Mobility Ireland is comprised of a range of member organisations including vehicle manufacturers, public transport providers, energy companies and hydrogen producers [17].

2.4 Ireland's Heat Sector

2.4.1 Current Technologies

Using CSO data from the latest census (2016), Table 2 presents the current fuels used for space heating requirements in Ireland in domestic households. Oil and natural gas are the dominant sources heating 41% and 34% of homes, respectively. Electricity was used to heat 9% of households with coal, peat, LPG and wood used to heat the remaining housing stock.

Table 2 Residential space heating requirements, CSO 2016 [18].

Household Central Heating By Fuel Type (2016 Census)		
Fuel Type	**No. Households**	**%**
Oil	686,004	41%
Natural Gas	569,166	34%
Electricity	146,302	9%
Coal	86,611	5%
Peat	90,029	5%
LPG	9,990	1%
Wood	33,976	2%
Other	11,068	1%
Not Stated	41,345	2%

2.4.2 Decarbonising Heat

SEAI has studied the sector in detail, including examinations of the transitions followed by other comparable countries. Looking ahead to 2030 and beyond, several options were identified for decarbonising the heat sector in Ireland [19].

- **Improved Energy Efficiency:** Before considering how to supply heat to Irish homes, energy consumption must be reduced; technologies that are needed here are wall, roof and floor insulation, improved windows, doors, draught proofing, and heating controls.
- **Heat Pumps:** A heat pump system harnesses energy from free renewable sources outside the building (including air, water and the ground/geothermal), for heating and producing hot water. As shown in Table 2, most of Ireland's homes are heated by oil, gas and solid fuels. By improving insulation levels and air tightness these homes could be put in a state to enable a shift from direct fossil fuel use to electric heat pumps. The 'Climate Action Plan 2019' targets 600,000 heat pumps being installed in Irish homes by 2030.
- **District Heat:** District heating infrastructure can have a large impact and cost effectively make use of heat that is currently wasted, particularly in areas of

concentrated heat demand, e.g. Dublin. Large power stations and data centres produce large amounts of waste heat suitable for heat networks. The Government is currently supporting district heating projects via the Climate Action Fund. Currently, South Dublin County Council and Codema are developing Ireland's first large scale district heating network in Tallaght [20].

- **Renewable Gas:** Renewable gas injected into the gas grid can perform the same as fossil gas, so consumers can use their existing boilers and do not need to change technology to make use of it. Renewable gas is discussed in more detail later in the report in section 2.10.3.

2.5 Ireland's Electricity Infrastructure

2.5.1 Infrastructure

The electricity transmission network in Ireland consists of 110kV, 220kV and 400kV lines and substations. The transmission system in Northern Ireland is operated at 275kV and 110kV. The 400kV, 275kV and 220kV networks form the backbone of the transmission system. They have higher power carrying capacity and lower losses than the 110kV network. The 110kV circuits provide parallel paths to the 220kV, 275kV and 400kV networks and are the most extensive element of the all-island transmission system, reaching into every county in Ireland. See Figure 18 for a map of the existing and planned 110kV infrastructure in Ireland.

In Ireland, the 400kV network provides a high capacity link between the Moneypoint generation station on the west coast and Dublin on the east coast. EirGrid is planning a new 400kV interconnector between Ireland and Northern Ireland called the North South Interconnector. See Figure 19 for a map of the existing and planned 220kV and 400kV infrastructure in Ireland.

The transmission network in North West region of Ireland is predominantly 110kV. There is no 400kV infrastructure and limited 220kV infrastructure in the area. There is a 110kV transmission network in the area which supplies a relatively low local demand. Development of this network is mainly required to connect a high level of renewable generation. There are few planned new major infrastructure projects for the area. In EirGrid's latest transmission development plan (TDP) 2019-2028, two potential developments mentioned are the 110kV North Connaught Project in Mayo and the RIDP North West project in Donegal [21].

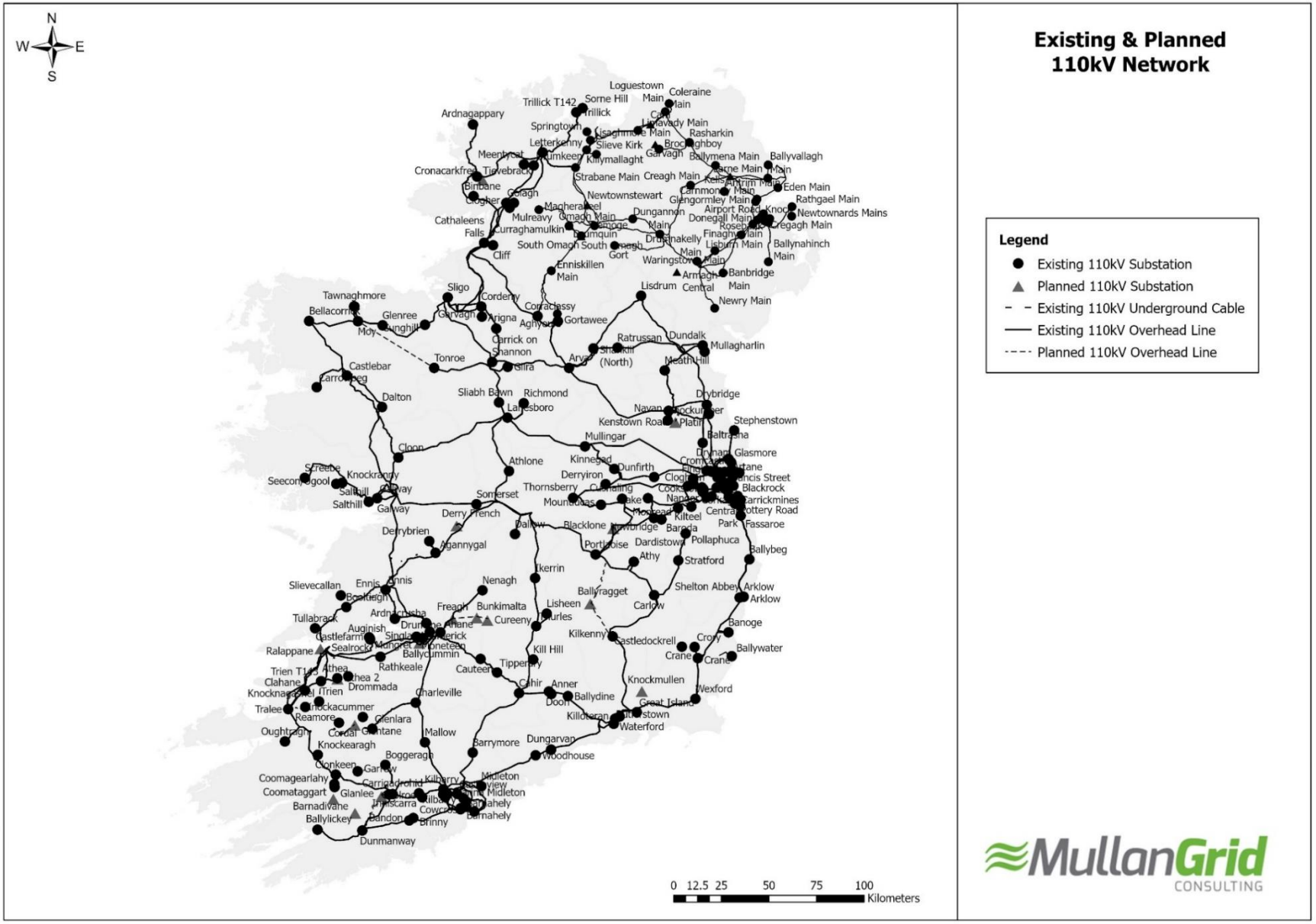

Figure 18 Existing & Planned 110kV Transmission Network in Ireland.

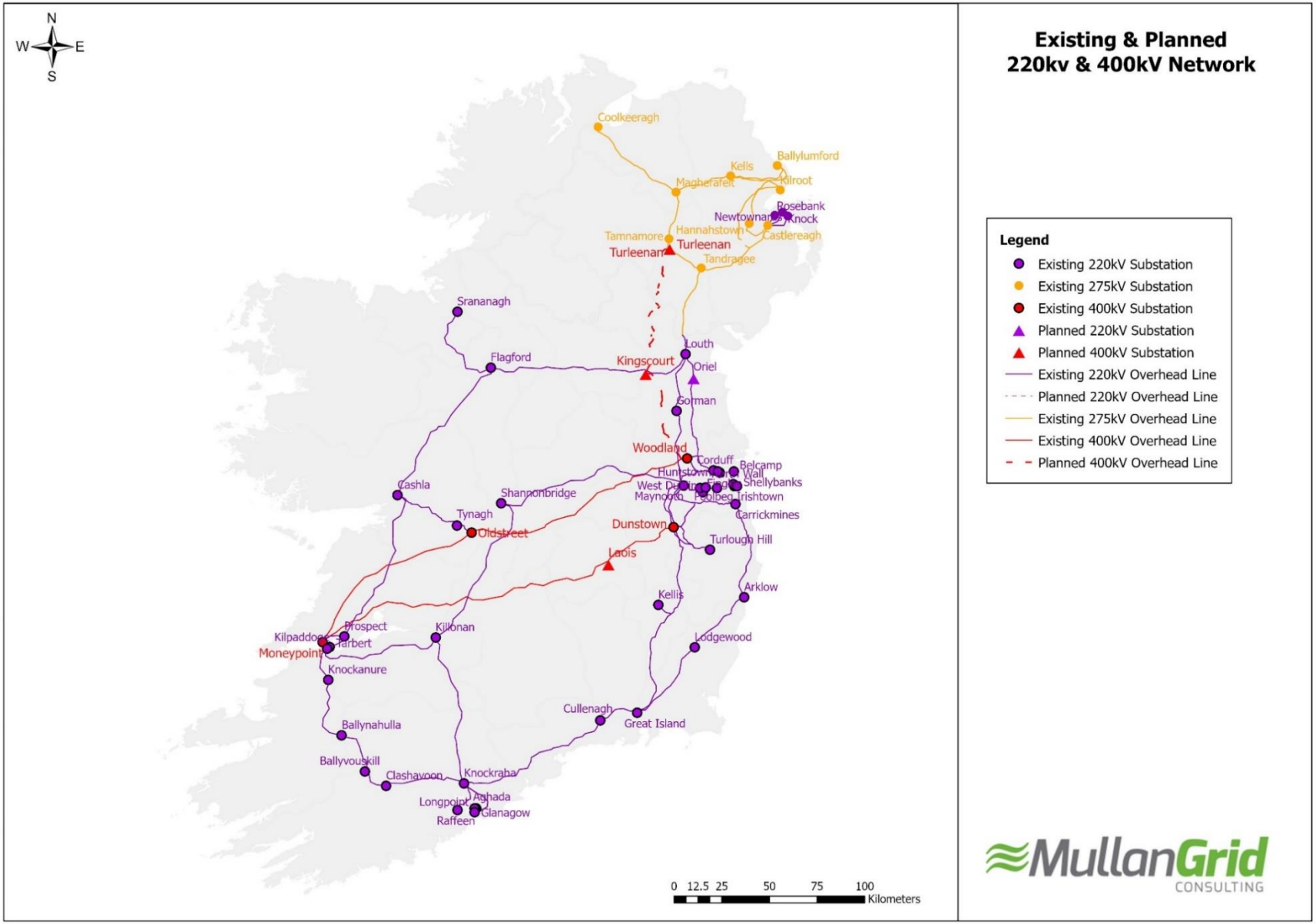

Figure 19 Existing & Planned 220kV & 400kV Transmission Network in Ireland.

2.5.2 Electricity Demand

Demand in the Irish electricity system is forecast to increase significantly (approximately 40%) in the coming decade as shown in Figure 20. The growth is expected to be driven by new data centres connecting to the grid and the roll out of 1 million electric vehicles (EVs) and more than 600,000 heat-pumps. In 2019 the total electricity requirement (TER) in Ireland was approximately 30.9 TWh [22]. EirGrid estimate that the total electricity requirement may increase to 45.5 TWh in 2030 and 49.5 TWh in 2040 [23].

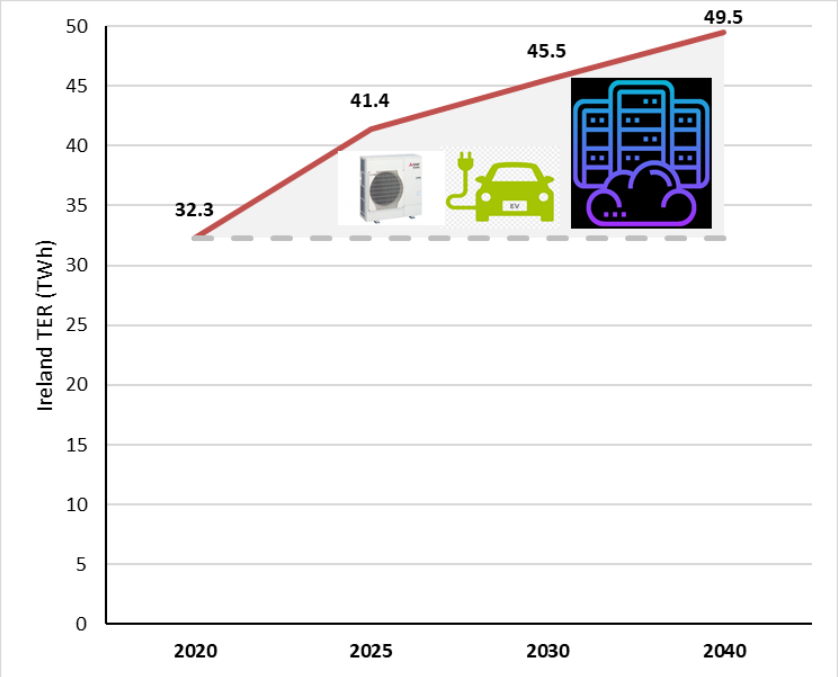

Figure 20 Ireland Total Electricity Requirement (TER) 2020-2040 [22][23].

EirGrid in its latest TDP outlined the oversupply of generation in the North West/ Border Midlands and West (BMW) region (See Figure 21). The Border, Midlands and West planning area has a wide variety of generation sources. These are dispersed around the planning area and include wind, hydro and Gas power stations. There is a 110kV transmission network in the area which supplies a relatively low local demand. Development of this network is mainly required to connect a high level of renewable generation. The excess of generation in the area is set to increase significantly in the coming years. This is due to generators that currently have connection agreements and live connection offers connecting to the transmission and distribution networks. To cater for the high levels of generation described above, network reinforcement is necessary. This will enable the efficient export of generation from this area towards areas with high demand, such as the eastern seaboard/Dublin.

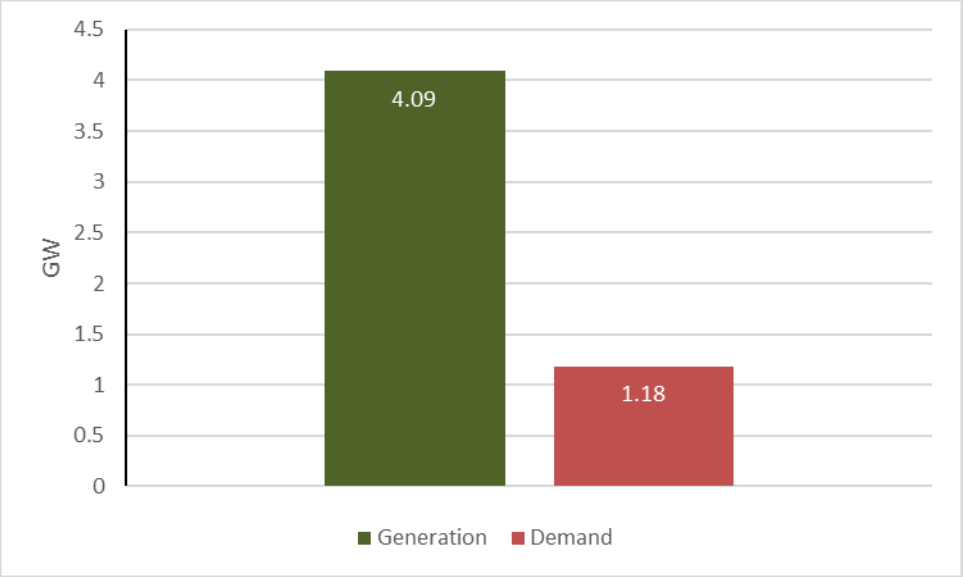

Figure 21 Demand & Generation in the Border, Midlands, and West Regions 2028 [21].

Data Centres

Alongside normal growth of the electricity demand, Ireland is currently experiencing high demand growth due to the relatively large capacity of new data centres locating in Ireland, mainly in the Dublin area. Figure 22 breaks down the projected data centre capacity by region.

Critical to the viability of data centres is the proximity of the facilities to high speed fibre networks and electricity networks. Data centres usually require high levels of redundancy in the fibre and electricity connections. Data centres also appear to strongly value the benefit of clustering. This allows for the sharing of resources. The resilience of the fibre network and the benefits of clustering appears to be the main reasons why existing and new data centres are being located in the Dublin area.

The ability of the transmission system to accommodate further renewables in constrained areas like the North West region would substantially benefit from new large demand connections, particularly data centres that have high capacity factors. For example, there is already fibre optic networks in the North Mayo area so 40-50 MW of new data centre load would more nearly double the demand capacity in the area.

EirGrid recently published a consultation paper on data centre connection policy [24], in which they outline the pipeline of data centres for Ireland and the Dublin region:

- 900 MVA of connected data centres in Dublin.
- 400 MVA of contracted data centres in Dublin.

- Further 1100 MVA of planned data centres consisting of Live, Stage 1, Application or Inquiry projects.
- In total, 2400 MVA pipeline of data centres for Dublin Area.
- Outside of Dublin, there is a pipeline of 500 MVA.
- Total of 3GW of applications and contracted capacity for data centres.

The typical load currently drawn by these customers is approximately 40% of their contracted Maximum Input Capacity. This is expected to rise as these customers build out to their full potential. A significant proportion of this extra load is contracted to materialise in the Dublin region [25]. In 2019 the total electricity requirement in Dublin was approximately 15.9 TWh, this equates to 51.4% of the total electricity requirement in Ireland (30.9 TWh) [22].

A review of literature was carried out to understand the location, scale and potential electricity consumption of data centres in Ireland. However, there is difficulty in attaining information from literature on the sizing and electricity consumption of data centres. Mayo Renewable Power has plans for a data centre in Killala Co. Mayo, but it is currently unclear as to what size data centre is planned. Although EirGrid in its 'Tomorrows Energy Scenarios 2019' estimate 47 MVA of data centre capacity in the western region for 2030 [23].

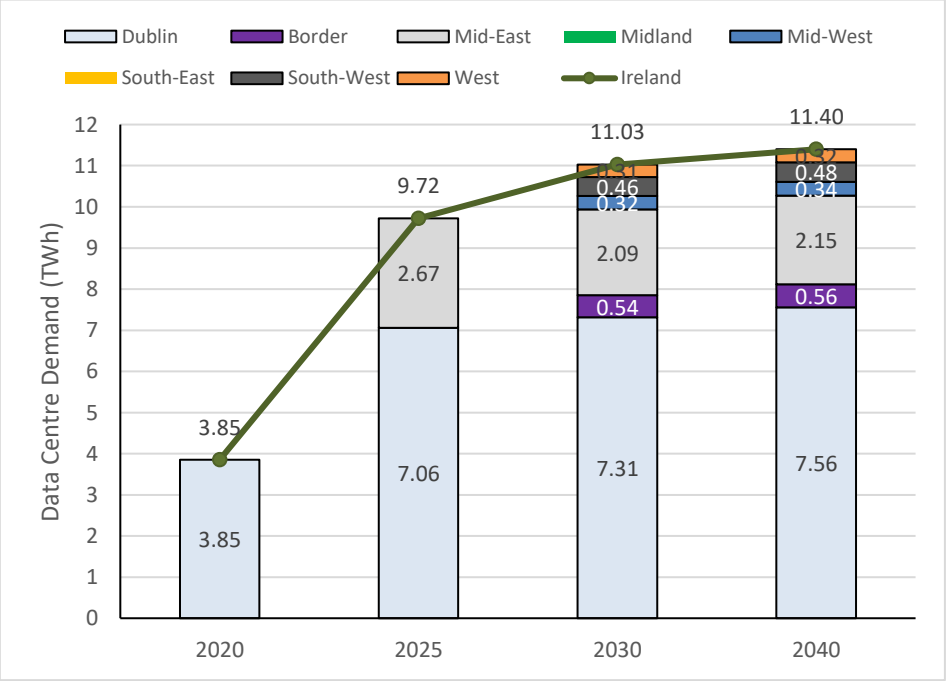

Figure 22 Potential Data Centre Demand 2020-2040 [23].

Electric Vehicles (EVs)

The Coordinated Action scenario from EirGrid's 'Tomorrows Energy Scenarios 2019' accounts for 1,000,000 EVs on Irish roads in 2030 [23]. This projection is in line with the target announced in the governments 'Climate Action Plan 2019'[26]. The forecasted demand by region is illustrated in Figure 23 and it demonstrates the impact of deploying 1,000,000 EVs is modest in comparison to the predicted data centre growth.

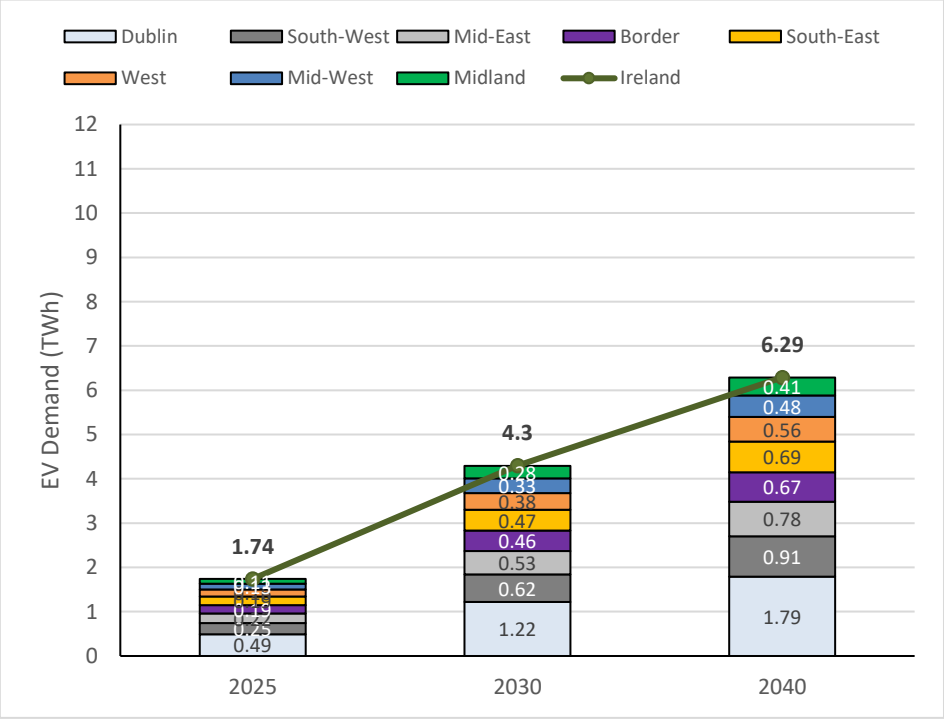

Figure 23 Potential EV Demand 2020-2040 [23].

Heat Pumps

The Coordinated Action scenario from EirGrid's 'Tomorrows Energy Scenarios 2019' accounts for 600,000 EV's heat pump installations by 2030 [23]. This projection is in line with the target announced in the governments 'Climate Action Plan 2019'[26]. From Figure 24, demand growth arising from 600,000 heat pumps in 2030 is estimated by EirGrid to be 2.67TWh and is relatively low in comparison to data centre demand (11.03TWh).

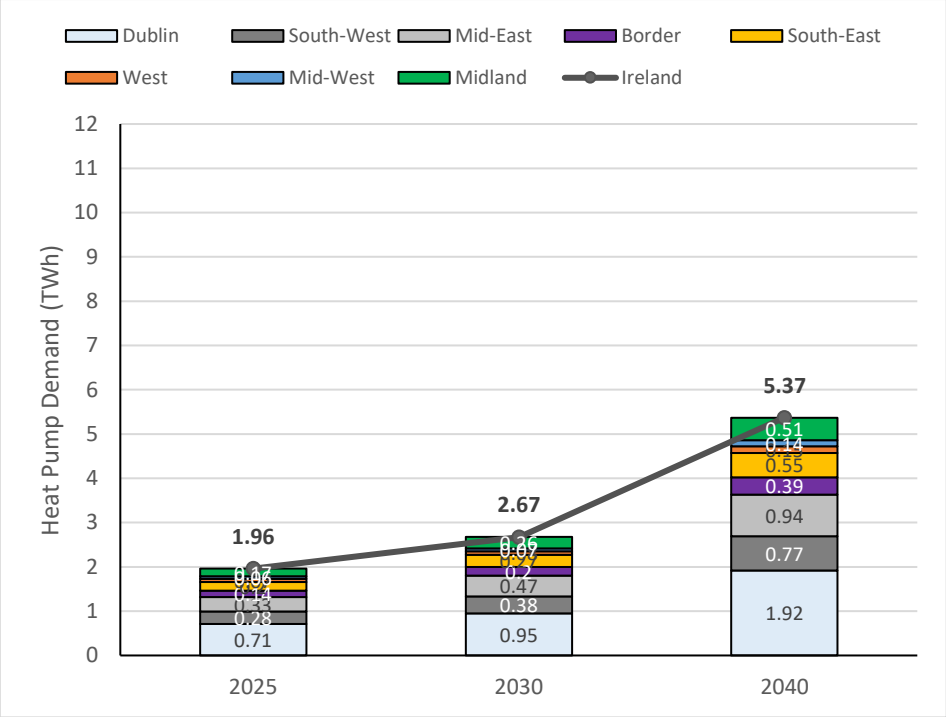

Figure 24 Potential Heat Pump Demand 2020-2040 [23].

2.5.3 Renewable Generation

EirGrid formulated three scenario's for the 2019 Tomorrow's energy scenario's workstream [23]. Two of the scenario's account for Ireland meeting the 2030 70% RES-E target.

The 'Coordinated Action' scenario sees the target achieved with a high onshore wind generation portfolio. This includes an additional 3800 MW of onshore wind, and 1800 MW of offshore wind, along with 2000 MW of Solar PV being developed by 2030. This scenario is closely aligned to the governments 'Climate Action Plan 2019'. Therefore, projections on future renewable generation capacity and their locations from the Coordinated Action Scenario are presented in Figure 25- Figure 27.

Figure 25 illustrates the potential onshore wind capacity growth in the Border and West regions of Ireland. It is estimated that the combined capacity for both regions could increase from 1770 MW in 2020 to 3000 MW in 2030.

The bulk of offshore wind capacity is expected to be developed along the east coast. This is due to more favourable seabed and subsurface geology for construction in the Irish Sea in comparison to the Atlantic Sea.

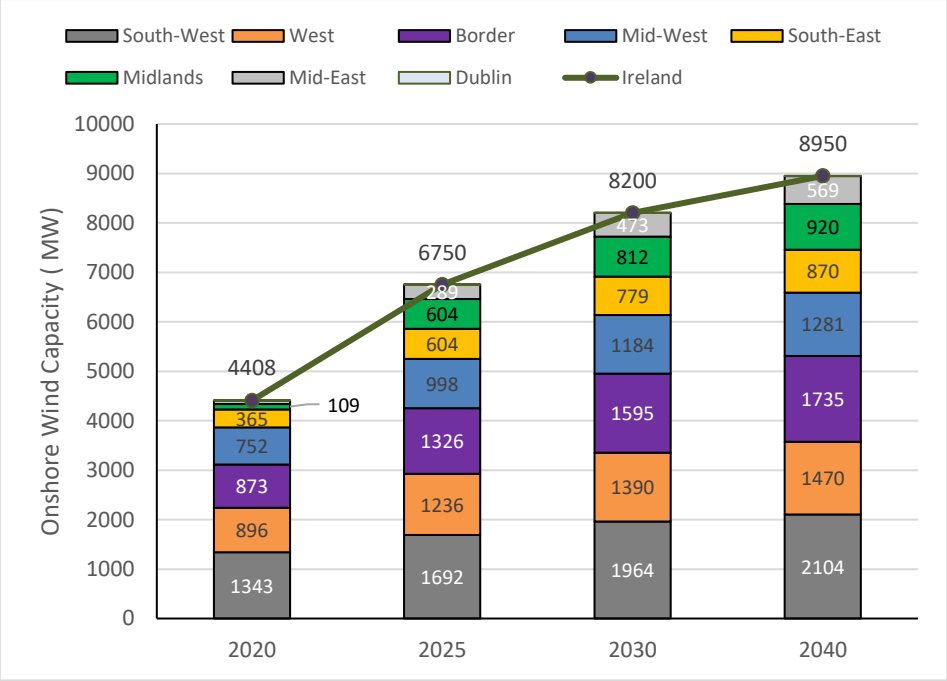

Figure 25 Potential Onshore Wind Capacity 2020-2040 [23].

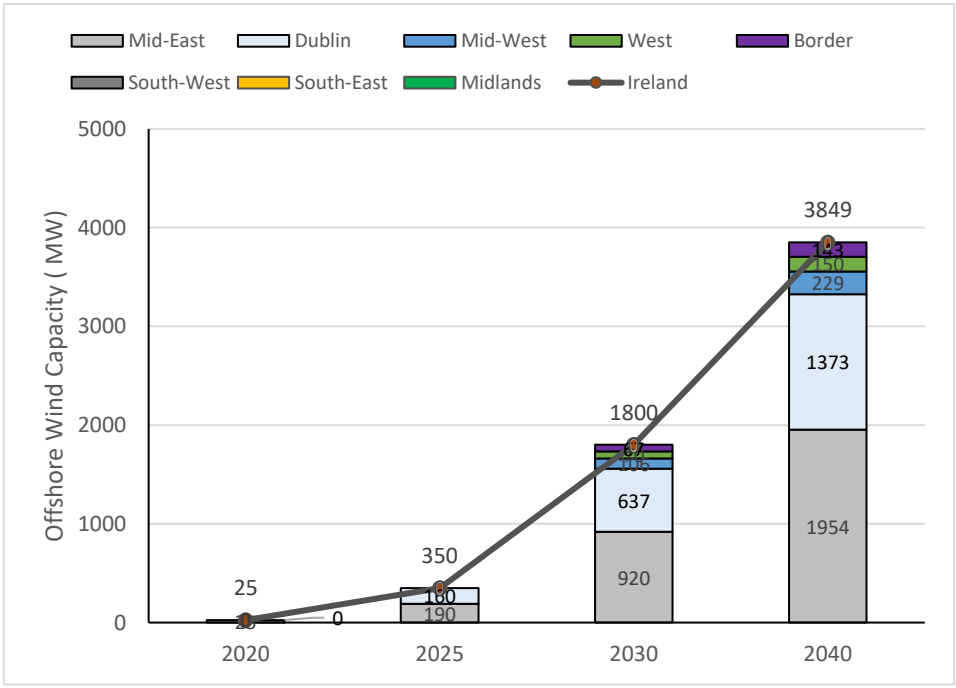

Figure 26 Potential Offshore Wind Capacity 2020-2040 [23].

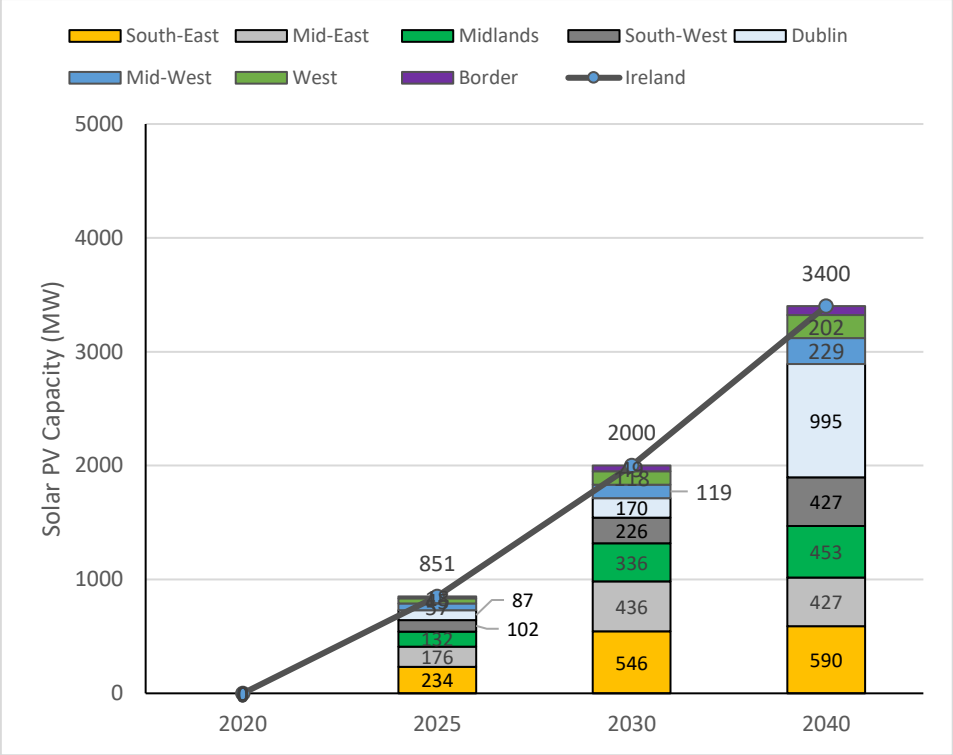

Figure 27 Potential Solar PV Capacity 2020-2040 [23].

2.5.4 Barriers to Future Renewable Development

Requirement for Flexible Power System

The transformation of the power system towards a clean, renewable powered system poses many challenges to system operators. Increasing the share of electricity generation from sources such as wind and solar brings about added uncertainty and variability to electricity production. Uncertainty is problematic since it can result in suboptimal preparation of the system to balance production from variable generation [27]. The variability of the output from wind and solar power can cause balancing resources to cycle more frequently and may generate ramps of extreme steepness or duration. A power system may be considered flexible if it can overcome these challenges. While Ma et al. [28] define a flexible power system to have the capabilities of dealing with uncertainty and variability in demand and generation to maintain system reliability at reasonable additional costs. Flexible power plants, storage facilities, demand side management and coupling the power sector with the transport and heat sectors are mechanisms to provide the system with flexibility.

The requirement for power system flexibility in Ireland has been investigated by academics. O'Dwyer and Flynn [29] analysed various combinations of installed storage capacity, storage volume, interconnection levels and installed wind capacity and concluded that there was added flexibility through the ability to supply reserves where the system could operate more efficiently with reduced start-up costs. In addition, the loading of the conventional plants was more efficient with reduced costs.

The electrification of the heat and transport sectors and demand side management have been identified by EirGrid to provide flexibility to the Irish power system [30]. The climate action plan outlines the ambition for 1,000,000 electric vehicles in Ireland by 2030. The introduction of smart meters can provide consumers an opportunity to avail of cheaper electricity tariffs during the night hours where curtailments are prominent to charge up their electric vehicles – demand side management concept. In the heat sector, a scenario is envisaged where 17% of households in 2030 will have heat pumps installed. However, while the electrification of these sectors offers potential in terms of system flexibility – a large EV and/or heat pump roll out may require significant investment in grid infrastructure.

Compared to electricity, Wang et al. [31] mention that hydrogen production/storage could simultaneously support both zero emission transport and provide demand flexibility to the power system. Utilizing the power-to-gas concept, hydrogen could be used as a medium to store electricity by using low cost power or excess renewable power to produce hydrogen which is then reconverted into electricity when needed. Power-to-gas offers grid operators a larger flexible resource since systems are in the MW scale with rapid ramping characteristics.

High Levels of Dispatch Down for Renewable Generators

Transmission Network Overloads

EirGrid's tomorrow's energy scenarios workstream also provides detail on the transmission circuits that will be overloaded in 2030 [32]. These overloads on the network contribute to the constraining and dispatch down of renewable generators. EirGrid's line overload data for the 'Coordinated Action' scenarios have been mapped in a colour code format and presented in Figure 28 and Figure 29. The line overload data indicates the maximum overload expressed as a percentage of the rated capacity.

Figure 28 shows the 110kV network is heavily overloaded in the North West region. The oversupply of renewable generation in the North West region (identified earlier in section 2.5.2) is a driving factor for overloads on the transmission network. With a high level of renewable generation trying to export power to Dublin and the lack of 220kV and 400kV infrastructure in the region, the modelling done by EirGrid indicates a congested 110kV network in the entire North West region.

Figure 29 highlights the lack of 220kV and 400kV infrastructure linking the North West region to the greater Dublin area. In addition, there is no interconnection to Europe or the UK within the region whereas the South West and South East regions benefit from the planned Celtic (Cork-France) and Greenlink (Wexford-Great Britain) interconnectors.

Table 3 EirGrid TES System Needs Assessment Key Assumptions [32].

		Coordinated Action
Variable RES	Onshore Wind	8,200 MW
	Offshore Wind	1,800 MW
	Solar PV	2,000 MW
RES-E	Penetration	70%
	70% Target Met	Yes
Electrification	No. Electric Vehicles	900,000
	No. Heat Pumps	600,000
Large Energy Users	Max Import	1,700 MVA
	Annual Demand	12.6 TWh
Interconnection	Interconnectors in Service	EWIC, North South, Celtic, Greenlink

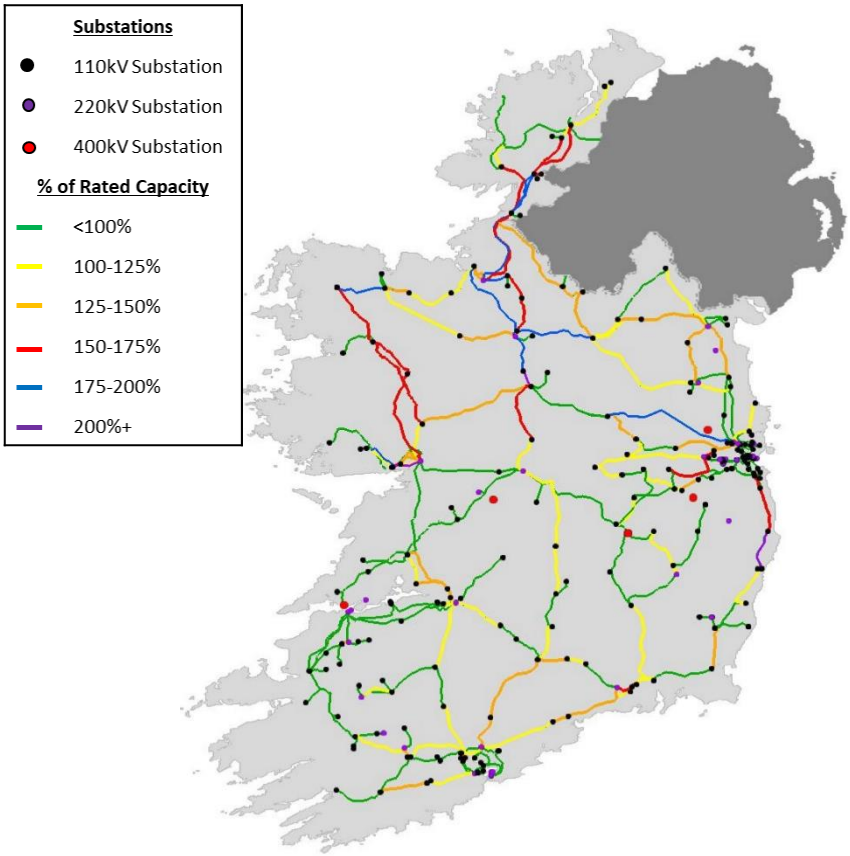

Figure 28 Coordinated Action 110kV Line Overloads [32].

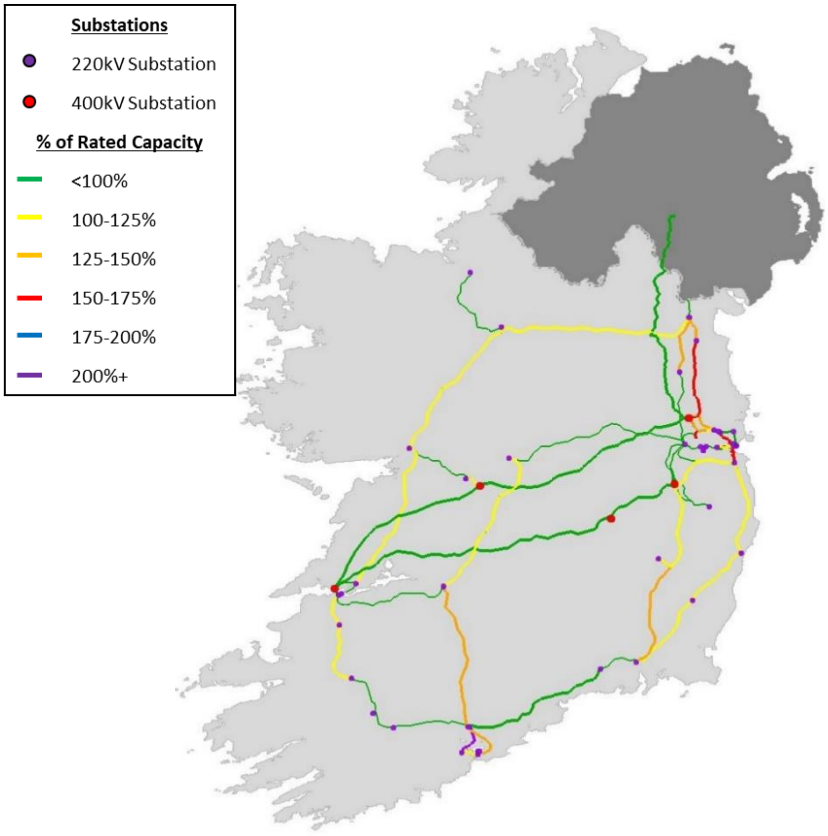

Figure 29 Coordinated Action 220kV & 400kV Line Overloads [32].

Historical Dispatch Down

The dispatch down of renewable generation is the intentional reduction in the overall output of a renewable energy source (RES) ordered by a transmission system operator (TSO) for system security reasons. TSOs define system operational constraints that the system cannot be allowed to operate beyond without effecting system reliability/stability. Wholesale electricity markets determine the most economic mix of generation plant to run on the system in each trading period, but this schedule sometimes results in a generation mix that would cause the system to become unstable. At these times, the TSOs take actions to move the system away from the market scheduled dispatch and this results in increases in wholesale generation costs (known in Ireland as dispatch balancing costs).

Curtailment of renewables is said to occur when this re-dispatching of renewables is the result of system wide limits being exceeded. When this re-dispatch occurs due to a local issue it is known as constraint. The level of generation and the line ratings of the network in the local area are typical factors that influence constraints. In addition, outages required for network reinforcement works give rise to constraints.

As the portion of electricity from variable renewable sources grows to achieve EU targets and reduce emissions, grid balancing will become increasingly more difficult to maintain. In recent years, wind curtailment levels have fluctuated between 1.3% and 3.7% (See Table 4). 2017 was a record year for wind capacity installation with 729 MW added to the All Island system and a total contribution of 25% of Electricity Demand [33]. As a result of a low-capacity factor, curtailment was under 3%.

Table 4 All Island Wind Capacity, Curtailment and Capacity Factor 2011-2019 [34].

All Island				
Year	Wind Installed Capacity (MW)	Wind Capacity Factors	Constraints	Curtailments
2011	2,090	28%	0.40%	1.80%
2012	2,296	27%	0.80%	1.30%
2013	2,556	28%	0.90%	2.30%
2014	2,989	27%	1.40%	2.60%
2015	3,192	31%	1.80%	3.30%
2016	3,731	26%	1.40%	1.50%
2017	4,459	26%	1.20%	2.70%
2018	4,937	27%	2.20%	3.80%
2019	5,389	27%	4.00%	3.70%

Figure 30 provides a breakdown of constraint and curtailment by region of the island of Ireland in 2019. The worst affected regions of Ireland for dispatch down were North West (9.8%) and South West (8.5%) regions. The North West region encompasses counties Donegal, Mayo, Sligo, Roscommon and Leitrim. Constraints in the North West (NW) region have been above the system average for the past 10 years due to the level of wind generation connected in the region in the past 15 years and the network outages being taken to reinforce the network. The South-West region also experienced significant constraints in 2019, this was a consequence of issues with a transformer at Moneypoint 400kV substation that connects Ireland's two 400kV lines to Woodland 400kV substation (North Dublin) and Dunstown 400kV substation (South Dublin). The outage at Moneypoint is likely to have also impacted on constraints for generation located in the North West and West regions of Ireland. Analysis carried out by MullanGrid estimates that, for 2019, dispatch down cost Irish wind farms approximately €50 million in lost revenue [35].

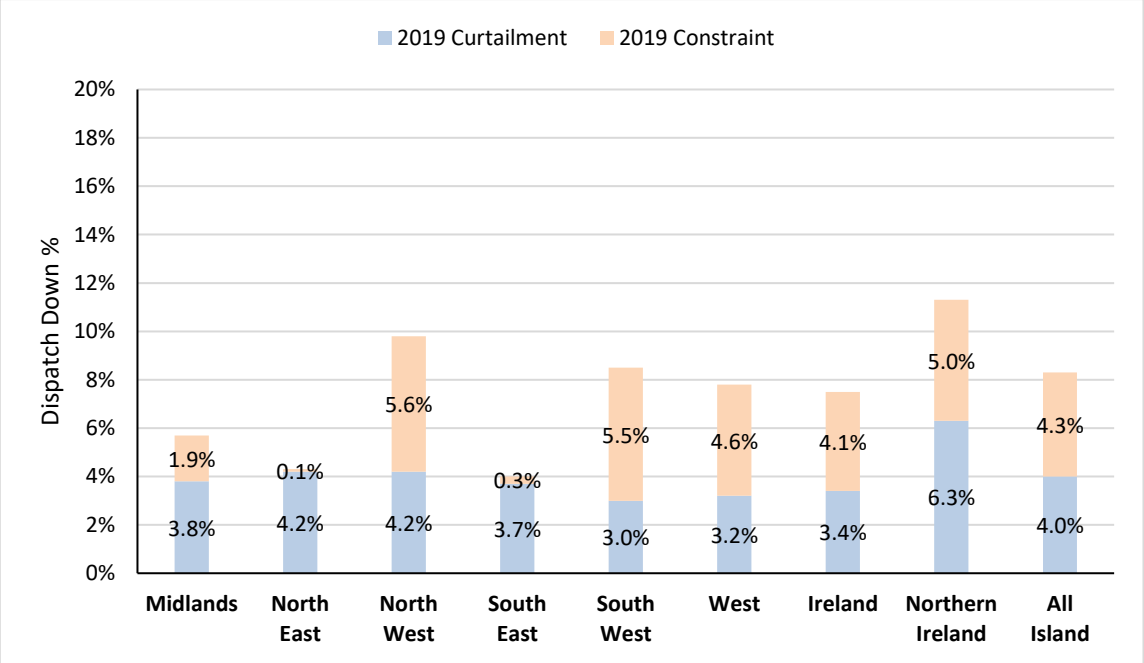

Figure 30 Controllable Wind Dispatch Down By Region 2019 [36].

ECP-1 Constraint Report Projections

Enduring Connection Policy (ECP) is the current system for issuing connection offers / grid capacity for new generation and storage technologies. EirGrid are required to carry out system studies to inform ECP applicants about the possible constraint levels. EirGrid have completed constraint studies for each wind area, providing ECP-1, contracted and connected generation with information on the possible levels of constraint and curtailment for a range of scenarios and study years [37]. The years 2020, 2021 and 2022 were modelled for 33%, 66% and 100% build out rates of generation. In addition, a “future grid” scenario was included which models constraints on a 2025+ network with all planned generation up to ECP-1 connected.

EirGrid in its modelling used wind profiles based on the 2015 wind year which was the windiest in the past 20 years, the capacity factor assumed was approximately 36% which is notably higher than the 2019 figure of 28% [36]. An intact network was also assumed which means that the constraint modelling does not account for any constraints arising from outages on the transmission system.

In this review, multiple scenarios have been mapped and presented in a colour coded format to identify the highly constrained areas of Ireland. Figure 31 indicates the estimated range of constraint for the various wind areas of Ireland in 2020. Looking at the North West region which consists of wind areas A, B and C, estimated wind constraint levels for are in the range of 8-11%. Constraint levels for windfarms in Mayo were estimated to be 11%.

Considering a 2022 network with a 100% build out of generation (see Figure 32), then wind constraints are estimated by EirGrid to be in the range of 14-25% for the North West region. Constraints in Mayo were estimated to be 25%, although it is not a realistic scenario to consider a 100% build out of generation by 2022. However, nonetheless considering a 33% build of generation in the Mayo region then constraints are estimated to be 24%. Going beyond 2025, the future grid scenario indicates constraint levels for Mayo windfarms of 14% (See Figure 33). This scenario assumes the North Connacht reinforcement is complete and a <60% RES-E level in Ireland which further highlights the requirement for storage and/or additional electricity infrastructure in the region. While EirGrid’s analysis also modelled curtailment, it is not considered realistic given that a very high build-out relative to a very short time frame was analysed e.g. 2.5GW solar and 6.1GW wind connected in 2020-2022 resulting in

solar and wind curtailment reaching up to 9% and 15% respectively, without the addition of system upgrades planned to occur beyond the 2022 cut-off date.

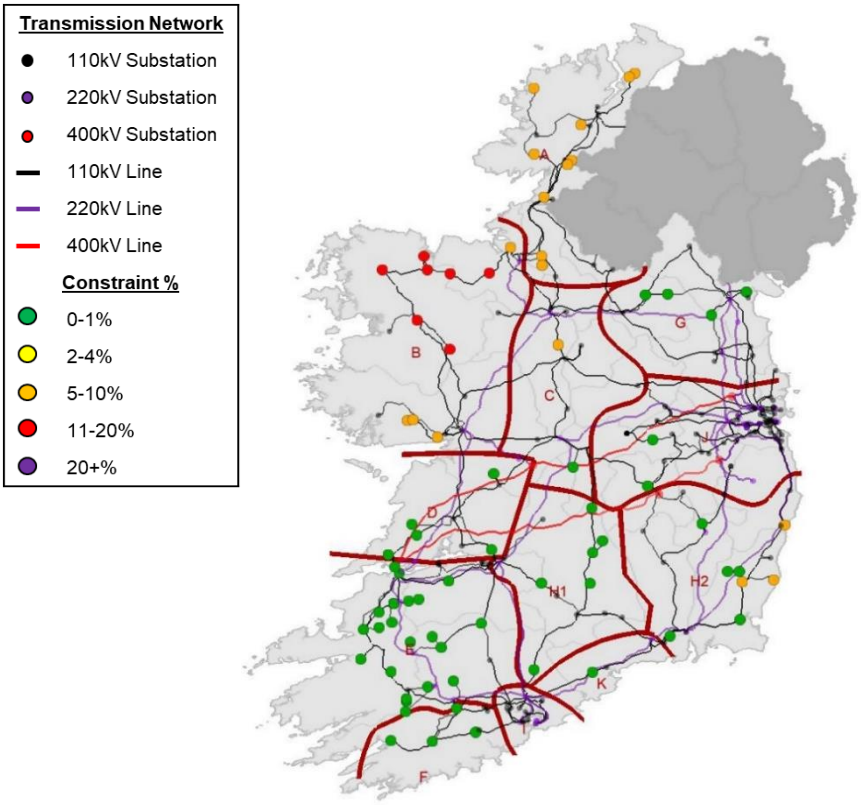

Figure 31 Initial 2020 Constraint Projections [37].

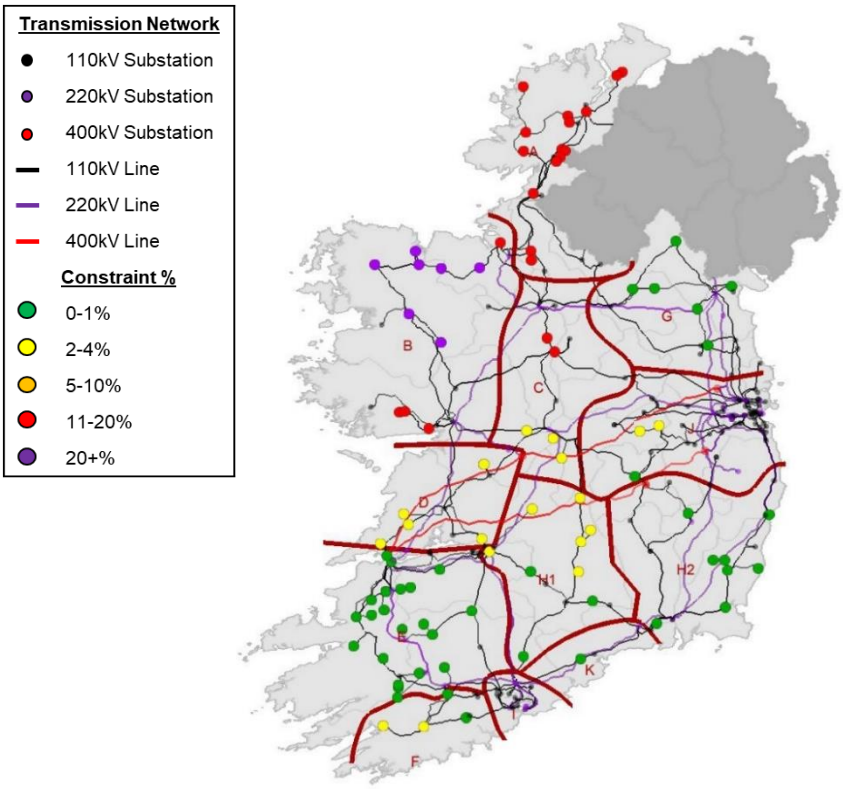

Figure 32 2022 All Constraint Projections [37].

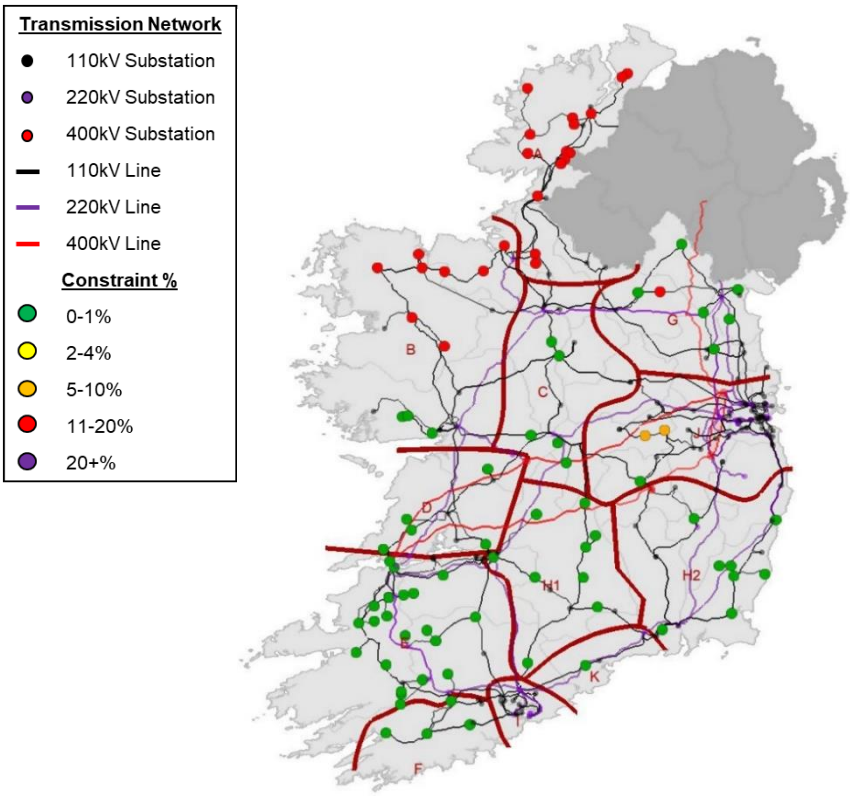

Figure 33 Future Grid Constraint Projections [37].

In Ireland electricity is bought and sold on the Integrated Single Electricity Market (I-SEM). This was launched in October 2018 and brings the Irish electricity market in line with the rest of Europe. In I-SEM, auctions take place daily where generators compete to supply electricity in hourly blocks. I-SEM is composed of three different markets. There are two 'ex ante' markets – called the Day Ahead and the Intraday – which means electricity is bought and sold before the market closes. And there is a third, called the Balancing Market, which takes place after trading has ceased [38]. Since the start of I-SEM, negative pricing events have become more prominent. These occur when market prices clear at a value less than zero, meaning generators are willing to pay for their power to be consumed. It is an economic signal that there is a significant over-supply in the market. In addition, there are some large generators that incur a cost when they reduce their generation below a certain point. It can, depending on the market, be cheaper for them to sell their electricity at a loss and keep going than it is to power down only to power up later.

2.6 Introduction to Hydrogen

2.6.1 Global Hydrogen

The main demand for hydrogen today globally comes from the industry sector. Hydrogen is used in the production of carbon steels, special metals and semiconductors (See Figure 34). It is also widely utilized as a reducing agent and carrier gas in the electronics industry. In electricity generation, hydrogen has applications in generator cooling and corrosion prevention in power plants [39]. Over 96% of current hydrogen production is fossil-based [39]. Steam methane reforming is the most common method. Electrolysis contributes to around 4% of global hydrogen supply.

Hydrogen is a fundamental component for the manufacture of ammonia (NH_3) – also known as azane. The Haber-Bosch process combines hydrogen and nitrogen together directly by synthesis to create ammonia. At present, the hydrogen used originates from natural gas steam reforming. Almost 90% of ammonia production goes into fertilizer production [39]. Ammonia can also be used in refrigeration plants.

In oil refineries, hydrogen is used to process crude oil into refined fuels such as gasoline and diesel, and also to remove contaminants such as sulphur. Developing

economies such as China and India have increased the demand for hydrogen in refineries due to increased oil consumption. The regulations implemented that require low sulphur diesel have also increased hydrogen demand.

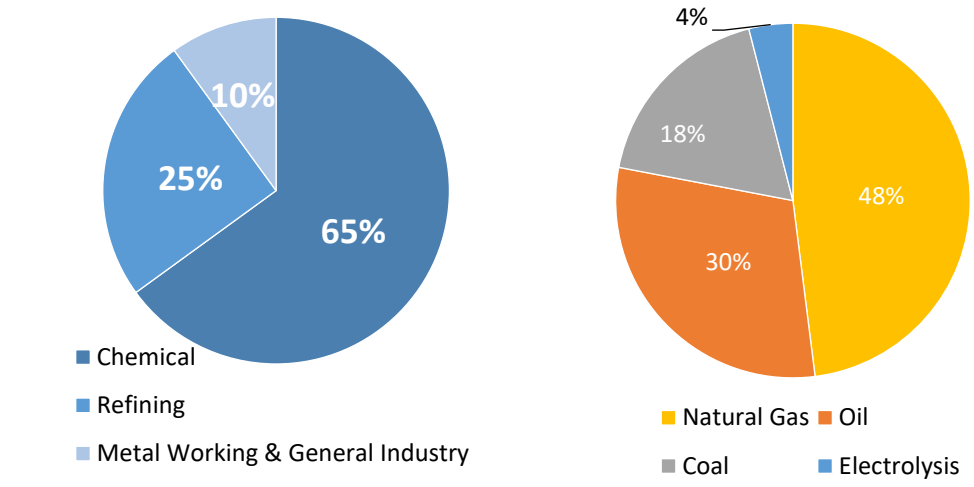

Figure 34 Global H_2 Demand & Production 2016 [39].

2.6.2 Hydrogen in Ireland Today

Figure 35 shows the existing and planned hydrogen projects in Ireland.

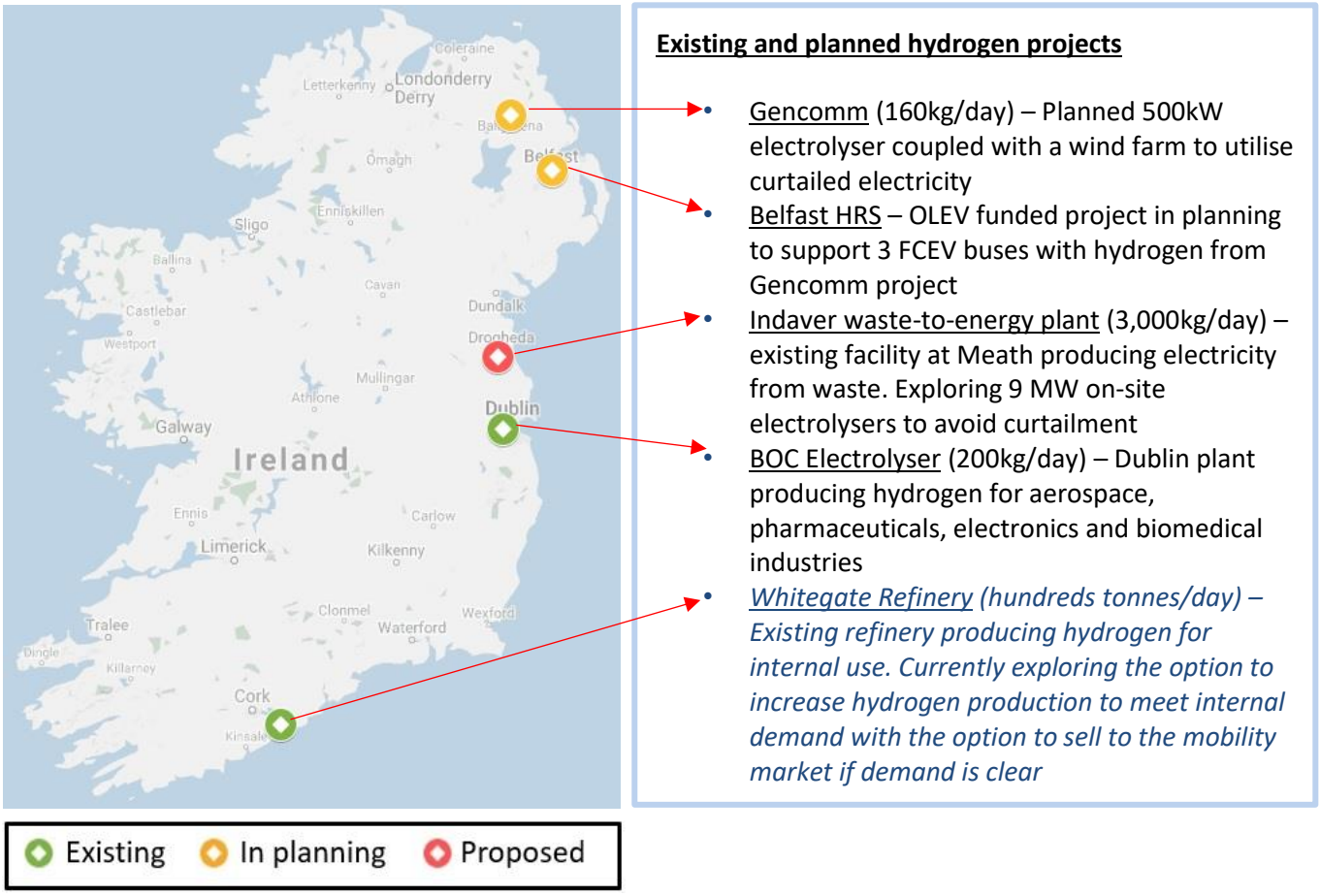

Figure 35 Existing & Planned Hydrogen Projects [40].

2.6.3 Power-to-Gas Concept & Role in Energy Transition

The concept of power-to-gas (illustrated in Figure 36) involves converting electricity to hydrogen via electrolysis. Green hydrogen (often called renewable hydrogen) refers to hydrogen produced from water by electrolysis powered by renewable sources, such as wind or solar. The whole process, from production to use, is emissions free, with only water and oxygen as by-products. Green hydrogen produced from low carbon renewable sources of energy can enable the decarbonisation of sectors that otherwise may be extremely challenging purely by means of electrification. These sectors include industry, transport and heat. Power-to-gas allows for sector coupling with the electricity system.

An electrolyser is a device which splits water into hydrogen and oxygen using electricity. Electrolysers can provide a flexible load that offers low-cost balancing services to the power system while also producing hydrogen for use cases in transport and industrial applications, or injection into the gas grid. The storage capacity of downstream sectors can be used as a buffer to adjust hydrogen production and hence electricity consumption in real time depending on the requirements of the power system. In addition, the storage capacity can absorb variable renewable energy over long periods allowing for seasonal storage [41].

Hydrogen could potentially in the medium to long term become a way to transport and distribute renewable energy over long distances, especially in cases where the electricity grid has insufficient capacity or it is too impractical or expensive to build [41]. Offshore wind could be classed in this bracket, where hydrogen could be produced offshore and transported to the shore via the existing natural gas grid pipelines or newly installed pipelines. Furthermore, countries with abundant renewable supply could produce hydrogen for regions with limited potential or higher costs of renewable generation.

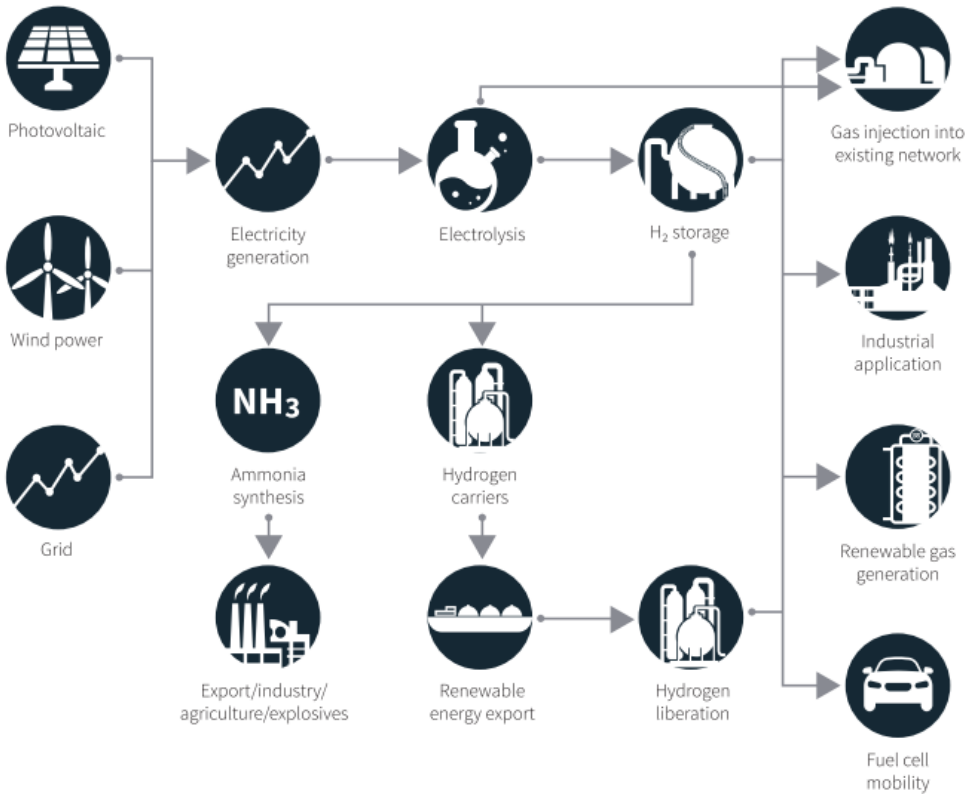

Figure 36 Power-To-Gas Concept [42].

2.6.4 Hydrogen Production

Electrolysis

Electrolysis allows for green hydrogen production when electrolysers are co-located with renewable generators. Electrolysers may be deployed to Hydrogen Refuelling Stations (HRS) where onsite production can be facilitated by using electricity supplied from the grid.

There are a variety of electrolyser solutions available with differing levels of maturity, efficiency and costs. Alkaline (ALK) water electrolysis is the longest established, mature technology with relatively low capital costs. New market entrants with lower operating costs include Polymer Electrolyte Membrane Electrolysis (PEM), and Solid Oxide Fuel Cell (SOEC) technologies [42]. Figure 37 depicts the conceptual set-up of each technology.

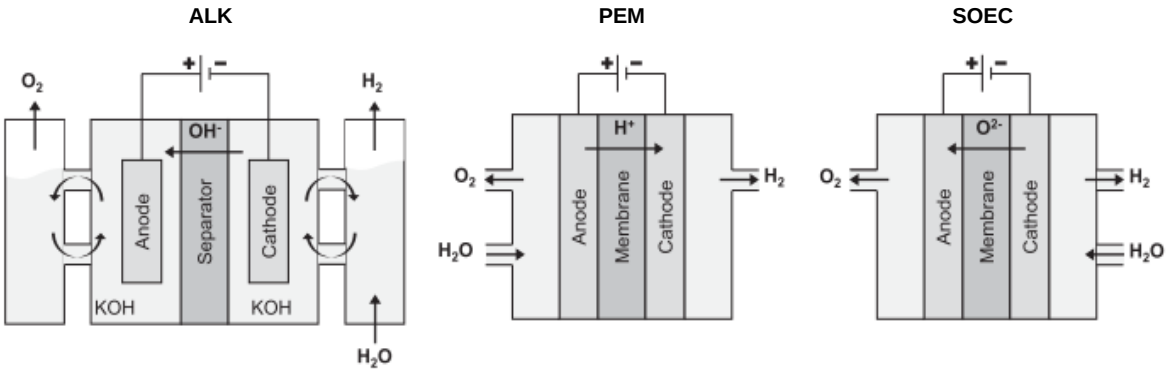

Figure 37 ALK, PEM, SOEC Technologies conceptual set-up.

ALK electrolysers have been widely used for large-scale industrial applications since 1920. These systems are durable and readily available. The capital costs are relatively low in comparison to competing technologies due to the avoidance of noble metals and mature stack components [13-14]. However, low current density and operating pressure are drawbacks for the technology in terms of system size and hydrogen production costs. Also, dynamic operation with frequent start-ups and varying power input is limited and can negatively affect system, efficiency and gas purity [45].

PEM systems were first introduced in the 1960's by General Electric (GE) to overcome the drawbacks of ALK systems [46]. The technology is less mature than ALK and is generally used for small-scale applications [45]. Key advantages are high power density and cell efficiency, with the provision of highly compressed and pure hydrogen. Further, PEMs allow for flexible operation. The expensive cost of materials including platinum (catalyst) and fluorinated membrane materials are drawbacks for the technology. An additional disadvantage is the high system complexity for high operating pressure and water purity requirements. The lifetime of PEM electrolysers is currently shorter than the lifetime of an ALK electrolyser. Figure 38 illustrates the components for PEM and ALK electrolyser systems.

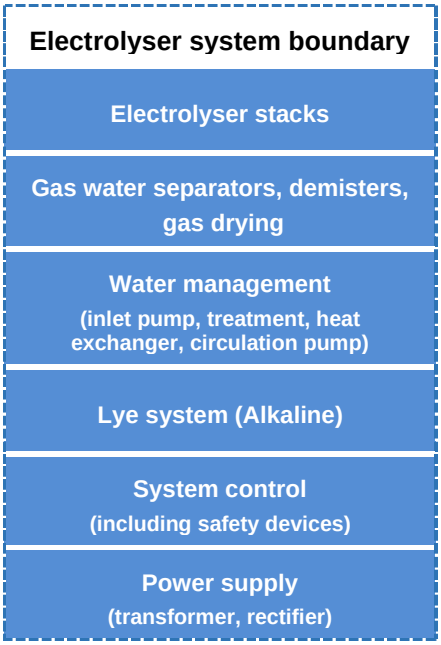

Figure 38 Electrolyser System Boundary [47].

The latest technological development in hydrogen production via electrolysis has come from SOEC electrolysers. These systems are not yet widely commercialised, however potential advantages of high electrical efficiency, low material cost and the options to operate in reverse mode as fuel cell or in co-electrolysis mode producing syngas are attracting interest in investment from companies [48]. The high operating temperatures contributes to material degradation and poses a key challenge to further development.

Gas Reformation

Most hydrogen produced today is made via steam-methane reforming (SMR). The production process involves using high-temperature steam (700°C–1,000°C) to produce hydrogen from a methane source, such as natural gas. In steam-methane reforming, methane reacts with steam under 3–25 bar pressure in the presence of a catalyst to produce hydrogen, carbon monoxide, and carbon dioxide. Steam reforming is endothermic—that is, heat must be supplied to the process for the reaction to proceed [49]. Hydrogen produced via SMR is often referred to as ‘grey hydrogen’.

Carbon capture and storage (CCS) technology can be deployed to large scale/ industrial SMR plants to reduce CO_2 emissions. Hydrogen produced from SMR plants using CCS technology is referred to as ‘blue hydrogen’.

2.6.5 Hydrogen Storage

Proven physical-based storage methods have become important to the industry [50]. (See Figure 39). These include methods based on either compression or cooling or a combination of the two. New hydrogen storage technologies are currently being investigated which are material-based methods.

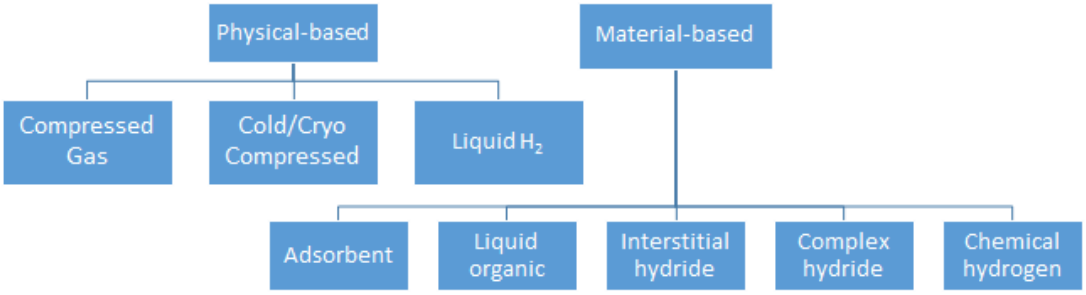

Figure 39 Hydrogen storage methods [50].

Cooling and compression may be combined for hydrogen storage in mobility applications. The cooling takes place before compression. This requires an additional energy input. Cryogenic compression results in a higher energy density in comparison to compressed hydrogen [50].

In addition to storing gaseous hydrogen under pressure, it is possible to store cryogenic hydrogen in the liquid state [50]. The chip industry requires liquid hydrogen with high levels of purity. As an energy carrier, liquid hydrogen has a higher energy density than gaseous hydrogen but requires liquefaction at -253°C, and hence complex technical plant at higher energy input levels and economic costs. Liquefaction requires more than 30% of the energy content of hydrogen.

An alternative to physical storage methods is supplied by hydrogen storage in solids and liquids on surfaces [50]. The storage densities achieved to date are not adequate, the cost and time in charging discharging hydrogen are too high, and/or the process costs are too high.

2.6.6 Filling Centres and Compression

The term filling centre relates to the physical infrastructure required to fill gas bundles/and or tube trailers. This physical infrastructure consists of compressor skids, piping and filling equipment. Mechanical compressors are widely used at present, hydrogen compression is driven by pistons linked to a crankshaft which convert the continuous rotational movement of the pistons into linear movement.

2.6.7 Hydrogen Transportation

There are three main transportation methods for hydrogen used by suppliers today; the methods are delivered via gaseous pipelines, pressurized tube trailers and cryogenic liquid tankers. In special circumstances, hydrogen can be transported by barge [51]. The potential for hydrogen delivery in Ireland is limited due to a content limit (0.1%) on the volume of hydrogen that can be injected into the natural gas grid [52]. Pressurized tube trailers can transport compressed hydrogen gas via road infrastructure at pressures between 200 and 500 bar. Figure 40 shows a BOC Gas hydrogen tube trailer already in use today.

Figure 40 BOC Hydrogen Tube Trailer for Hydrogen Transportation [53].

2.6.8 Hydrogen Distribution

Centralized Versus Distributed Production

Hydrogen production facilities can be classed as centralized, semi-centralized and distributed production facilities. The term distributed relates to small scale on-site production, which offers a viable approach for hydrogen refilling stations (HRS) where the initial demand is low in the introductory phase of the technology [54].

Large centralized production facilities (750,000 kg/day) benefitting from economies of scale may be required in the long term [54]. Centralized production requires higher capital investment along with substantial hydrogen transport and delivery

infrastructure. Semi-centralized production facilities located in close proximity (40km-160km) to the use cases for hydrogen may become important in the energy transition. These production facilities may service 5,000-50,000 kg/day and provide a level of economy of scale while minimizing hydrogen delivery costs [54].

Hydrogen Refilling Infrastructure

A Hydrogen refuelling station (HRS) is an infrastructure designed for filling a vehicle with hydrogen fuel. HRS may be integrated into the conventional fossil fuel refuelling or independent infrastructure. HRSs are composed of a basic unit which includes as minimum a high-pressure storage system and one or more dispensers. If the hydrogen is produced on site or is delivered to the station at an intermediate pressure or in the liquid state, the basic unit also requires an intermediate storage system and compression system [55]. See Figure 41 for a schematic of hydrogen refuelling infrastructure.

Figure 41 Hydrogen Refilling Infrastructure [55].

2.7 Hydrogen Production via Electrolysis

The main purpose of this section of the literature review is focused on the state of knowledge on the costs associated with each of the system components. This analysis focuses on understanding the following parameters:

- Electrolyser CAPEX
- Electrolyser OPEX
- Electrolyser Efficiency
- Electrolyser Balance of Plant
- Compression CAPEX
- Compression OPEX

2.7.1 Electrolyser CAPEX

Until recently CAPEX costs associated with the electrolyser that could be found in the literature were values representing a range of currencies and constant year dollar values – occasionally these values included other system components as well. This made it difficult to understand larger industry trends for predicting the cost improvements as the industry matured. Efforts by Glenk et al. were made to harmonize these important CAPEX parameters [56]. Their review included only original sources of data and excluded literature that did not provide clear costs estimates or methodologies for producing cost estimates. The cost data from the sources that remained was then harmonized into 2016-euro costs to aid technology comparisons. Cost estimates for the years 2003 to 2030 were included for ALK and PEM electrolyser technologies. Figure 42 provides a snapshot of these cost estimates. Glenk et al. were able to analyse the trends in electrolyser annual cost reductions, although the estimates for cost improvements still reflect the wide range of possible electrolyser prices. For PEM systems Glenk et al. suggest that a 4.77 +/- 1.88% per year cost reduction would be possible, while 2.96 +/- 1.23% per year decline would be possible for ALK systems [56].

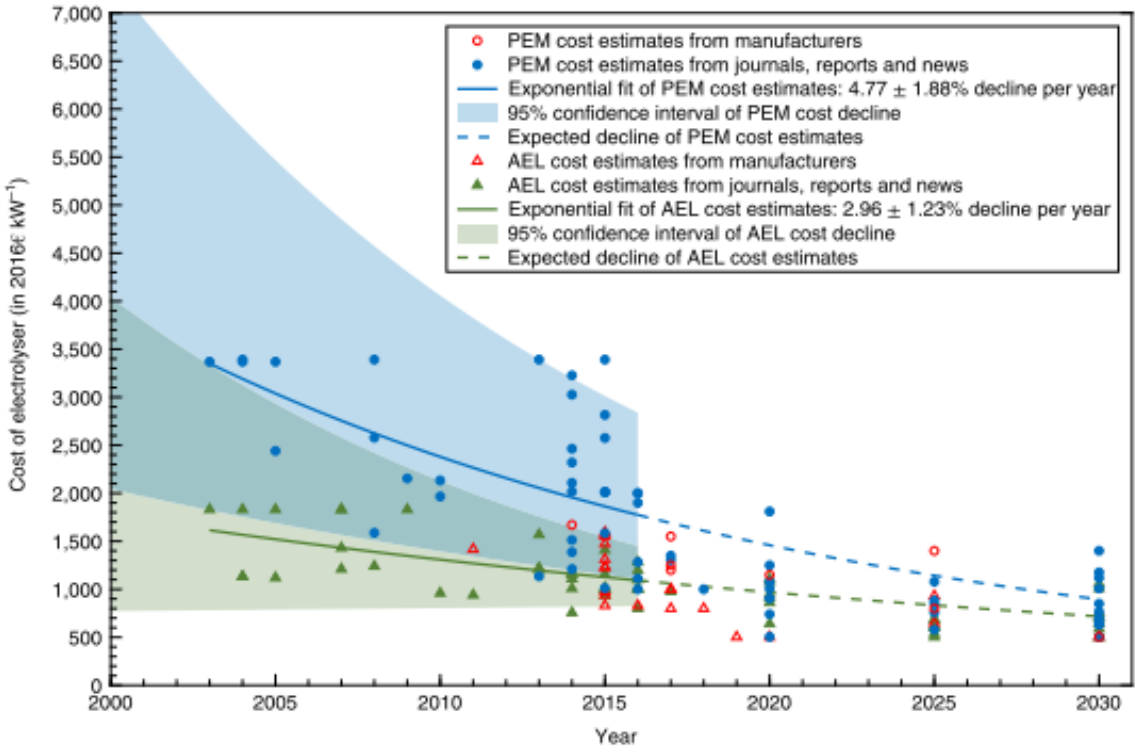

Figure 42 Capital Cost of electrolyser technologies. Cost data are from multiple sources for alkaline electrolysis (ALK) and PEM electrolysis [56].

Christensen et al. build on the review of Glenk et al. and assess hydrogen production costs from Electrolysis in both the United States and Europe [57]. A Monte Carlo style approach was adopted by Christensen et al. to analyse renewable hydrogen systems and the potential annual cost reductions. A low (min), mid (mean), high (max) projection for ALK, PEM and SOEC electrolyser systems was formulated based on the Glenk et al. cost estimates. The results of the analysis are shown in Table 5. For both ALK and PEM systems, Christensen et al. suggest that cost reductions in the range of 0.5-2% could be achieved.

Table 5 Christensen et al. CAPEX Annual Reduction [57].

System Type	Scenario	(2020 $/ MW)	Rate of improvement (%/yr)
ALK	Low	571,000	0.5%
ALK	Mid	988,000	2.0%
ALK	High	1,268,000	2.5%
PEM	Low	385,000	0.5%
PEM	Mid	1,182,000	2.0%
PEM	High	2,068,000	2.5%

Christensen et al. in their assessment of hydrogen production costs also draw a comparison to cost estimates for electrolysers from more recent studies from the international energy agency (IEA), IRENA and Bloomberg New Energy Finance [58][59] [60]. Electrolyser CAPEX ranges for the years 2020, 2022, 2025, 2030 and 2050 are provided in Table 6.

Table 6 Comparison of Electrolyser CAPEX Christensen et al. [57]

Report	System Type	Year of estimate	(2020 $/ MW)	Christensen et al. (2020 $/ MW)	Reference
IEA	ALK	2020	500,000	571,000 - 1,268,000	[58]
IEA	ALK	2030	400,000	541,000 - 1,208,000	[58]
IEA	ALK	Long Term	200,000	487,000 - 1,090,000	[58]
IRENA	ALK	2020	840,000	571,000 - 1,268,000	[59]
IRENA	ALK	2050	200,000	487,000 - 1,090,000	[59]
Bloomberg	ALK	2019	1,200,000	571,000 - 1,268,000	[60]
Bloomberg	ALK	2022	600,000 - 1,100,000	565,000 - 1,256,000	[60]
Bloomberg	ALK	2025	400,000 - 1,000,000	556,000 - 1,238,000	[60]
Bloomberg	ALK	2030	115,000 - 135,000	541,000 - 1,208,000	[60]
Bloomberg	ALK	2050	80,000 - 98,000	487,000 - 1,090,000	[60]
IEA	PEM	2020	1,100,000	385,000 - 2,068,000	[58]
IEA	PEM	2030	650,000	365,000 - 1,968,000	[58]
IEA	PEM	Long Term	200,000	325,000 - 1,781,000	[58]
Bloomberg	ALK	2019	1,400,000	385,000 - 2,068,000	[60]
Bloomberg	ALK	2030	425,000 - 1,000,000	365,000 - 1,968,000	[60]
Bloomberg	ALK	2050	150,000 - 200,000	325,000 - 1,781,000	[60]

Table 20 in Appendix A provides a database of cost estimates included in the Glenk et al. report and a number of additional sources for the purpose of this review. The types of publications used include manufacturer Interviews conducted by Glenk et al., journal articles and reports.

2.7.2 Electrolyser OPEX

Electrolyser OPEX costs are commonly modelled as a percentage of the electrolyser investment CAPEX. Fixed annual OPEX costs range from 1-4% [61][57]. FCHJU estimate the current (2021) annual OPEX costs to be 3.6% of the electrolyser investment costs, with OPEX costs of 42,000 €/ MW for an investment of 1,154,000 €/ MW [62]. Looking to 2030, FCHJU estimate that cost reductions in electrolyser equipment are aligned with reductions in annual OPEX costs but in there is little change in terms of the OPEX as a percentage of CAPEX, the OPEX costs in 2030 are estimated to be 18,000 €/ MW for an investment of 402,000 €/ MW.

2.7.3 Electrolyser Efficiency

Based on a review of literature and interviews with electrolyser manufacturers, estimates for ALK and PEM electrolysers efficiencies were sourced for 2020, 2025 and 2030. The electrolyser efficiency is defined as the energy content (based on the higher heating value) of the hydrogen produced divided by the amount of electricity consumed. Table 7 provides a range of efficiencies for the respective years and technology.

Table 7 Electrolyser Efficiencies 2020-2030.

Year	Technology	kWh/kg	Efficiency	Sources
2020	ALK	55-60	66-72%	[63], Manufacturer
2025	ALK	50-55	72-79%	[63]
2030	ALK	50	79%	[63]
2020	PEM	50-55	72-79%	[63], Manufacturer
2025	PEM	48-51	77-82%	[63]
2030	PEM	47-50	79-84%	[63]

2.7.4 Electrolyser Balance of Plant

The balance of plant (BOP) costs are those associated with piping, pumps and electrical installations. Glenk et al. conducted a review of balance of plant costs with input from manufacturers [56]. For ALK systems, BOP costs for the period 2020-2030 are estimated to be in the range of 120,000 €/ MW to 130,000 €/ MW. For the same period, the BOP costs for PEM systems were estimated to in the range of 115,000 €/ MW to 150,000 €/ MW.

2.7.5 Compression CAPEX

In addition to the electrolyser a renewable hydrogen system will require a compressor and piping in order to get it ready to be injected into a pipeline or to be put into tanker trucks and shipped. Data for compressor CAPEX is sparse, and often presented in an aggregate metric with other system components. Electrolysers typically output hydrogen at pressures between 15-60 Bar.

2.7.6 Compression OPEX

Hydrogen compression equipment involves a high maintenance cost, due to the presence of a high number of components which include gears, valves, pistons and a crank shaft. The maintenance cost of mechanical compressors is estimated at 5% of the total investment cost per year [64].

2.8 Cost Comparison of Hydrogen Production Options

The IEA reviewed the cost of hydrogen production sources in 2018 in a publication titled “The Future of Hydrogen”. Natural gas and coal were reported to be the cheapest sources of production. Figure 43 outlines the range of production costs for natural gas, coal and renewables. Considering the Irish governments policy on coal in the energy system, coal would not be considered feasible for Ireland. The graph shows costs for renewable production from electrolysis in the range of 2.6-6.4 €/kg. At production costs under 3 €/kg, renewable hydrogen production is very competitive with natural gas, both with and without carbon capture utilisation and storage (CCUS).

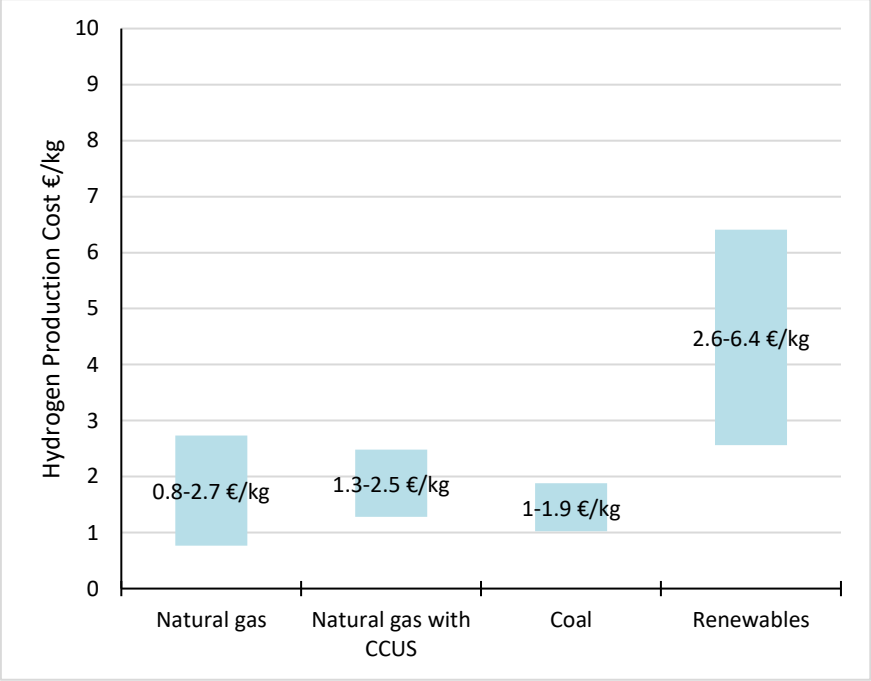

Figure 43 IEA Hydrogen Production Cost Comparison 2018 [65].

Bloomberg New Energy Finance (BNEF) in August 2019 carried out an analysis of hydrogen production costs in 2019 [60]. The levelized cost of hydrogen (LCOH) of hydrogen was calculated for both ALK and PEM electrolyser systems manufactured in China and Europe. Analysis on a dedicated wind scenario where all of the wind farms output is available to the electrolyser showed production prices in the range of 2.2-3.9 €/kg. A scenario was also modelled where only curtailed electricity was available to the electrolyser, the corresponding production price was between 1-7.4 €/kg. The full list of scenarios that were modelled are presented in Table 8.

Table 8 BNEF Levelized Cost of Hydrogen Production via Electrolysis [60].

Scenario	Electrolyser	Capacity Factor	Electricity (€/MWh)	LCOH (€/kg)
Grid Connected	ALK (Chinese)	91%	85	4.7
Grid Connected	ALK (Western)	91%	85	5.3
Grid Connected	PEM (Western)	91%	85	5.8
Grid Connected/Off-Peak	ALK (Chinese)	50%	38	2.4
Grid Connected/Off-Peak	ALK (Western)	50%	38	3.4
Grid Connected/Off-Peak	PEM (Western)	50%	38	4.3
Curtailed Electricity	ALK (Chinese)	15%	0	1.0
Curtailed Electricity	ALK (Western)	15%	0	4.7
Curtailed Electricity	PEM (Western)	15%	0	7.4
Dedicated Wind	ALK (Chinese)	51%	35	2.2
Dedicated Wind	ALK (Western)	58%	37	3.2
Dedicated Wind	PEM (Western)	62%	39	3.9

In August 2020, SGN and Scottish power energy networks published a report titled “Realising the green power-to-hydrogen opportunity in the East Neuk”[66]. SGN are a gas distribution company that have operations in Scotland and the South of England. The report presented production costs from electrolysis for a number of scenarios, the key findings are below:

i. Assuming electrolyser owners would be able to access wholesale prices (excluding grid fees and taxes), grid power-based electrolysis could be as low as 1.3 €/kg (£1 ~ €1.11).
ii. If electrolyser owner pays the commercial or industrial electricity price, including transport costs and other levies, the cost of hydrogen production was estimated to be 3.7 €/kg.
iii. Dedicated renewable power hydrogen production costs were 3.1 €/kg.
iv. There are subsidies of up to 7.8 €/kg available for mobility applications and 3.7 €/kg for heating applications.

2.9 Energy Storage Technologies for Power Systems

As discussed earlier in section 2.5.4, there are certain times when there is an oversupply of renewable generation which focuses attention on energy storage systems. These systems may be connected to the grid-scale or behind the meter (onsite at the generator). Figure 44 illustrates the growth in the deployment of storage technologies across the globe since 2013.

Energy storage systems provide a means to import electricity from a generator or power grid for conversion into a form that may be stored at off-peak demand, when energy cost is usually low or during surplus generation, and converted back to electricity at peak demand or when needed. The applications for energy storage systems on the power grid include [67]:

- **Energy arbitrage:** It involves storing electricity at off-peaks when the price is low and selling it at peak demand periods when the price is high.
- **Load levelling:** It is the utilization of the stored energy at peak periods, thereby reducing the requirements of peaking generators.
- **Renewable integration:** Storage systems could minimize the effect of intermittency of renewable energy resources and increase their penetration in power systems.
- **Spinning reserve:** Storage systems could reduce the requirement for idling generators in power systems. Such generators are dedicated to ‘take over’ of any sudden failure of a major generator, but energy storage systems could defer the option of operating them.
- **Customer-side peak shaving:** This involves reliability back-up support by electrical storage systems through the use of uninterruptible power supply (UPS) to address ‘short- and long-period interruptions, voltage peaks and flickers.
- **Primary frequency regulation:** This involves the provision of frequency stability support for power networks through the charge/discharge characteristics of energy storage systems, thereby regulating the voltage and frequency.
- **Network Investment deferral:** Involves the use of storage to defer transmission and distribution infrastructure investment.

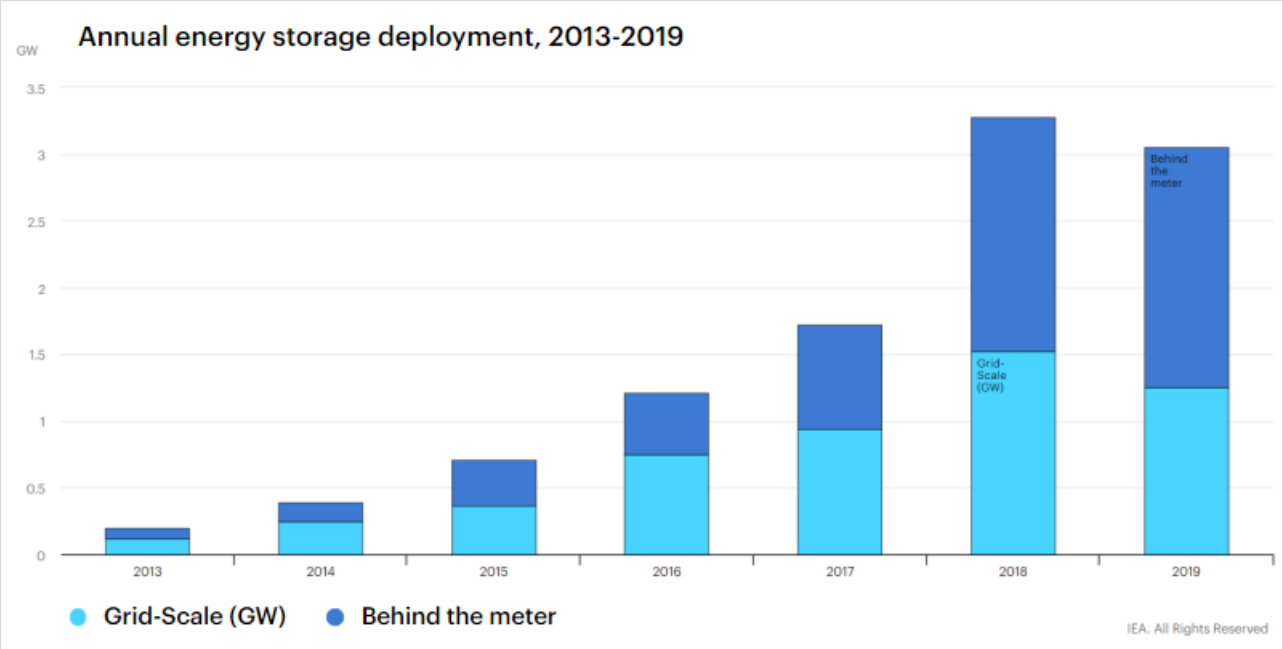

Figure 44 IEA Annual Energy Deployment 2013-2019 [68].

A range of storage technologies are available depending on the application. Current utility scale energy technologies come in the form of electrical, mechanical, electrochemical and chemical storage. Table 9 outlines a number of technologies widely available for grid scale applications.

Table 9 Energy Storage Technologies Technical Capability Comparison [69].

Type	Technologies	Power rating (MW)	Storage duration (h)	Cycling or lifetime	Efficiency* (%)	Response time
Electrical	Super-capacitor	0.01-1	ms-min	10,000-100,000	80-98	10-20ms
	SMES	0.1-1	ms-min	100,000	80-95	< 100ms
Mechanical	PHS	100-1,000	4-12h	30-60 years	70-85	sec-min
	CAES	10-1,000	2-30h	20-40 years	40-75	sec-min
	Flywheels	0.001-1	sec-hours	20,000-100,000	70-95	10-20ms
Electrochemical	NaS battery	10-100	1min-8h	2,500-4,400	70-90	10-20ms
	Li-ion battery	0.1-100	1min-8h	1,000-10,000	85-98	10-20ms
	Flow battery	0.1-100	1-0h	12,000-14,000	60-85	10-20ms
Chemical	Hydrogen	0.1-1000	min-months	5-30 years	25-45	sec-min
	Power to Gas/Methane	50-1.000	min-months	5-30 years	18-34	sec-min

***The efficiency (round trip efficiency) is the percentage of electricity put into storage that is later retrieved.**

Electrical Storage

Supercapacitor

Supercapacitors offer a direct storage of electricity. They store electricity at a very fast rate, possessing several thousand charge/discharge cycles without material degradation compared to batteries, and are suitable for transient voltage stability applications [70].

Superconducting Magnetic Energy Storage (SMES)

The direct current passed through a superconducting coil and induces a magnetic field in the superconductors, thus, allowing energy to be stored. SMES has an efficiency of 80-95% and a very fast response time. However, there are environmental concerns of strong magnetic fields which are major obstacles for the technology.

Mechanical Storage

Pumped Hydro Storage (PHS)

Pumped hydroelectric storage facilities store energy in the form of water in an upper reservoir, pumped from another reservoir at a lower elevation. During periods of high electricity demand, power is generated by releasing the stored water through turbines in the same manner as a conventional hydropower station. During periods of low demand, the upper reservoir is recharged by using lower-cost electricity from the grid to pump the water back to the upper reservoir. Turlough Hill (292 MW) in Co. Wicklow is Ireland's only pumped hydro storage facility. While the technology is effective for energy arbitrage, it is limited by geographical capacity constraints and environmental concerns.

Compressed Air Energy Storage (CAES)

CAES systems store energy in the form of a compressed air in underground caverns, and the energy is later supplied to electrical networks through a conversion process. The air is compressed into an underground reservoir, which facilitates the storage of energy in a 'pressure gradient'; the energy is discharged through a combustion process to operate an expansion turbine which spins an electrical generator [67]. Challenges include the requirement for an underground cavern, dissipation of heat into the atmosphere, consumption of fossil fuels, and generation of pollutant emissions arising from combustion processes.

Flywheel Energy Storage

A flywheel is essentially an electromechanical system which stores energy in the form of kinetic energy; and contains a rotating cylinder on magnetic bearings coupled with an electrical machine, which acts as a motor during charging, and as a generator during discharging. The technology is very efficient and suitable for power quality supports but is limited by its power rating (<1 MW) and its storage capacity.

Electrochemical Storage

Li-ion Battery

Lithium-ion (Li-ion) batteries are typically used in power grid applications and the operation of electric vehicles. A Li-ion battery has a high ‘energy-to-weight’ ratio and low self-discharge loss. Li-ion batteries have a high efficiency and discharge duration of seconds to hours, making them suitable for frequency regulation and peak shifting. In terms of long-term energy storage, considering a congested power system with high levels of renewable power, another drawback is that li-ion batteries store electrons and fill up and must release power back into the power system to free up storage capacity. Li-ion batteries have limited potential as they typically only have up to 8 hours of storage.

NaS Battery

The Sodium Sulphur (NaS) battery has a high power and energy density more than four times that of lead–acid BES [67]. The battery is maintained at a temperature of 300–350 °C. A major shortcoming of NaS batteries is the need for an external heat source for its efficient operation.

Flow Battery

The flow battery is an electrical storage system where the electrolyte contains one or more dissolved electro-active species flowing through a power cell/reactor in which the chemical energy is converted to electricity’ [67]. Its shortcomings are possession of a low energy density, and the need for pumping mechanisms.

Chemical Storage

Hydrogen

As discussed earlier, electrolysis is the process where electrical power is converted into hydrogen - a fuel which has many uses across the energy sector. Until very recently, electrolysis was not considered to be economically viable for storing

renewable power due low to the high costs for renewable power and the high capital costs and low efficiencies for electrolysers. Nowadays with falling costs for renewable power and electrolysers, hydrogen storage offers power systems with high shares of renewable energy a viable option for long term energy storage. There have also been efficiency improvements in both ALK and PEM systems with the latter round trip efficiency at approximately 45%, this efficiency is low in comparison to other technologies such as Li-ion batteries (~85%). However, a main advantage is that the technology can remove electrons from a power system for use in sectors like heat and transport while freeing up space on the power system for renewable generation. Furthermore, electrolysers can be deployed in MW modules that allow for a flexible scale up of plant.

Power to Gas/Methane

Hydrogen produced via electrolysis can further react with CO_2 to form methane. These systems are referred to as power-to-methane systems. CO_2 used for methanation can be obtained from various sources, but certain contaminants and water need to be removed before it can be fed into methanation to avoid catalyst poisoning [71]. Methane produced by methanation, is a versatile and easy to store substance, and it forms the majority of natural gas. However, when used as an energy source the CO_2 will be re-released. The electrolyser efficiency and cost have also been obstacles for power to methane systems. An advantage is that the existing gas grid infrastructure is suitable for injection/storage and it does not have the same injection constraints/limits that hydrogen currently has. A main drawback is that the methanation process following on from electrolysis reduces the overall efficiency of the storage system to 18-34%.

2.10 Ireland’s Gas Infrastructure

2.10.1 Infrastructure

Gas Networks Ireland builds, develops, and operates Ireland’s gas infrastructure. The Gas Networks Ireland network currently consists of 2,477 km of high-pressure steel transmission pipelines and 11,913 km lower pressure polyethylene distribution pipelines, as well as Above Ground Installations (AGIs), District Regulating Installations (DRIs) and compressor stations. AGIs and DRIs are used to control and reduce pressures on the network [72].

In terms of Gas Supplies, Ireland obtains gas from three entry points, which are: Moffat (Scotland), Inch (Kinsale) and Bellanaboy (Corrib).

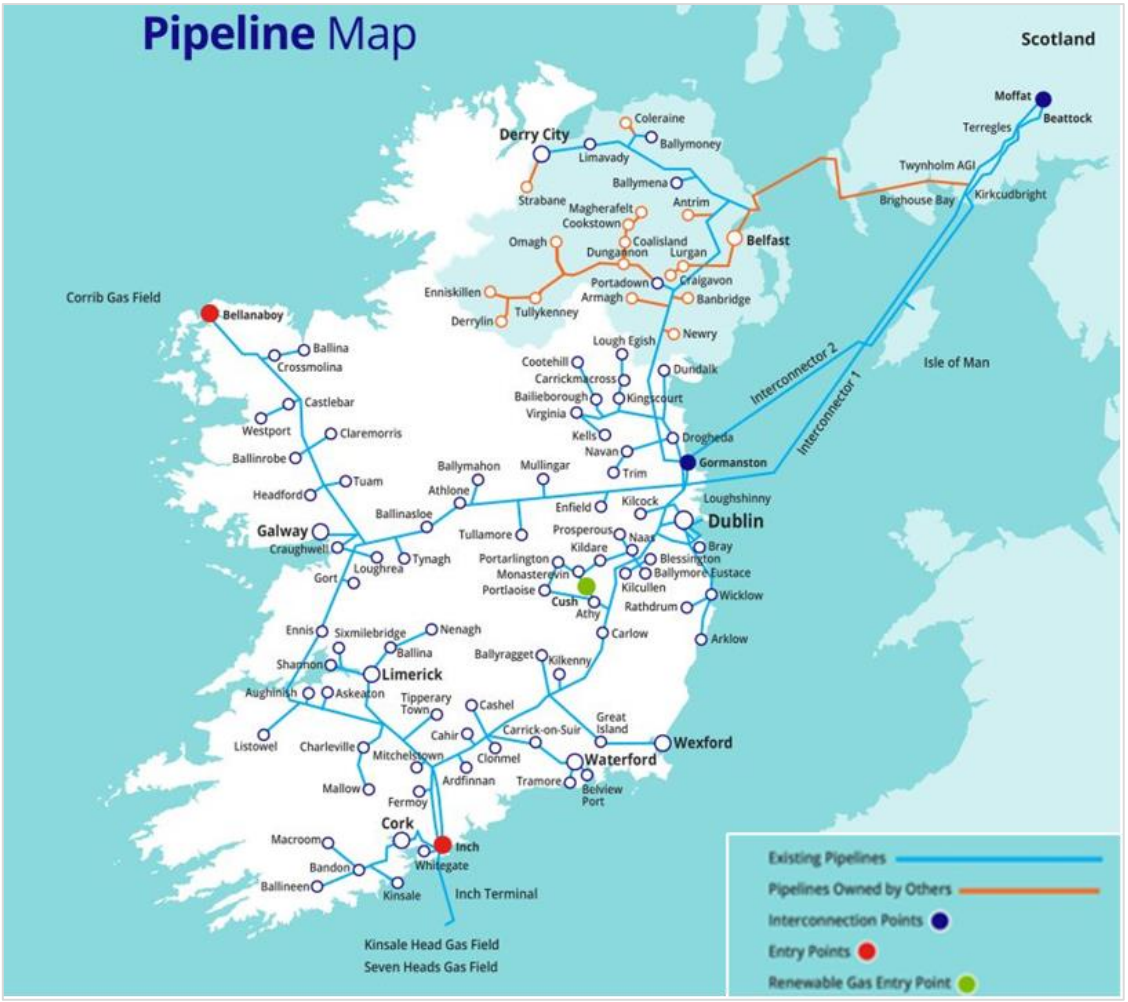

Figure 45 GNI Pipeline Map [73].

2.10.2 Ireland's Gas Supply up to 2020

Corrib Gas field located off the coast of Mayo commenced supplying gas to Ireland in 2015. Since 2015, the field had the ability to supply up to 60% of Ireland's gas demand [74]. However recent projections from GNI indicate that the supply capacity will be significantly reduced in the next years with projections for 2028 as low as 15% [72].

It is expected that Inch production gas and the reserves from the Southwest Kinsale Storage facility will be exhausted and cease production by the end of 2020 [74].

Ireland is connected to Scotland via three separate subsea interconnector pipes. The entry point for supply into the Irish Gas system is at Moffat (Scotland).

In 2019, Corrib Gas field accounted for approximately 59% of Ireland's gas usage with some 6% from Inch/Kinsale. The balance (35%) was supplied from Moffat in Scotland via subsea interconnectors.

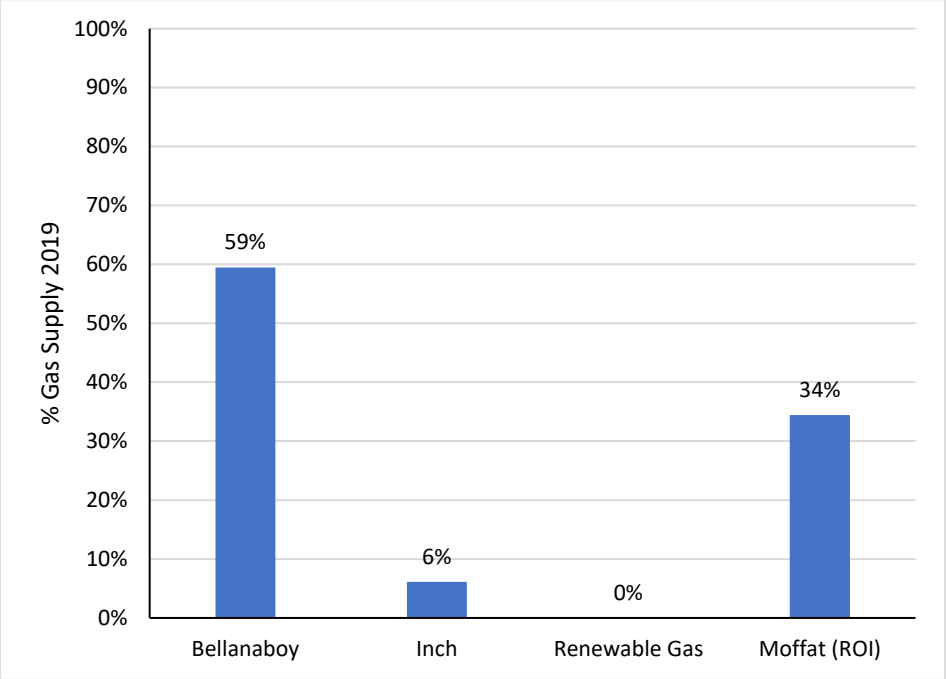

Figure 46 2019 Ireland's Estimated Gas Supply 2019 [75].

2.10.3 Ireland's Gas Supply Beyond 2020

Ireland's first renewable gas production facility located in Nurney, Co. Kildare produces Biomethane via Anaerobic Digestion [76]. Developing additional renewable gas production plants in combination with facilitating the injection of Green Hydrogen into the gas network will be crucial for the decarbonisation of Ireland's Gas system out to 2050. Hydrogen can be injected into the gas transmission grid at pressure between 30-85 bar.

GNI and Ervia commissioned a report to examine pathways to a net zero carbon gas network for Ireland by 2050 [77]. The pathway includes injecting 50% net zero carbon gas and zero carbon gases into the network to displace half of the natural gas demand. The remaining 50% of natural gas demand will require abating via carbon capture storage (CCS). It is envisaged that CCS technologies will increasingly capture and store the CO_2 emissions from natural gas used for power generation and large industry. GNI is targeting 11TWh/annum renewable gas in the network by 2030 and at which point hydrogen will be added to the mix. Looking to 2050 hydrogen is expected to account for approximately 14% of demand with renewable gas supplying 36% and the balance being supplied by abated natural gas (CCS).

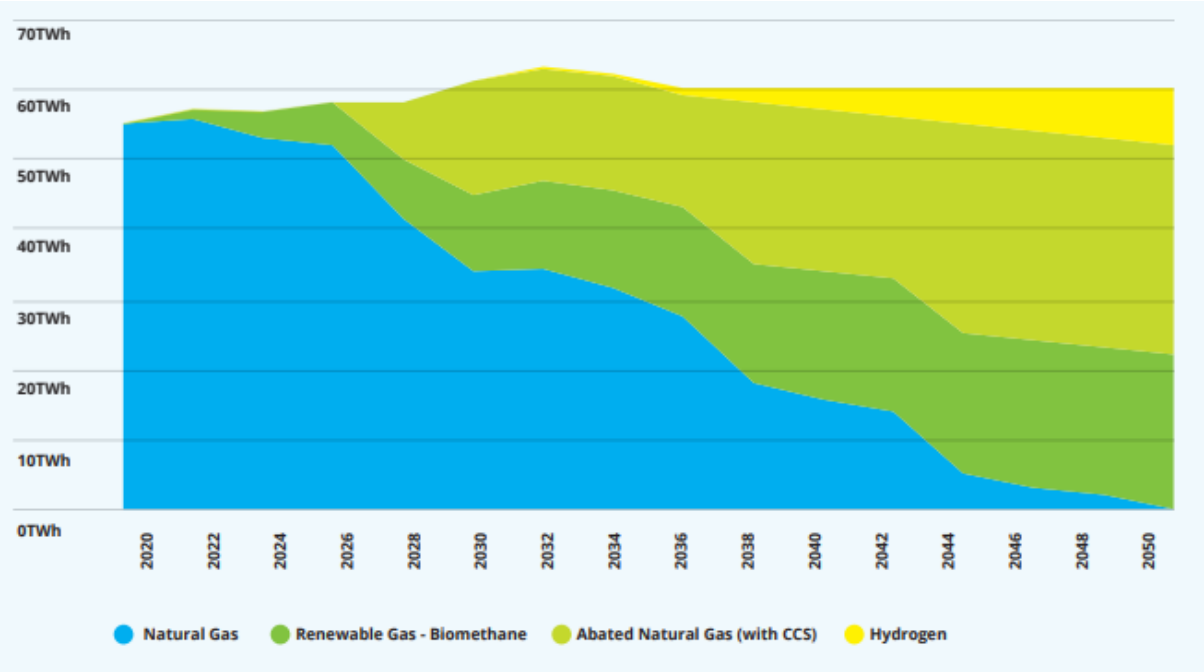

Figure 47 Ireland's Potential Gas Supply 2020-2050 [77].

2.11 Economics of Onshore Wind Generation

2.11.1 Global Economics of Onshore Wind

The recent decline in the cost of renewable energy suggests that the production of hydrogen from renewable power through a power-to-gas process might become more economical. While hydrogen can be obtained through multiple processes, its production from renewable electricity via power-to-gas (PtG) bears the advantage of complementing the intermittent power supply from wind and solar energy installations. In this section of the literary review, the decreasing trend in onshore wind generations costs are illustrated.

The levelized cost of electricity (LCOE) of an onshore wind farm is determined by: the total installed costs; lifetime capacity factor; the O&M costs; the economic lifetime of the project; and the cost of capital [78]. The global weighted-average LCOE of onshore wind has decreased significantly since 2010. IRENA reported a reduction in LCOE from 70 €/MWh in 2010 to 45 €/MWh in 2019 (Conversion = 1.17 US Dollar ~ 1Euro) [78]. See Figure 48.

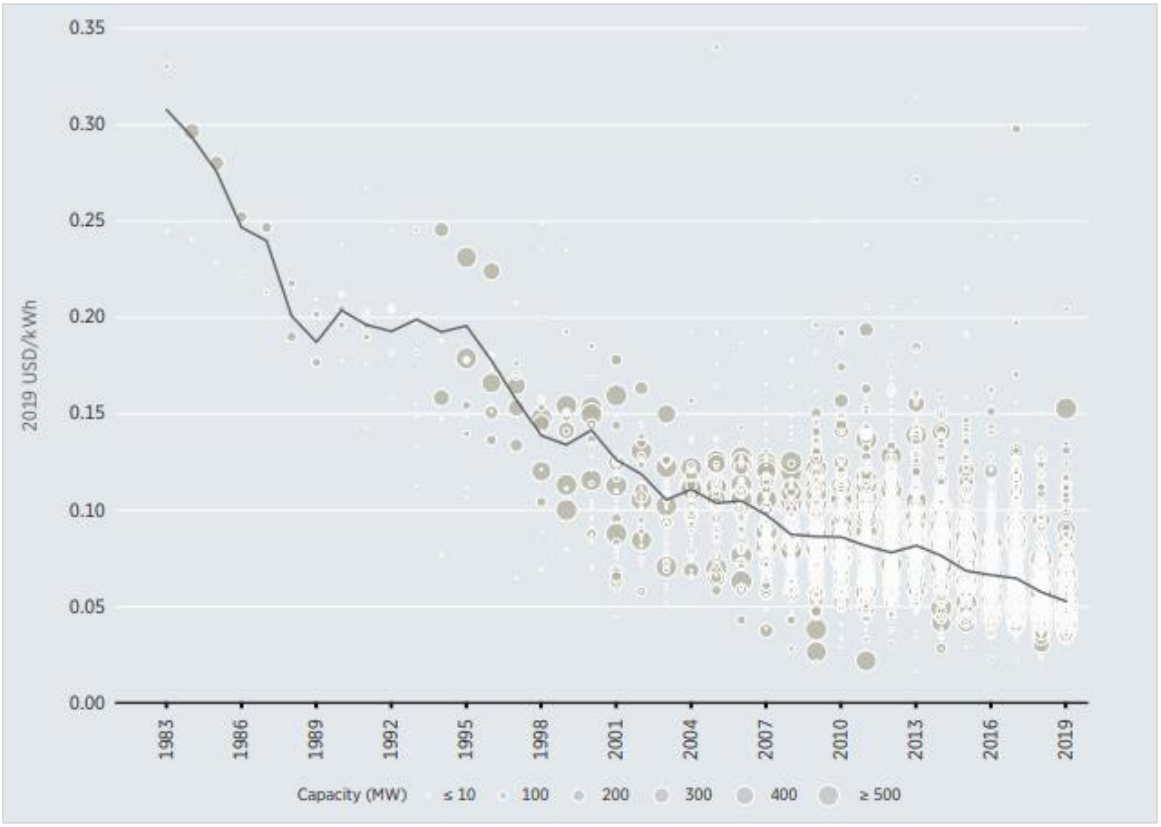

Figure 48 LCOE of onshore wind projects and global weighted average, 1983–2019 [78].

IRENA reported that the total installed costs for wind in Europe decreased from 2,000,000 €/ MW to 1,500,000 €/ MW between 2010-2019. See Table 10.

Table 10 IRENA Installed Cost Ranges and Weighted Averages for Onshore wind projects by region 2010-2019 [78].

	2010			2019		
	5th percentile	Weighted average	95th percentile	5th percentile	Weighted average	95th percentile
	(2019 USD/kW)					
Africa	2 226	**2 291**	3 196	1 448	**1 952**	2 189
Other Asia	1 829	**2 501**	2 762	1 392	**2 368**	3 709
Central America and the Caribbean	2 497	**2 664**	2 787	1 737	**1 737**	1 737
Eurasia	2 284	**2 432**	2 501	1 277	**1 633**	2 035
Europe	1 575	**2 405**	3 602	1 071	**1 800**	2 233
North America	1 594	**2 407**	3 696	1 099	**1 636**	2 162
Oceania	2 993	**3 501**	3 882	1 157	**1 555**	1 788
Other South America	2 399	**2 644**	2 729	1 123	**1 718**	2 270
Brazil	2 252	**2 539**	2 603	1 224	**1 559**	2 061
China	1 173	**1 491**	2 038	1 115	**1 223**	1 340
India	1 013	**1 412**	1 941	1 039	**1 055**	1 082

The recent decline in the LCOE of onshore wind has been driven by [78]:

- **Increased Capacity Factors:** With the increase in turbine sizes and swept areas, the process of optimising the rotor diameter and turbine ratings has led to increased energy yield and thus project viability for the asset owner (depending on site characteristics).
- **Lower O&M costs:** The combination of digital technologies that has allowed for improved data analytics and autonomous inspections. In addition, there have been improvements in the reliability and durability of new turbines, while larger turbines have reduced the number of turbines for a given capacity. Improved O&M practices have also contributed to lower O&M costs. Increased competition in the O&M servicing sector for onshore wind has also helped drive down costs.
- **Competitive Procurement:** The shift from feed-in-tariff support schemes to competitive auctions is also leading to further cost reductions, as it drives competitiveness across the supply chain.

- **Lower cost of capital:** Onshore wind is a proven technology across the world. Banks are now more comfortable with the risks associated with onshore wind which has led to cheaper debt for developers.
- **Economies of Scale:** increased scale of operation has impacted manufacturing costs, installation costs (reduced number of turbines required for a project due to the higher turbine ratings), and O&M costs.

Increased Capacity Factors

Across Europe, IRENA reported significantly higher capacity factors for onshore wind when comparing 2010 and 2019 figures. In both Spain and Denmark, there were increases from 27-39%. While in Germany there was an increase from 24-31%. During the same period, the UK had an increase from 30-33%.

According to BNEF , the capacity factor of onshore wind is rising 1% point year-on-year according to [79]. The mean forecast for the capacity factor of onshore wind in 2030 is approximately 40%. See Figure 49.

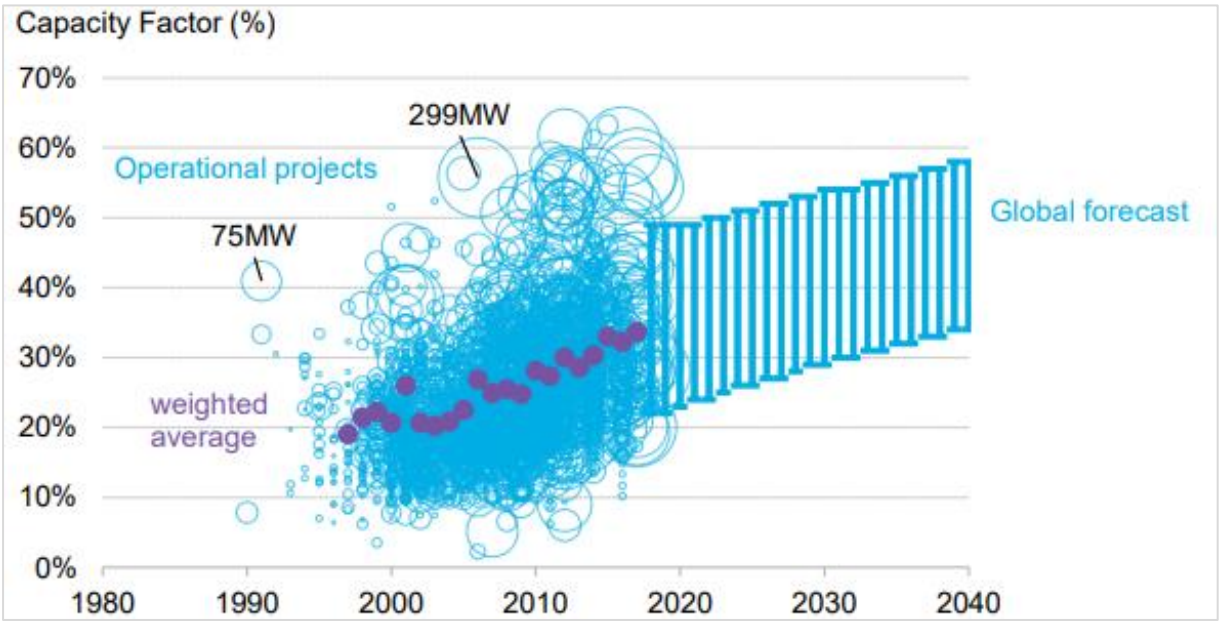

Figure 49 BNEF Wind Capacity Factors Historical & Projected [79].

Lower O&M Costs

BNEF reported a fall in onshore wind O&M costs from 40,000 €/ MW/yr in 2010 to 16,000 €/ MW/yr in 2019 [79]. See Figure 50. These costs include routine and unscheduled maintenance, minor and major component parts and labour costs.

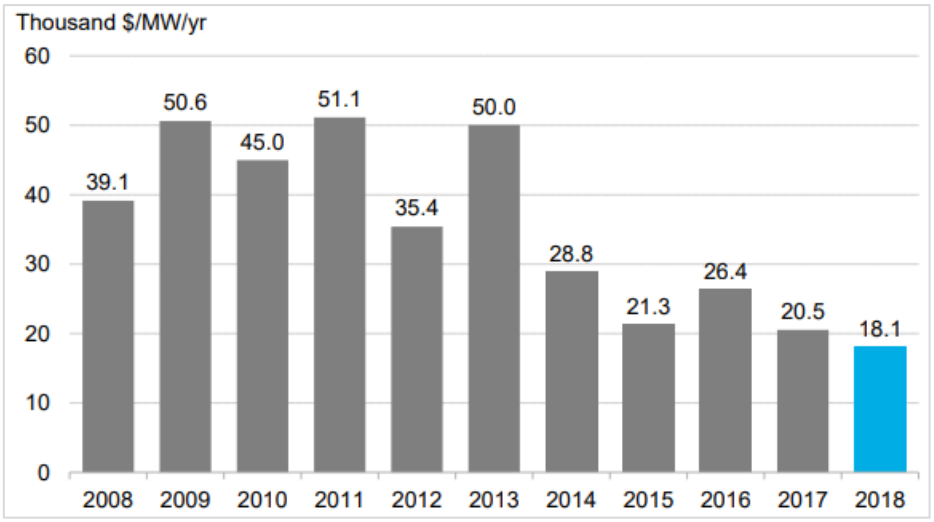

Figure 50 BNEF Historical O&M Costs Globally [79].

Competitive Procurement

Most European countries have moved to award support mechanisms for renewable energy through auctions. Over the past 6 years, onshore wind has consistently seen capacity awarded capacity between 34-70 €/MWh (See Figure 51). For example, in December 2019 Poland awarded 2.2GW of onshore wind capacity in an auction at an average price of €45/MWh [80]. While in Germany, more than 6 GW of onshore wind were auctioned in 2017 and 2018, out of which more than 5 GW were awarded at an average price of 52.4 €/MWh. However, prices in Germany have increased in the past 18 months as auctions have been undersubscribed due to the complexity of the planning/consent process [80]. During October 2019, 204 MW were awarded at an average of 62.2 €/MWh.

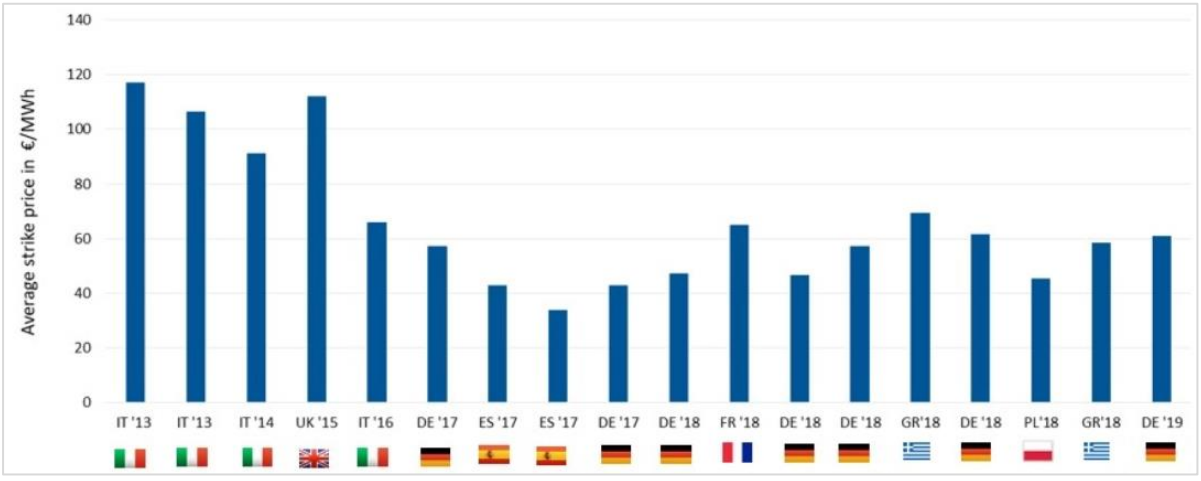

Figure 51 Wind Europe Average Strike Prices in EU Auctions for Onshore Wind [81].

Lower Cost of Capital

The cost of capital is closely tied to policy and regulatory stability, with uncertain future events being priced as risk premium in the cost of financing [82]. Angelopoulo et al. reviewed the cost of capital for onshore wind generation in Europe in 2016 [83]. The study involved conducting a number of interviews with industry members. The review formed part of the "DIA-CORE" project which assessed RES policies in the 28 EU Member States. The estimations from Angelopoulo et al. are presented in Table 21 in Appendix A.

The cost of debt ranged from 1.8% in Germany to 12.5% in Greece. While in Ireland the cost of debt was 6.5-7.5%. The cost of equity ranged from 6-20% with Germany the lowest and Estonia the highest. The cost of equity was estimated to be 11-12% in Ireland. The Debt to Equity ratio in Ireland was estimated to be 70:30.

2.11.2 Economics of Onshore Wind in Ireland

Historically Onshore wind generation was subsidised through the Renewable Energy Feed-in Tariff (REFIT) schemes. These were designed to ensure Ireland met its goal of 40% of electricity coming from renewable sources by 2020 [84]. They also provided certainty to renewable electricity generators by providing them with a minimum price for each unit of electricity exported to the grid over a 15-year period. This ensured wind generators received a price for electricity of approximately 80 €/MWh.

RESS is the new Renewable Electricity Support Scheme in Ireland. It is a critical component of the National Energy and Climate Plan. The DCCAE, CRU and EirGrid worked together to deliver RESS 1. RESS 1 uses a competitive auction process to determine which generators receive support. For projects that are successful in the RESS 1 Auction, this support typically applies for approximately 15 years [85].

The CAPEX and turbine costs for wind farms in Ireland are assumed to be in line with the European average as discussed earlier in section 2.11.1.

The average capacity factor of onshore wind in Ireland was between 27-32% in the period 2011 to 2019 [86]. EirGrid estimate this will increase to c.35% in 2030 [23].

In Ireland, there are additional factors that affect the LCOE of wind to those outlined in section 2.11.1. The factors vary by location and include:

- **TLAF**: Transmission Loss Adjustment Factors (TLAFs) are allocated to generators (including generators embedded in the distribution system). These

are calculations of the losses and are calculated jointly by EirGrid/SONI and approved by the Regulatory Authorities (RAs) on an annual basis.

- **DLAF**: Distribution Loss Adjustment Factors (DLAFs) applied by ESB.
- **TUoS Charges**: Transmission Use of System Charge (TUoS) is the system of charging for transporting power in bulk across the transmission system (110kV,220kV and 400kV network). It applies to Generators on an all-island basis, demand customers in Ireland (larger commercial or business users of electricity), and suppliers. It is also paid by distribution system customers who rely upon the transmission system [87].
- **Local Authority Rates**: Wind generators must also pay rates on a per MW basis to the Local authority.

2.12 Renewable Hydrogen Applications

2.12.1 Transport

In an internal combustion engine, fuel is burnt at high temperatures, producing carbon emissions and pollutants such as nitrogen oxides (NOx). Hydrogen is generally used in a fuel cell where Hydrogen reacts chemically with atmospheric oxygen at a much lower temperature, producing an electric current that powers the vehicle.

Some of the key benefits of FCEVs include:

- Fuel cells emit only water vapour and heat – no CO_2 or NOx pollutants.
- Hydrogen vehicles are as quick and convenient to refuel as conventional cars, (less than 3 minutes).
- Limited behavioural change for the owner in comparison to BEVs, which have a significantly longer charge time and lower driving range which requires a different approach to operating/owning a car.
- Long driving range (the Hyundai Nexo has a range of over 650 km).
- A pathway to complete decarbonization of road transport.
- Integration of intermittent renewables for transport.

Figure 52 Current Mobility Vehicles in operation across Europe [88][89][40][90][91].

Hydrogen gas has high energy density by weight, but low energy density by volume versus hydrocarbons. Therefore, it requires a larger storage tank. Increasing gas pressure improves the energy density by volume, making for smaller, but heavier storage tanks. FCEV cars and vans typically operate at 700 bar pressure due to space limitations. However, heavy-duty FCEVs such as trucks and buses operate at 350 bar with more space available for hydrogen storage tanks.

High Level Review of International Hydrogen Mobility

USA

- California Target for 1m FCEVs by 2030 [92].
- 6558 FCEV in use: Led by California USA has the highest uptake of FCEV in the world (~ 5,000 of these are Toyota Mirai).
- This fleet is supported by only ~45 HRS.

China

- Target for 1m FCEVs & 1,000 HRS by 2030 [92].
- Extensive investment in fuel cell technology: In 2018 China invested $12.4 billion in FC systems and companies.
- Ten Cities Thousand Vehicles Plan: China hopes to replicate its success in BEVs with FCEV.

Japan

- Target for 800,000 FCEVs & 900 HRS by 2030[93].
- 2,800 FCEVs in use: Japan has the second highest deployment of FCEVs.
- Toyota plans to ramp up production of FCEVs from 30,000 per year in the early 2020s to 300,000 per year by 2030 [94].

France

- France has hydrogen mobility hubs in several cities and regions serving captive fleets. The hubs are driven by local demand, but together form the foundations of a national infrastructure network.
- There were c.400 hydrogen vehicles on the roads in France by the end of 2018, including 100 hydrogen taxis in Paris.
- The HysetCo joint venture that owns the taxis and refuelling infrastructure plans to expand the fleet to 600 by the end of 2020[95].

Germany

- Only Japan has more hydrogen refuelling stations than Germany, with 100 constructed at the end of 2019 [96].
- The German strategy since 2010 has been to establish a national refuelling network as a prerequisite for vehicle adoption. They are now entering a second phase to build 300 further stations as demand increases and more vehicle models become available.

Switzerland

- High taxes for diesel trucks in Switzerland has driven demand for alternatives and the joint venture Hyundai Hydrogen Mobility is planning to deliver 1,600 hydrogen fuelled trucks by 2025 [97].
- The joint venture plans to offer a full hydrogen mobility service, providing the vehicles, fuel and refuelling infrastructure for a single per-kilometre price.

UK

- UK H_2 Mobility roadmap indicates up to 1,600,000 FCEVs and 1,150 stations in 2030 [98].
- HydroFLEX hydrogen train currently being tested, a diesel train retrofitted with a fuel cell to enable it to run purely on hydrogen [99].

2.12.2 Gas Grid Injection

As discussed earlier in the report, there are several options available to Ireland for heat sector decarbonisation. These include electrification and renewable gas.

The electrification options are feasible for new build houses that are well insulated, but the majority of the housing stock today is not compatible. A complete electrification of heat would imply that the gas grid is no longer used and becomes a stranded asset. However, a complementary solution exists: decarbonising the gas grid by blending natural gas with renewable gases like hydrogen and biogas, in the same way as we are progressively decarbonising the electricity grid.

Hydrogen can make up 5 to 20% of the volume content of natural gas supply without any infrastructure modifications. Some cities and regions can even transform their gas grid into a pure hydrogen grid. This is interesting as pipeline transportation of hydrogen reaches 95-100% efficiency. This benefit makes hydrogen an economically attractive option when transporting renewable energy at scale and over large distances[100].

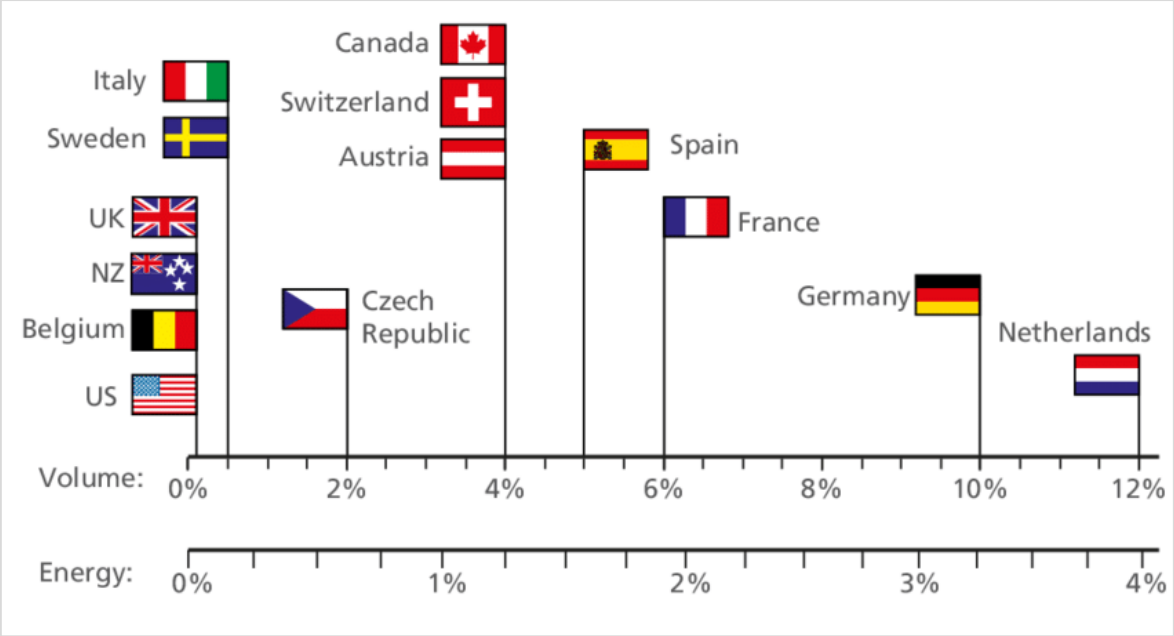

Figure 53 Hydrogen blending limits across Europe [101].

Qualitative analysis on the benefits of Hydrogen Gas Grid Injection:

- **Enabling Sectoral Integration**: Hydrogen is an energy carrier and feedstock and offers a clean, sustainable, and flexible option to convert renewable electricity into a chemical energy carrier for use in the heat sector [102].
- **Decarbonisation of the gas grid**: In 2018 natural gas contributed to 27% of energy related CO_2 emissions in Ireland [103], these emissions could be displaced through the transition to hydrogen.
- **Investment in gas infrastructure stays relevant:** Investing in new gas network infrastructure to facilitate hydrogen injection avoids the possibility of the gas grid becoming a stranded asset [104].
- **Substantial cost savings delivered to consumers:**
    - At a household level, hydrogen does not require the 'deep retrofit' needed to convert properties to electric heat (e.g installation of underfloor heating/ high levels of insulation), nor are new appliances or internal infrastructure required [74].
    - In an Ervia/KPMG publication, it is estimated that using renewable gas including hydrogen for home heating would deliver significant cost savings up to 2050 for consumers in Ireland, with a per household cost of roughly one-quarter of that of the electrification of heat pathway [74].

High Level Review of International Hydrogen Gas Grid Injection

UK – H21 Leeds City Gate

Northern Gas Networks, the gas distributer for the North of England, through its H21 project has already proved conversion of the existing gas grid to carry 100% hydrogen is technically possible and economically viable. See the 2016 H21 Leeds City Gate report [105]. The concept involves hydrogen production via four Steam Methane reformers and the use of local salt caverns to store the hydrogen both on an intraday and inter-seasonal basis.

H21 is now focused on delivering two key pieces of work, enabling a first policy decision on hydrogen to be made:

- Presenting the quantified safety evidence that proves a future hydrogen gas networks can be managed to the same high safety standard as the natural gas network at present.
- Establishing a clear pathway for decarbonising heat, setting out the design requirements of the infrastructure needed to convert the North of England to hydrogen.

2.12.3 Hydrogen Injection Pathways in Ireland

Gas Networks Ireland and Ervia are investigating the potential for hydrogen production and transportation using the gas network. This will involve evaluating the compatibility of the high-pressure steel transmission pipelines with hydrogen. Ireland's low-pressure distribution network has polyethylene pipework which is understood to be compatible with 100% hydrogen [77].

Potential pathways for the injection of hydrogen include:

- Blending: where hydrogen is injected into the gas network as a volumetric percentage of the natural gas flowing past the point of injection at a given time. It may be possible for hydrogen to make up 5-20% of the volume content of natural gas supply without any infrastructure modifications [104].
- Dedicated Hydrogen Pipelines: whereby the pipelines are isolated from that of the natural gas grid and all the end users. The pipeline assets are designed and operated as a hydrogen grid. This approach recognises hydrogen has different properties from natural gas and operational procedures and regulations can be designed from day 1 with specifically hydrogen in mind.

- Methanisation: hydrogen is combined with Carbon Dioxide in a biological or chemical process. This transforms hydrogen into methane (CH_4) which is effectively identical to the gas in the existing pipelines today. This approach removes many of the barriers of injecting hydrogen into the gas network. However, an inherent disadvantage is that methanisation adds significant capital cost and reduces the efficiency of the injection process.

2.12.4 Industry

Of all sectors globally, industry has the highest hydrogen demand, especially for refining and chemical and steel manufacturing. As these industries use high-carbon hydrogen, replacing it with low-carbon hydrogen would be an ideal opportunity to ramp up demand while decreasing GHG emissions in the short term.

Some large projects are already applying carbon capture to fossil-based hydrogen production in both sectors such as Shell's Quest project in Canada [106].

In terms of electrolytic hydrogen, a number of important large-scale developments (up to 100 MW) were announced in 2019 and are expected to be operational in the early 2020s including the UK Gigastack project. Most of these announcements involve oil refining or methanol and ammonia production which is discuss in section 2.12.5.

The Gigastack project, led by ITM Power, Ørsted, Phillips 66 Limited and Element Energy are working together to show how renewable hydrogen derived from offshore wind can supply the Humber refinery in North Lincolnshire. At present, a Front-End Engineering Design ('FEED') study on a 100 MW electrolyser system using staged installations with a nominal capacity of 20 MW is being carried out. The FEED study will detail the actual design of a hydrogen production system connected to a wind farm and industrial off-taker using ITM Power's new generation of electrolyser stack technology, renewable energy directly from Ørsted's Hornsea Two offshore wind farm [107].

Electrolytic hydrogen is gaining momentum in steelmaking. Without making any major changes to existing direct reduced iron furnaces, up to 35% of the natural gas can be substituted by hydrogen [108]. Steelmakers are pursuing blending as a transition strategy to forge the way to the deployment of the pure hydrogen direct reduced iron route, for which a large pilot plant is under construction in Sweden and a first demonstration trial is projected for 2025 [109].

2.12.5 Ammonia Production

As discussed earlier in section 2.6.1, Hydrogen is a fundamental component for the manufacture of ammonia. Almost 90% of ammonia production goes into fertilizer production [39]. Ammonia manufacturing is the world's third biggest industrial process emitter of carbon dioxide, creating half a billion tonnes of CO_2 each year – 1.8 percent of global CO_2 emissions.

Ammonia is a form of Nitrogen, the main ways in which it is lost in agriculture are the storage and application of organic manures, chemical fertiliser applications and grazing animals.

In Ireland today, agriculture is responsible for 99% of all ammonia emissions. Ammonia is a gaseous form of Nitrogen, the main ways in which it is lost in agriculture are the storage and application of organic manures, chemical fertiliser applications and grazing animals. Air pollutants like ammonia are not greenhouse gases, but they do negatively impact on human and animal health while also damaging ecosystems [110]. Ireland currently imports ammonia from continental Europe. Ammonia production from green hydrogen presents Ireland with an opportunity to decarbonise the Agriculture sector in Ireland which accounts for 30% of greenhouse gas emissions.

In Australia, there are plans to construct a 210- MW solar park along with a 160- MW hydrogen electrolyser to produce green hydrogen and ammonia at Dyno Nobel's existing ammonia production sites in Queensland, which currently rely on natural gas. This project will seek to produce 20,000 tonnes of ammonia per year from 3,600 tonnes of renewable hydrogen on a commercial scale. The Australian firm produces over 360,000 tonnes of ammonium nitrate annually.

Air Products, in conjunction with ACWA Power and NEOM, plan to deliver a world-scale green hydrogen-based ammonia production facility powered by renewable energy. The project is scheduled to be completed by 2025. The project will use 4 GW of renewable power from solar, wind and storage to produce 650 tons of carbon-free hydrogen per day using Halidor Topsoe's ammonia technology, which allows it to be transported safely using existing technology, according to the company. Halidor indicated the hydrogen will be converted into 3,500 tons per day of green ammonia for transportation and then converted back into hydrogen to power buses and trucks around the world [111].

2.12.6 Maritime

In the shipping industry diesel engines are used almost exclusively today. Oceangoing vessels use either heavy fuel oil or marine diesel as fuel, while inland waterway vessels use commercial diesel fuel [112].

Fuel cells can help play a key role in helping marine industries address GHG emissions on the water, and in ports. Batteries work well for vessels for very short routes, and which have frequent charging possibilities. For longer routes and larger vessels, hydrogen fuel cells are the most practical zero-emission solution. Some key benefits of fuel cell powered marine vessels include [113]:

- Modular power systems are scalable for many load requirements.
- Deployed in parallel, dispatchable configurations to meet variable power requirements.
- Flexible configurations that adapt to vessel space constraints.
- Long range and quick refuelling.

Figure 54 San Francisco Hydrogen FC Ferry [114].

2.13 Main Conclusions from Literature Review

An extensive literature review was completed to understand the entire energy system, the following conclusions are drawn:

- As discussed in section 2.2.2, the transport and residential sectors combined accounted for 64% of energy related emissions in 2018. According to the SEAI, neither sector will achieve their binding climate targets for 2020 set out under the National Renewable Energy Action Plan Ireland [11].
- The electricity sector is on track to achieve its 40% RES-E target for 2020 as shown in section 2.2.3. The Climate Action Plan 2019 set out a target of 70% RES-E for the sector in 2030 [4]. Since Ireland's existing and planned renewable electricity generation fleet is predominantly made up of variable and intermittent sources such as wind energy, achieving this target and going beyond it poses challenges.
- In 2019, Ireland dispatched down 7.5% of the available output from onshore wind energy [7]. This increased to 12.6% in the first quarter of 2020, with further increases in the second quarter of the year to 14.6%. These large increases highlight the current inefficiencies that exist in the Irish electricity system. (See section 2.5.4).
- EirGrid estimate that considerable volumes of energy could be lost in the coming years as Ireland develops more onshore and offshore wind capacity (see section 2.5.4). The 'Future Grid' scenario (2027+) modelled in EirGrid's ECP-1 constraint report analysis indicates constraint levels of up to 14% in the North West region [37].
- The North West region of Ireland including counties Donegal and Mayo is a region with significant renewable energy potential. A major obstacle to future renewable growth in the region is the inadequate electricity transmission infrastructure. Long term energy storage technologies along with the construction of new transmission infrastructure in the area could be key to Ireland fully harnessing its renewable energy potential. (See section 2.5.4).
- Falling costs for renewable power illustrated in section 2.11, and electrolyser equipment has focused attention on green hydrogen production and storage. There have also been efficiency improvements in both ALK and PEM electrolyser systems with the latter at approximately 80% [63] (See section 2.7).

The round-trip efficiency of hydrogen storage (~45%) is relatively low in comparison to Li-ion battery storage (~85%). A main advantage of hydrogen storage is that it can remove electrons from a congested power system for use in sectors like heat and transport. This frees up space for renewable generation on the power system. Hydrogen also offers a longer duration storage option in comparison to other storage technologies including batteries. Furthermore, electrolysers can be deployed in MW modules that allow for a flexible scale up of plant.

- Hydrogen mobility is already a reality in countries such as Germany, France, China and the USA. Both China and the USA have announced targets for 1 million FCEVs by 2030. In the next decade, the purchase costs of FCEVs are expected to lower as the production volumes for FCEVs ramp up and economies of scale are achieved. (See section 2.12.1).
- The Irish government announced in budget 2021 that up to €12 million of funding has been allocated to encourage the deployment of FCEV buses and trucks [16]. In addition, supports are now available for a new vehicle purchase grant to help freight and commercial bus operators to buy electric, gas or hydrogen fuelled vehicles. (See section 2.3.2).
- Hydrogen is currently produced via electrolysis at one location on in Ireland [40]. This involves a small-scale electrolyser plant located at a BOC gas depot in Co. Dublin. The electrolyser has a capacity of 200kg/day and uses grid electricity to produce hydrogen for the aerospace, pharmaceutical, electronics and biomedical industries. (See section 2.6.2)
- Ireland has a significant reliance on fuel imports. In the transport sector, 100% of petroleum products and crude oil are imported. In 2018, petrol and diesel vehicles accounted for over 95% of the private car fleet and 100% of the goods vehicle fleet (i.e. vans, trucks) [13]. (See section 2.3)
- Ireland’s indigenous natural gas sources are becoming depleted. Kinsale gas field will cease production by the end of 2020, while Corrib gas field is expected to be depleted by the late 2020’s. Looking to 2030, Ireland will be 100% reliant imported natural gas from the UK. (See section 2.10)

Aims & Objectives

The aim of the project is to investigate the challenges for the integration of renewables in the Irish energy system and explore how green hydrogen can be part of the solution.

1 Explore the emissions reduction pathways for Ireland in a climate and biodiversity emergency.
2 Identify the obstacles for further renewable development in the electricity sector out to 2030.
3 Understand the potential use cases for green hydrogen in the Irish energy system and in hard to decarbonise sectors such as heat and transport.
4 Develop Total Cost of Ownership (TCO) models for light and heavy-duty vehicles in Ireland.
5 Develop a model to estimate the delivery cost of hydrogen via a truck and tube-trailer.
6 Develop a financial model for a 'Green Hydrogen' production facility.
7 Analyse the business case for green hydrogen applications in the heat and transport sectors in Ireland and determine the hydrogen price acceptable to the consumer.
8 Perform a techno-economic analysis on the business case for green hydrogen production in Ireland:
    i. Produce Hydrogen from dispatched down electricity on a windfarm.
    ii. Produce Hydrogen from both windfarm electricity and imported electricity.
9 Review the potential socio-economic benefits arising from large-scale hydrogen production on the island of Ireland.

3 Methodology

The concept of this research project was formed on the recent climate change agenda. Based on the review of literature, hydrogen presents itself as a potential solution to addressing inefficiencies in the Irish electricity system and provides a pathway for the decarbonisation of the heat and transport sectors. This section of the report details the methodology applied to evaluate the viability of hydrogen applications in the heat and transport sectors. The financial model developed to evaluate the investment in renewable hydrogen is also described in detail.

3.1 Modelling Approach

Renewable Hydrogen Production Model

Background

The renewable hydrogen production model considers the main techno-economic drivers of CAPEX and OPEX for the onshore wind farm and the various components required for hydrogen production and compression. These components include the electrolyser system, compressors, and storage vessels. The model incorporates cost reduction projections sourced from literature for the system components.

The model was developed in Microsoft Excel 2016, which is low cost to setup, and the programming is not complex to learn or interpret. It can be easily checked against other similar models and can be open sourced, which also points towards the limitations of the model.

The annual electricity generation from the wind farm is based on a EirGrid wind profile (2008 wind year) at hourly resolution. MullanGrid curtailment and constraint hourly profiles are also incorporated into the model. Wind farm CAPEX and OPEX values in €/ MW are input into the model to compute the total costs of the wind farm.

The method identified to quantify the feasibility and financial viability of the electrolyser and the windfarm investment is the financial indicator Internal Rate of Return (IRR). The IRR is a measure of the rate of return expected from an investment. Mathematically it is defined as the discount rate which, when applied to discount a series of cash outflows followed by cash inflows, returns a net present value (NPV) of zero. In other words, the IRR is the equivalent constant interest rate at which a given series of cash outflows must be invested for the investor to earn a given series of cash inflows as income [115]. The project is deemed to be viable if the project IRR is higher

than or equal to the hurdle rate calculated from the debt/equity ratio, cost of equity and the cost of debt. The IRR of the windfarm and electrolyser plant is compared against the IRR of a windfarm without electrolysis (see Figure 55). This indicates whether deploying an electrolyser improves the business case of the windfarm. See Appendix B for an overview of the production model.

The model analyses the combined investment of the windfarm and the electrolyser and determines the hydrogen production price and if a subsidy is required on top of the sale price acceptable to the end user. This essentially estimates the viable sale price for hydrogen to achieve the desired IRR. This is a cost optimal approach to modelling.

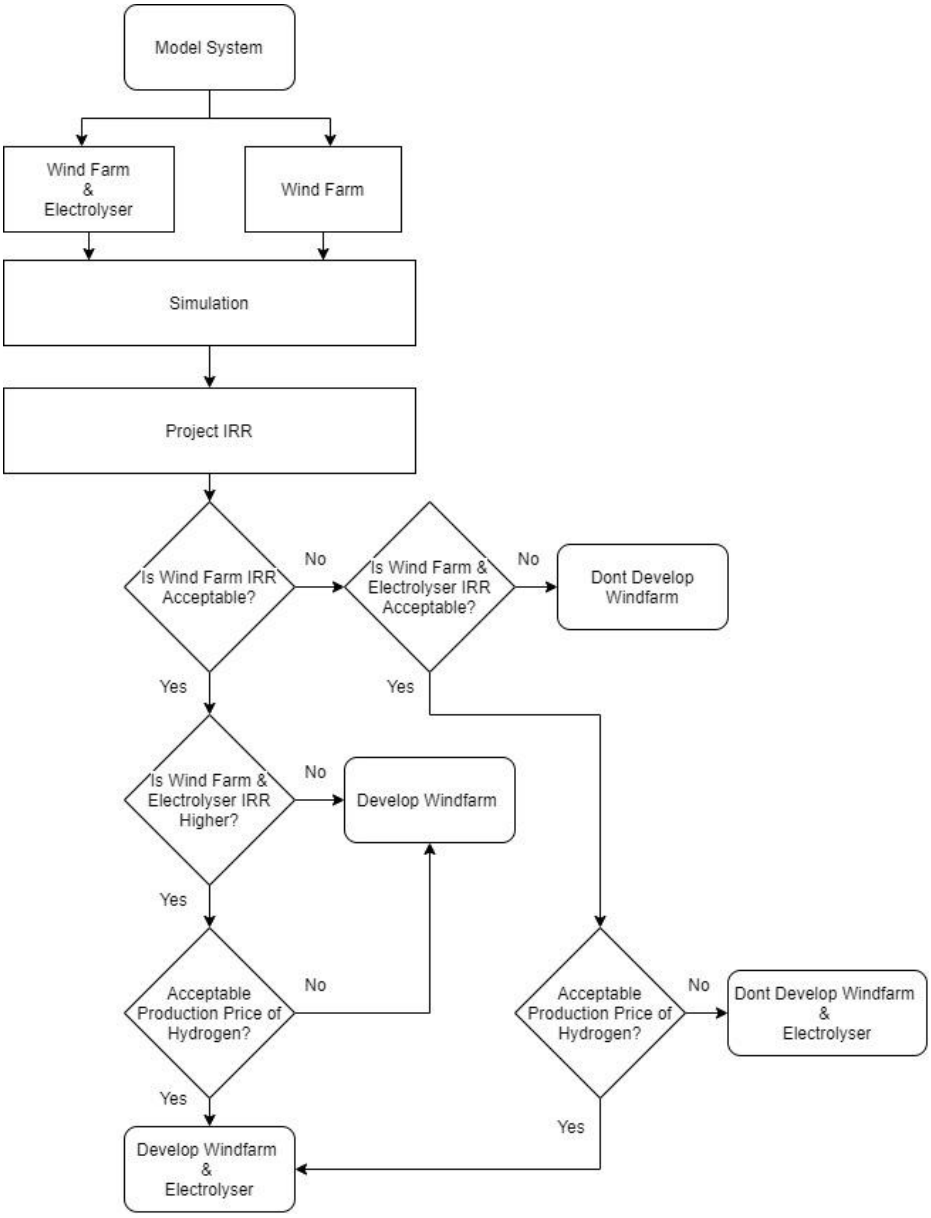

Figure 55 Wind & Electrolyser Model Schematic.

Another approach widely used to evaluate renewable hydrogen projects is the levelized cost of hydrogen (LCOH). The LCOH usually is calculated as follows: the total project life-cycle cost divided by the total lifetime energy production. The LCOH determines the cost of hydrogen production that will allow a project to break even. For this approach, the LCOE of the renewable electricity generation source is approximated separately and is used as an input to the calculation. This approach does not consider the combined investment of both the windfarm and electrolyser. As a result, a drawback with this approach in comparison to the lumped investment approach applied to this report is that electrolyser sizing cannot be optimised relative to the windfarm as the investments are treated independently.

Dispatch Model

Figure 56 indicates a high-level overview of the electricity dispatch model for the hydrogen production facility. The electrolyser and compressor can have electricity supplied by the wind farm and/or the electrical grid. The energy management system optimises the electricity dispatch to attempt to ensure the storage buffer is maintained by first seeking to utilise dispatched down electricity ($E_{DD,H}$), then exportable grid electricity on the windfarm ($E_{EWF,H}$) and finally using imported electricity from the grid ($E_{G,H}$) when there is no available energy on the wind farm. These are calculated from equations (1), (2) and (3) respectively.

$$E_{DD,H} = \sum_{t=0}^{T=8760} P_{DD,H}(t) \times \Delta t(t) \quad (1)$$

$$E_{EWF,H} = \sum_{t=0}^{T=8760} P_{EWF,H}(t) \times \Delta t(t) \quad (2)$$

$$E_{G,H} = \sum_{t=0}^{T=8760} P_{G,H}(t) \times \Delta t(t) \quad (3)$$

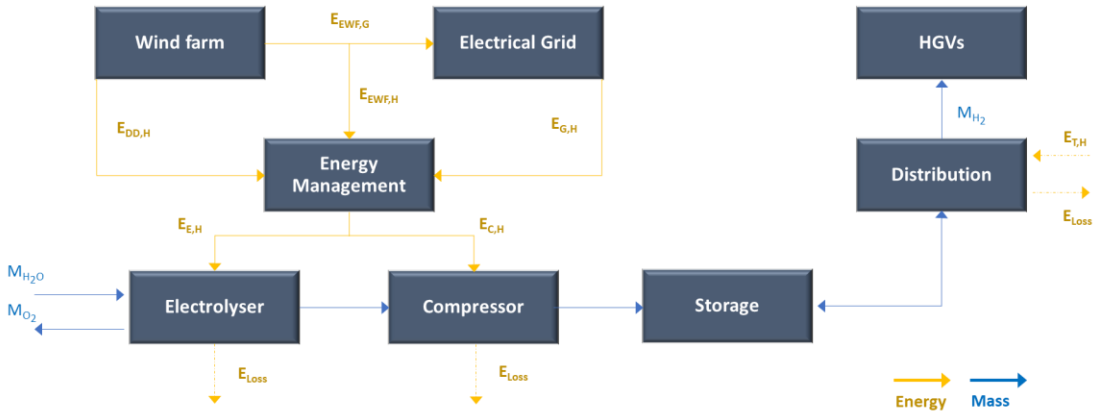

Figure 56 System Overview

The dispatched down electricity dispatched to the hydrogen production facility ($P_{DD,H}(t)$) at time t is described by equation (4). The hourly hydrogen demand is calculated by equation (5). The exportable wind farm electricity dispatched to the hydrogen production facility at time t follows equation (6). The grid imported electricity at time t to satisfy the hourly hydrogen demand is described by equation (7).

$$P_{DD,H}(t) = MIN\ (P_{DD}(t), P_E) \tag{4}$$

$$P_H(t) = \frac{HD(\rho_{E,E})(\rho_{E,C})}{O_{Days} \times 24} \tag{5}$$

$$P_{EWF,H}(t) = IF(P_{DD,H}(t) \geq P_H(t), 0\ , \text{MIN}\left(P_{EWF}(t), MIN\left(P_E, P_H(t)\right) - P_{DD,H}(t)\right)) \tag{6}$$

$$P_{G,H}(t) = IF(P_{DD,H}(t) + P_{EWF,H}(t) \geq P_H(t), 0\ , MIN\left(P_G(t), MIN\left(P_E, P_H(t)\right) - P_{DD,H}(t) - P_{EWF,H}(t)\right)) \tag{7}$$

The capacity factor of the electrolyser (λ_E) is described by equation (8).

$$\lambda_E = \frac{E_{DD,H} + E_{EWF,H} + E_{G,H}}{(8760)(P_E)} \tag{8}$$

The total hydrogen production ($M_{E,H}$) is calculated from equation (9). The electrolyser capacity (P_E) and the capacity factor (λ_E) based on the available electricity and market demand for hydrogen are inputs to the calculation. The electrolyser electricity consumption per kg of hydrogen produced ($\rho_{E,E}$) is also required to estimate the hydrogen production volumes.

$$M_{E,H} = \frac{(P_E)(\lambda_E)(8760)}{\rho_{E,E}} \tag{9}$$

Table 11 lists the dispatch model parameters.

Table 11 Wind farm & hydrogen production facility dispatch model parameters

Variable	Unit	Value	Description
P_{WF}	MW	Calculated	Wind farm capacity
$E_{DD,H}$	MWh	Calculated	Dispatched down electricity dispatched to hydrogen production facility
$E_{EWF,H}$	MWh	Calculated	Grid exportable windfarm electricity dispatched to hydrogen production facility
$E_{G,H}$	MWh	Calculated	Electricity imported from the grid to hydrogen production facility
P_E	MW	Calculated	Electrolyser capacity
HD	kg	Calculated	Annual hydrogen demand
$\rho_{E,E}$	MWh/kg	0.05	Electrolyser electricity consumption per kg of hydrogen produced
$\rho_{E,C}$	MWh/kg	0.022	Compressor electricity consumption per kg of hydrogen compressed
O_{Days}	-	350	Number of days a year plant is in operation
λ_E	%	Calculated	Electrolyser capacity factor
$M_{E,H}$	kg	Calculated	Annual hydrogen production

Financial Model

The model analyses the combined investment of the windfarm and the electrolyser and determines the hydrogen production price and if a subsidy is required on top of the sale price acceptable to the end user. The IRR is iteratively calculated from Microsoft excel, equation (10) indicates the formula to derive the IRR from the net cash flow (C_t) for the time period (t) and also the initial investment costs (C_0). The project is deemed to be viable if the project IRR is higher than or equal to the weighted average cost of capital (WACC) shown in equation (11). The WACC is calculated from the debt ratio (r_d), cost of debt (D), equity ratio (r_e) and the cost of equity (E) and the corporate tax rate (T_c).

$$NPV = 0 = \sum_{t=1}^{T} \frac{C_t}{(1+IRR)^t} - C_0 \quad (10)$$

$$WACC = (r_d \times D) + (r_e \times E \times (1 - T_c) \quad (11)$$

The initial investment costs are (C_0) described by equation (12) and account for the wind farm investment costs (C_{WF}) and the hydrogen production facility investment costs (C_H).

$$C_0 = C_{WF} + C_H \quad (12)$$

The wind farm investment costs from equation (13) comprises costs for the wind turbines (C_{WTG}), balance of plant ($C_{BOP,WF}$) and grid connection costs (C_G) which are

input in €/ MW with the total system cost based on the wind farm installed capacity (P_{WF}). The project development costs (C_D) are also included.

$$C_{WF} = (C_{WTG} + C_{BOP,WF} + C_G)(P_{WF}) + C_D \quad (13)$$

The hydrogen production facility investment costs (C_H) calculated from equation (14) comprises costs for the electrolyser (C_E), balance of plant ($C_{BOP,E}$) which are input in €/ MW with the total electrolyser cost based on the installed capacity (P_E). The compressor unit costs (C_C), storage tank costs (C_S) and project development costs (C_D) are also included.

$$C_H = (C_E + C_{BOP,E})(P_E) + (C_C)(m) + (C_S)(S_H) + C_D \quad (14)$$

Table 12 shows the wind farm & hydrogen production facility investment input parameters.

Table 12 Wind farm & hydrogen production facility investment input parameters

Variable	Unit	Value	Description
T	Years	25	Lifetime of project
C_{WTG}	€/ MW	800,000	Wind turbine generator cost per MW installed
$C_{BOP,WF}$	€/ MW	200,000	Balance of plant cost per MW installed
C_G	€/ MW	220,000	Grid connection cost per MW of maximum export capacity (MEC)
C_D	€	1,000,000	Development cost for windfarm
P_E	MW	Calculated	Electrolyser capacity
C_E	€/ MW	660,000	Electrolyser cost per MW
$C_{BOP,E}$	€/ MW	130,000	Electrolyser balance of plant cost per MW
C_C	€/kg/h	9,290	Compression equipment cost per kg/h for compression from 30-350 bar
m	kg/h	1575	Compressor filling rate to hydrogen storage tank
C_S	€/kg	470	Hydrogen storage cost per kg
S_H	kg	37,800	Hydrogen storage capacity onsite
C_D	€	1,000,000	Development costs associated with hydrogen production facility

The net cash flow (C_t) from equation (15) accounts for the revenue (R_t) and operational costs for the wind farm and hydrogen production facility (O_t) over the lifetime of the project.

$$C_t = R_t - O_t \quad (15)$$

The revenue from the project is calculated from equation (13). The revenue streams include the exportable wind farm electricity ($E_{EWF,G}$) sold at the wholesale electricity market price (C_{GE}), the hydrogen production volumes ($M_{E,H}$) sold at the market price for the desired use case (C_{H_2}) and including the level of regulatory support / subsidy (S_{H_2}).

$$R_t = (E_{EWF,G})(C_{GE}) + (M_{E,H})(C_{H_2} + S_{H_2}) \quad (16)$$

The project operational costs are described by equation (17) and account for the wind farm operational costs (O_{WF}), hydrogen production facility operational costs ($O_{O\&M,H}$) and the energy costs for hydrogen production (O_E).

$$O_t = O_{WF} + O_{O\&M,H} + O_E \quad (17)$$

The wind farm OPEX from equation (18) comprises costs for land leasing/rent (O_R), wind farm servicing / operation and maintenance ($O_{O\&M,WF}$), transmission use of system charges (O_{TUoS}), community benefit charge (O_C), council rates (O_{CR}) and insurance (O_I).

$$O_{WF} = (P_{WF})(O_R + O_{O\&M,WF} + O_{TUoS} + O_{CR} + O_I) + (E_{WF})(O_C) \quad (18)$$

$$E_{WF} = (P_{WF})(\lambda_{WF})(8760) \quad (19)$$

The hydrogen production facility OPEX (O_H) calculated from equation (20) accounts for the operation and maintenance costs for the electrolyser, compressor and storage systems ($O_{O\&M,H}$) which are calculated by equation (21). Insurance costs ($O_{I,H}$) and water costs (O_W) are also included.

$$O_H = O_{O\&M,H} + (O_{I,H})(P_E) + (O_W)(\rho_{W,E})(E_H) \quad (20)$$

$$O_{O\&M,H} = \left(O_{\%,C_E}\right)(C_E)(P_E) + \left(O_{\%,C_C}\right)(C_C)(m) + \left(O_{\%,C_S}\right)(C_S)(S_H) \quad (21)$$

The energy costs for hydrogen production (O_E) are calculated by equation (22). Energy costs grid imported electricity are included, these are based on the quantity of imported energy ($E_{G,H}$) and the market price of grid imported electricity (C_{GE}).

$$O_E = \left(E_{G,H}\right)(C_{GE}) \quad (22)$$

Table 13 shows the wind farm & hydrogen production facility operational cost input parameters.

Table 13 Wind farm & hydrogen production facility operational input parameters

Variable	Unit	Value	Description
O_R	€/ MW	7,250	Annual land rent per MW installed wind capacity
$O_{O\&M,\ WF}$	€/ MW	20,000	Annual variable WTG servicing costs per MW
O_{TUoS}	€/ MW	7,000	Annual TUoS costs per MW
O_C	€/MWh	2	Annual community benefit fund contribution per MWh energy produced
O_{CR}	€/ MW	11,150	Annual council rates per MW
O_I	€/ MW	1,115	Annual insurance costs per MW
$O_{I,H}$	€/ MW	1115	Insurance cost per MW for hydrogen production facility
O_W	€/l	4×10^{-3}	Mains water cost per litre
λ_{WF}	%	Calculated	Annual wind farm capacity factor
$\rho_{W,E}$	L/kg	15	Electrolyser water consumption per kg of hydrogen produced
$O_{\%,CE}$	%	2	Electrolyser annual operational cost as a percentage of capital cost
$O_{\%,CC}$	%	2	Compressor annual operational cost as a percentage of capital cost
$O_{\%,CS}$	%	2	Storage tanks annual operational cost as a percentage of capital cost
$E_{EWF,H}$	MWh	Calculated	Grid exportable windfarm electricity dispatched to hydrogen production facility
$E_{G,H}$	MWh	Calculated	Electricity imported from the grid to hydrogen production facility
C_{GE}	€/MWh	55	Market price of grid imported electricity
$E_{DD,H}$	MWh	Calculated	Dispatched down electricity from wind farm utilised by hydrogen production facility
λ_E	%	Calculated	Annual electrolyser capacity factor
$\rho_{E,E}$	MWh/kg	0.050	Electrolyser electricity consumption per kg of hydrogen produced

Vehicle TCO Model

Using Microsoft Excel 2016, vehicle TCO models were developed to analyse a range of vehicle categories and fuel types. The TCO model determines the direct and indirect costs of owning a vehicle over a fixed period. Included in these costs are fuel costs, maintenance costs, insurance and taxes. Government incentive schemes such as purchase grants, tax deductions and a guarantees of origin scheme have also been incorporated in the model. By comparing the TCO for various fuel types including petrol, diesel, battery electric, hybrid, and fuel cell vehicles a suitable price of hydrogen to the consumer is determined. Equation (23) shows the formula for calculating the vehicle TCO.

$$\mathrm{TCO} = \mathrm{C} + \mathrm{O} - \mathrm{D} \tag{23}$$

Table 14 TCO Calculation Parameters

Variable	Unit	Description
C	€	Capital costs associated with the vehicle purchase and putting it into service
O	€	Operating costs of vehicle, including fuel, insurance, maintenance & repair
D	€	Disposal value

Hydrogen Tube Trailer Delivery Model

Since windfarms tend to be located in isolated areas due to wind speeds, planning legislation and land availability, it was also necessary to develop a delivery model to evaluate the cost of transporting hydrogen from the production source to a refuelling station. Hydrogen tube trailers were identified as the means of transportation. The model accounts for the truck and trailer CAPEX & OPEX. Technical parameters including the tube trailer capacity and the pressure of hydrogen are considered in the model. The model outputs the delivery costs of hydrogen on a cost per kilogram per kilometre basis €/kg/km.

The price of hydrogen transportation is approximated by equation (24) and accounts for the annual tractor unit, trailer, and driver costs for the corresponding hydrogen delivery volumes.

$$P_{trans,i} = \frac{A_{tractor,i}\ x\ A_{trailer,i}\ x\ A_{driver,i}}{HD_i} \quad (24)$$

The annual cost of the tractor unit is calculated from equation (25). The cost is based on the lifetime cost per km of a FCEV truck, distance from the production facility to survey respondent, number of trips required based on tube trailer capacity (calculated by equation (26) and the number of days in operation per year.

$$A_{tractor,i} = C_{km,FCEV}\ x\ L_{trip,i}\ x\ N_{trip,i}\ x\ 2\ x\ O_{days} \quad (25)$$

$$N_{trip,i} = \frac{HD_i}{M_{trailer}\ x\ O_{days}} \quad (26)$$

Equation (27) is used to calculate the annual trailer cost based on the lifetime of the unit. The variables accounted for are the number of tube trailers required (calculated by equation (28), investment and operational costs of the tube trailer and its lifetime.

$$A_{trailer,i} = N_{trailer,i}\ x\ \frac{C_{inv,trailer}}{T_{trailer}} x\ (C_{O,trailer}\ x\ C_{inv,trailer}) \quad (27)$$

$$N_{trailer,i} = \frac{\left(t_{journey,i} + t_{load}\right)\ x\ N_{trip,i}}{t_{tractor,available}} \quad (28)$$

Equation (29) approximates the annual cost relating to the FCEV truck driver. This encompasses the round-trip journey time, tube trailer loading/unloading time and the corresponding driver wages for a full year of operation.

$$A_{driver,i} = \left(t_{journey,i} + t_{unload}\right) x\, N_{trip,i}\, x\, O_{days}\, x\, C_{driver} \quad (29)$$

Table 15 shows the variables in the hydrogen delivery model.

Table 15 Variables used in hydrogen delivery model

Variable	Unit	Value	Description
$P_{trans,i}$	€/kg	Calculated	Price of hydrogen delivery to survey respondent / hub
$A_{tractor,i}$	€	Calculated	Annual costs of FCEV truck/tractor unit delivering to survey respondent / hub
$A_{trailer,i}$	€	Calculated	Annual costs of trailer unit delivering to survey respondent / hub
$A_{driver,i}$	€	Calculated	Annual driver costs for delivering to survey respondent / hub
HD_i	kgH_2	Calculated	Annual hydrogen demand for survey respondent
$C_{km,FCEV}$	€/km	0.76	Cost per km of FCEV over lifetime of truck from total cost of ownership model
$L_{trip,i}$	km	Calculated	Distance from production facility to survey respondent
$N_{trip,i}$	Trips/Days	Calculated	Number of trips per day required to respondent considering trailer capacity
O_{days}	Days	350	Number of days in operation per year
$M_{trailer}$	kg	400	Gaseous hydrogen tube trailer capacity @ 350 bar
$N_{trailer,i}$	Item	Calculated	Number of tube trailers required to service survey respondent
$C_{inv,trailer}$	€	200,000	Investment cost for tube trailer unit
$T_{trailer}$	Yrs	15	Lifetime of tube trailer
$C_{O,trailer}$	%	2	Operational cost for tube trailer unit as a percentage of investment cost
$t_{joruney,i}$	hrs	Calculated	Round trip journey time from production facility to survey respondent
t_{load}	hrs	0.75	Time to load/unload hydrogen from tube trailer to respondent
$t_{tractor,available}$	hrs/day	24	Time per day truck/trailer is available for operation
C_{driver}	€/hr	27.8	Driver hourly cost to employer

3.2 Developing a Base Case

The methodology is aimed at determining a base case, defined as a business plan, technically viable and financially sustainable, for the construction and operation of a windfarm to produce green hydrogen via electrolysis.

The base case is focused on an electrolyser with access to wind energy when it is available and access to electricity from the wholesale market. Factored into the electricity price is the cost for a Guarantees of Origin (GoO) certificate which ensures that the hydrogen produced is 100% renewable. This configuration allows the electrolyser to provide a secure green hydrogen supply and achieve high-capacity factors (>60%).

In 2030, it is expected that capacity factors are improved for newer wind turbine technology and that CAPEX and OPEX for the Electrolyser equipment are reduced as result of learning curves and economies of scale from large scale deployment across Asia, Europe, Australia and America.

3.3 Costing the Electrolyser System

The report by Glenk et al. has been followed and more recent cost estimates for PEM and ALK electrolysers in 2019/2020 publications have been added. Using Microsoft excel, 2nd order polynomial equations were formed to estimate the CAPEX for both ALK and PEM electrolysers between 2020 and 2030 (See Figure 57). The equation constants and estimated CAPEX for both technologies are presented in Table 16.

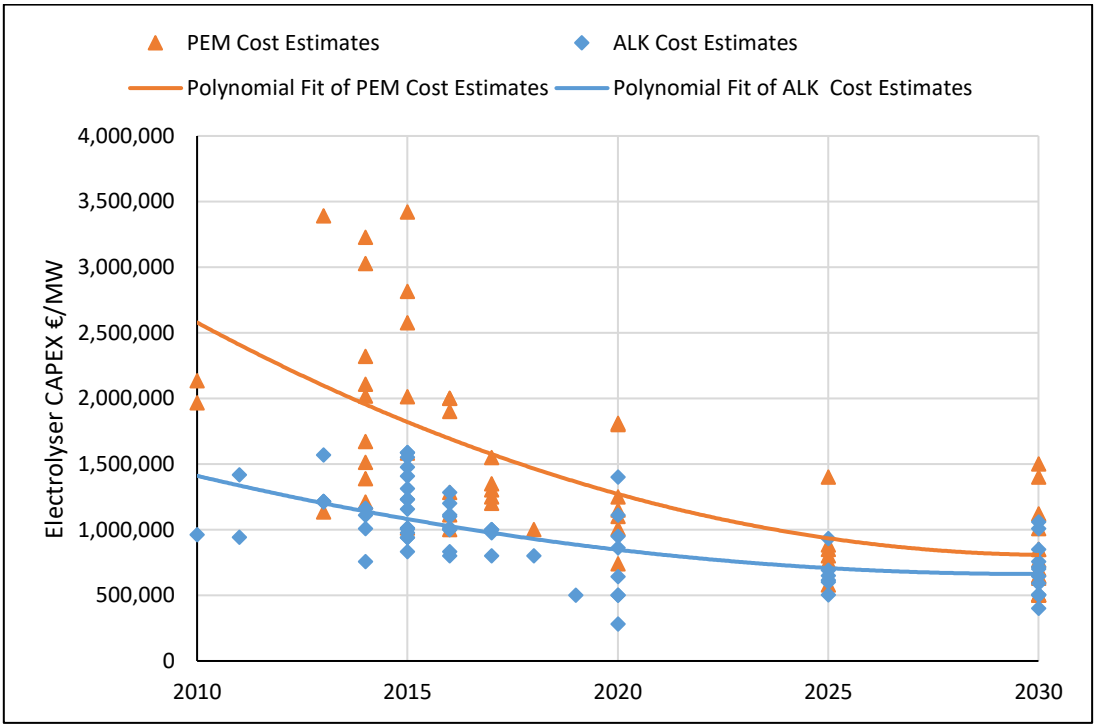

Figure 57 Electrolyser CAPEX Estimates 2010 – 2030.

$$\boldsymbol{CAPEX}\ (€/\boldsymbol{MW}) = \boldsymbol{ax^2} + \boldsymbol{bx} + \boldsymbol{c}$$

Equation 1.

Table 16 Costing the Electrolyser 2020-2030.

CAPEX (€/ MW) = ax²+ bx + c			
Equation Constants	a	b	c
ALK	1,894	-7,688,309	7,803,792,473
PEM	4,209	-17,091,398	17,352,989,047
CAPEX in Year (x)	2020	2025	2030
ALK CAPEX (€/ MW)	850,000	710,000	660,000
PEM CAPEX (€/ MW)	1,270,000	940,000	810,000

4 Analysis & Discussion

4.1 Electricity, Gas Price, Fuel Price Analysis

Petrol and Diesel Prices

The prices presented in Figure 58 are the conventional fuel prices assumed for the vehicle TCO analysis discussed in section 4.2. It is assumed that the other components in the price of fuels remain constant and that an increase in the carbon tax is the main source for rising fuel prices up to 2030. The carbon price is assumed to quadruple by 2030 to €80/tCO_2 in line with the Climate Action Plan 2019.

Using these assumptions, petrol and diesel prices in 2030 are expected to increase to 1.46 €/L and 1.49 €/L respectively. It is worth mentioning that these projections do not account for price fluctuations due to supply and demand factors or political unrest.

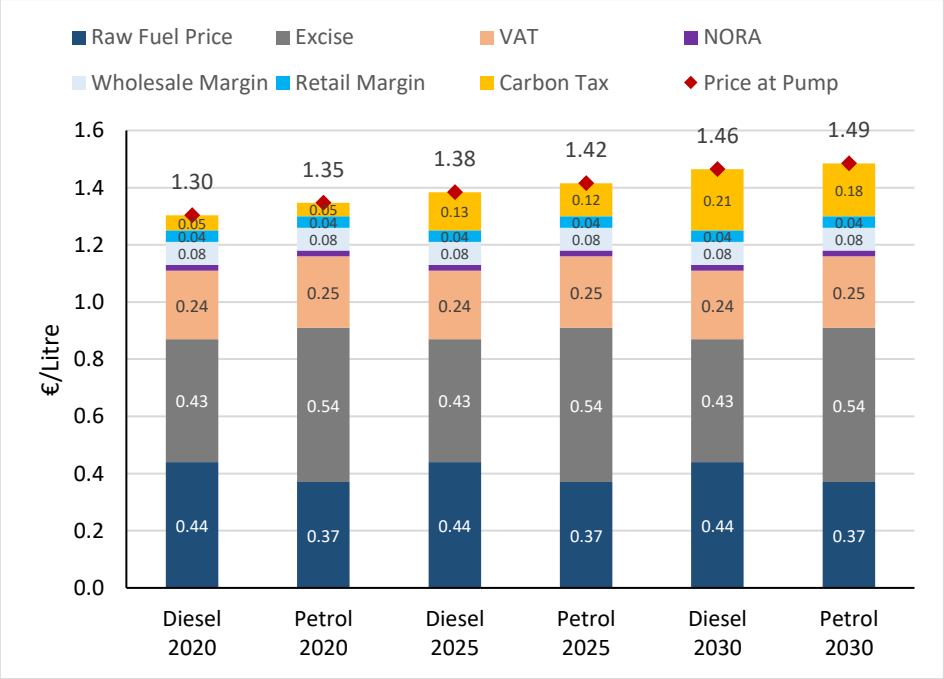

Figure 58 Petrol & Diesel Price Projections 2030

Electricity Prices

Wholesale electricity prices in Ireland have been on a downward trend in recent years as the level of wind capacity in Ireland has increased. Wind farms, once constructed, are inexpensive to run as wind generation has a low marginal cost. Wind generation therefore displaces higher cost electricity sources such as gas plants or imports. This dynamic means wind reduces power prices across the entire electricity market [116].

In order to estimate future wholesale electricity prices, analysis of historical prices was carried out using publicly available data from the single electricity market operator (SEMO) website [117]. The analysis also looked at the price during curtailment periods. EirGrid the system operator issues real time dispatch instructions to individual generators to reduce or increase their output. Curtailment periods were defined using wind dispatch instruction data for 20 windfarms in the Republic of Ireland and 10 windfarms in the North of Ireland.

Table 17 presents the average day-ahead market price during all periods and curtailment periods for 2019 and the first two quarters of 2020. Some key observations include:

- The average day ahead market price in 2019 was 50 €/MWh.
- During 2019 curtailment periods, the average day-ahead market price was 31 €/MWh.
- In the first half of 2020 with record levels of curtailment and constraint in Ireland, the average day ahead price was considerably lower at 31 €/MWh. This price was also probably reduced due to a fall in electricity demand from COVID 19 in March 2020.
- During 2020 Q1 & Q2 curtailment periods, the average price during curtailment was 17 €/MWh.

For the 2030 analysis presented later in section 4.4.1, it is assumed that the price of electricity is in line with the 2019 price. This is a conservative price projection, and it is possible that the actual price will be lower as more renewable generation connects in 2030. However, electricity prices are extremely volatile and hard to predict as Table 17 illustrates.

Table 17 Review of Day Ahead Market Price 2019 -2020 YTD.

Average Day Market Price €/MWh		
Period	During Curtailment €/MWh	All Periods €/MWh
2019	31	50
Q1 2020	22	37
Q2 2020	6	26
2020 YTD	17	31

Gas Prices

The UK government in 2019 released natural gas price projections for the period 2020-2030 [118]. The price reflects European gas market conditions, with the European market linked to other regional markets (especially North America and Asia), and quotes the UK spot price.

Making assumptions about fossil fuel prices far into the future is extremely challenging, as there are many unknowns (e.g. future economic growth rates across the world, development of new technologies, global climate change policies, technological developments). In 2030, the price of natural gas is expected to be in the range of 15-31 €/MWh as seen in Figure 59. Applying a carbon tax of 80€/tCO_2 in Ireland, the equivalent parity price range for hydrogen would be 1.05-1.6 €/kg.

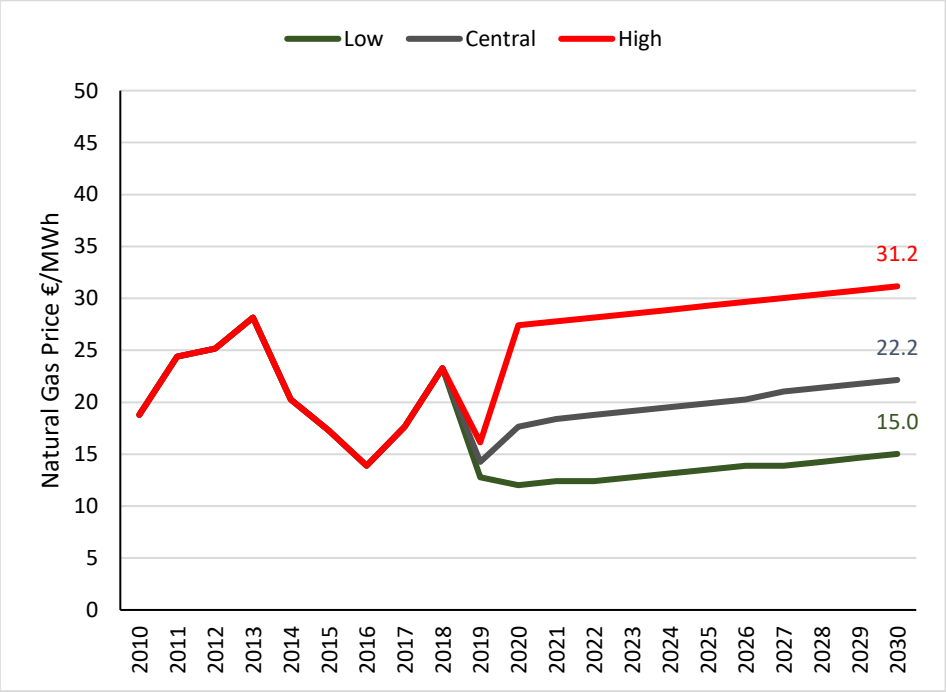

Figure 59 UK Government Gas Price Projections 2020-2030 [118].

4.2 The Case for Hydrogen Mobility

This section of the report presents the results of the total cost of ownership (TCO) model for various vehicle types with cost projections out to 2030. The vehicle types assessed include the private car, taxi car, van, 25 tonne truck, single decker bus, double decker bus and a train. These vehicles were deemed to be the most likely vehicle types to reach maturity by 2030. Maritime and Aerospace applications are currently at a prototype/ infancy stage and should be considered in the context of 2040.

By comparing the TCO for various fuel types including petrol, diesel, battery electric, hybrid and fuel cell vehicles, a suitable price of hydrogen to the consumer is determined. See Appendix D for 2030 vehicle assumptions.

Vehicle Registration Tax (VRT) Exemption

Battery electric cars and vans: Currently receive a €5000 VRT exemption in the Republic of Ireland. These will be in place until the end of 2021, at which point it expected this incentive will be reduced and removed completely between 2025 and 2030.

FCEVs: Recognising the less mature level of deployment of FCEVs, it is assumed that VRT exemptions of; €5,000 in 2021, €5,000 in 2025 & €1,000 in 2030 exist.

SEAI Purchase Grants

Battery electric vehicles: Currently also eligible for a purchase grant, which varies depending on the type and use of the vehicle. These grants will be in place at the levels shown below until the end of 2021 and it is assumed that they are removed between 2025 and 2030:

- Private cars - €5,000
- Business cars, taxis and vans - €3,800
- Additional grant for Taxis - €7,000

FCEVs:

- Private cars - €5,000 in 2021, €5,000 in 2025 & €1,000 in 2030
- Taxis and vans - €3,800 in 2021, €1,900 & €950 in 2030
- Taxis receive additional grant - €7,000, €3,500 in 2025 & €1750 in 2030

Accelerated Capital Allowance: Vehicles

Applies to cars used for business – companies can reduce their tax bill in the year of purchase by 12.5% of the purchase price of a battery electric car up to €24,000 (€3000).

For both BEVs and FCEVs it is assumed that the value of this inventive will be €3,000 in 2021 and €600 in 2025 and removed for all zero emission vehicle types by 2030.

Motor Tax

Zero emission vehicles in Ireland currently pay the lowest motor tax bracket of €120 per year.

Motor tax for both BEV and FCEV vehicles will increase by one tax bracket each year, leading to tax of: €120 in 2021, €170 in 2025 and €180 in 2030.

Car TCO Analysis

Private Car TCO

Fuel cell car costs follow the US DOE fuel cell cost down curves assuming a D segment car (medium/large saloon) and fuel cell sales in line with the stated fuel cell sales targets in key markets (USA, China, South Korea and Japan). The annual TCO analysis assumes first-time owner of the vehicle with costs evaluated over a period of 4 years.

The VRT exemption and purchase grant have been extended for FCEVs so that they receive the support as BEV. By 2025, the FCEV is expected to become very cost competitive, once the policy support is included, with the BEV option only slightly cheaper.

Figure 60 indicates the purchase costs assumed for the private car comparison and Figure 61 shows the private car TCO analysis for the period 2020-2030.

Key Findings:

- If current BEV incentives are extended to FCEV then they will be very cost competitive in the mid to late 2020s (assumes RED certificate price of €1.51).
- In the early years (2022), the high upfront/purchase costs for the FCEV option mean that the TCO is considerably higher than the BEV option. With economies of scale in FCEV vehicle production, the TCO appears to decline significantly by 2025 with a slight increase in 2030 when vehicle incentives are reduced.

- Assuming a price at the pump of 10 €/kg H2, FCEVs are cheaper on an annual TCO basis than conventional petrol and diesel-powered cars.
- Assuming a price at the pump of 5 €/kg H2, FCEVs annual TCO costs are closely aligned to BEVs in the mid to late 2020's.
- BEVs appear to have a cheaper TCO in comparison to petrol and diesel vehicles in 2022. This is likely due to the purchase grant and VRT exemption incentives that reduce the upfront costs and also lower maintenance costs.

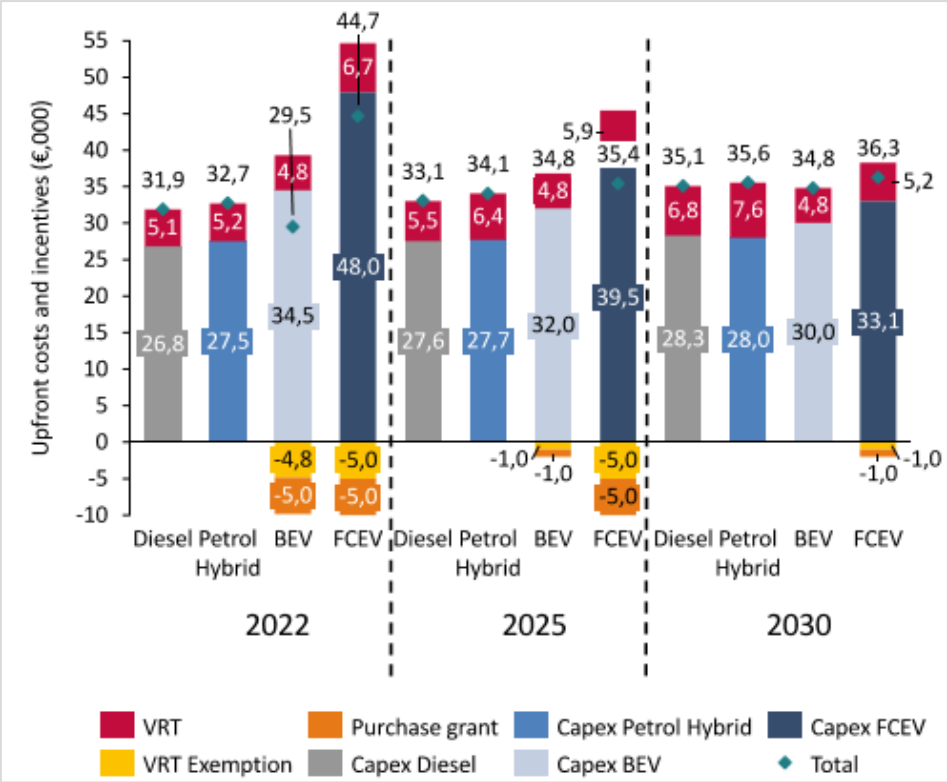

Figure 60 Private Car Purchase Costs.

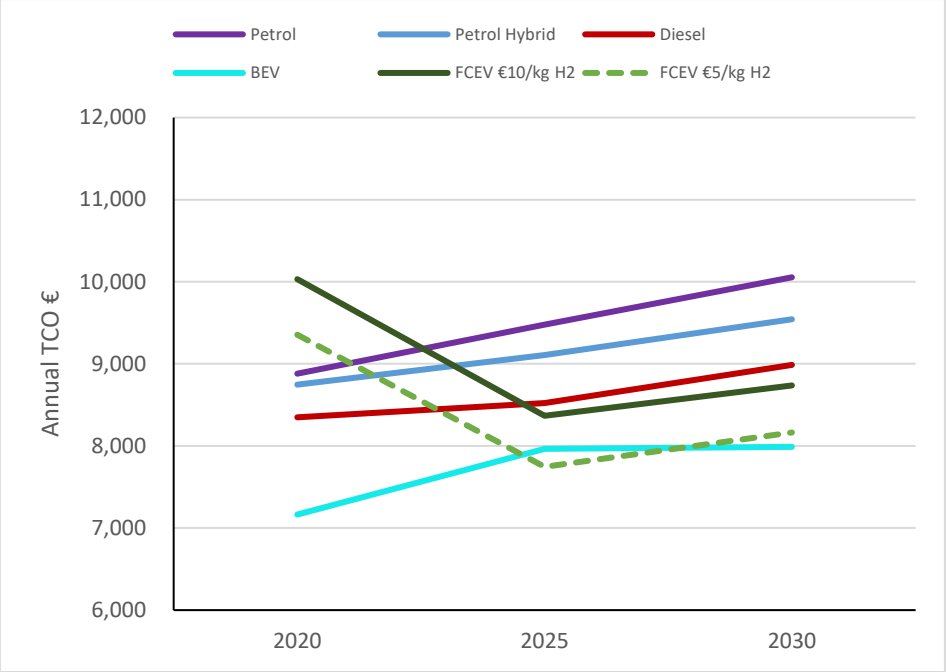

Figure 61 Private Car Annual TCO Including Green H_2 Incentives.

Taxi Car TCO

The TCO for taxi cars follow the same pattern as private cars.

Figure 62 indicates the purchase costs assumed for the taxi comparison and Figure 63 shows the private car TCO analysis for the period 2020-2030.

Key Findings:

- At 5 €/kg, the FCEV taxi is very cost competitive with BEV but offers a longer range and shorter refuelling times.
- In the early years (2020-2025), the high upfront/purchase costs for the FCEV option mean that the TCO is considerably higher than the BEV option. With economies of scale in FCEV vehicle production, the TCO appears to decline significantly by 2025 with a slight increase in 2030 when vehicle incentives are reduced.
- BEVs appear to have a cheaper TCO in comparison to petrol and diesel vehicles in 2022. This is likely due to the purchase grant and VRT exemption incentives that reduce the upfront costs and also lower maintenance costs.

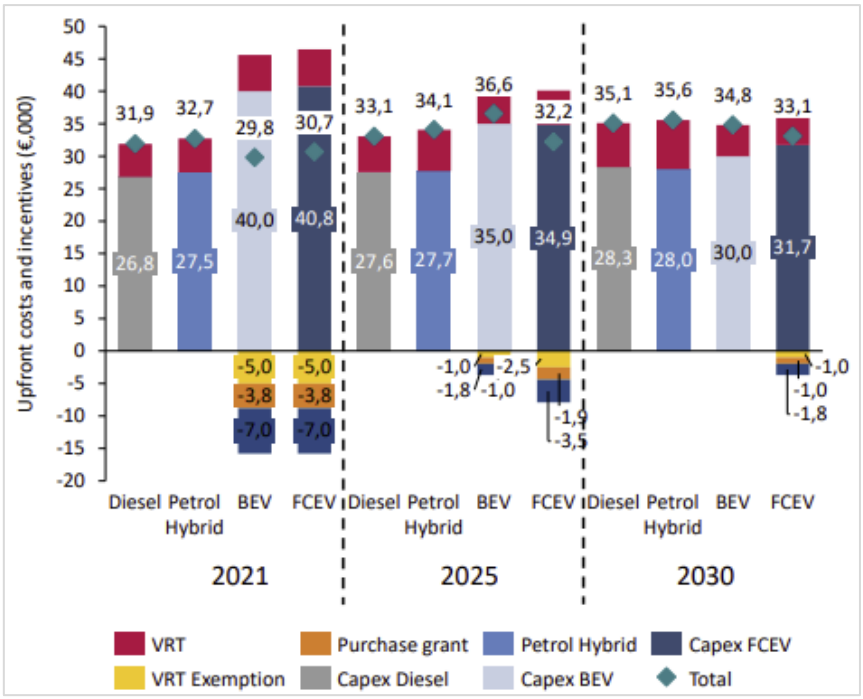

Figure 62 Taxi Car Purchase Costs.

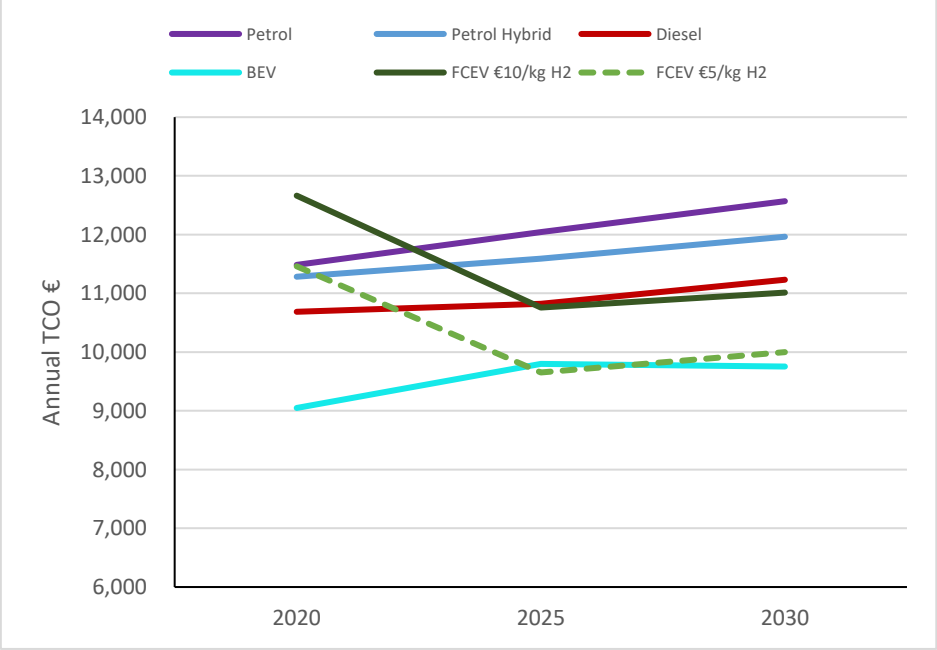

Figure 63 Taxi Car Annual TCO Including Green H_2 Incentives.

Van TCO Analysis

This analysis assumes a large panel van and first-time ownership over a 12-year period. Figure 64 indicates the purchase costs assumed for the taxi comparison and Figure 65 shows the private car TCO analysis for the period 2020-2030.

Key Findings:

- In the early years (2020-2025), the high upfront costs for the FCEV option mean that the TCO is considerably higher than the BEV option. With economies of scale in FCEV vehicle production, the TCO appears to decline significantly by 2025 with a slight increase in 2030 when vehicle incentives are reduced.
- BEVs appear to have a cheaper TCO in comparison to petrol and diesel vehicles in 2022. This is likely due to the purchase grant and VRT exemption incentives that reduce the upfront costs and also lower maintenance costs.
- Assuming a price at the pump of 10 €/kg H2, FCEV vans are the most expensive option in comparison to BEV, diesel and petrol vans. While for a price at the pump of 5 €/kg H2, FCEVs annual TCO costs are competitive with BEVs. Although slightly higher, the FCEV van may be a favourable option for certain logistic companies due to the longer driving range associated with fuel cells.

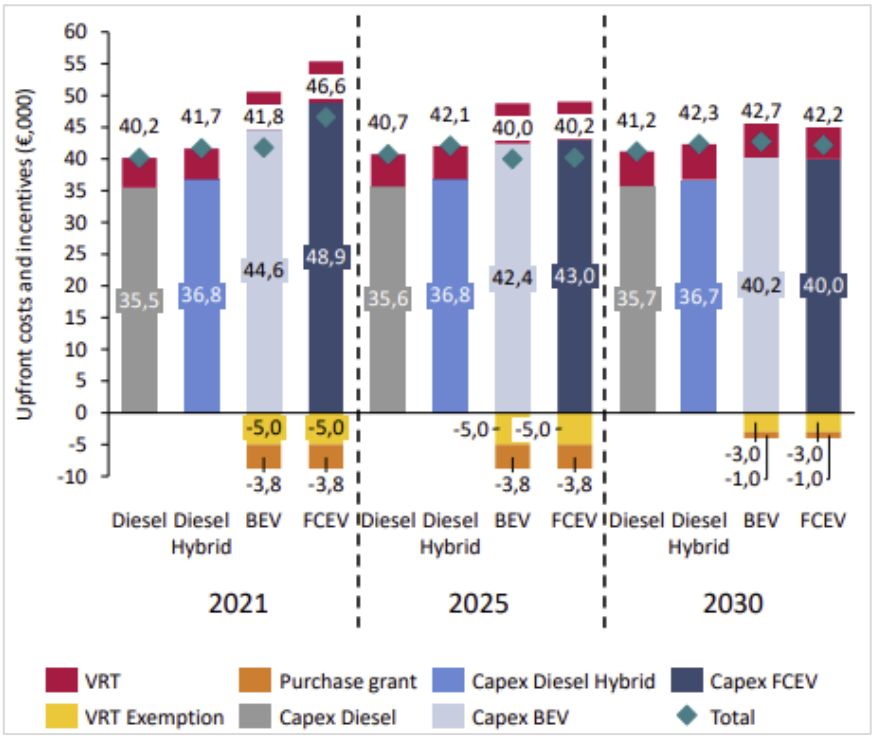

Figure 64 Large Panel Van Purchase Costs.

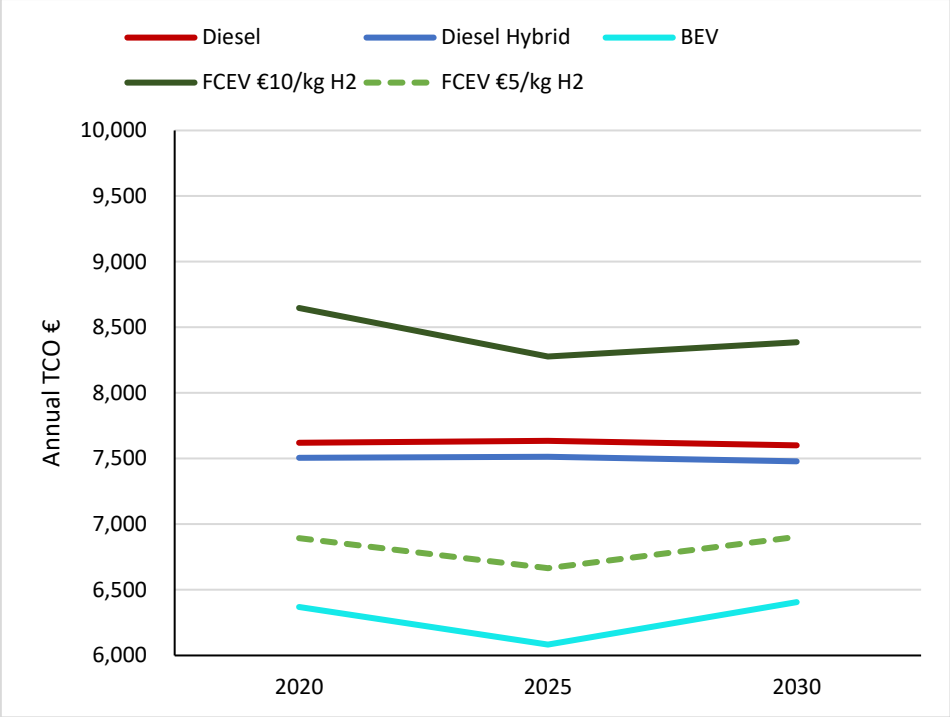

Figure 65 Van Annual TCO Including Green H_2 Incentives.

Truck TCO Analysis

This analysis assumes a 25 Tonne truck and first-time ownership over a 10-year period. This vehicle would represent a large rigid truck that would be typically used to deliver heavy aggregate/quarry products in construction. Figure 66 indicates the purchase costs assumed for the truck comparison and Figure 67 shows the truck TCO analysis for the period 2020-2030.

<u>Key Findings:</u>

- In the early years (2020-2025), the high upfront costs for the FCEV option mean that the TCO is considerably higher than the BEV option. With economies of scale in FCEV vehicle production, the TCO appears to decline rapidly by 2025 with purchase costs decreasing significantly from €358k to €138k. The declining trend in purchase costs for FCEV trucks sees the TCO continue to reduce out to 2030.
- Assuming a price at the pump of 10 €/kg H2, FCEV trucks struggle to compete with conventional fuelled vehicles and the BEV option.

- Assuming a price at the pump of 5 €/kg H2, FCEVs annual TCO costs are on parity with BEVs. The FCEV truck may be a favourable option for logistic companies due to the longer driving range associated with fuel cells.

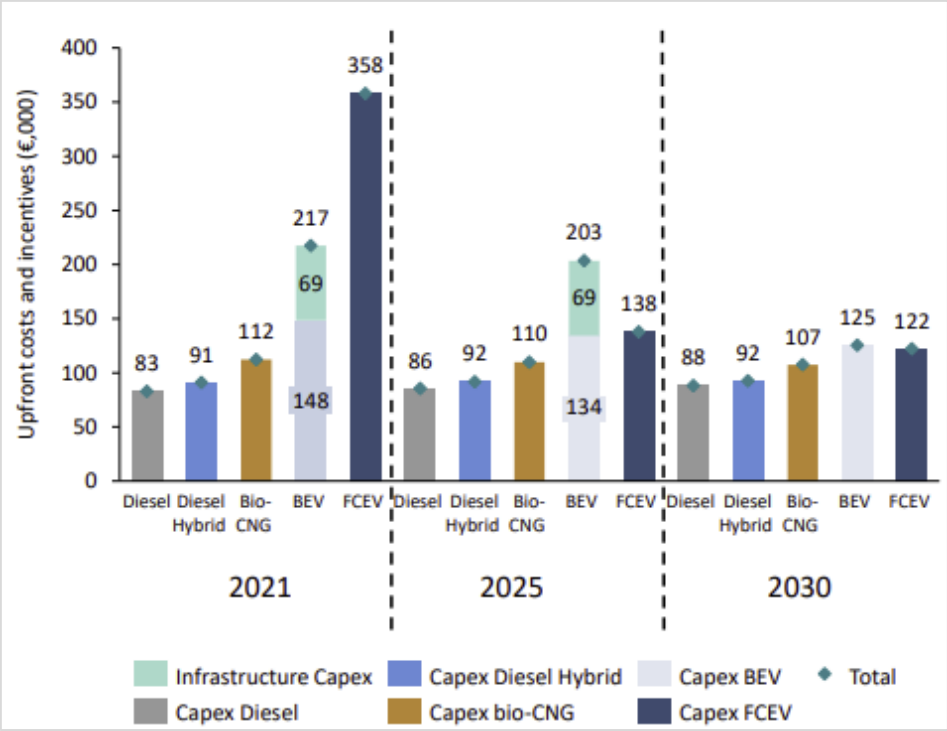

Figure 66 25 Tonne Truck Purchase Costs.

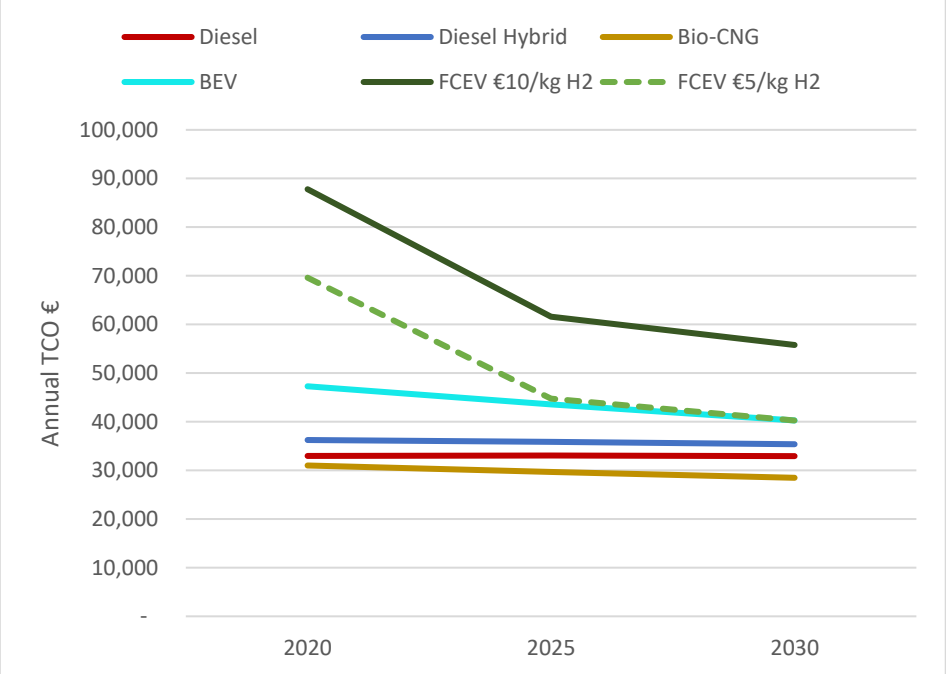

Figure 67 25 Tonne Truck TCO Including Green H_2 Incentives.

Double Decker Bus TCO Analysis

This analysis assumes a double decker bus and first-time ownership over a 12-year period. This type of vehicle is currently part of the Dublin Bus fleet. Figure 68 indicates the purchase costs assumed for the bus comparison and Figure 69 shows the truck TCO analysis for the period 2020-2030.

Key Findings:

- Buses don't benefit from the purchase incentives available to cars. This means FCEV and BEV buses are always more expensive than conventional buses. In the early years (2020-2025), the high upfront/purchase costs for the FCEV option mean that the TCO is considerably higher than the diesel hybrid option. With economies of scale in FCEV vehicle production, the TCO appears to decline rapidly by 2025 with purchase costs decreasing significantly from €358k to €138k. The declining trend in purchase costs for FCEV trucks sees the TCO continue to reduce out to 2030.
- Assuming a price at the pump of 10 €/kg H2, FCEV buses struggle to compete with diesel hybrid and BEV option. While for a price at the pump of 5 €/kg H2, the FCEV double decker bus annual TCO very competitive in 2030 and on parity with the BEV option.
- If the Irish government bans the purchase of diesel hybrid buses in the 2020s then hydrogen buses are a lead contender as the best bus technology for purchase in the future.

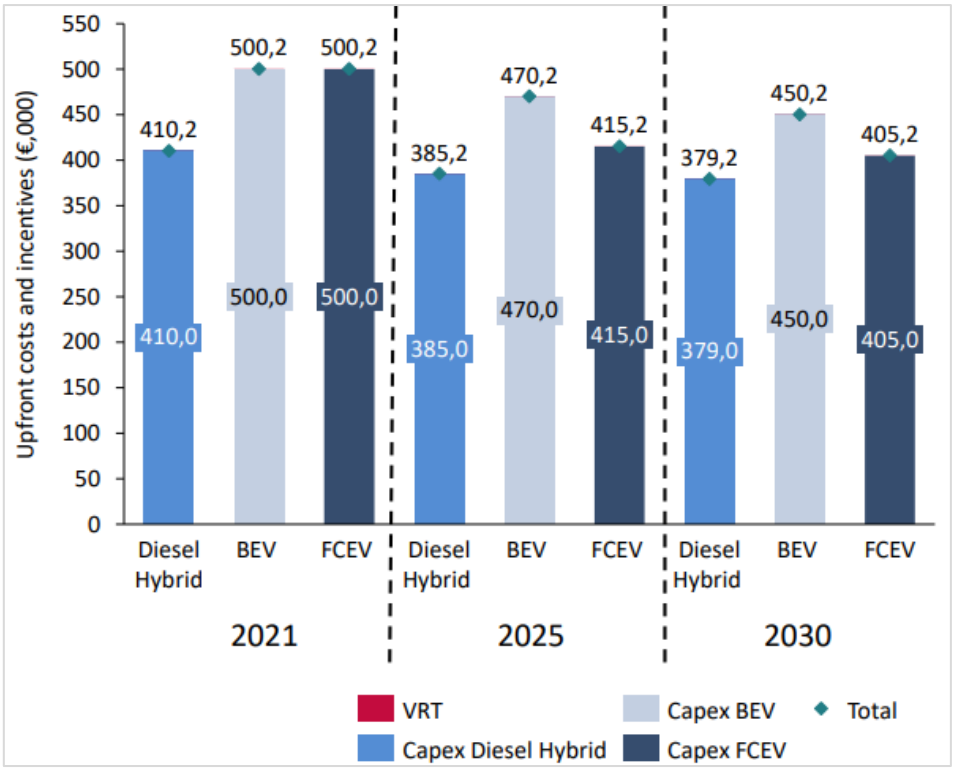

Figure 68 Double Decker Bus Purchase Costs.

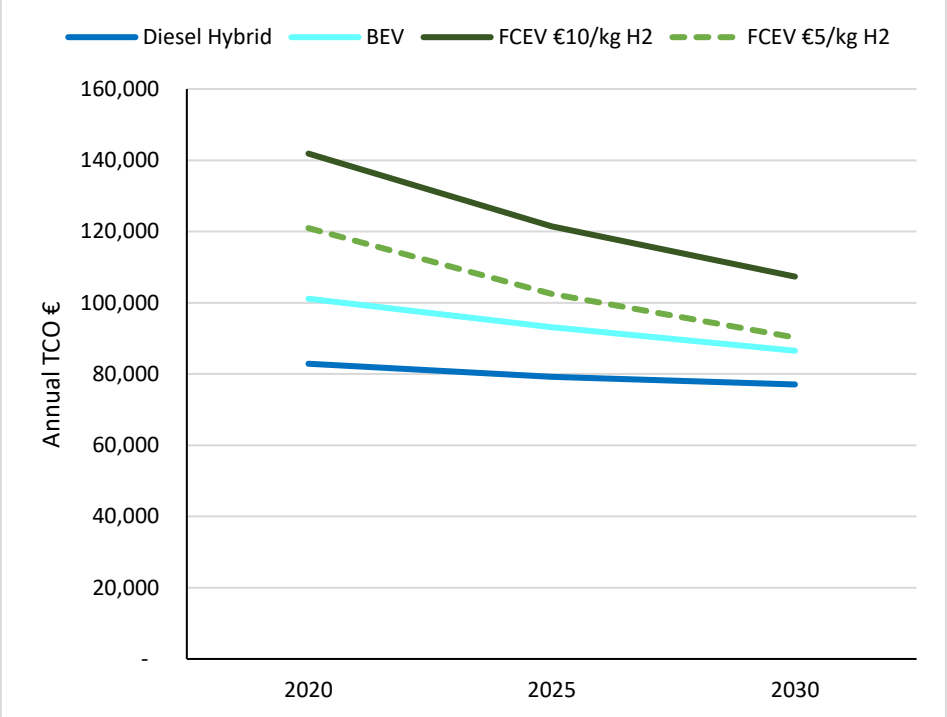

Figure 69 Double Decker Bus Annual TCO Including Green H_2 Incentives.

Train TCO Analysis

This analysis assumes a 160-seater train and first-time ownership over a 10-year period. This type of vehicle would be typical of the Irish rail fleet. Large fuel users such as trains are very sensitive to fuel prices. As the cost of fuel cells comes down and the price of diesel goes up with the carbon tax fuel cell trains become more cost competitive. Figure 70 indicates the purchase costs assumed for the train comparison and Figure 71 shows the train TCO analysis for the period 2020-2030. Electric trains were not considered for the comparison due to the complexity associated with sourcing costs for rail electrification (including overhead power lines / cabling).

Key Findings:

- FC Trains do not appear to benefit from the purchase incentives available to cars. This means FCEV trains are more expensive to purchase than conventional diesel trains.
- Hydrogen offers an option to decarbonise train routes where electrification is too expensive or routes with low passenger numbers.
- Assuming a price at the pump of 10 €/kg H2, FC trains offer a viable means of decarbonisation of rail in Ireland in 2030. While for a price at the pump of 5 €/kg H2, the FC train annual TCO costs are the cheapest option in 2030.

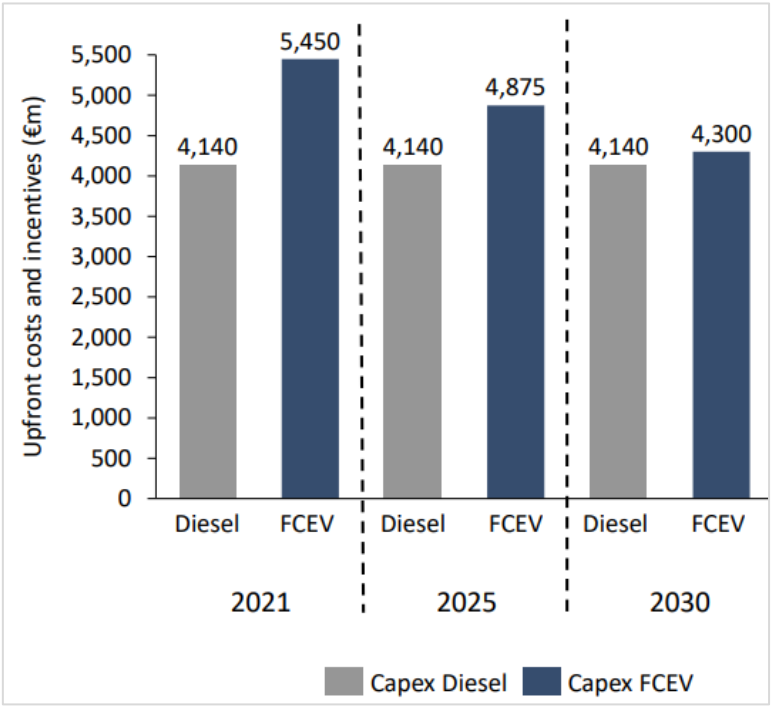

Figure 70 Train Purchase Costs.

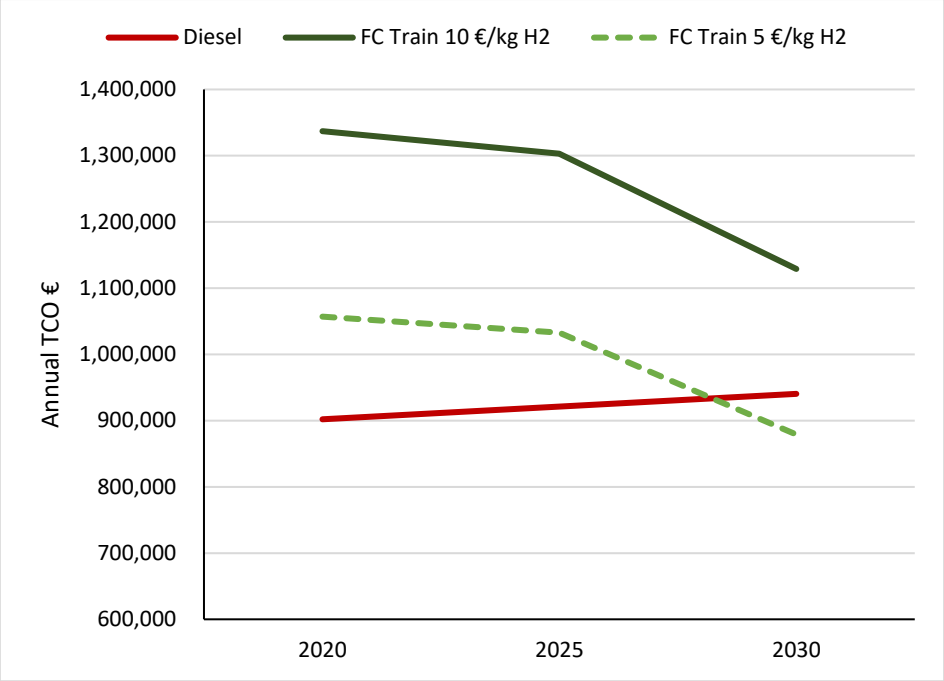

Figure 71 Train Annual TCO.

‘The Case for Hydrogen Mobility’ Summary of Findings

- The private car and taxi car TCO analysis indicated that with regulatory support and a price of hydrogen at the pump of 5 €/kg then FCEVs are cost competitive with BEVs in the mid to late 2020’s. However, at a pump price of 10 €/kg the FCEV option is more closely aligned to the diesel TCO.
- The van TCO analysis indicated that BEVs are the superior choice for the in terms of cost. However, for a price at the pump of 5 €/kg, FCEVs annual TCO costs are competitive with BEVs. Although slightly higher, the FCEV van may be a favourable option for certain logistic companies due to the longer driving range associated with fuel cells.
- The Truck (25 tonne) TCO analysis indicated that the FCEV option costs are on parity with the BEV option for a sale price at the pump of 5 €/kg from 2025. Conventionally fuelled trucks appear to be the most economical option during the period 2020-2030. With a price of 10 €/kg at the pump, the FCEV TCO is considerably higher than the BEV option.
- The double decker bus TCO analysis indicated that FCEVs may be cost competitive with the BEV option by 2025. However, the diesel hybrid option is the cheapest option for the 2020-2030 period. If the Irish Government bans the purchase of conventionally fuelled buses (including diesel) in the 2020s then FCEV buses are among the leading zero emission options.
- The train TCO analysis illustrated that for a price at the pump of 10 €/kg H2, FCEV trains offer a viable means of decarbonisation of rail in Ireland in 2030. Considering a price at the pump of 5 €/kg H2, the FCEV train annual TCO costs are cheaper than the diesel option in 2030.

4.3 Cost of Hydrogen Distribution

4.3.1 Truck & Trailer Delivery

In this section, analysis on the cost of hydrogen distribution via truck and trailer for a small, medium and large-scale production facility is presented. At present, gaseous hydrogen delivery tube trailer capacities are in the range of 200-400 kg for operating pressures of 350 bar. However, it is expected that in the next 10 years gaseous hydrogen delivery tube trailer capacity will improve. Hence, scenarios have been modelled for current carrying capacities (200- 400kg) and a scenario which sees trailer capacities reaching 900 kg. See Appendix E for a list of trailer CAPEX assumptions.

It is assumed that the tractor unit hauling the trailer is a fuel cell powered truck opposed to diesel which is widely utilised for hydrogen delivery today. This provides the lowest emission pathway for hydrogen distribution. The operating costs for the truck on a per km basis were calculated from section 4.2 ”The Case for Hydrogen Mobility” and used in the delivery model.

Figure 72 to Figure 74 illustrate the cost of hydrogen distribution via truck and trailer for a small, medium and large-scale hydrogen production facility respectively.

Key Findings:

- For a small-scale production facility (330 kg/day) and assuming a trailer carrying capacity of 400 kg at 350 bar, the cost of distributing hydrogen is less than 1.50 €/kg when the destination for the hydrogen is within a 30km radius.
- Considering a medium-scale production facility (3300 kg/day) and assuming a trailer carrying capacity of 400 kg at 350 bar, the cost of distributing hydrogen is less than 1.50 €/kg within a 170km radius.
- In the case of the large-scale production facility (16500 kg/day) and assuming a trailer carrying capacity of 400 kg at 350 bar, the cost of distributing hydrogen is less than 1.50 €/kg within a 200km radius.
- If gaseous hydrogen trailer capacity increases to 900 kg as predicted in literature, then the cost of transporting hydrogen over long distances is significantly reduced. For the large-scale demand scenario, costs are 1 €/kg for a one-way distance of 300km. However, this does not take into account the associated losses and inefficiencies.

330 kg/day Demand - Small Scale at 350 Bar

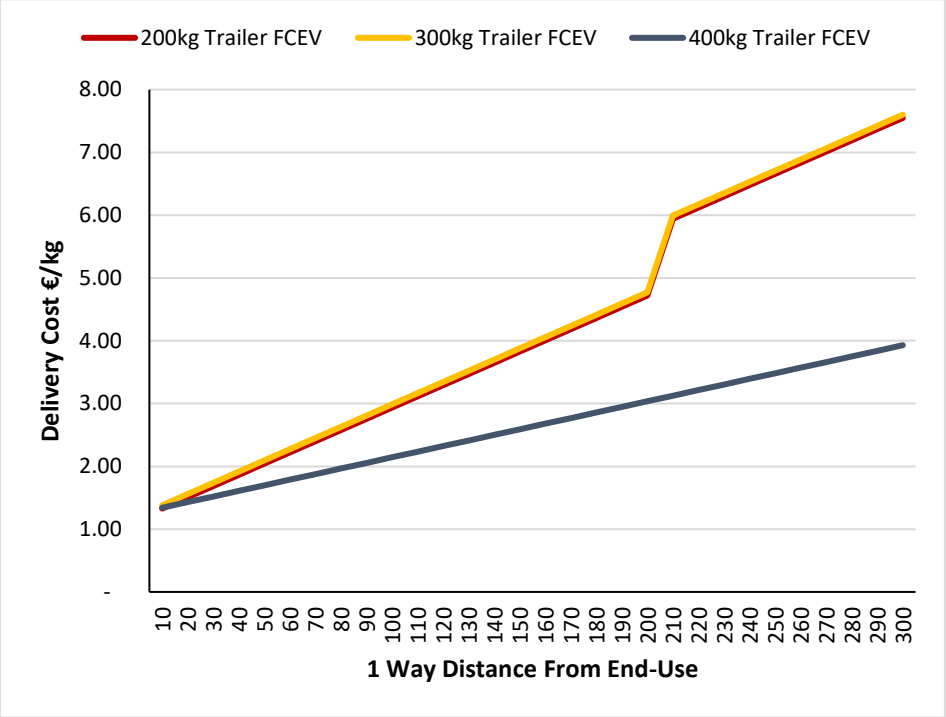

Figure 72 Hydrogen Delivery Costs - 330 kg/day.

3300 kg/day Demand – Medium Scale at 350 Bar

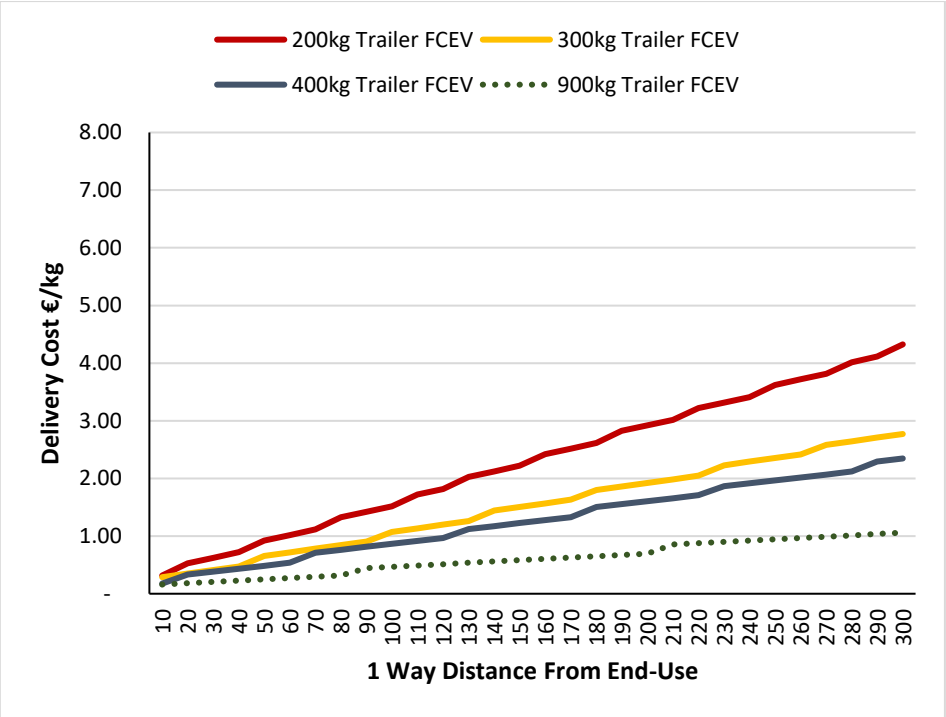

Figure 73 Hydrogen Delivery Costs - 3300 kg/day.

16,500 kg/day Demand - Large Scale at 350 Bar

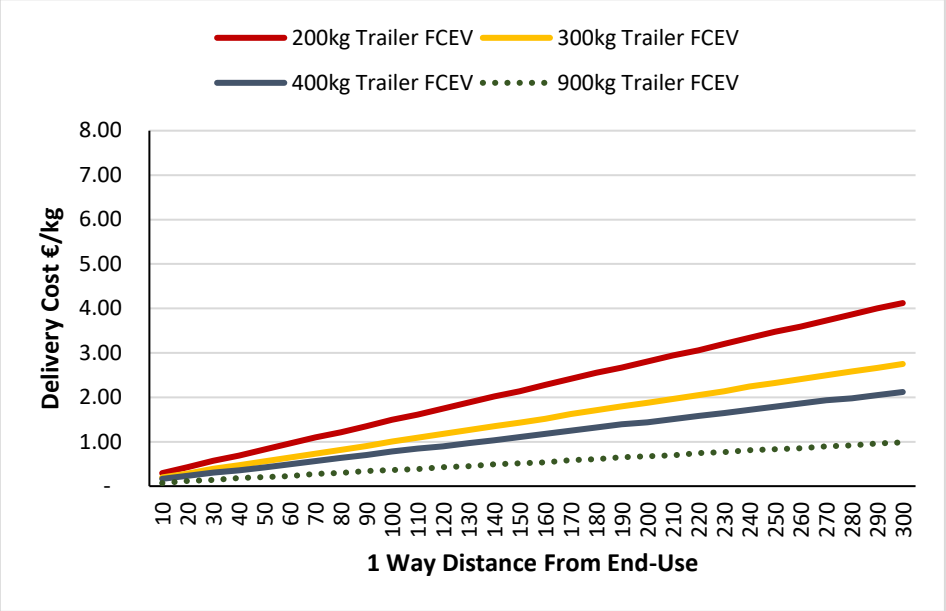

Figure 74 Hydrogen Delivery Costs – 16,500 kg/day

'The Cost of Hydrogen Distribution' Summary of Findings

The main findings from the analysis on the cost for hydrogen distribution were:

- Considering a large-scale demand scenario, and a trailer carrying capacity of 400 kg which are currently deployed then the price of gaseous 350bar hydrogen delivery is estimated to be less than 1.5 €/kg for a one-way distance up to 200km.
- Assuming gaseous hydrogen trailer capacity increases to 900 kg as predicted in literature, then the cost of transporting hydrogen over long distances may be significantly reduced. For the large-scale demand scenario, costs are 1 €/kg for a one-way distance of 300km.

4.4 The Case for Hydrogen Mobility from Renewable Power

4.4.1 Windfarm Electricity & Green Imported Electricity

In this section the business case of a small (1 MW), medium (10 MW) and large scale (50 MW) alkaline (ALK) electrolyser deployed to a windfarm with access to wholesale market electricity was investigated. ALK electrolysis was selected as it is the most mature electrolyser technology with the lowest capital costs today and projected for 2030. The electrolyser is assumed to have a water supply from the local grid and pay industrial water rates (see Table 35). It is assumed that electricity price includes the cost for a GoO certificate. This certificate ensures that the hydrogen produced is 100% renewable. Based on section 4.2, the price of hydrogen acceptable to the heavy-duty mobility end user (truck, bus) is assumed to be 7.50 €/kg at 350 bar pressure. This price is higher than the parity price (~5 €/kg) with fully electric vehicles, however fleet operators may be willing to pay a higher price for hydrogen fuel due to a lower refuelling time and superior driving range for FCEVs. Delivery costs are assumed to be 1.50 €/kg. The heavy-duty vehicle's refuelling method is via a hydrogen tube-trailer delivered to the vehicle depot.

The financial model described in section 3.1 was used to determine the minimum/viable sale price for hydrogen acceptable to the investor over the lifetime of the project. If the viable sale price is higher than the price acceptable to the end user, then a financial support / subsidy required is determined from the model. As described earlier, this is a cost optimal approach to modelling.

Three windfarm sizes were considered in the base case scenarios for the deployment of the small, medium and large-scale electrolysers.

- 5 MW windfarm & 1 MW ALK electrolyser.
- 40 MW windfarm & 10 MW ALK electrolyser.
- 200 MW windfarm & 50 MW ALK electrolyser.

Since the dispatch down of renewable generation is a driving factor behind the recent emphasis on green hydrogen production, a sensitivity analysis was carried out on a range of dispatch down levels for the optimal sized windfarm. Scenarios were modelled for dispatch down ranging from 0-40%. This range is based on the projections discussed in section 2.5.4.

The projected electrolyser CAPEX out to 2030 was costed based on a comprehensive review of literature (see section 3.3). Sensitivity analysis was also undertaken on electrolyser CAPEX, the analysis accounts for a high uptake in electrolysis globally with economies of scale yielding a further 20% reduction to the projections for electrolyser costs in the literature. Analysis was also carried out on a scenario where global electrolyser uptake is slower than what is expected, and the electrolyser CAPEX is 20% higher than projections from literature.

Since onshore wind generation is a variable source of electricity, electrolysers may require access to imported electricity from the wholesale market to ensure a secure supply of hydrogen and to achieve high-capacity factors (>60%) which are imperative from an economic point of view. Electricity prices are extremely difficult to predict and as mentioned earlier in the report negative pricing has become more prominent in recent years. The base case assumes the purchase price of electricity is 55 €/MWh and in line with the average price for 2019. The average wholesale market price for the first half of 2020 was c.30 €/MWh. Therefore, a range of market prices from 0-60 €/MWh were modelled to capture the potential for an increased frequency of negative pricing in the market as more renewable generation connects out to 2030.

Small Scale Electrolysis Business Case 2030 - 1 MW Electrolyser

Base Case

For small scale electrolysis, the daily hydrogen production corresponding to a 64% capacity factor was modelled to be 330 kgH_2/day. This capacity factor was the highest possible for the ALK electrolyser when accounting for the power consumption from the compressor system. A 5 MW windfarm was identified for the base case, this would be representative of a small-scale windfarm in Ireland. In addition, windfarms less than 5 MW are “uncontrollable” for the transmission system operator and therefore cannot have their output dispatched down. Refer to Appendix E for a list of the system assumptions.

Key Findings:

- The hydrogen sale price to achieve an IRR/hurdle rate of 8% for the project was modelled to be 13.40 €/kg which is higher than the price acceptable to the mobility use case (7.50 €/kg).
- A subsidy of 5.90 €/kg ensured the project achieved the hurdle rate of 8%.
- The hydrogen production cost was calculated to be 3 €/kg.

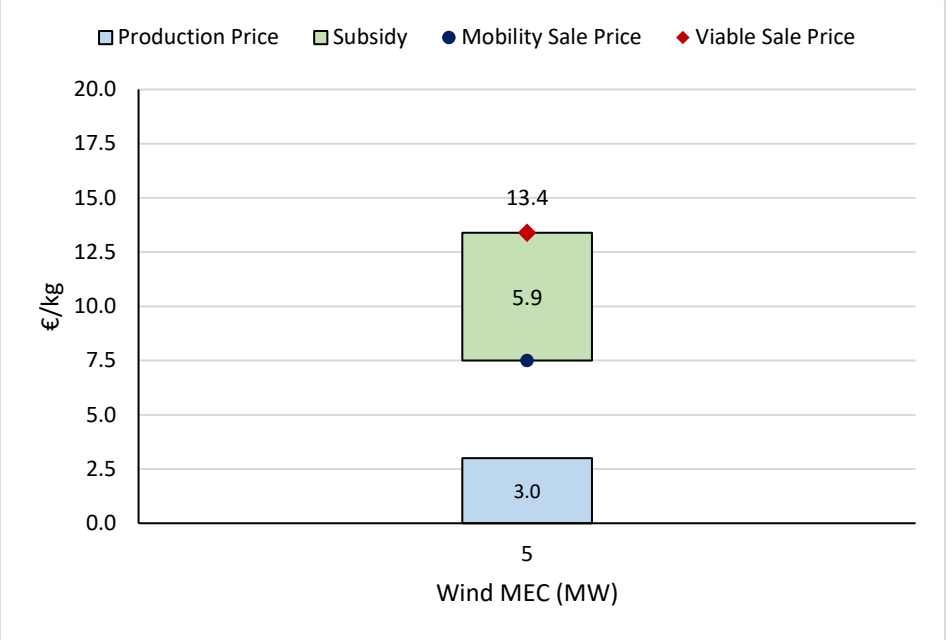

Figure 75 Small Scale Alkaline Electrolysis Base Case.

Wind Dispatch Down Sensitivity

Figure 76 outlines the impact of a 1 MW electrolyser on dispatch down levels in the range of 0-40% for a 5 MW windfarm. The impact on the production price of hydrogen can be seen in Figure 77.

Key Findings:

- The 1 MW alkaline electrolyser developed alongside a 5 MW windfarm captured close to 85% of dispatched down energy when dispatch down levels were 10%. However, with dispatch down levels >10% the electrolyser was less effective at capturing energy but still had a material impact on dispatch down levels.
- Increased levels of dispatch down from 10%-40%, resulted in additional energy losses for the windfarm. In turn there was a higher subsidy & sale price required. The level of subsidy required increased from 5.40 €/kg to 6.40 €/kg. The viable sale price of hydrogen increased from 12.90 €/kg to 13.90 €/kg.

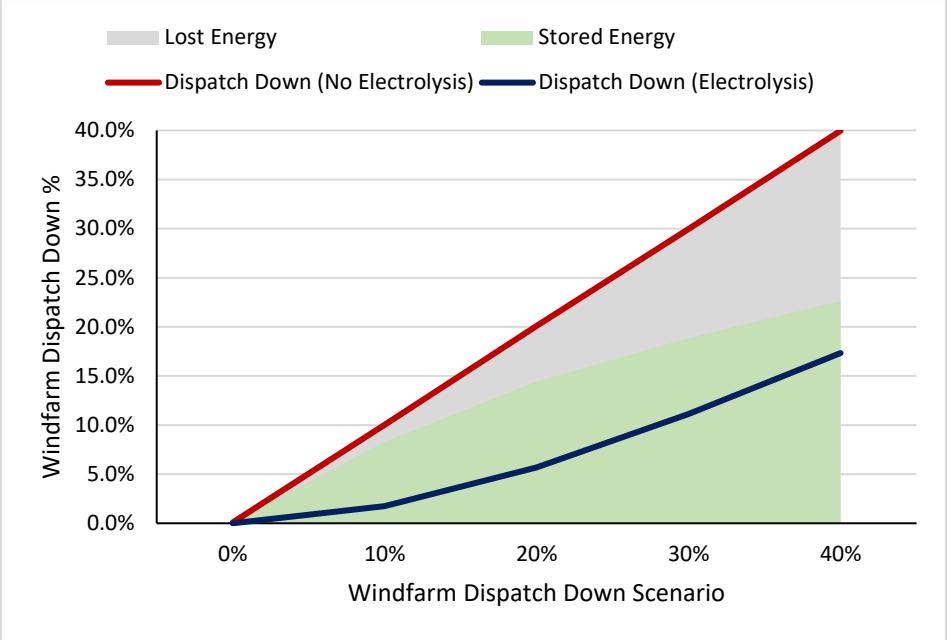

Figure 76 Wind Dispatch Down Sensitivity Storage Potential – Small Scale Electrolysis.

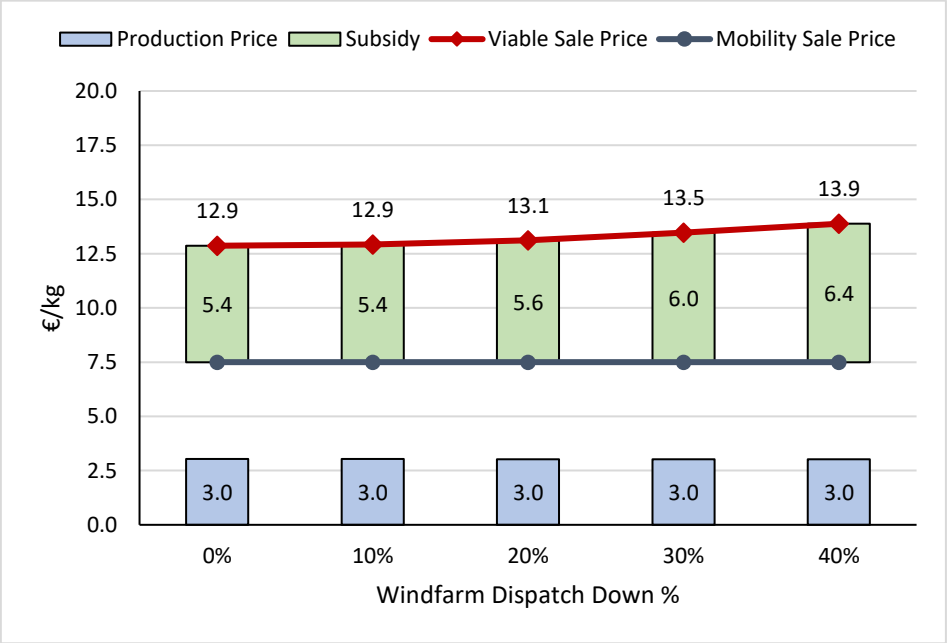

Figure 77 Wind Dispatch Down Sensitivity Price Impact – Small Scale Electrolysis.

Electrolyser CAPEX Sensitivity

The Electrolyser CAPEX sensitivity analysis on small scale electrolysis is displayed in Figure 78. Scenarios for both CAPEX reductions and increases up to 20% were modelled for 2030.

Key Findings:

- Assuming CAPEX reductions of 20% are achieved on 2030 projections from literature, the viable sale price for small scale electrolysis to hydrogen mobility is estimated to be 11.90 €/kg. A reduced subsidy of 4.40 €/kg was necessary to ensure the project achieved the hurdle rate of 8%.
- With costs increases of 20% on projections from literature, the viable sale price for small scale electrolysis to hydrogen mobility is estimated to be 13.90 €/kg. An increased subsidy of 6.40 €/kg ensured the project achieved the hurdle rate of 8%.

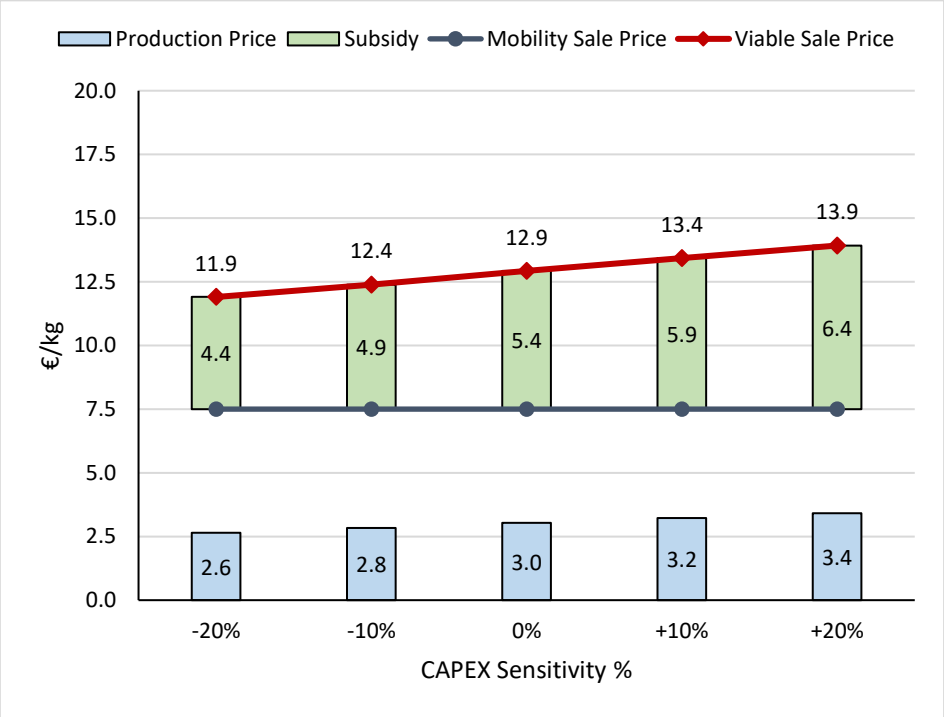

Figure 78 Electrolyser CAPEX Sensitivity - Small Scale Electrolysis.

Electrolyser Electricity Price Sensitivity

The wholesale electricity price sensitivity analysis carried out on small scale electrolysis is presented in Figure 79.

Key Findings:

- Assuming the average wholesale price of electricity in 2030 is 30 €/MWh, in line with the first half of 2020; hydrogen production costs reduced to 2.70 €/kg.
- The lower production cost yielded a lower viable sale price for the small-scale electrolyser to hydrogen mobility is estimated to be approximately 12.50 €/kg. A subsidy of 5 €/kg was required.

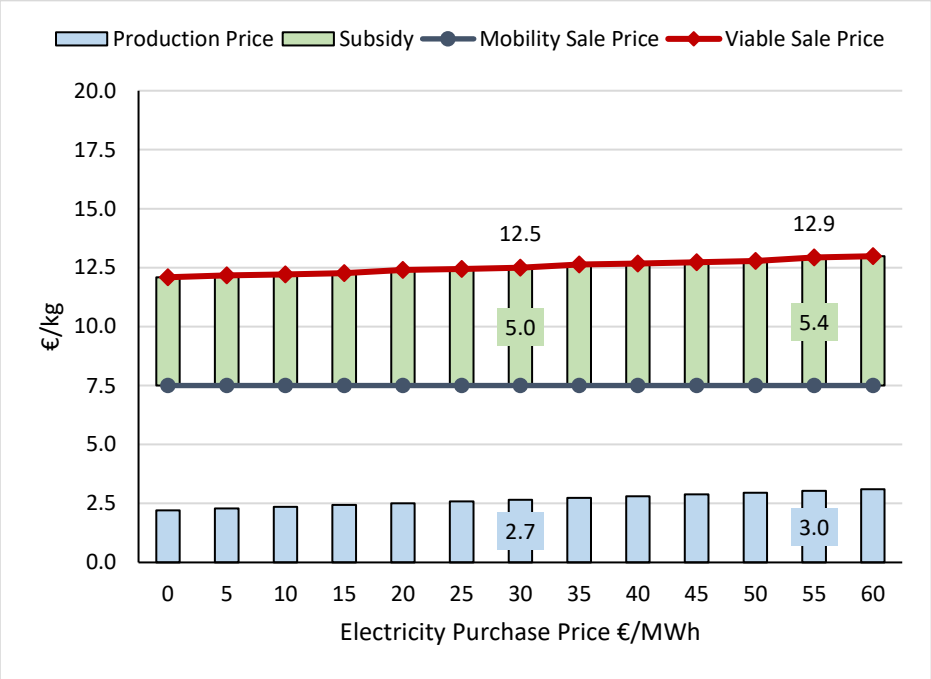

Figure 79 Electricity Wholesale Price Sensitivity - Small Scale Electrolysis.

Medium Scale Electrolysis Business Case 2030 - 10 MW Electrolyser

Base Case

For medium scale electrolysis in 2030, the daily hydrogen production corresponding to a 64% capacity factor is 3300 kgH_2/day. It is assumed that the price of hydrogen acceptable to the mobility user is 7.50 €/kg with transportation costs of 1.50 €/kg.

A 40 MW windfarm was chosen as the base case for the medium scale electrolyser, this represents a medium-large sized windfarm in Ireland. Refer to Appendix E for a list of the system assumptions.

Key Findings:

- The viable hydrogen sale price for the project is estimated to be 10.60 €/kg. This represents a more competitive price in comparison to the small-scale electrolyser & windfarm (13.40 €/kg).
- A subsidy of 3.10 €/kg ensured the project achieved the hurdle rate of 8%.
- The hydrogen production price was modelled to be 2.70 €/kg.

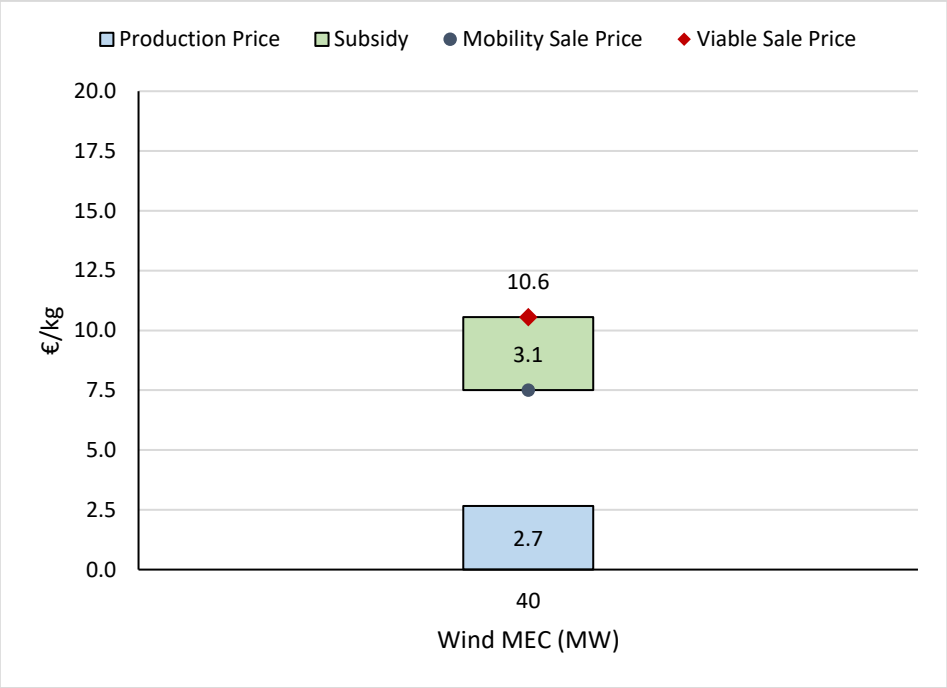

Figure 80 Medium Scale Alkaline Electrolysis Base Case.

Wind Dispatch Down Sensitivity

Figure 81 outlines the impact of a 10 MW electrolyser on dispatch down levels in the range of 0-40% for a 40 MW windfarm. The impact on the production price of hydrogen can be seen in Figure 82.

Key Findings:

- The 10 MW alkaline electrolyser developed alongside a 40 MW windfarm captured close to 90% of dispatched down energy when dispatch down levels were 10%. However, with dispatch down levels >10% the electrolyser was less effective at capturing energy but still had a material impact on dispatch down levels. The 40% dispatch down scenario was reduced to 15%.
- With increased levels of dispatch down from 10%-40%, the viable sale price of hydrogen increased from 10.60 €/kg to 11.10 €/kg. The subsidy required increased from 3.10 €/kg to 3.60 €/kg.

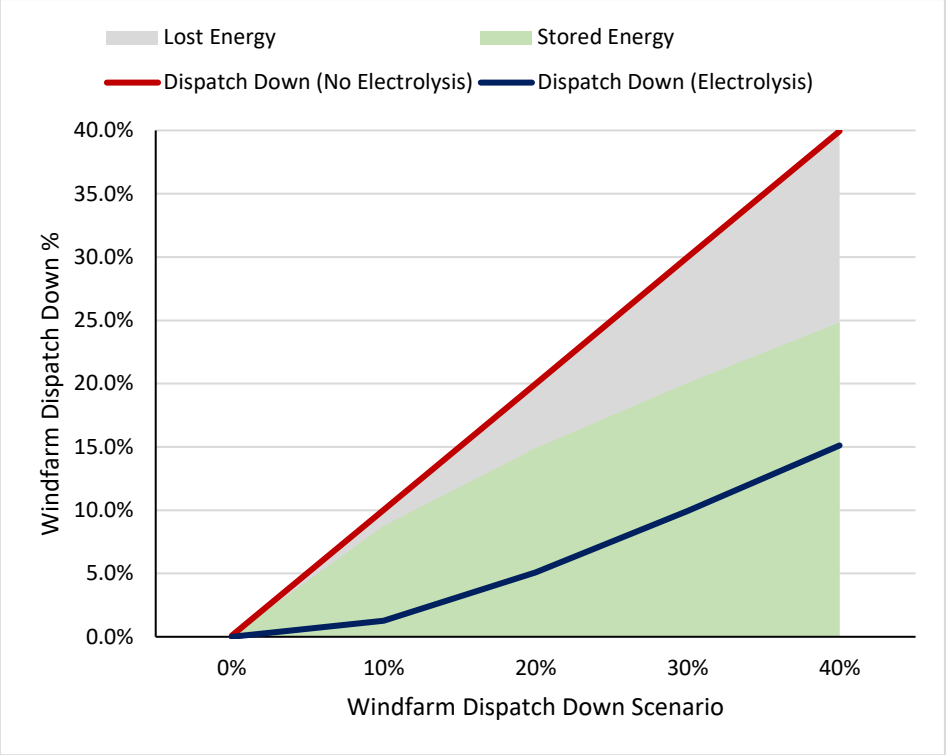

Figure 81 Wind Dispatch Down Sensitivity Storage Potential – Medium Scale Electrolysis.

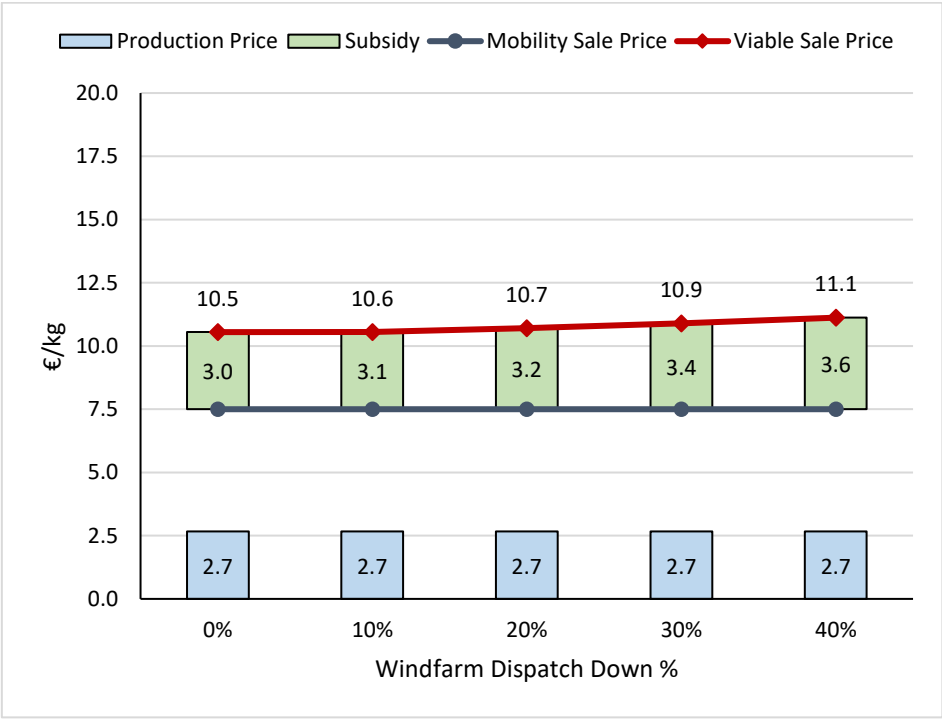

Figure 82 Wind Dispatch Down Sensitivity Price Impact – Medium Scale Electrolysis.

Electrolyser CAPEX Sensitivity

The Electrolyser CAPEX sensitivity analysis on medium scale electrolysis is displayed in Figure 83. Scenarios for both CAPEX reductions and increases up to 20% were modelled for 2030.

Key Findings:

- Modelling additional CAPEX reductions of 20% on 2030 projections from literature, the viable sale price for small scale electrolysis to hydrogen mobility is estimated to be 9.90 €/kg with a subsidy of 2.40 €/kg required.
- Assuming costs increases of 20% on projections from literature, the viable sale price for medium scale electrolysis is estimated to be 11.20 €/kg with a subsidy of 3.70 €/kg required.

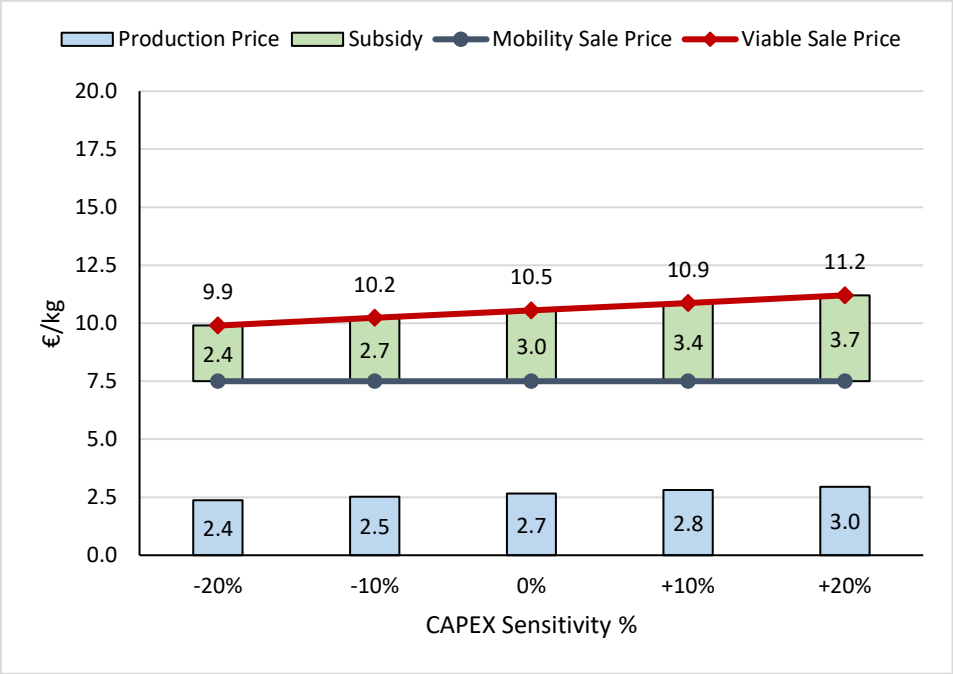

Figure 83 Electrolyser CAPEX Sensitivity - Medium Scale Electrolysis.

Electrolyser Electricity Price Sensitivity

The wholesale electricity price sensitivity analysis carried out on the medium scale electrolysis is presented in Figure 84.

Key Findings:

- Assuming the average wholesale price of electricity in 2030 is 30 €/MWh and in line with prices for the first half of 2020, then the viable sale price for medium scale electrolysis is 10.10 € with a subsidy of 2.6 €/kg required.

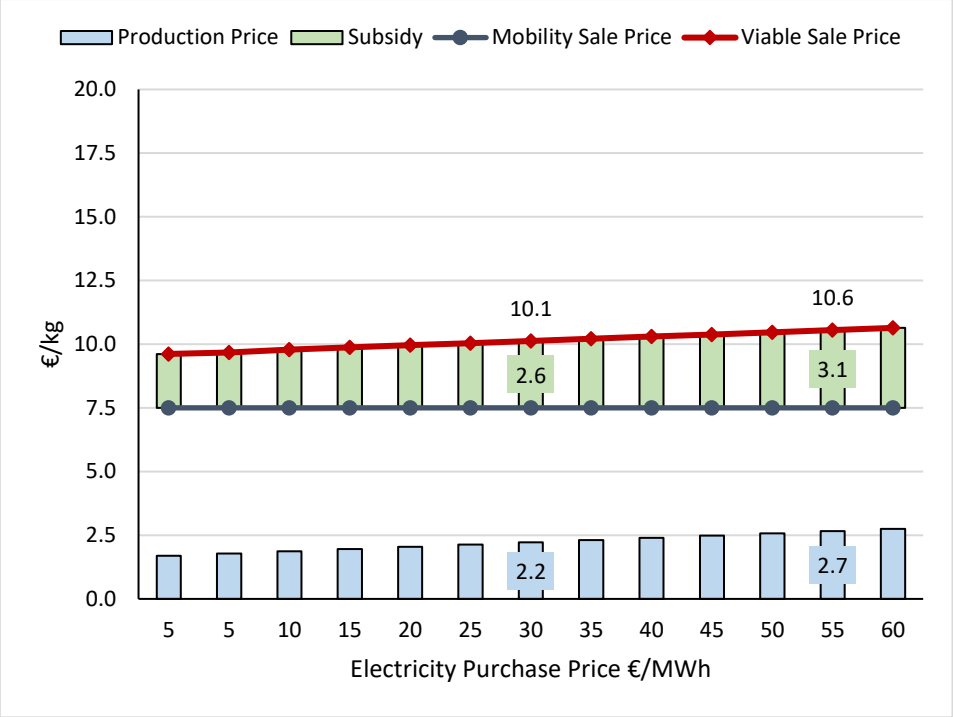

Figure 84 Electricity Wholesale Price Sensitivity - Medium Scale Electrolysis.

Large Scale Electrolysis Business Case 2030 - 50 MW Electrolyser

Base Case

For large scale electrolysis in 2030, the daily hydrogen production corresponding to a 64% capacity factor is approximately 16,500 kgH_2/day. It is assumed that the price of hydrogen acceptable to the mobility end user is 7.50 €/kg with transportation costs of 1.50 €/kg.

A 200 MW windfarm was selected as the base case for the large-scale electrolyser, this is larger than any windfarm currently connected in Ireland. Refer to Appendix E for a list of the system assumptions.

Key Findings:

- The viable hydrogen sale price for the project was estimated to be 10.30 €/kg. The increased scale of the windfarm & electrolyser yielded a lower viable sale prices in comparison to the small (13.40 €/kg) and medium (10.60 €/kg) scale electrolysers.
- A subsidy of 3.10 €/kg ensured the project achieved the hurdle rate of 8%.
- The hydrogen production price was modelled to be 2.60 €/kg.

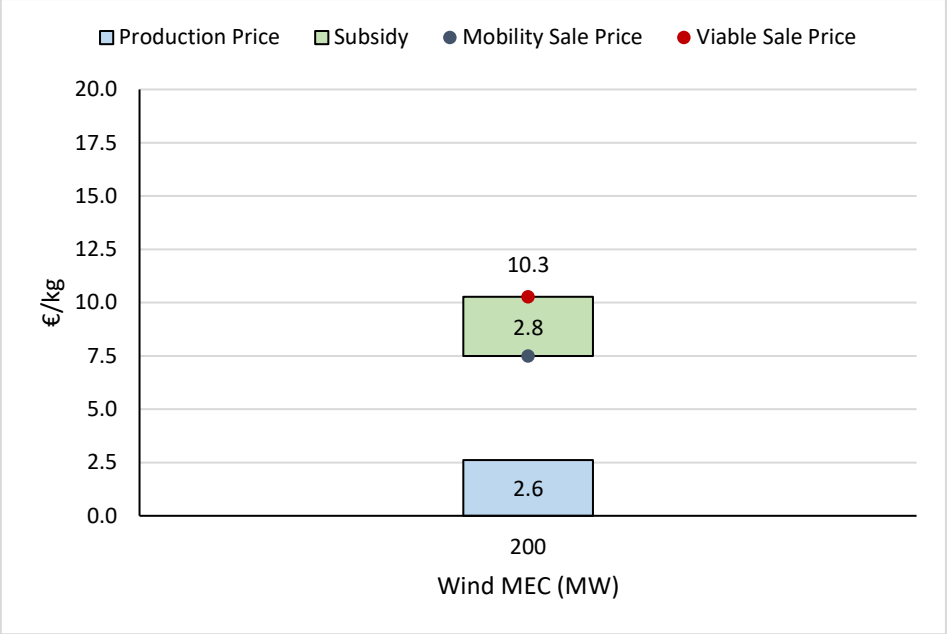

Figure 85 Large Scale Alkaline Electrolysis Base Case.

Wind Dispatch Down Sensitivity

Figure 86 outlines the impact of a 50 MW electrolyser on dispatch down levels in the range of 0-40% for a 200 MW windfarm. The impact on the production price of hydrogen can be seen in Figure 87.

Key Findings:

- The 50 MW alkaline electrolyser developed alongside a 200 MW windfarm captured close to 90% of dispatched down energy when dispatch down levels were less than 10%. Going beyond 10% the electrolyser was less effective at capturing energy but still had a material impact on dispatch down levels. The 40% dispatch down scenario was reduced to 14.6%.
- With increased levels of dispatch down from 10-40%, the viable sale price of hydrogen increased from 10.30 €/kg to 10.80 €/kg. Therefore, the subsidy required increased from 2.80 €/kg to 3.30 €/kg.
- Developing a 200 MW windfarm with up to 40% of its output lost in 2030 would not be considered a viable investment. However, deploying a large-scale electrolyser created value for the lost energy through hydrogen mobility. This illustrates an example of how hydrogen can facilitate more renewable generation on the electricity system.

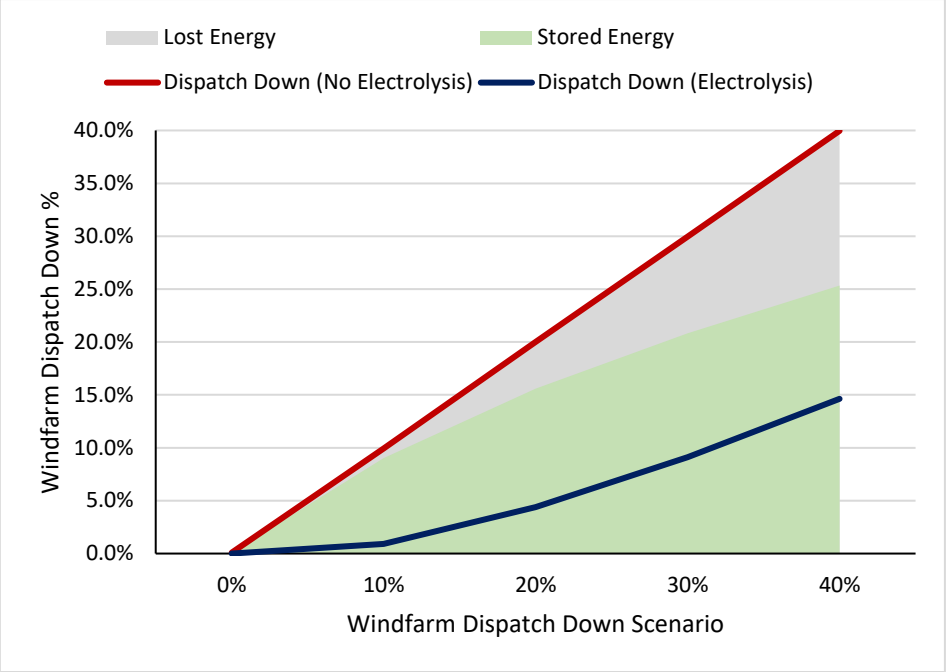

Figure 86 Wind Dispatch Down Sensitivity Storage Potential – Large Scale Electrolysis.

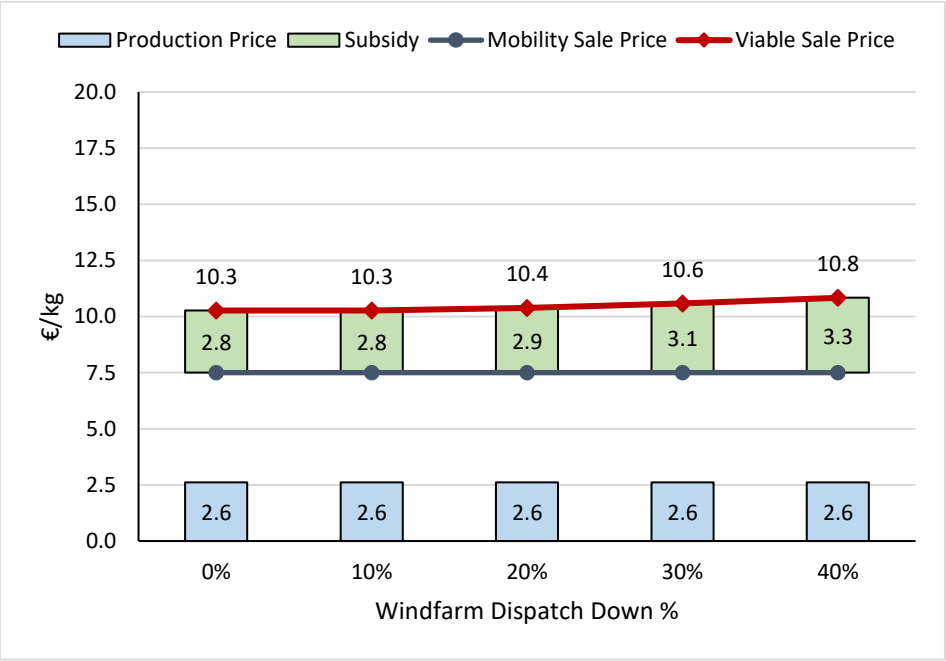

Figure 87 Wind Dispatch Down Sensitivity Price Impact – Large Scale Electrolysis.

Electrolyser CAPEX Sensitivity

The Electrolyser CAPEX sensitivity analysis on large scale electrolysis is displayed in Figure 88. Scenarios for both CAPEX reductions and increases up to 20% were modelled for 2030.

Key Findings:

- Applying additional cost reductions of 20% on 2030 projections from literature, the viable sale price for large scale electrolysis is reduced to 9.60 €/kg with a subsidy of 2.10 €/kg required.
- With costs increases of 20% on projections from literature, the viable sale price for large scale electrolysis is estimated to be 10.90 €/kg with a subsidy of 3.40 €/kg required.

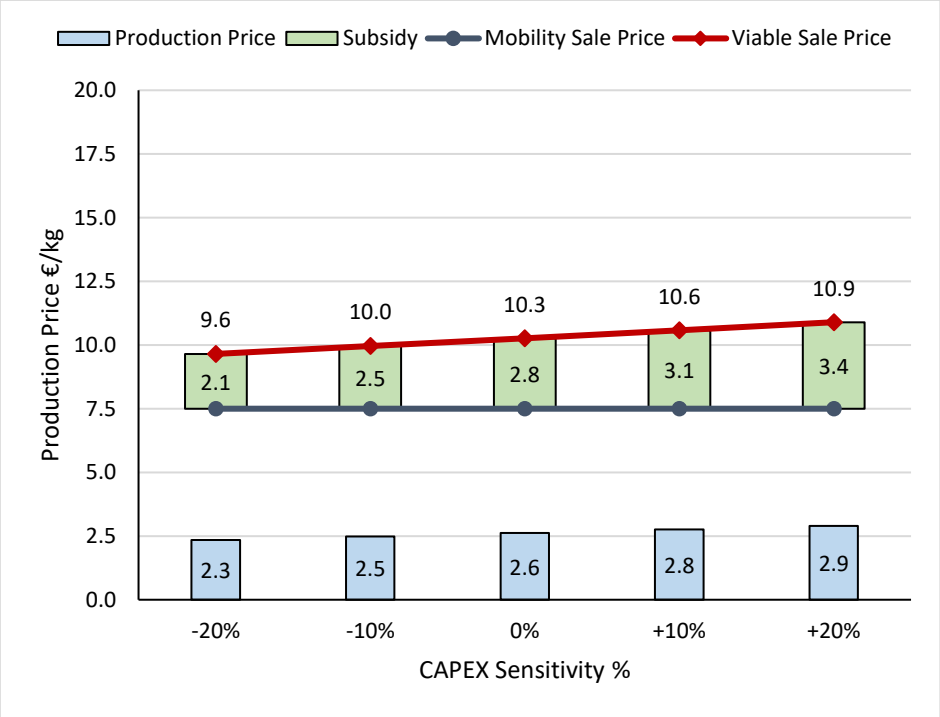

Figure 88 Electrolyser CAPEX Sensitivity - Large Scale Electrolysis.

Electrolyser Electricity Price Sensitivity

The wholesale electricity price sensitivity analysis carried out for the large-scale electrolysis scenario is presented in Figure 89.

Key Findings:

- The price of electricity for the large-scale electrolyser is critical due to the volumes of electricity imported at times of low wind to satisfy a daily demand for hydrogen of 16,500 kg/day. For the 2030 large scale electrolyser, approximately 90,700 MWh of electricity was imported. The total electricity requirement for the electrolyser was 550,400 MWh.

- Assuming the average wholesale price of electricity in 2030 is 30 €/MWh and in line with prices for the first half of 2020, then the viable sale price for large scale electrolysis is 9.80 €/kg with a subsidy of 2.30 €/kg required.

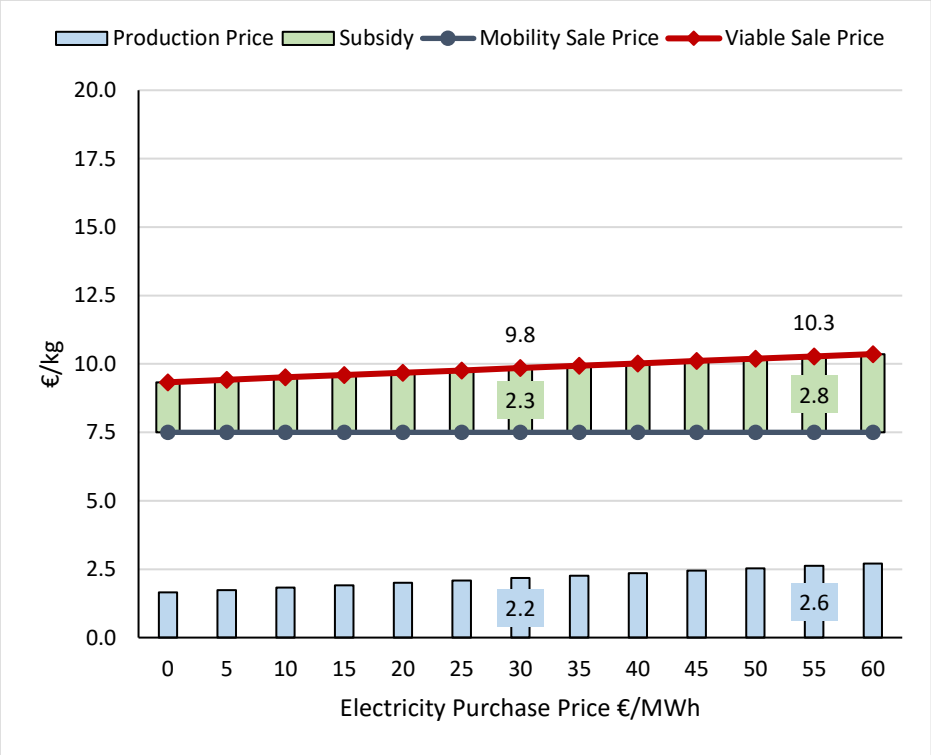

Figure 89 Electricity Wholesale Price Sensitivity - Large Scale Electrolysis.

'Produce Hydrogen from Windfarm Dispatched Down Electricity

In this section, the business case of a large-scale alkaline electrolyser deployed to a 200 MW windfarm with access to dispatch down electricity only was investigated.

Following on from analysis of the large-scale electrolyser in section 4.4.1, the base case assumes a 50 MW electrolyser is deployed to the 200 MW windfarm which experiences dispatch down levels of 10%. For this exercise it was assumed that the hydrogen production facility sells hydrogen to the mobility market for 7.50 €/kg only when there is an excess wind resource available.

The base case scenario assumes 10% dispatch down which is a conservative estimate based on the literature review. Therefore, a sensitivity analysis was carried out on a range of dispatch down levels for the 200 MW windfarm. Scenarios were modelled for dispatch down ranging from 10-40%.

Key Findings:

- Analysing Figure 90, the viable sale price to mobility was considerably higher in comparison to the scenario where the electrolyser had access to all of the windfarm output and imported electricity. This is due to the low utilisation factor for the electrolyser (approximately 14%). The viable sale price to mobility was 28.3 €/kg with a subsidy of 20.8 €/kg required to ensure the IRR of 8% was achieved.
- With increased levels of dispatch down from 10-40%, the electrolyser capacity factor increased from 14% to 39%, see Figure 91. The higher capacity factor reduced the viable sale price from 28.3 €/kg to 15.5 €/kg. Therefore, reducing the subsidy required from 20.80 €/kg to 8 €/kg.
- From a project developers' point of view, it appears that this option is not economically feasible, which was also shown by Gunawan et al [119]. The level of subsidy required is higher than what is available in other jurisdictions currently (e.g. UK support is up to 7 €/kg for hydrogen mobility [66]). In addition, an intermittent supply of hydrogen may not be technically feasible for transport or logistics companies.
- This option should not be discounted for electricity system operators however, as the electrolyser was effective at storing electricity as illustrated earlier in Figure 86. Provided a market exists for hydrogen, Electrolysers could be deployed to capture dispatched down renewable electricity at substations which are in congested areas of the transmission network.

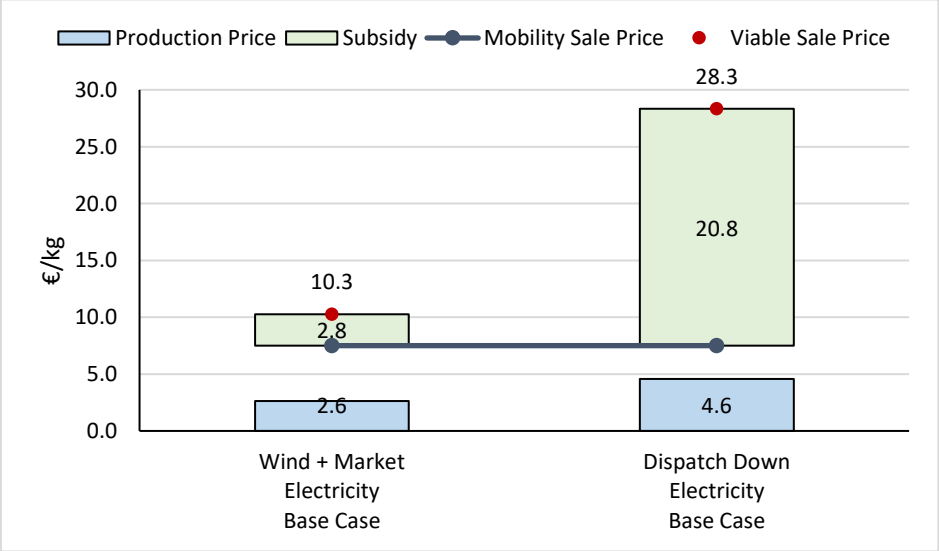

Figure 90 Base Case Comparison: Dispatch Down Electricity Only Vs Wind + Market Electricity

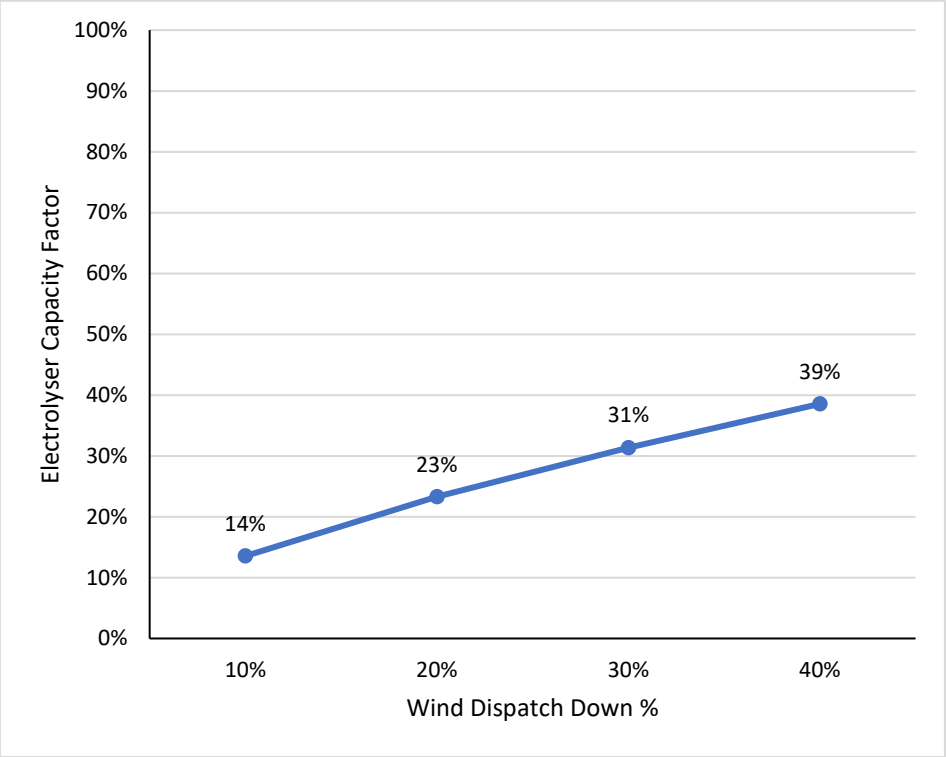

Figure 91 Wind Dispatch Down Sensitivity Capacity Factor Impact - Dispatch Down Electricity Scenario.

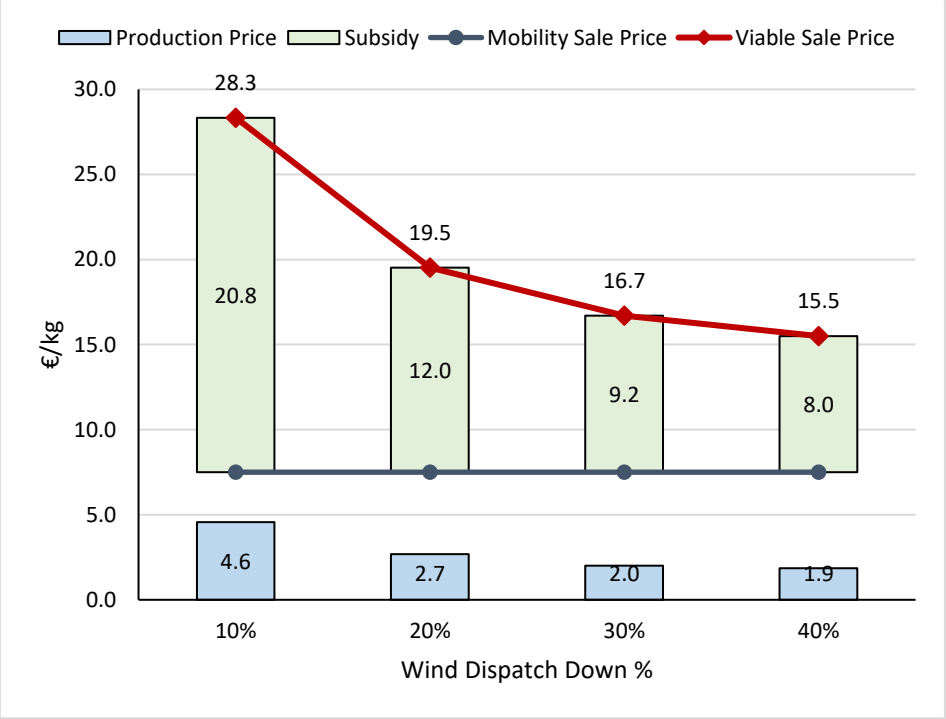

Figure 92 Wind Dispatch Down Sensitivity Price Impact – Dispatch Down Electricity Scenario.

The Case for Hydrogen Mobility from Renewable Power' Summary of Findings

The main findings from the analysis on the case for hydrogen mobility from renewable power were:

- Considering a 1 MW Electrolyser deployed to a wind farm sized at 5 MW with access to green imported renewable electricity, the viable hydrogen sale price was estimated to be 13.4 €/kg. Assuming an acceptable sale price to the use case of 7.5 €/kg then regulatory support of up to 5.9 €/kg may be required to provide a business case for this option.
    - With an increased level of dispatch down, the level of regulatory support also increased. For a scenario with 40% dispatch down, the viable hydrogen sale price was 13.9 €/kg.
    - With electrolyser CAPEX sensitivities of ±20%, the viable sale price of hydrogen ranged from 11.9-13.9 €/kg. The level of regulatory support was between 4.4-6.4 €/kg.
    - Considering a reduced price of electricity from 55 €/MWh to 30 €/MWh for imported electricity, the viable hydrogen sale price reduced to 12.5 €/kg with regulatory support of 5 €/kg.
- For a 10 MW Electrolyser deployed to a wind farm sized at 40 MW with access to green imported renewable electricity, the viable hydrogen sale price was estimated to be 10.6 €/kg. With an acceptable sale price to the use case of 7.5 €/kg then regulatory support of up to 3.1 €/kg may be required to provide a business case for this option.
    - With an increased level of dispatch down, the level of regulatory support also increased. For a scenario with 40% dispatch down, the viable hydrogen sale price was 11.1 €/kg.
    - With electrolyser CAPEX sensitivities of ±20%, the viable sale price of hydrogen ranged from 9.9-11.2 €/kg. The level of regulatory support was between 2.4-3.7 €/kg.
    - Considering a reduced price of electricity from 55 €/MWh to 30 €/MWh for imported electricity, the viable hydrogen sale price reduced to 10.1 €/kg with regulatory support of 2.6 €/kg.

- For a 50 MW Electrolyser deployed to a wind farm sized at 200 MW with access to green imported renewable electricity, the viable hydrogen sale price was estimated to be 10.3 €/kg. With an acceptable sale price to the use case of 7.5 €/kg then regulatory support of up to 2.8 €/kg may be required to provide a business case for this option.
    - With an increased level of dispatch down, the level of regulatory support also increased. For a scenario with 40% dispatch down, the viable hydrogen sale price was 10.8 €/kg.
    - With electrolyser CAPEX sensitivities of ±20%, the viable sale price of hydrogen ranged from 9.6-10.9 €/kg. The level of regulatory support was between 2.1-3.4 €/kg.
    - Considering a reduced price of electricity from 55 €/MWh to 30 €/MWh for imported electricity, the viable hydrogen sale price reduced to 9.8 €/kg with regulatory support of 2.3 €/kg.
- Following a review of the business case of a 50 MW alkaline electrolyser deployed to a 200 MW windfarm with access to dispatch down electricity, the viable hydrogen sale price was estimated to be 28.3 €/kg. With an acceptable sale price to the use case of 7.5 €/kg then regulatory support of up to 20.8 €/kg may be required to provide a business case for this option.
    - With increased levels of dispatch down from 10-40%, the electrolyser capacity factor increased from 14% to 39%. The higher capacity factor reduced the viable sale price from 28.3 €/kg to 15.5 €/kg.
    - From a project developers' point of view, it appears that this option is not economically feasible. Furthermore, an intermittent supply of hydrogen may not be technically feasible for transport or logistics companies.

4.5 The Case for Hydrogen Gas Grid Injection from Renewable Power

This section presents the business base for injecting hydrogen into the gas grid at 30 bar pressure. Based on section 4.4.1, the most economical configuration for hydrogen production involved a large-scale electrolyser deployed to a 200 MW windfarm with access to both windfarm and market electricity that is green certified through GoO certificates. Since the price of natural gas is quite low in comparison to electricity, the base case assumes a large-scale production facility to produce the lowest cost hydrogen for gas grid injection. The price for hydrogen gas grid injection is assumed to be 1.60 €/kg. This is the equivalent hydrogen price for the UK governments price projections for natural gas in 2030, discussed in section 4.1.

Since the price of natural gas is cheaper than electricity, potential policy measures and optimistic but realistic cost reductions were modelled to understand the case for hydrogen gas grid injection. Sensitivity analysis was conducted for an increased carbon tax for natural gas. The base case assumed a carbon tax of 80 €/tCO_2, while the sensitivity analysis looked at the impact of increasing the carbon tax to 300 €/tCO_2 in line with ESRI recommendations [120]. The impact of cost reductions/increases of 20% in projected electrolyser CAPEX and access to lower cost electricity at 30 €/MWh were also studied.

Base Case

For large scale electrolysis in 2030, the daily hydrogen production corresponding to a 64% capacity factor is approximately 16,500 kgH_2/day. It is assumed that the price of hydrogen acceptable to the consumer is 1.60 €/kg and that hydrogen can be injected to the grid at 30 bar pressure. This removes the requirement for additional compression. In addition, there are no transportation costs for hydrogen, however there are cost associated with developing and operating a hydrogen injection station. To minimise gas pipeline costs, it is assumed that the windfarm and injection station are located directly beside an existing gas grid above ground installation/connection point.

Refer to Appendix E for system assumptions.

Key Findings:

- As shown in Figure 93, the viable sale price to achieve an IRR of 8% for the project was modelled to be 6.30 €/kg. The production cost calculated was 1.80 €/kg which is higher than the projected price of natural gas in 2030. A subsidy of 4.7 €/kg was required.
- Since compression to 350 bar pressure is not necessary for gas grid injection, less electrical power is consumed in delivering hydrogen to the end user in comparison to hydrogen mobility. Therefore, the production costs associated with hydrogen gas grid injection are lower. However, hydrogen mobility still presents itself as the preferrable market as it is the higher value application with less subsidisation required.

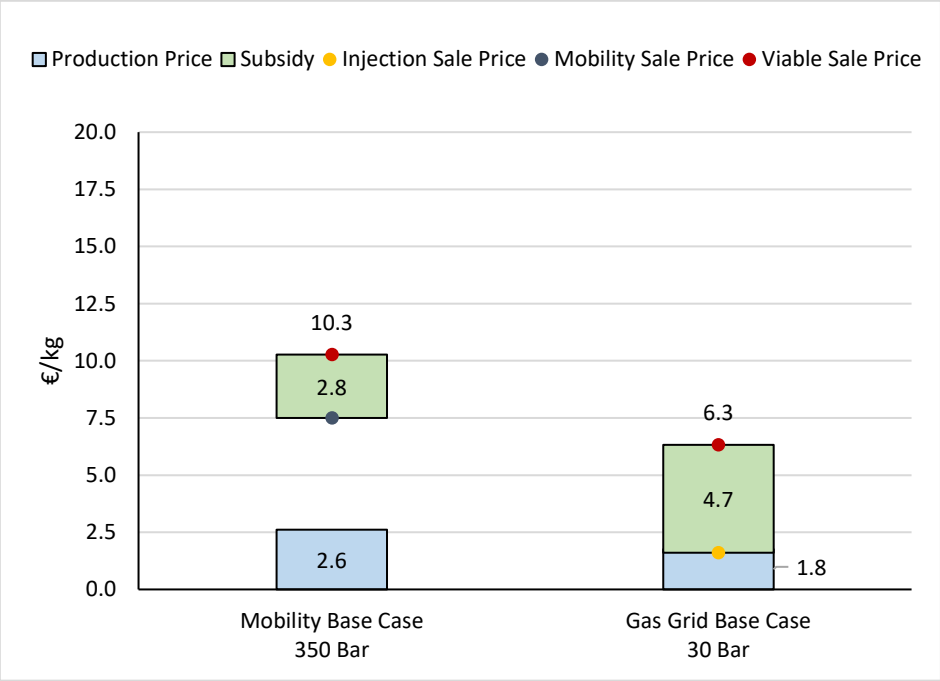

Figure 93 Base Case: Gas Grid Injection.

Carbon Tax Increase 80-300 €/tCO_2

A potential policy measure to improve the business case for hydrogen gas grid injection includes increasing the carbon tax on natural gas from 80€/tCO_2 to 300 €/tCO_2 in 2030. Implementing this potential policy measure increases the price of hydrogen acceptable to the consumer to 3.10 €/kg as shown in Figure 94.

Key Findings:

- By increasing the carbon tax to 300 €/tCO_2, the level of subsidisation required reduced from 4.70 €/kg to 3.20 €/kg.
- An increase in carbon tax on natural gas could help create a more level 'playing field' for hydrogen gas grid injection while also providing additional funds to subsidize green hydrogen.

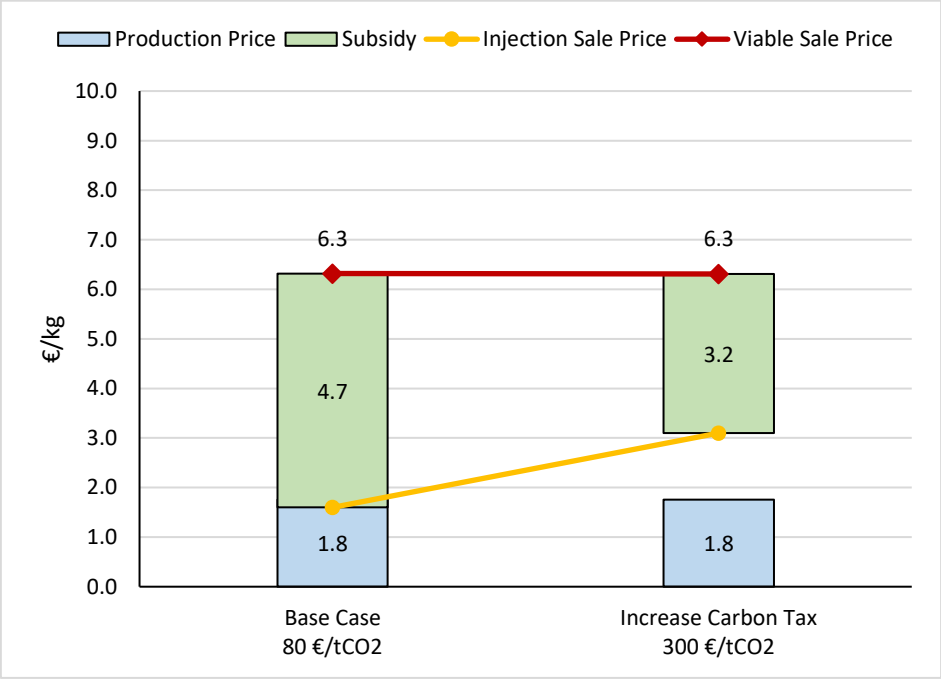

Figure 94 Carbon Tax to 300€/tCO_2: Gas Grid Injection.

Electrolyser CAPEX Sensitivity

The Electrolyser CAPEX sensitivity analysis on large scale electrolysis for gas grid injection is displayed in Figure 95. Scenarios for both CAPEX reductions and increases up to 20% were modelled for 2030.

Key Findings:

- If additional cost reductions of 20% are achieved on 2030 projections from literature, then the viable sale price for large scale electrolysis is approximately 5.90 €/kg with a subsidy of 4.30 €/kg required.
- With costs increases of 20% on projections from literature, the viable sale price for large scale electrolysis is estimated to be 6.80 €/kg with a subsidy of 5.2 €/kg required.

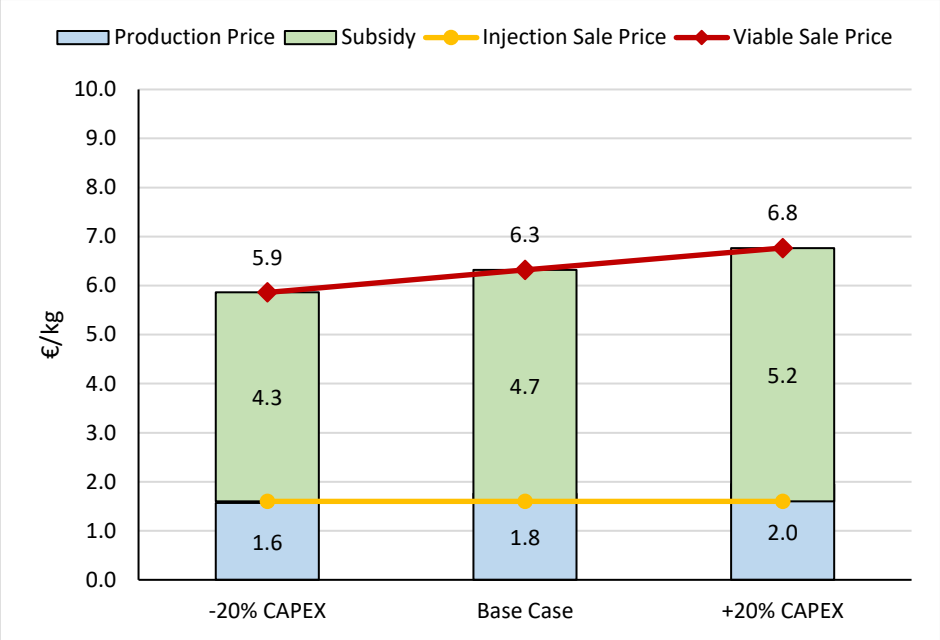

Figure 95 Electrolyser CAPEX Sensitivity: Gas Grid Injection.

Electrolyser Electricity Price Sensitivity

The wholesale electricity price sensitivity analysis carried out on large scale electrolysis for gas grid injection is presented in Figure 96.

Key Findings:

- Assuming the average wholesale price of electricity in 2030 is 30 €/MWh and in line with prices for the first half of 2020, then the viable sale price for large scale electrolysis is 6.10 €/kg with a subsidy of 4.50 €/kg required.

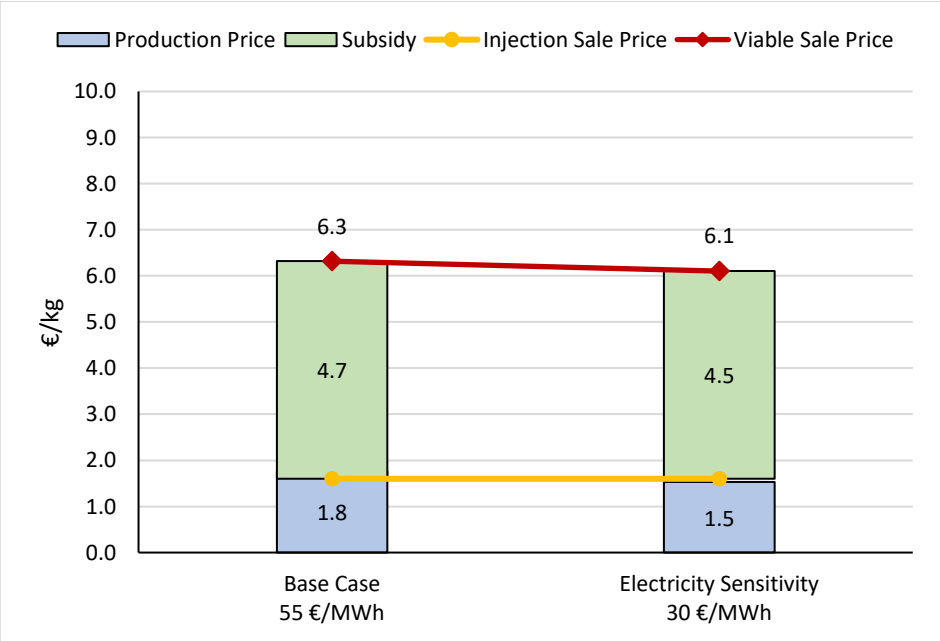

Figure 96 Electrolyser Electricity Price Sensitivity: Gas Grid Injection.

The Case for Hydrogen Gas Grid Injection from Renewable Power' Summary of Findings

The main findings from the analysis on the case for hydrogen gas grid injection from renewable power were:

- Considering a 50 MW electrolyser deployed to a 200 MW wind farm with access to imported electricity at the wholesale market price:
    - Hydrogen mobility presented itself as the preferrable market as it is the higher value application with less subsidisation required.
    - By increasing the carbon tax from 80 €/tCO_2 to 300 €/tCO_2, the level of subsidisation required reduced from 4.70 €/kg to 3.20 €/kg.
    - An increase in carbon tax on natural gas could help create a more level 'playing field' for hydrogen gas grid injection while also providing additional funds to subsidize green hydrogen.

4.6 Benefits of Large-Scale Green Hydrogen Deployment

4.6.1 Emissions Reduction

In this section of the report, the potential vehicle deployment and green hydrogen supply for the residential sector arising from the 1 MW (small), 10 MW (medium) and 50 MW (large) electrolyser are examined. The potential emissions reduction in both the transport and heat sectors were also estimated. Potential cost savings from reductions in CO_2, Nitrogen Oxides (NOx) and Particulate Matter (PM) emissions in the transport sector were also calculated.

Transport Emissions Displaced

Figure 97 outlines the potential vehicle deployment arising from the production scenarios presented in section 4.4. The potential diesel CO_2 emissions displaced are shown in Table 18. According to the World Health Organisation, there were 1,500 premature deaths in Ireland in 2013 because of air pollution [121]. Across Europe, transport emissions are responsible for about half of all air pollution and are the largest single contributor. This varies by country and region; urban areas are much more acutely affected by air pollution from transport. The main pollutants from transport emissions are NOx and PM. The more harmful of the two is PM, which penetrates deep into the lungs and has a range of harmful physical and chemical effects on the body. While diesel vehicles emit fewer carbon emissions than petrol vehicles, they emit significantly more NOx emissions.

A 2017 report by the Irish Environmental Protection Agency calculated that the cost per tonne of NOx emissions may be up to €9350 (Dublin) [122]. PM emissions were estimated to cost up to €67,650 (Dublin). The potential savings arising from the deployment of green hydrogen in transport are shown in Table 19 - Table 21.

Key Findings

- Large scale electrolysis with a daily hydrogen supply of 16500kg/day could facilitate zero emission transport by supplying green hydrogen to:
  - ✓ **47,900 Passenger Cars:** displacing up to 82 $KtCO_2$ from diesel cars.
  - ✓ **20,290 Vans:** displacing up to 74 $KtCO_2$ from diesel vans.
  - ✓ **1,940 Trucks:** displacing up to 67 $KtCO_2$ from diesel trucks.
  - ✓ **1,760 Buses:** displacing up to 100 $KtCO_2$ from diesel buses.
  - ✓ **80 Trains:** displacing up to 77 $KtCO_2$ from diesel buses.

- Replacing 1,760 diesel buses with fuel cell buses supplied from the large-scale 50 MW Green hydrogen production facility could deliver potential savings of:
  - ✓ €8 million annually by displacing CO_2 emissions (Carbon tax – 80 €/tCO_2).
  - ✓ €0.34 million annually from the reduction of NOx.
  - ✓ €0.05 million annually from the reduction of PM.
  - ✓ €84 million over the period 2030-2040.

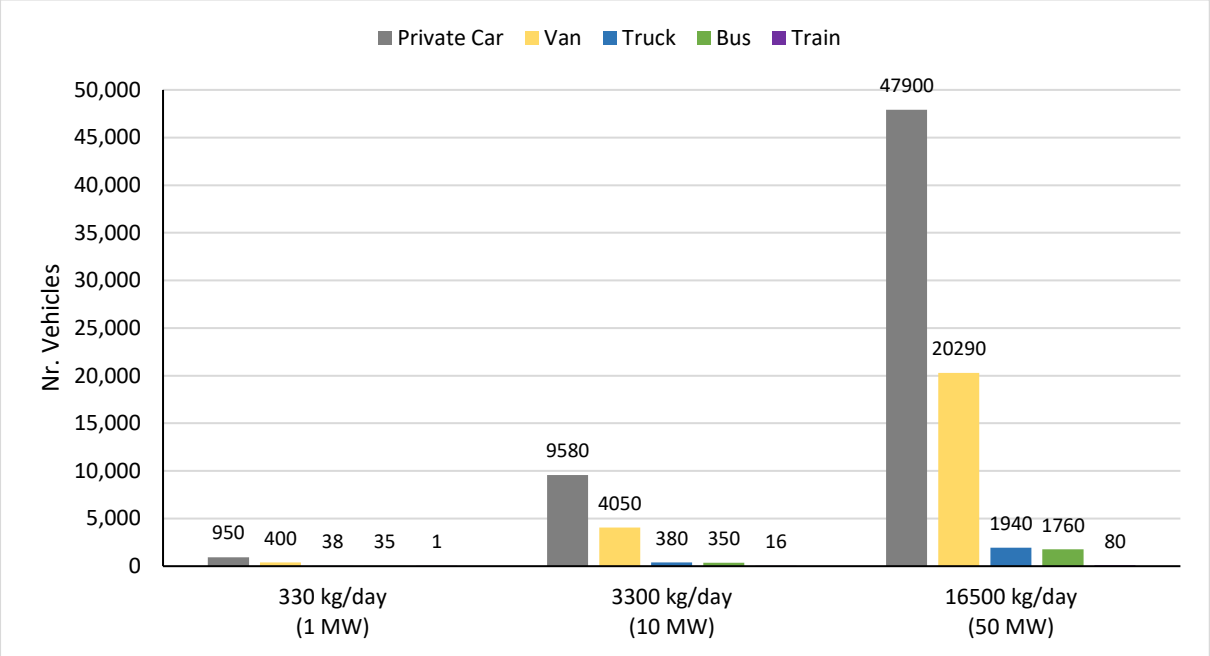

Figure 97 Potential Vehicle Deployment from Small, Medium and Large-Scale Electrolysis.

Table 18 Potential Vehicle Emissions Displaced - Small, Medium and Large-Scale Electrolysis.

Electrolyser	MW	1	10	50
Daily Production	kg/day	330	3300	16500
Private Car	$KtCO_2$	2	16	82
Van	$KtCO_2$	1	15	74
Truck	$KtCO_2$	1	13	67
Bus	$KtCO_2$	2	20	100
Train	$KtCO_2$	1	15	77

Table 19 Annual Carbon Tax Savings in Transport from Small, Medium and Large-Scale Electrolysis.

Electrolyser	MW	1	10	50
Daily Production	kg/day	330	3300	16500
Private Car	€	129,910	1,310,039	6,550,196
Van	€	115,982	1,174,316	5,883,178
Truck	€	104,983	1,049,832	5,359,671
Bus	€	158,372	1,583,719	7,963,845
Train	€	77,184	1,234,944	6,174,720

Table 20 Annual NOx Savings in Transport from Small, Medium and Large-Scale Electrolysis.

Electrolyser	MW	1	10	50
Daily Production	kg/day	330	3300	16500
Private Car	€	9,593	96,739	483,694
Van	€	6,882	69,676	349,069
Truck	€	8,172	81,719	417,197
Bus	€	6,774	67,741	340,639
Train	€	1,290	20,645	103,224

Table 21 Annual PM Savings in Transport from Small, Medium and Large-Scale Electrolysis.

Electrolyser	MW	1	10	50
Daily Production	kg/day	330	3300	16500
Private Car	€	5,784	58,328	291,639
Van	€	3,112	31,508	157,851
Truck	€	1,285	12,854	65,621
Bus	€	1,065	10,655	53,579
Train	€	203	3,247	16,236

Heat Emissions Displaced

As outlined earlier in section 2.2.2, the residential sector accounts for a quarter of the energy-related CO_2 emissions. The injection of green hydrogen into the gas grid is a potential decarbonisation measure for gas grid operators. With hydrogen blends in the gas grid < 20% (vol%), energy delivery is approximately 95% efficient according to Abeysekera et al. [123]. In 2030, it is assumed that hydrogen blends are less than 20% and that the average household connected to the gas grid consumes 11.5 MWh/yr in line with SEAI's 'energy in the residential sector 2018' report [18]. Using these assumptions, the CO_2 emissions benefit and carbon savings arising from green hydrogen production for small, medium and large-scale electrolysis were estimated in Table 22.

Key Findings

- Large scale electrolysis with a daily hydrogen supply of 16500kg/day could decarbonise up to as many as 16,500 households in Ireland. In doing so, this could displace 70 $KtCO_2$ emissions arising from natural gas.
- At a carbon tax of 80€/tCO_2 in 2030, a large-scale green hydrogen production facility could deliver annual carbon savings of up to €5.6 million in the residential sector.

- Increasing the carbon tax to 300€/tCO_2 in 2030 could be lever used to create a more level playing field for green hydrogen injection to the gas grid. At the same time, annual carbon savings of up to €20.9 million could be achieved in the residential sector from the deployment of a large-scale electrolyser producing green hydrogen.

Table 22 Annual Carbon Tax Savings in the Residential Sector from Small, Medium and Large-Scale Electrolysis.

Electrolyser	MW	1	10	50
Daily Production	kg/day	330	3300	16500
Hydrogen Supplied	kgH2/yr	114,428	1,144,275	5,721,375
Natural Gas Equivalent	MWh	3814	38139	190693
Households Decarbonised	Nr.	330	3310	16570
CO_2 Emissions Displaced	$ktCO_2$	1.4	14.0	69.8
Carbon Savings - 80 €/tCO_2	€	111,670	1,116,701	5,583,504
Carbon Savings - 300 €/tCO_2	€	418,763	4,187,628	20,938,138

4.6.2 Job Creation

At present in a time of economic uncertainty in Ireland and the World globally, the IEA developed a sustainable recovery plan in cooperation with the International Monetary Fund (IMF)[124]. The report indicates there is an opportunity for individual countries to pour investment into clean energy and create employment to offset job losses in the energy sector from the pandemic and in the fossil sector from decarbonisation.

Based on the IEA and IMF analysis, there are 1.41 jobs created for every 1 million euro of capital investment in wind energy (€1 ~ $1.17). For the same investment in hydrogen, there are 5.13 jobs created. Applying this job creation estimate to Ireland, it is unclear as to how many of these jobs would be created in Ireland. However, for the purpose of this report it has been assumed that all of the jobs created are in the Irish economy. Using these assumptions, Table 23 demonstrates the potential job creation arising from the small, medium and large-scale hydrogen production facility.

<u>Key Findings</u>

- An investment of €9.94 million in a 5 MW onshore wind farm and 1 MW electrolyser for green hydrogen production could create up to 30 jobs.
- For a total investment of €67.14 million, A 40 MW onshore wind farm and 10 MW electrolyser developed in Ireland could create up to 170 jobs in the renewable sector.

- An investment of €326.5 million to develop 200 MW of onshore wind along with 50 MW of electrolysis for green hydrogen production may create up to 820 jobs in Ireland.
- Creating and implementing the necessary policy measures to encourage green hydrogen production at scale in Ireland could create significant job creation. In addition, a large portion of the jobs created could benefit rural Ireland since isolated/rural areas are favourable for developing onshore wind projects.

Table 23 Job Creation from Small, Medium and Large-Scale Electrolysis from Onshore Wind.

Wind Farm	MW	5	40	200
Electrolyser	MW	1	10	50
Daily Production	kg/day	330	3300	16500
Wind CAPEX	€	6,900,000	47,150,000	231,150,000
Hydrogen CAPEX	€	3,044,266	19,994,080	95,370,398
Wind Employment	Nr. Jobs	10	70	330
Hydrogen Employment	Nr. Jobs	20	100	490
Total Employment	Nr. Jobs	30	170	820

4.6.3 Reduced Dependency on Fuel Imports

As discussed in section 2.3.1, Ireland has no domestic commercial oil production and is 100% dependent on petroleum product and crude oil imports. Along with the electrification of transport, green hydrogen can help reduce fuel imports in the sector. From Figure 97, A large scale 50 MW electrolyser could supply hydrogen for approximately 50,000 private cars annually. This represents roughly 2.4% of the private car fleet.

In section 2.10.2, Ireland's current and future gas supply was reviewed. One of the key findings was that Ireland's indigenous gas supplies are becoming depleted. Kinsale ceased production in July 2020 and Corrib may be depleted by the mid to late 2020's. This will mean Ireland will be 100% reliant on imported natural gas from the UK. In a post Brexit world in 2030, the UK could afford to hike their price for natural gas knowing Ireland have no alternative. Developing indigenous renewable gas sources including green hydrogen at scale for gas grid injection will be crucial in reducing Ireland's dependence on the UK for natural gas supplies.

4.7 Main Findings from Analysis Carried Out

The main findings from the analysis carried out on Vehicle TCO, hydrogen production and gas grid injection include:

- FCEVs appear to be cost competitive with BEVs in the mid-late 2020's when considering a sale price at the pump of 5-10€/kg. Heavy-duty applications including trucks, buses and trains appeared to be the most suitable for hydrogen deployment from 2025. Lighter duty FCEVs including passenger cars, taxis and vans appeared to be less favourable in terms of TCO in comparison to BEVs.
- Hydrogen gaseous 350bar delivery via truck and trailer can be expensive over long distances due to the limited trailer carrying capacity of approximately 400kg. Assuming gaseous hydrogen trailer capacity increases to 900 kg as predicted in literature, then the cost of transporting hydrogen over long distances may be significantly reduced. For the large-scale demand scenario and comparing the 400 kg and 900 kg trailer capacities, delivery costs are reduced from 2€/kg to 1 €/kg for a one-way distance of 300km.
- Hydrogen production from dispatched down electricity only does not appear to be economically viable. For a 50 MW alkaline electrolyser deployed to a 200 MW windfarm with access to dispatch down electricity, the viable hydrogen sale price was estimated to be 28.3 €/kg. With an acceptable sale price to the use case of 7.5 €/kg then regulatory support of up to 20.8 €/kg may be required to provide a business case for this option.
- From the analysis on the business case of an electrolyser deployed to a wind farm with access to grid imported electricity, large scale electrolysers appear to benefit from economies of scale. The viable sale price for the large scale 50MW facility was estimated to be in the range of 9.6-10.9€/kg, whereas the viable sale price for the smaller scale 1MW facility was estimated to be in the range of 11.9-13.9€/kg.
- Hydrogen mobility appears to the preferrable market in comparison to gas grid injection as it is the higher value application. In 2030, the price of natural gas is expected to be in the range of 15-31 €/MWh as seen in Figure 57. Applying a carbon tax of 80€/tCO2 in Ireland, the equivalent parity price range for hydrogen would be 1.05-1.6 €/kg. Increasing the carbon tax on natural gas from 80€/tCO2

to 300 €/tCO2 in 2030 was estimated to increase the equivalent parity price range for hydrogen to 3.10 €/kg. An increase in carbon tax on natural gas could help create a more level 'playing field' for hydrogen gas grid injection while also providing additional funds to subsidize green hydrogen.

- Large scale electrolysis with a daily hydrogen supply of 16500kg/day could decarbonise up to as many as 16,500 households in Ireland and in doing so, could displace 70 $KtCO_2$ emissions arising from natural gas. It can also facilitate zero emission transport by supplying green hydrogen to:
  - ✓ **47,900 Passenger Cars:** displacing up to 82 $KtCO_2$ from diesel cars.
  - ✓ **20,290 Vans:** displacing up to 74 $KtCO_2$ from diesel vans.
  - ✓ **1,940 Trucks:** displacing up to 67 $KtCO_2$ from diesel trucks.
  - ✓ **1,760 Buses:** displacing up to 100 $KtCO_2$ from diesel buses.
  - ✓ **80 Trains:** displacing up to 77 $KtCO_2$ from diesel buses.
- Along with the electrification of transport, green hydrogen can help reduce fuel imports in the sector. A large scale 50 MW electrolyser could supply hydrogen for approximately 50,000 private cars annually. This represents roughly 2.4% of the private car fleet.

5 Conclusions

Section 2 of the report provides an extensive literature review of the energy system and achieves a number of the project objectives, which include:

1 Explore the emissions reduction pathways for Ireland in a climate and biodiversity emergency.
2 Identify the obstacles for further renewable development in the electricity sector out to 2030.
3 Understand the potential use cases for green hydrogen in the Irish energy system and in hard to decarbonise sectors such as heat and transport.

This project set out to investigate the challenges for the integration of renewables in the Irish energy system and explore how green hydrogen can be part of the solution. As part of this investigation, the methodology outlined in section 3 was applied to achieve the following objectives:

4 Develop Total Cost of Ownership (TCO) models for light and heavy-duty vehicles in Ireland.
5 Develop a financial model for a 'Green Hydrogen' production facility.
6 Analyse the business case for green hydrogen applications in the transport and heat sectors in Ireland and determine the hydrogen price acceptable to the consumer.
7 Develop a model to estimate the delivery cost of hydrogen via a truck and tube-trailer.
8 Perform a techno-economic analysis on the business case for green hydrogen production in Ireland:
    i. Produce Hydrogen from dispatched down electricity on a windfarm.
    ii. Produce Hydrogen from both windfarm electricity and imported electricity.
9 Review the potential socio-economic benefits arising from large-scale hydrogen production on the island of Ireland.

The following conclusions are drawn from a review of Ireland's energy system, and the potential role for green hydrogen:

1) Improved energy efficiency, electrification and renewable gas are key mitigation measures available to Ireland to help reduce emissions and ensure future renewable energy targets are achieved. Green hydrogen produced from renewable electricity is a renewable gas that could potentially be deployed (along with improved energy efficiency and electrification) in Ireland to reduce emissions across a number of sectors, including the heat and transport sectors which have accounted for the largest share of CO_2 emissions in recent times. Objective 1.
2) The Irish government announced in budget 2021 that up to €12 million of funding has been allocated to encourage the deployment of FCEV buses and trucks. Continued government support for hydrogen in transport may be necessary to encourage FCEV uptake in the next decade. Providing this support to hydrogen in the short to medium term could be important to put Ireland on a pathway to net zero emissions by 2050. This financial support could potentially help Ireland to reduce its dependency on imported petroleum products. Objective 1.
3) The dispatch down of renewable generation is on an upward trend. This is an inefficiency in the Irish electricity system and prohibits renewable generators from harnessing their full potential. Very high levels of dispatch down may be a barrier to future renewable development due to the negative impact on the economics of a renewable generator. In 2019, Ireland's controllable renewable generation fleet had 7.7% of their output dispatched down. Dispatch down increased to 12.5% in the first half of 2020. Avoiding continued high levels of dispatch down requires significant investment in electricity transmission infrastructure and long-term storage technologies. This will be key to enabling Ireland to overcome high levels of dispatch down which are an obstacle for further renewable development in the electricity sector out to 2030. Objective 2.
4) Hydrogen offers a long-term storage option to capture surplus variable renewable generation at times of oversupply. FCEVs offer a zero-emission option for decarbonisation of the transport sector. Green hydrogen may also be

injected into the gas grid to displace emissions from natural gas in the heat sector. By removing electrons from the power system for use in heat and transport, hydrogen can also provide more space for renewables on the electricity system. There appears to be a technically viable use case for hydrogen in both the transport sector and heat/gas grid injection sector in Ireland with the potential for emission reductions in both sectors. Objective 3.

5) TCO models were developed to analyse the sale price of hydrogen acceptable to the consumer for light and heavy-duty vehicles. From the vehicle TCO analysis, it appeared that FCEVs are cost competitive with BEVs in the late 2020's with a sale price of hydrogen acceptable to the consumer in the range of 5-10€/kg. Objectives 4 & 6.
6) A financial model for a 'Green Hydrogen' production facility was developed to analyse the business case for an electrolyser deployed to a wind farm. The optimal production scenario for supplying hydrogen mobility appeared to be one where hydrogen is produced from both onsite windfarm electricity and grid imported electricity. The hydrogen production analysis indicated that providing regulatory support of up to 7 €/kg may be required to encourage renewable energy developers and transport fleet operators based in Ireland to consider hydrogen as a viable investment. This level of support appears to be in line with other European jurisdictions including the UK. Objectives 5 & 6.
7) Gas grid injection appears to be a lower value revenue stream for hydrogen in comparison to mobility as shown in Figure 93. The acceptable hydrogen price to the consumer based on the UK governments price projections for natural gas in 2030 appeared to be 1.60 €/kg. High-level analysis on the business case for green hydrogen gas grid injection concluded that support of up to 5.20 €/kg may be required to ensure it is a feasible investment. Increasing the carbon tax on natural gas to 300 €/tCO_2 in 2030+ could be a potential lever to reduce the level of support for green hydrogen injection. This is an area that requires further investigation to understand the volumes of hydrogen that can be injected and blended with natural gas. Objective 6.
8) Hydrogen delivery costs via tube trailer appear to be expensive considering the current trailer capacities available on the market. At present, gaseous hydrogen delivery tube trailer capacities are in the range of 200-400 kg for operating pressures of 350 bar. For a 400kg trailer capacity, delivery costs were

estimated be up to 1.5 €/kg for delivery within a 30km radius. These costs appear to be high in the context of a target sale price of 5 €/kg for FCEVs. However, it is expected that in the next 10 years gaseous hydrogen delivery tube trailer capacities will increase to approximately 900kg which may help to improve the economics of hydrogen delivery via tube trailer. Objective 7.

9) The business case for producing hydrogen from only dispatched down electricity for the mobility sector did not appear to stack up. In addition, an intermittent supply of hydrogen may not be technically feasible for transport or logistics companies. A review of the business case of a 50 MW alkaline electrolyser deployed to a 200 MW windfarm with access to dispatch down electricity, indicated regulatory support of up to 20.8 €/kg would be necessary to provide a viable business case. This far exceeds the level of regulatory support being mooted for hydrogen (up to 7€/kg in the UK). Objective 8(i).
10) The analysis carried out showed how green hydrogen can provide a business case for onshore windfarms located in highly constrained areas of Ireland. At levels of 20%+ dispatch down, and assuming there is no compensation available, then it is unlikely that developers would consider a windfarm a viable investment. However, co-locating an electrolyser at the windfarm created value for a higher portion of energy available on the windfarm. Objective 8(ii).
11) In a climate and biodiversity emergency in Ireland, green hydrogen presents an opportunity to decarbonise the energy system and at the same time create additional jobs in the Irish economy. Objective 9.

Recommendations for Future Work

- Analyse the potential for hydrogen in the North West region of Ireland. Engage with renewable energy developers, transport operators, manufacturing companies with combustion processes and gas suppliers to understand the appetite for green hydrogen in Ireland.
- Develop a financial model to consider an offshore wind farm and electrolyser configuration for green hydrogen production. Analyse the potential for hydrogen from offshore wind in Ireland.

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Appendices

Appendix A

Table 24 Electrolyser CAPEX Estimates 2010 – 2030 including Glenk et al. [56].

Type	Year of Estimate	CAPEX €/ MW	Type of Publication	Reference
ALK	2010	959,987	Report	[125]
ALK	2011	1,416,500	Manufacturer Interview	[56]
ALK	2011	940,777	Journal Article	[126]
ALK	2013	1,569,015	Report	[127]
ALK	2013	1,214,721	Journal Article	[128]
ALK	2013	1,214,721	Report	[129]
ALK	2013	1,210,463	Report	[130]
ALK	2014	1,160,027	Journal Article	[45]
ALK	2014	1,160,027	Journal Article	[131]
ALK	2014	1,109,591	Report	[63]
ALK	2014	1,008,719	Report	[132]
ALK	2014	756,539	Journal Article	[133]
ALK	2015	1,588,834	Manufacturer Interview	[56]
ALK	2015	1,584,484	Manufacturer Interview	[56]
ALK	2015	1,551,038	Manufacturer Interview	[56]
ALK	2015	1,475,311	Manufacturer Interview	[56]
ALK	2015	1,408,251	Journal Article	[134]
ALK	2015	1,312,531	Manufacturer Interview	[56]
ALK	2015	1,231,971	Manufacturer Interview	[56]
ALK	2015	1,229,426	Manufacturer Interview	[56]
ALK	2015	1,156,778	Report	[56]
ALK	2015	1,012,267	Journal Article	[135]
ALK	2015	1,005,894	Journal Article	[56]
ALK	2015	1,005,894	Report	[56]
ALK	2015	975,928	Manufacturer Interview	[56]
ALK	2015	940,184	Manufacturer Interview	[56]
ALK	2015	938,108	Report	[63]
ALK	2015	831,371	Manufacturer Interview	[56]
ALK	2016	1,283,018	Report	[136]
ALK	2016	1,200,000	Report	[137]
ALK	2016	1,111,599	Journal Article	[138]
ALK	2016	1,100,000	Report	[139]
ALK	2016	1,012,267	Report	[129]
ALK	2016	1,000,000	Journal Article	[140]
ALK	2016	1,000,000	Report	[56]
ALK	2016	831,371	Manufacturer Interview	[56]
ALK	2016	800,000	Report	[56]
ALK	2017	1,000,000	Manufacturer Interview	[56]
ALK	2017	1,000,000	Manufacturer Interview	[56]
ALK	2017	975,000	Report	[56]
ALK	2017	800,000	Manufacturer Interview	[56]
ALK	2018	800,000	Manufacturer Interview	[56]
ALK	2019	500,000	Manufacturer Interview	[56]
ALK	2020	1,400,000	Report	[58]
ALK	2020	1,109,591	Report	[130]
ALK	2020	948,196	Journal Article	[141]
ALK	2020	861,440	Report	[129]

ALK	2020	640,536	Report	[63]
ALK	2020	500,000	Manufacturer Interview	[56]
ALK	2020	500,000	Report	[58]
ALK	2020	280,000	Journal Article	[142]
ALK	2025	932,000	Manufacturer Interview	[56]
ALK	2025	690,000	Report	[56]
ALK	2025	650,000	Manufacturer Interview	[56]
ALK	2025	615,318	Report	[63]
ALK	2025	600,000	Report	[143]
ALK	2025	502,947	Report	[56]
ALK	2030	1,059,155	Report	[130]
ALK	2030	1,008,719	Journal Article	[144]
ALK	2030	850,000	Report	[58]
ALK	2030	756,539	Report	[145]
ALK	2030	714,661	Report	[129]
ALK	2030	700,000	Report	[56]
ALK	2030	645,000	Journal Article	[146]
ALK	2030	590,100	Report	[63]
ALK	2030	504,359	Report	[132]
ALK	2030	502,947	Journal Article	[56]
ALK	2030	500,000	Manufacturer Interview	[56]
ALK	2030	400,000	Report	[58]
PEM	2010	2,133,303	Report	[147]
PEM	2010	1,965,839	Report	[125]
PEM	2013	3,391,096	Report	[127]
PEM	2013	1,134,809	Report	[148]
PEM	2014	3,227,231	Report	[149]
PEM	2014	3,026,156	Report	[132]
PEM	2014	2,320,053	Journal Article	[144]
PEM	2014	2,108,222	Report	[63]
PEM	2014	2,017,438	Journal Article	[131]
PEM	2014	1,670,019	Manufacturer Interview	[56]
PEM	2014	1,513,078	Report	[150]
PEM	2014	1,386,988	Report	[56]
PEM	2014	1,210,463	Report	[56]
PEM	2015	3,420,039	Journal Article	[151]
PEM	2015	2,815,583	Report	[152]
PEM	2015	2,575,088	Report	[56]
PEM	2015	2,011,788	Journal Article	[56]
PEM	2015	1,583,688	Report	[63]
PEM	2015	1,012,267	Journal Article	[135]
PEM	2016	2,000,000	Journal Article	[140]
PEM	2016	2,000,000	Report	[56]
PEM	2016	1,900,000	Report	[139]
PEM	2016	1,283,018	Report	[136]
PEM	2016	1,111,599	Journal Article	[138]
PEM	2016	1,000,000	Report	[153]
PEM	2017	1,550,000	Manufacturer Interview	[56]
PEM	2017	1,350,000	Report	[56]
PEM	2017	1,303,639	Report	[56]
PEM	2017	1,250,000	Manufacturer Interview	[56]
PEM	2017	1,200,000	Manufacturer Interview	[56]
PEM	2018	1,000,000	Journal Article	[140]
PEM	2020	1,810,017	Report	[152]
PEM	2020	1,800,000	Report	[58]
PEM	2020	1,250,000	Journal Article	[140]

PEM	2020	1,150,000	Manufacturer Interview	[56]
PEM	2020	1,100,000	Report	[58]
PEM	2020	1,008,719	Report	[63]
PEM	2020	740,338	Report	[56]
PEM	2025	1,400,000	Manufacturer Interview	[56]
PEM	2025	882,629	Report	[63]
PEM	2025	850,000	Report	[56]
PEM	2025	800,000	Manufacturer Interview	[56]
PEM	2025	756,539	Report	[148]
PEM	2025	579,395	Report	[56]
PEM	2030	1,500,000	Report	[58]
PEM	2030	1,400,557	Report	[149]
PEM	2030	1,119,255	Report	[139]
PEM	2030	1,008,719	Journal Article	[144]
PEM	2030	850,000	Report	[137]
PEM	2030	850,000	Journal Article	[154]
PEM	2030	766,626	Report	[63]
PEM	2030	700,000	Report	[56]
PEM	2030	650,000	Report	[58]
PEM	2030	645,000	Journal Article	[146]
PEM	2030	630,449	Report	[148]
PEM	2030	504,359	Report	[132]
PEM	2030	502,947	Journal Article	[56]
PEM	2030	500,000	Manufacturer Interview	[56]

Table 25 Dia-Core Project: Financial indicators' estimations for onshore wind energy projects [83].

Country	*WACC*	*CoE*	*CoD*	*D/E ratio*
Austria	6.5%	8–10%	4.5–5.5%	75:25
Belgium	5–6%	10.8%	5–5.5%	80:20
Bulgaria	10%	12–13%	7.5–8%	50:50
Croatia	12%	–	–	70:30
Cyprus	8–12%	15%	4.5–9%	70:30
Czech Republic	8%	12%	6.5–7.5%	70:30
Denmark	5–6.5%	10–11.2%	4.5–5.5%	80:20
Estonia	6.4–13%	15–20%	4.5–4.7%	65:35
Finland	6–7%	12–15%	3–5%	75:25
France	5.7%	10.5–11.5%	5.7%	80:20
Germany	3.5–4.5%	6–9%	1.8–3.2%	80:20
Greece	12%	14–16%	8.5–12.5%	55:45
Hungary	11.3%	14–15%	8–10%	65:35
Ireland	9%	11–12%	6.5–7.5%	70:30
Italy	7–9%	10–13%	8–10%	65:35
Latvia	9.3%	16.1%	6%	70:30
Lithuania	8–9%	16.6%	6%	70:30
Luxembourg	–	–	–	–
Malta	–	–	–	–
Netherlands	6–6.7%	13.7–14.2%	4.7–6.3%	70:30
Poland	8.7–10%	14–14.5%	6.1–8.1%	70:30
Portugal	7.5–8.5%	12–13%	6%	60:40
Romania	11.1%	16–18%	7–10%	50:50
Slovakia	8.1%	13.6%	6–7.3%	70:30
Slovenia	11%	17.4%	8.2–9.9%	75:25
Spain	10%	13–15%	9–10%	70:30
Sweden	7.4–9%	10–12%	4.5–6%	60:40
United Kingdom	6.5%	7–15%	5–5.5%	75:25

WACC: weighted average cost of capital; CoE: cost of equity; CoD: cost of debt; D/E ratio: debt-to-equity ratio.

Appendix B

Hydrogen Production Model Overview

Year of Build		
Year of Build	2030	

Check For Production >= Demand	YES

Hydrogen End Uses		
Mobility H2 Demand	330	kg/day
Industry H2 Demand	0	kg/day
Gas Grid Capacity	0	kg/day

Key Levers	
Level of Constraint	10%
Electrolyser Load Factor	64%
IRR Target	8%
CAPEX Sensitivity	0%

Solve Constraint

Solve Electrolyser Load Factor

Wind Farm + Electrolyser System		
Electricity Grid Connected	Yes	
MEC	5	MW
MIC	1.00	MW
Electrolsyer Type	ALK	
Electrolsyer Capacity	1.00	MW
Electrolyser Output Pressure	30	Bar
Additional Compression	YES	
Output Pressure	350	Bar
Gas Grid Connection	Yes	
Storage Buffer	100%	% daily demand

Market Assumptions		
Annual Inflation	1.5%	
Annual Carbon Tax Increase	1.5%	
Electricity Purchase Price - Electrolyser	55.0	€/MWh
15 Year PPA Price	60.0	€/MWh
Market price for electricity year	55.0	€/MWh
Mobility Sale Price	7.5	€/kg
Industry Sale Price		€/kg
Gas Grid Sale Price	1.6	€/kg
Distribution Costs	1.5	€/kg

Wind + Market Electricity: Key Results		
Economic Viability		
Windfarm Investment	6,900,000	€
Windfarm IRR (Without Electrolysis)	1.7%	%
Windfarm + Electrolyser Investment	10,979,266	€
Windfarm + H2 IRR	8.0%	
Technical Information		
Wind Farm Capacity Factor	38.0%	
Constraint %	10.0%	
Constraint % (Electrolysis)	1.72%	
Electrolyser Capacity Factor - Average	64.0%	
Electrolyser Full Load Hours - Average	6,022	Hrs
H2 Demand	120,450	kg
H2 Production	120,450	kg
Eelectricity Imports	1,497	MWh
H2 Production Price		
H2 Production Price @ 350Bar	€ 3.94	€/kg
H2 Subsidy	7.23	€/kg

Solve IRR Wind & Market

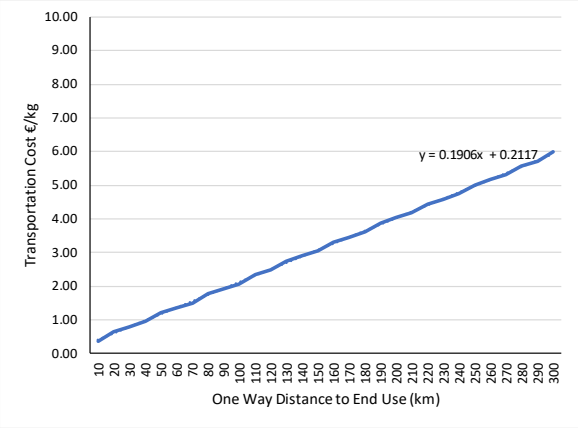
Dispatched Down Electricity Only: Key Results		
Economic Viability		
Windfarm Investment	6,900,000	
Windfarm IRR	1.7%	
Windfarm + Electrolyser Investment	10,979,266	
Windfarm + H2 IRR	8.0%	
Technical Information		
Wind Farm Capacity Factor	38.0%	
Constraint %	10.0%	
Constraint % (Electrolysis)	1.72%	
Electrolyser Capacity Factor - Average	15.4%	
Electrolyser Full Load Hours - Average	1,631	Hrs
H2 Demand	18,746	kg
H2 Production	18,746	kg
Eelectricity Imports	0	MWh
H2 Production Price		
H2 Production Price @ 350Bar	€ 8.72	€/kg
H2 Subsidy	41.8	€/kg

Solve IRR Dispatch Down Only

Appendix C

Year	**2030**
Fuel Type	**FCEV**

Item	Metric	Value
Daily H2 Demand	kg/day	3300
Trailer Capacity	kg	200
Average Speed	km/hr	80
Driver Shift	hrs	12
Truck Load/Unload Time	hr/trip	1
Truck Availability	hr/day	24
Driver Salary	€/hr	25
Operating Days	days/yr	365
Trailer Lifetime	yrs	15
200kg Trailer CAPEX	€	125,000
200kg Trailer OPEX	% CAPEX	2%
FCEV Tractor Unit	€/km	1.28
Profit Margin	%	15%



1 Way: Distance From End-Use	Annual Production	Trailer Capacity	No. Trips	Distance Travelled	Time Per Trip	Total Delivery Time	Trucks Required	Drivers Required	Truck Annual Cost	Trailer Annual Cost	Driver Annual Cost	Cost Per kg
km	kg/yr	kg/trailer	trips/day	km/yr	hr/trip	hr/yr	-	-	€	€	€	€/kg
10	1,204,500	200	17	124,100	1.25	7757	1	2	158,917	10,833	219,000	0.37
20	1,204,500	200	17	248,200	1.5	9308	2	3	317,834	21,667	328,500	0.64
30	1,204,500	200	17	372,300	1.75	10859	2	3	476,751	21,667	328,500	0.79
40	1,204,500	200	17	496,400	2	12410	2	3	635,668	21,667	328,500	0.94
50	1,204,500	200	17	620,500	2.25	13962	2	4	794,585	21,667	438,000	1.20
60	1,204,500	200	17	744,600	2.5	15513	2	4	953,501	21,667	438,000	1.35
70	1,204,500	200	17	868,700	2.75	17064	2	4	1,112,418	21,667	438,000	1.50
80	1,204,500	200	17	992,800	3	18615	3	5	1,271,335	32,500	547,500	1.77
90	1,204,500	200	17	1,116,900	3.25	20167	3	5	1,430,252	32,500	547,500	1.92
100	1,204,500	200	17	1,241,000	3.5	21718	3	5	1,589,169	32,500	547,500	2.07
110	1,204,500	200	17	1,365,100	3.75	23269	3	6	1,748,086	32,500	657,000	2.33
120	1,204,500	200	17	1,489,200	4	24820	3	6	1,907,003	32,500	657,000	2.48
130	1,204,500	200	17	1,613,300	4.25	26372	4	7	2,065,920	43,333	766,500	2.75
140	1,204,500	200	17	1,737,400	4.5	27923	4	7	2,224,837	43,333	766,500	2.90
150	1,204,500	200	17	1,861,500	4.75	29474	4	7	2,383,754	43,333	766,500	3.05
160	1,204,500	200	17	1,985,600	5	31025	4	8	2,542,670	43,333	876,000	3.31
170	1,204,500	200	17	2,109,700	5.25	32577	4	8	2,701,587	43,333	876,000	3.46
180	1,204,500	200	17	2,233,800	5.5	34128	4	8	2,860,504	43,333	876,000	3.61
190	1,204,500	200	17	2,357,900	5.75	35679	5	9	3,019,421	54,167	985,500	3.88
200	1,204,500	200	17	2,482,000	6	37230	5	9	3,178,338	54,167	985,500	4.03
210	1,204,500	200	17	2,606,100	6.25	38782	5	9	3,337,255	54,167	985,500	4.18
220	1,204,500	200	17	2,730,200	6.5	40333	5	10	3,496,172	54,167	1,095,000	4.44
230	1,204,500	200	17	2,854,300	6.75	41884	5	10	3,655,089	54,167	1,095,000	4.59
240	1,204,500	200	17	2,978,400	7	43435	5	10	3,814,006	54,167	1,095,000	4.74
250	1,204,500	200	17	3,102,500	7.25	44987	6	11	3,972,923	65,000	1,204,500	5.01
260	1,204,500	200	17	3,226,600	7.5	46538	6	11	4,131,839	65,000	1,204,500	5.16
270	1,204,500	200	17	3,350,700	7.75	48089	6	11	4,290,756	65,000	1,204,500	5.31
280	1,204,500	200	17	3,474,800	8	49640	6	12	4,449,673	65,000	1,314,000	5.56
290	1,204,500	200	17	3,598,900	8.25	51192	6	12	4,608,590	65,000	1,314,000	5.72
300	1,204,500	200	17	3,723,000	8.5	52743	7	13	4,767,507	75,833	1,423,500	5.98

Examination copy 01/09/2021

Appendix D

The Vehicle TCO assumptions presented in Table 22-Table 27 are based on a report compiled by hydrogen mobility Ireland [40].

Table 26 Private Car Vehicle TCO Analysis Assumptions

Private Car		2030			
Metric	**Unit**	**Petrol Hybrid**	**Diesel**	**BEV**	**FCEV**
First Owner Lifetime	years	4	4	4	4
CAPEX	€	28,000	28,300	30,000	33,100
CO_2 Emissions	gCO_2/km	104.09	93.55	0.00	0.00
Purchase Tax	€	7560	6792	4800	5296
Purchase Tax Deduction	€	0	0	0	-1000
Purchase Grant	€	0	0	0	-1000
Annual Tax	€	2280	1560	720	720
Maintenance and Repair	€	1440	1440	720	720
Mileage	km	18000	18000	18000	18000
Fuel Consumption	l,kWh,kg/100km	4.35	3.54	13.65	0.64
Fuel Price	€/l,kg,kWh	1.49	1.4608	0.20	5
RED II Cert Price	€/kg/kWh	0.0	0.0	0.0	1.5
RED II Multiplier		0.0	0.0	4.0	1.0
RED II Value	€	0.0	0.0	-817.1	-345.7
Insurance	€	3468	3468	3468	3468
Residual Value	%	33%	33%	33%	33%
Infrastructure Cost	€	0	0	1000	0

Table 27 Private Car Vehicle TCO Analysis Assumptions

Taxi Car		2030			
Metric	**Unit**	**Petrol Hybrid**	**Diesel**	**BEV**	**FCEV**
First Owner Lifetime	years	4	4	4	4
CAPEX	€	28,000	28,300	30,000	33,100
Purchase Tax	€			4800	5296
Purchase Tax Deduction	€			0	-1000
Purchase Grant				0	-760
Maintenance and Repair	€	2560	2560	1280	1280
Mileage	km	32000	32000	32000	32000
Insurance	€	6165	6165	6165	6165
Residual Value	%	25%	25%	25%	25%
Infrastructure Cost	€	0	0	1500	0
eSPSV Grant	€	0		0	0
RED II Value	€	0	0	-1453	-615

Table 28 Large Panel Van TCO Analysis Assumptions

Large Van		2030			
Metric	**Unit**	**Diesel**	**Diesel Hybrid**	**BEV**	**FCEV**
First Owner Lifetime	years	12	12	12	12
CAPEX	€	35725	36725	40200	40000
CO_2 Emissions	gCO_2/km	183.28	162.62		
Purchase Tax	€	5466	5619	6150.6	6120
Purchase Tax Deduction	€	0	0	-1500	-1500
Purchase Grant	€	0	0	0	0
Annual Tax	€	5196	5196	1104	1104
Maintenance and Repair	€	7668	7668	5364	5364
Mileage	km	23000	23000	23000	23000
Fuel Consumption	l,kWh,kg/100km	6.94	6.16	28.99	1.29
Fuel Price	€/l,kg,kWh	1.21	1.21	0.12	5.00
Insurance	€	13,956	13,956	13,956	13,956
Residual Value	%	0%	0%	0%	0%
Infrastructure Cost	€	0	0	2000	0

Table 29 Truck TCO Analysis Assumptions

Large Rigid 25t		2030				
Metric	**Unit**	**Diesel**	**Diesel Hybrid**	**bio-CNG**	**BEV**	**FCEV**
Lifetime	years	10	10	10	10	10
CAPEX	€	88,180	92,459	107,417	125,473	122,027
Powertrain Overhaul	€	5,750	34,500	5,750	92,000	46,000
Maintenance and Repair	€	79,350	83,950	72,450	57,500	79,350
Mileage	km	50000	50000	50000	50000	50000
Fuel Consumption	MJ/km	9.27	8.49	10.6605	3.52	7.45
Fuel energy density	MJ/l,kg,kWh	35.97	35.97	48.38	3.60	120
Fuel Consumption	l/100km, kWh/100km, kg/100km	25.8	23.6	22.0	97.8	6.2
Fuel Price	€/l,kg,kWh	1.21	1.21	0.9	0.12	5
Infrastructure CAPEX	€	0	0	0	69000	0

Table 30 Double Decker Bus TCO Analysis Assumptions

Double Decker Bus		2030			
Metric	**Unit**	**Diesel**	**Diesel Hybrid**	**BEV**	**FCEV**
Lifetime	years	12	12	12	12
CAPEX	€	289,250	289,250	362,026	405,000
Registration Tax (VRT)	€	200	200	200	200
Annual Tax	€	4836	4836	4836	4836
Powertrain Overhaul	€	6785	37950	92000	62100
Powertrain Maintenance	€	11500	11500	17250	17250
Annual Maintenance	€	11500	11500	11500	11500
Mileage	km	45000	45000	45000	45000
Fuel Consumption	l/100km kWh/100km, kg/100km	46.9	34.4	168	7.6
Fuel Price	€/l,kg,kWh	1.21	1.21	0.12	5
RED II Cert Price	€/kg	0.00	0.00	0.02079	1.51
RED II Multiplier		0.00	0.00	1.00	1.00
RED II Value	€	0.00	0.00	-18860.688	-31013.928
Infrastructure CAPEX	€	0	0	40250	0
Infrastructure Maintenance	€	0	0	5750	0
Driver Salary	€	46000	46000	46000	46000
Depot Overheads	€	8050	8050	8050	8050

Table 31 Train TCO Analysis Assumptions

160 Seat Train		2030	
Metric	**Unit**	**Diesel**	**FCEV**
Unit Lifetime	Years	35	35
Lifetime	Years	10	10
CAPEX	€	4,140,000	4,300,000
Infrastructure CAPEX	€	960,000	850,000
Annual Mileage	km	200,000	200,000
Fuel Consumption	L, kg/km	1.20	0.25
Fuel Price	€/L, €/kg	1.21	5.00
CO_2 Emissions	gCO_2/km	3976	
Annual Maintenance	€	140,000	114,000
Total Annual Cost	€	940,400	879,000

Appendix E

Table 32 Trailer CAPEX Assumptions.

Item	Metric	2020	2025	2030
Trailer Lifetime	yrs	15	15	15
200 kg Trailer CAPEX	€	125000	125000	125000
300 kg Trailer CAPEX	€	187500	187500	187500
400 kg Trailer CAPEX	€	250000	250000	250000
900 kg Trailer CAPEX	€	390,000	390,000	390,000

Table 33 Project Financing Assumptions

Project Financing	Metric	
Debt Tenor	Yrs	15
Developer Margin	%	15%
Equity/Debt Ratio	%	30:70
Cost of Equity	%	11.5%
Cost of Debt	%	6.5%
WACC/ Hurdle Rate	%	8.0%

Table 34 Onshore Wind Techno-Economic Assumptions.

Onshore Wind	Metric	2030
WTG's	€/ MW	600,000
BOP	€/ MW	200,000
Grid Connection	€/ MW	200,000
Development	€	1,000,000
Variable O & M (Service Costs)	€/ MW	18,000
G - TUoS	€/ MW/Month	500
D- TUoS	€/ MW/Month	1463
PSO Levy	€/MVA/Month	1220
Capacity Factor	%	38%
CLAF	-	0.98
Availability	%	98%
Internal Losses	%	2%

Table 35 Alkaline Techno-Economic Assumptions.

Alkaline Electrolysis	Metric	2030
Electrolyser CAPEX	€/ MW	660,000
BOP	€/ MW	130,000
Stack Replacement	€/ MW	200,789
Development	€	1,000,000
Gas Grid Injection Station	€	900,000
Gas Grid Injection Station OPEX %	%	5%
Efficiency/Power Consumption	kWh/kg	50
Annual OPEX %	%	3%
Water Cost	€/l	0.004
Output Pressure	Bar	30
Stack Lifetime	Hours	100,000
Availability	%	98%
Degradation	%/1000 Hrs	0.1%
Water Consumption	l/kg	15

Table 36 Hydrogen Storage CAPEX Assumptions.

Storage	Metric	2030
350 Bar Storage	€/kg	470

Table 37 Hydrogen Compression CAPEX Assumptions.

Compression	Metric	30-350Bar
Compressor Power Consumption	kWh/kg H2	22
Filling Centre Costs 1kg/h	€	9,293
Filling Centre - 20 kg/h	€	514,500
Filling Centre - 100 kg/h	€	1,488,500
Filling Centre - 400 kg/h	€	3,717,000

Appendix F

Research experience during my masters:

Table 38 Research experience gained during master's project.

Task Title	Q2 2018	Q3 2018	Q4 2018	Q1 2019	Q2 2019	Q3 2019	Q4 2019	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Electricity System Curtailment Thesis - DCU											
ABO Wind Ireland - Graduate Engineer											
SEAI Funded Project - Managing Curtailment in 2030 & 2040											
Hydrogen Master's Thesis - DCU											
Element Energy - Researcher Hydrogen Mobility Ireland											
Mullan Grid - Project Engineer											

Presented at:

- Hydrogen mobility Ireland monthly steering group meetings.
- Irish wind energy association (IWEA) dispatch down working group.
- Environ 2020 conference.