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Green hydrogen for heating and its impact on the power system

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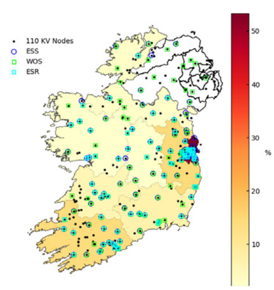
HIGHLIGHTS

- Impact on the power system of hydrogen for heating and a 70% renewable target.
- Resulting net emission increase from water electrolysis for hydrogen generation.
- The Marginal Abatement Cost of electrolysers is 114.3 euro/tCO2.
- Electricity prices increase 1–2% with scale deployment electrolysers.
- Power system wide wind capacity factors increase by 0.01 with electrolyser deployment.

GRAPHICAL ABSTRACT



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ABSTRACT

With a relatively high energy density, hydrogen is attracting increasing attention in research, commercial and political spheres, specifically as a fuel for residential heating, which is proving to be a difficult sector to decarbonise in some circumstances. Hydrogen production is dependent on the power system so any scale use of hydrogen for residential heating will impact various aspects of the power system, including electricity prices and renewable generation curtailment (i.e. wind, solar). Using a linearised optimal power flow model and the power infrastructure on the island of Ireland this paper examines least cost optimal investment in electrolysers in the presence of Ireland's 70% renewable electricity target by 2030. The introduction of electrolysers in the power system leads to an increase in emissions from power generation, which is inconsistent with some definitions of green hydrogen. Electricity prices are marginally higher with electrolysers whereas the optimal location of electrolysers is driven by a combination of residential heating demand and potential surplus power supplies at electricity nodes.

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Nomenclature

Acronyms and symbols

AC	Alternating Current
BAU	Business as Usual
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
ENGINE	Electricity Network and Generation INvEstment
ESR	Electrolyser and H_2 storage system
GTEP	Generation and Transmission Expansion Planning
GW	Gigawatt
GWh	Gigawatt-hour
H_2	Hydrogen
HVDC	High Voltage Direct Current
ISEM	Integrated Single Energy Market
kV	kilovolt
kW	kilowatt
MACC	Marginal Abatement Cost Curve
$MtCO_2$	Million tons of CO_2
MW	Megawatt
MWh	Megawatt-hour
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
OPF	Optimal Power Flow
RES	Renewable Energy Source
RET	Renewable Energy Target
tCO_2	tons of CO_2
TW	Terawatt
TWh	Terawatt-hour

Constants

Δ_h	Time span of h
η	Electrolyser efficiency
Γ	Energy per m^3 of H_2
γ	Dissipation coefficient
$\gamma_g^{\{n,e\}}$	Emissions rate
IC_g	Investment cost of technology g
LT_g	Lifetime of technology g
μ	Ratio of active to reactive power demand
ρ_s	Probability of scenario s
$SOC^{min/max}$	Min/Max capacity of H_2 storage
SOC^o	Initial H_2 in storage
Υ_i	Number of households at node i connected to mains gas
ξ_i	Fraction of homes in node i with a gas boiler
C_{ESR}	Opex of electrolyser
$d_{h,i}$	Total household heat demand at time period h and node i
M	Large number
N_i	Number of households at node i
$\lambda_{s,g,t}^{\{n,e\}}$	Cost of power production
$\lambda_{s,t}^{CO_2}$	Emissions cost
r	Interest rate
VoLH	Value of Lost Heating
VoLL	Value of Lost Load

Indices and Sets

Ω_{ho}	Set of homes connected to the Gas network
e	Existing transmission lines/power capacity
g/Ω_g	Index/Set of generation technologies
h	Time period
i/Ω_i	Index/Set of grid nodes
k/Ω_l	Index/Set of transmission lines
n	new power capacity
s/Ω_s	Index/Set of scenarios
t/Ω_t	Index/Set of time stages
tr/Ω_{tr}	Index/Set of transformers

Variables

OMC_h^{gen}	Maintenance and operation cost of power generation
OMC_h^{net}	Maintenance and operation cost of transmission network
$SOC_{h,i}$	State of Charge of the Electrolyser
$P_{s,g,i,h}^{n,\ e}$	Active power generated
$P_{s,i,h}^{PNS}$	Active power not served
$P_{h,i}$	Active power consumed by the electrolyser
$Q_{s,i,h}^{PNS}$	Reactive power not served
$Q_{h,i}$	Reactive power consumed by the power converter
$u_{h,i}^{ch}$	Hydrogen charge
$u_{h,i}^{dch}$	Hydrogen discharge
$u_{*,h}$	Usage of power line/transformer
$u_{g,i,h}$	Usage of power capacity
$x_{g,i,t}$	Investment decision in technology type g
x_i^{esr}	ESR Investment decision at node i
$\phi_{h,i}$	Heating not served with H_2
ENSC	Energy not served cost
HNS	Total heating not served
OME	Operation and Maintenance of the Electrolyser
TC	Total cost
TEC	Total electricity generation cost
TEmiC	Total emissions cost
TInvC	Total investment cost
TMC	Total maintenance and operation cost

Introduction

A net-zero carbon emissions transition and massive electrification into the next decade will require the power system to produce substantially more electricity. The International Energy Agency estimates that global energy demand could grow 9% by 2030 [1]. The growth of electricity demand will be driven by policies to tackle climate change and electrifying economies, including the electrification of the transport and heating sectors. The challenge is to achieve this with minimal carbon emissions. For the power system to reach these electrification goals, in addition to increased generation from renewable sources, it requires additional flexibility [2]. Hydrogen can facilitate both the decarbonisation of electricity generation and increased electrification [3]. The former by providing essential services like power generation smoothing and balancing. The latter by acting as an energy carrier for heating needs. Hydrogen gas as an energy carrier can be mixed with methane (natural gas) in a process called blending without significant modifications to existing natural gas fueled equipment and infrastructure. This paper examines the impact that hydrogen generation could have on a real power system and CO_2 emissions.

Transitioning power systems largely reliant on fossil fuels and based on a design that is to a great extent similar to their design 100 years ago, to systems that include high shares of asynchronous power generation is not an easy challenge. To tackle increasing electricity demand and at the same time mitigate climate change impacts, hydrogen is considered as one potential enabler of the transition to a low carbon economy [4,5]. Evaluating the impact of introducing electrolysers on the power system is additionally complicated by policy targets that envisage the share of renewable electricity generation almost doubling by 2030. Hydrogen is abundant and can be extracted from several compounds in different ways, e.g. as “green” hydrogen. Green hydrogen (i.e. primarily not relying on fossil fuels as a source or for its extraction) is the alternative with the lowest carbon footprint [4] but there is no harmonised definition of green hydrogen though there are several green hydrogen standards in development [6]. The electrolyser technology is increasingly becoming financially viable [7,8] but evaluations are often based on test power systems [9] or on electrolysers with dedicated off-grid solar or wind power plants [10]. An assessment of the interaction of electrolysis with the power grid in a real life setting ultimately determines whether green hydrogen is practically feasible. The physical laws of power flow impose complex constraints within a power system, particularly related to the scarcity of generation and transmission network capacity. The model employed in this research linearises the power flow equations for tractability but retains the reactive component of power, which is essential to study the interface between electrolysers and the power system. A notable contribution of this modelling approach is that transmission losses and congestion are quantified plus optimal node selection for electrolyser units can be considered endogenously.

The predominant use of energy by households is for residential heating, with space and water heating representing 78% of final energy usage [11]. One emerging technology that helps reduce the dependency on natural gas for heating is blending hydrogen with natural gas. Replacing up to 10%[1] of natural gas with hydrogen is feasible with the current gas network infrastructure [13]. Hydrogen is abundant but because of its physical properties it is commonly found in molecular form, mostly in covalent compounds with non-metallic elements. Water and renewable generated electricity is the preferred renewable scheme of electrolysis for hydrogen extraction. Earlier research focused on the role of hydrogen for energy storage but potential revenues for this purpose are not sufficient from a financial profitability perspective [14] and alternative uses of hydrogen, including for heating and transport, are being investigated [15–17]. The evaluation of hydrogen as a fuel within a transition to a low carbon future is not trivial because the viability and sustainability of its extraction via electrolysis is intricately linked to the characteristics of the connected power system. This research presents the optimal placement of electrolysers in a real-world power grid. And assesses the implications for the power system, including carbon emissions, of blending hydrogen with natural gas for residential heating both separately and contemporaneously with a policy target of achieving 70% renewable electricity generation by 2030.

The research contributes to the literature in three ways. First, it demonstrates within the context of a real power system the additional infrastructure requirements, both generation capacity and transmission, that are required to facilitate hydrogen electrolysis at scale. Second, the analysis incorporates endogenous location and investment in electrolysers (and new generation plant), which means that the least cost optimal modelling solutions represent best-case scenarios of power-to-hydrogen within a power system in contrast to more stylised scenarios [9,15]. Third, the analysis provides estimates of the impact on net emissions, electricity prices and renewable power curtailment, all of which have relevance for decisions surrounding power-to-hydrogen on other power systems. This work also differs from the existing literature in a number of aspects. First electrolysers are modelled not solely as a flexible load to smooth variable power but as a potential low carbon source of energy to serve heat demand. Secondly, we use an implementation of an optimal power flow (OPF) model that includes reactive power constraints, which is not typically a feature of OPF models. Our model allows for the reactive demand of the power converter in the electrolyser unit. Finally, the breadth of scope of the case study is a country-wide real power system; hence the paper presents the impact of a renewable policy concurrently with integrating hydrogen for heating. The results presented can serve to inform technical and policy decisions examining similar projects on other power systems.

The reminder of this paper is structured as follows. Section Literature review presents recent literature and how this work moves forward the state-of-the-art. Sections Methodology and Case Study present the modelling approach and case study, respectively. The results from the case study scenarios are described in section Results, while the key insights from the scenarios are discussed in section Discussion. Section Conclusions concludes.

Literature review

While the literature on the interplay of hydrogen and power systems is vast and growing, in this section we focus on several recent papers that are closely related to our work. Countries are actively exploring hydrogen as an alternative to fossil fuels, with several recent studies highlighting the possibilities, drivers and challenges for the power supply chain that

[1] Higher percentages could be feasible [12].

countries need to address (e.g. Refs. [18–26]). Ren et al. [18] summarise China's path towards a hydrogen economy. Despite substantial progress, several challenges remain towards achieving a hydrogen economy within China, including making technological improvements on the whole hydrogen supply chain that address the high costs of hydrogen infrastructure provision. Ren et al. emphasise hydrogen technologies as facilitators of large-scale development of renewable energy and decarbonisation within the economy and specifically conclude that hydrogen will not be an exclusive energy carrier but will complement and compete with electricity and biofuels in the future energy system. Maggio et al. [19] undertake a broader literature review of the drivers and obstacles for a hydrogen economy. Policy and regulatory frameworks focusing on reducing greenhouse gas emissions, as well as the need for additional energy storage and electricity grid balancing, are among the positive factors affecting development of a hydrogen economy. The high cost of hydrogen and fuel cell technologies are among the obstacles facing hydrogen development but the interface with the power system, and specifically electricity prices, are identified as key parameters influencing the commercial sustainability of hydrogen electrolysers.

There is still limited understanding of the interaction between scale deployment of hydrogen electrolysers within country-scale power system models though several recent papers are beginning to fill this gap. One set of papers entails a broad macro perspective on integration of hydrogen within power systems, often country-scale assessments, whereas another set of papers incorporate more technical constraints within their analysis. An assessment by Brey [20] of Spanish plans to decommission 16 GW of fossil-fuel based generation and integrate 65 GW of renewable capacity by 2030 is an example of the former. Brey examines the role of hydrogen electrolysers in enabling such a high level of renewable integration finding that hydrogen plays a dual role, primarily as long-term storage to flatten seasonality patterns, and secondly as fuel for gas turbines. Using a cumulative residual energy analysis, the paper provides a broad overview of the potential role for hydrogen but does not consider issues related to the power grid or network physical constraints. Similarly, Kakoulaki et al. [21] study Europe's potential to supply its hydrogen needs with green hydrogen. They estimate that 290 TWh per year of electricity required to produce Europe's hydrogen needs in contrast to combined technical renewable generation potential of 10,000 TWh per year. Thus, at a macro level there is ample renewable resource available to produce green hydrogen to satisfy demand, though Kakoulaki et al. acknowledge the need for more detailed technical analysis to fully understand the implications of producing green hydrogen.

The deployment of electrolysers is subject to the technical constraints of the power system. There are several issues that can impact on the performance of both electroloysers and the power system. For instance, the optimal sizing of renewable infrastructure complementary to hydrogen technology is not a trivial question. Sorgulu and Dincer [27] address this problem in a residential context. The work considers the single-valued monthly energy needs of a housing estate comprising 100 households and calculates the optimal number of wind turbines needed to produce hydrogen over the course of a year. Other studies such as de Santoli et al. [12], Khouya [28] and El-Taweel et al. [29] undertake similarly small case studies, and while they provide valuable insights to scope further project development in terms of hydrogen production and demand, the spatial dimension and scale of a power system adds additional layers of complexity that need to be considered.

A potential benefit of hydrogen electrolysers for the power system is its flexibile load [3] but depending on the end-use of the hydrogen there are additional power system benefits. Nastasi et al. [30] consider hydrogen both as flexible load within the power system and as a low carbon source of energy to serve heat demand. While the complexities of the power grid are not modelled explicitly, which has the advantage of simplifying the analytical problem, the research demonstrates that the combined effect on the power system of the electrical heating devices and electrolysers is more efficient than their operation in isolation. Other studies of small scale hydrogen production include Khouya [28] and de Santoli et al. [12]. The former examines the Levelised Cost of Energy (LCOE) of three dedicated wind and solar farms for hydrogen production in Morocco whereas the latter considers a small scale hydrogen to natural gas plant in Italy. While studies of this scale provide important insight, the research results are conditional on factors such as grid topology and consumption patterns. In the context of scale deployment of hydrogen production, modelling the interaction with the wider power system is also important. Hence, to fully understand the impact and benefit of hydrogen electrolysers it is important to consider the interface with the power system.

Green hydrogen is also advocated as a means to reduce emissions in different sectors of the economy (e.g. residential heating, or in manufacturing processes). Many studies have estimated potential emissions savings, including Pérez-Denicia et al. [31], Lubis et al. [32] and Partidário et al. [26] in México, Canada and Portugal, respectively. However, emissions savings associated with reduced heating or process fuel use is only one component of the net emissions impact. Also relevant are the power system's emissions associated with electroloyser operation, which are associated with the physical limitations of the power grid, e.g. congestion, and the composition of the generation fleet, especially the extent to which fossil based generation is called upon to meet additional load associated with electrolyser operation.

The interaction of an electrolyser with the power grid makes selecting the placement of the units a challenging task to address. One approach is to exogenously site electrolysers and subsequently examine the impact. For example, Gouareh et al. [33] use geographical information system (GIS) analysis of large sources of CO_2 emissions in Algeria to inform hydrogen production decisions. In a similar manner Nielsen and Skov [34] study the optimal location of power-to-gas plants in Denmark. Given the complexity of power systems, including network congestion, the deployment of electrolysers is not neutral with respect to its impact on the power system. Selecting electrolyser site placement endogenously may substantially impact modelling results. In a study by El-Taweel et al. [29] the financial viability of hydrogen for transport is based on electrolysers consuming cheap electricity and selling load balancing to the power system operator. An optimisation framework is used in the analysis but hydrogen stations are placed in ex-ante defined grid locations. With load balancing having a spatial dimension, the endogenous determination of investment in and location of electrolysers within the modelling approach could materially affect the results.

The modelling framework used to represent the power system is also relevant depending on the objective of the analysis. For instance, Rabiee et al. [9] show the potential of power-to-hydrogen as a flexible load using a non-linear OPF model. While a non-linear OPF model is generally preferable, the computationally feasibility of such models is limited to smaller grids. Rabiee et al.'s analysis is based on the IEEE 39 bus test system, whereas a similar modelling framework on a large or country scale system would be computationally impractical. In a similar vein Ge et al. [35] show that electrolysers can add flexibility to the power system and reduce wind power curtailment but the analysis is based on a 6 bus system across a period of 24 h. In a study examining reliability issues related to a power system comprising electrolysers, fuel cells and high penetration of renewables Zhang et al. [36] consider a substantially longer time horizon of a year and therefore accounts for demand seasonality. However, the least cost optimisation model is based on a single node power grid, which means that Kirchhoff's equations are not considered and thus the constraints imposed by the transmission network (e.g. congestion) are disregarded.

The consensus of the above literature is that hydrogen technologies can facilitate the decarbonisation of the power systems. Some of the papers present a macro view of the merits of hydrogen but do not consider the scarcity of the grid's assets. While others use small or test power systems with a highly detailed OPF model of the network rendering the approach computationally intractable on large scale systems. And some studies determine exogenously the location of electrolysers. This work builds on top and differs from the reviewed literature in 4 key aspects. First, the analysis uses a tractable but realistic OPF model, the linearisation of the Kirchhoff's equations preserves active and reactive power, whereby the effect of electrolysers upon transmission losses and congestion are inherently considered in the results. Second, the optimisation implements a techno-economic objective function to address the trade-offs among investment decisions, characteristics of the available technologies and renewable targets. Third, the model endogenously determines the optimal nodes for electrolysers. And lastly, because the study is on a county-wide real power system, this could provide better insights to stakeholders and policy-makers on the impact of electrolysers.

Methodology

The impact of hydrogen electrolysers can be evaluated within the framework of least cost generation and transmission expansion problems, GEP and TEP respectively. In essence, GEP and TEP determine the requirements for generation and transmission, respectively, stated as an alternating current power flow (AC-PF) problem subject to Kirchhoff's equations and system constraints. AC-PF is a complex non-linear system of equations. Several algorithms and methods are available to simplify and solve a GEP problem independently of [37,38] and concurrently with [39] the network. The OPF model is a common approach to the AC-PF problem whereby the model is recast as an optimisation problem.

For small power systems modelled with a full non-linear AC-PF approach a solution to the OPF problem is readily obtained with available solvers. However, in large scale real world applications tractability issues arise [40]. The modelling framework employed here is the ENGINE model, which follows the OPF approach [41–43]. ENGINE is a multi-stage stochastic joint optimisation of both the generation and transmission expansion planning (GTEP) problems. The ENGINE model incorporates a linearisation of the full AC optimal power flow: Kirchhoff's Current and Voltage laws. These represent the balance of supply and demand and the physical network constraints. The linearisation is important because a full non-linear AC model becomes intractable for a country-wide large-scale analysis. The assumptions made comprise the trigonometric terms. The methodology relies on the small angle assumption. However to obtain a more realistic estimate of the transmission losses, ENGINE retains the second order term in the Taylor series expansion of the reactive power. The inclusion of reactive power is important, as reactive power is a main contributor to losses in the power transmission network and hence its exclusion from network capacity expansion planning can underestimate the investment required. This means a more realistic representation of power flows and voltage magnitude differences across nodes are incorporated compared to the DC-OPF linearisation method, which preserves the active power component but discards the reactive part of the AC waveform.

In this paper an electrolyser and hydrogen storage system (ESR) formulation is added to the ENGINE model. ENGINE's optimisation problem is broken into two stages. The first stage optimises two investment decision variables. One variable is the location on the power grid where new electrolysers are constructed. The locations selected are the nodes that better utilise the rated hydrogen production of the units. In practice this assumes that hydrogen is injected into the distribution rather than transmission gas network. The other variable represents the generation and transmission expansion requirements. The results from the first stage are passed onto the second stage. In the second stage, the linearised AC optimal power flow model is solved as an economic-dispatch minimisation problem.

The impact of the electrolysers in conjunction with a renewable target is assessed from two angles: from the perspective of the power system, and from an environmental perspective. From the power system's perspective the metrics include transmission line reinforcement, power curtailment, load shedding, marginal electricity price and new generation/storage capacity. The environmental assessment quantifies the potential impact on CO_2 emissions both from burning natural gas for heating and fossil fuels used in electricity generation.

The investment-decision within the economic-dispatch problem is formulated as a minimisation problem. The objective function (1) represents system total cost, TC, which is the sum of the NPV of investment, variable costs, reliability, emissions, and operation and maintenance costs subject to physical constraints.

$$\min \ TC = TInvC + TMC + TEC + ENSC + TEmiC \quad (1)$$

The term TInvC is the NPV of the total investment costs in new power generation, storage and transmission network, as defined by Eq. (2).

$$\begin{aligned} TInvC &= \sum_{t\in\Omega^t} \frac{InvC_t^{gen}}{(1+r)^t}; \\ InvC_t^{gen} &= \sum_{g\in\Omega^g}\sum_{i\in\Omega^i} \frac{r(1+r)^{LT_g}}{(1+r)^{LT_g-1}} IC_g(x_{g,i,t}-x_{g,i,t-1}); \end{aligned} \quad (2)$$

where the parameters LT_g, r and IC_g are the lifetime, interest rate and investment cost for generation type g, respectively. For each available technology type g, the investment decision variable is represented by $x_{g,i,t}$.

The second term in objective function, TMC, represents the fixed operation and maintenance cost of generation and transmission as defined by Eq. (3). Eq. (4) presents the costs of existing and new capacity, OMC_g^e and OMC_g^n respectively.

$$TMC = \sum_{t\in\Omega^t} \frac{OMC_t^{gen} + OMC_t^{net}}{(1+r)^t}; \quad (3)$$

$$OMC_t^{gen} = \sum_{g\in\Omega^g}\sum_{i\in\Omega^i} OMC_g^n x_{g,i,t} + OMC_g^e u_{g,i,t}; \quad (4)$$

$$OMC_t^{net} = \sum_{k\in\Omega^l} OMC_k^e u_{k,t} + \sum_{tr\in\Omega^tr} OMC_{tr}^e u_{tr,t}. \quad (5)$$

In the model setup, the power lines are aggregated at 110 kV or higher. For reinforcement of the transmission infrastructure the capacity of existing assets can be increased but addition of new assets is not feasible. Hence, (5) only considers existing power lines and transformers, OMC_k^e and OMC_{tr}^e, respectively. The utilisation of lines and transformers is denoted by $u_{k,t}$ and $u_{tr,t}$, respectively.

Eq. (6) represents variable costs, i.e., the operational costs of generating electricity with both existing and new capacity. $P_{s,g,i,t}^{n,e}$ is the active power generated at node i by new or existing capacity of type g in scenario s and time t.

$$\begin{aligned} TEC &= \sum_{t\in\Omega^t} \frac{EC_t^{gen}}{(1+r)^t}; \\ EC_t^{gen} &= \sum_{s\in\Omega^s} \rho_s \sum_{g\in\Omega^g}\sum_{i\in\Omega^i} (\lambda_{s,g,t}^n P_{s,g,i,t}^n + \lambda_{s,g,t}^e P_{s,g,i,t}^e). \end{aligned} \quad (6)$$

In practice, the lack of a demand curve means artificially setting a scarcity price. The price is known as the Value-of-Lost-Load (VoLL). Although taken as an exogenous parameter within the model, regulatory authorities update this figure on a yearly basis. The fourth term in the objective function assigns a price to the demand not served (7). The cost applies to both, active and reactive forced power shedding, P^{PNS} and Q^{PNS}, respectively. In the present analysis the value is € 11,000/MWh consistent with the VoLL used in the Integrated Single Electricity Market (ISEM) on the island of Ireland [44].

$$ENSC = VoLL \sum_{t\in\Omega^t}\sum_{s\in\Omega^s} \rho_s \sum_{i\in\Omega^i} \frac{P_{s,i,t}^{PNS} + Q_{s,i,t}^{PNS}}{(1+r)^t}. \quad (7)$$

The power generation CO_2 emissions cost is denoted by TEmiC and given by Eq. (8), which includes emissions from existing and new power plants at rates given by γ_g^e and γ_g^n, respectively for generation technology type g.

$$TEmiC = \sum_{t\in\Omega^t}\sum_{s\in\Omega^s} \rho_s \lambda_{s,t}^{CO_2} \sum_{g\in\Omega^g}\sum_{i\in\Omega^i} \frac{\gamma_g^n P_{s,g,i,t}^n + \gamma_g^e P_{s,g,i,t}^e}{(1+r)^t}. \quad (8)$$

Except for the aspects of the ENGINE model central to this paper, due to space limits it is not feasible to represent the full ENGINE model here. A full description and an in-depth discussion of the linearisation, the power angle and transformer assumptions and other constraints within the ENGINE model are provided in Fitiwi et al. [42]. In the next section, 3.1, the Electrolyser model is presented, which is a new feature of the ENGINE model.

Electrolyser model

In this paper electrolysers are intended to serve residential heat demand, through the blending of hydrogen with natural gas. The ESR model is adapted from El-Taweel et al. [29] and integrated into ENGINE but allows for the fact that access to gas network is not available at all electricity grid nodes. Furthermore, it assumes that hydrogen blending occurs at injection points to the gas distribution network. With only one-third of Irish homes connected to the gas network the optimal placement of electrolysers to serve residential heat demand is prioritised towards nodes where a higher proportion of homes use natural gas for heating, as represented by Eq. (9), which gives the ratio of households at node i connected to mains gas.

$$\xi_i = \frac{\Upsilon_i}{\sum_{i\in\Omega_{ho}} N_i}. \quad (9)$$

The objective function (1) minimises the ESR investment (10) subject to meeting 90% of the total heat demand $\sum_{h,i\in\Omega_{ho}} d_{h,i}\xi_i$ and the ESR physical capacity constraints. Eq. (11) represents the hydrogen flow constraint, and Eq. (12) is hydrogen generation. $P_{h,i}$ is the power consumed by the ESR. x_i^{esr} is the investment decision variable in the ESR unit at node i. The minimisation of the investment cost results in the best utilisation of the ERS units, which also simplifies the model. Alkaline and proton-exchange-membrane electrolysers operating at close to full utilisation have an almost constant efficiency conversion [9], which is reflected by the ESR efficiency parameter, η, as a constant in Eq. (12).

$$u_{h,i}^{ch} - u_{max}^{ch} x_i^{esr} \le 0 \quad (10)$$

$$u_{min}^{ch} \le u_{h,i}^{ch} \le u_{max}^{ch}. \quad (11)$$

$$u_{h,i}^{ch} = \Gamma \eta P_{h,i}. \quad (12)$$

The Big-M method is used in (13) to link the power consumed by the ESR to the investment variable, $0 \le x_i^{esr} \le 1$. In this manner it is possible to maintain tractability and make the problem feasible such that the minimisation problem is formulated as a linear program instead of a mixed-integer linear programming (MILP) problem. Although the ESR consumes DC power, the thyristor bridge in the AC/DC converter consumes reactive power. The reactive power demand (14) is a fraction of the real power needed in the electrolysis process [45].

$$P_{h,i} - Mx_i^{esr} \le 0 \tag{13}$$

$$Q_{h,i} = \mu P_{h,i}. \tag{14}$$

The demand for heat is expressed in terms of the heat not served by the ERSs (15) and the volume of hydrogen, $u_{h,i}^{dch}$, discharged from the storage tank at node i. The unserved heat is constrained by the total heat demand in node $i \in \Omega_{ho}$ (16).

$$\phi_{h,i} = \Gamma d_{h,i}\xi_i - u_{h,i}^{dch} \tag{15}$$

$$0 \le \phi_{h,i} \le \Gamma d_{h,i}\xi_i. \tag{16}$$

The hydrogen tank state of charge, $SOC_{h,i}$, is modelled as a storage unit [29]. The availability is determined by the charge and discharge, the initial supply of H_2, SOC^o, linked to the decision variable x_i^{esr} and minimum and maximum capacity (18) and (19). A property of the hydrogen atom is its weight, being the lightest element. Hence, tank leakages are considered through the dissipation coefficient γ.

$$\begin{aligned} SOC_{h,i} = {} & SOC^o x_i^{esr} + SOC_{h-1,i} + u_{h,i}^{ch} \\ & - u_{h,i}^{dch} - \gamma SOC_{h,i} \end{aligned} \tag{17}$$

$$SOC_{h,i} - SOC^{min} x_i^{esr} \ge 0 \tag{18}$$

$$SOC^{min} \le SOC_{h,i} \le SOC^{max}. \tag{19}$$

Finally, investment in electrolyser units is included in the cost of new capacity, TInvC in Eq. (2), while the operation and maintenance cost of the ESR units, OME in Eq. (20), is included in overall system operation and maintenance costs, TMC in Eq. (3). The solution method comprises two stages, the first stage solves for the decision variables, i.e., grid and generation (including battery storage) expansion and the location of the ESR units assuming a fixed percentage of heat to be served by the ESR units. In the second stage, specifically for the ESR model, analogous to VoLL, the concept of Value-of-Lost-Heating (VoLH) is used. Hence, instead of setting a percentage of heat demand to be served, total heat demand not served (21) is penalised.

$$OME = C_{ESR} \sum_{h,i \in \Omega_{ho}} u_{h,i}^{ch} \tag{20}$$

$$HNS = VoLH \sum_{h,i \in \Omega_{ho}} \Delta_h \phi_{h,i}. \tag{21}$$

Case study

The case study application is based on the Irish power system. It is an isolated network consisting of 676 nodes and 900 transmission lines (including transformers) [46]. Ireland's location in the northern Atlantic provides the country with immense wind resources for renewable electricity generation though it has relatively limited interconnection with adjacent power systems. In 2019, the energy demand totalled 30.5 TWh; 35.7% was supplied from renewable sources [47]. With Ireland's policy target of 70% electricity from renewable sources by 2030 [48], there is an obvious policy focus on renewable generation from wind and solar resources. However, the role that hydrogen can play in contributing to that target is not widely appreciated but crosses a number of dimensions on the decarbonisation transition. As a flexible electricity load, hydrogen can enable greater integration of renewable generation and thereby potentially decarbonise electricity generation [3] plus also facilitate the decarbonisation of residential heating. With the absence of heavy industry, the residential sector is the single largest consumer of heat in Ireland [49] making its decarbonisation a priority policy goal [48].

The case study is build around two policy goals, the first being a Renewable Energy Target (RET), while the second entails the use of electrolysers and hydrogen storage to supply residential heating demand. For the purpose of this case study the RET applies to both jurisdictions in the island of Ireland, i. e, the Republic of Ireland (ROI) and Northern Ireland (NI) within the Integrated Single Energy Market. However, the location of the ESR units is subject to nodes in the Republic of Ireland with an existing gas connection, i.e., 205 possible nodes. Within the context of those two policies four scenarios are explored: the impact of introducing either policy only (RET-only and ESR-only), the combined effect (RET + ESR) and a business as usual reference case (BAU, i.e., considering no policy).

In the four scenarios, a conservative demand growth profile following the Transmission System Operator's Slow Change scenario is used [50]. The carbon price is set to € 30/tCO_2 and the System Non-Synchronous Power (SNSP), i.e., the ratio of renewable power and HVDC trades to demand, is 75% [51]. The capital cost of an ERS unit is assumed to be € 2000/kW, which is in accordance to upper bound estimates in recent literature reviews [52,53]. For instance, Proost [52] reports CAPEX estimates between € 1000–1950/kW in 2020 and € 850–1650/kW in 2030. Operating costs are based on El-Taweel et al. [29], where $C_{ESR} = 3\%CAPEX/(8760\ u_{max}^{ch})$. The ESR efficiency, η, is 60% [28,29]. The portfolio of new renewable capacity includes on-shore and off-shore wind, photovoltaic, and biomass. The set of new conventional generation options include coal, CCGT and OCGT gas plants both with and without carbon capture and storage (CCS) capabilities. Investment cost vary across technologies. The capital cost, potential cost reductions and technology parameter assumptions [29,52,54–57] are presented in Table 1.

Table 1 – Parameter assumptions of generator and storage technologies [29,52,54–57].

Technology	Operation cost[a] (€/MWh)	Emission rate (tCO2/MWh)	Investment cost (M€/MW)	Cumulative cost reductions (%) 2020	2025	2030
Offshore wind	22.80	0.02	3.65	0.05	0.10	0.20
Onshore wind	13.00	0.02	1.40	0.05	0.10	0.20
Solar PV	11.40	0.05	1.50	0.05	0.10	0.20
Biomass	54.00	0.23	2.25	0.02	0.05	0.10
Coal	34.00	0.93	0.90	0.05	0.08	0.10
Coal with CCS	38.00	0.19	4.40	0.05	0.08	0.10
CCGT	40.00	0.37	0.90	0.05	0.08	0.10
CCGT with CCS	55.00	0.04	2.40	0.05	0.08	0.10
Hydro	10.50	0.01	–	–	–	–
Gas oil fired	80.00	1.04	–	–	–	–
Heavy fuel oil fired	100.00	0.77	–	–	–	–
Storage	5.00	0.00	1.00	0.00	0.05	0.10
ESR	5.73	–	2.00	–	–	–

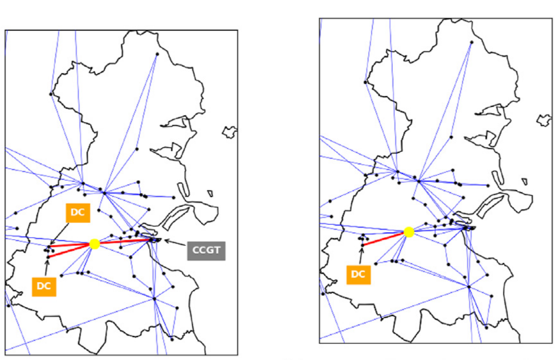
[a] Includes fuel costs but excludes emission costs.

Results

The results are presented for Northern Ireland and for the Republic of Ireland's 8 regions [58]: Border, Dublin, Mideast, Midlands, Midwest, Southeast, Southwest and West. The results are presented for key variables that are of relevance for renewable generation expansion, including transmission infrastructure, new capacity, renewable power and load curtailment, locational marginal prices and CO_2 emissions.

Transmission reinforcement

The GTEP model implemented in ENGINE determines the optimal reinforcement investment in existing transmission assets. Fig. 1 shows the reinforced assets for the four cases analysed. All the lines and transformers reinforced are in the Dublin region. These are basically strengthening the grid between a power plant or substation and two specific data center locations. The introduction of the ESR units has no impact hence the solutions are equivalent in the BAU and ESR-only cases, as illustrated in panel (a) of Fig. 1. In the BAU case, the power transmission requires 115 km of reinforcement. In contrast, under the RET-only scenario only 87 km of transmission line requires reinforcement, a reduction of 76% and which is illustrated in panel (b) of Fig. 1. As the introduction of ESR units has no impact on transmission, the RET-only and RET + ESR scenarios have equivalent outcomes.



(a) BAU and ESR-only solutions. (b) RET+ESR and RET-only solution.

Fig. 1 – Transmission expansion is only required in the Dublin region from power generation nodes to substation nodes to data centers (orange boxes). Black dots represent grid nodes. Blue lines are the existing power lines. Red lines represent the reinforced power lines. And the yellow node is the only reinforced transformer. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

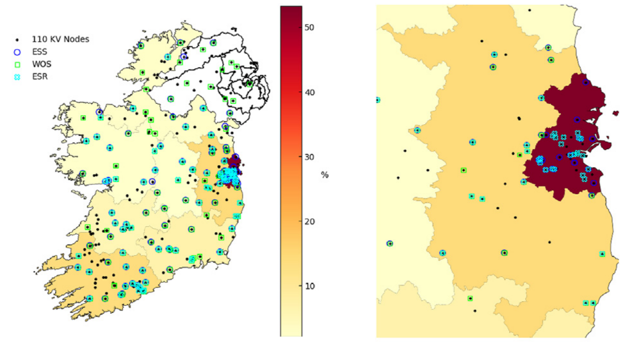
Capacity expansion

New capacity installed in each of the four scenarios analysed is shown numerically in Table 2. The scenarios that include the renewable target (RET + ESR and RET-only) have the biggest capacity expansion relative to BAU, comprising roughly 7 GW of onshore wind and 2 GW of storage. In the ESR-only case, the new capacity needed to meet 10% of the residential heat demand with hydrogen is 16.5 MW of renewable power and storage, and 155 MW of CCGT. Electricity demand from the electrolysis process is included in the renewable target as part of the overall demand. In the RET + ESR scenario the demand share supplied from renewables is larger than in the RET-only scenario and hence the larger additional installed capacity (330 MW or 3.6%) under the RET-only scenario.

Fig. 2 shows the aggregated heat demand per region as a fraction of total heating consumption, the distribution of new

Table 2 – Aggregated new power capacity and storage [MW] by technology.

	RET + ESR	RET-only	ESR-only	BAU
Onshore Wind	7098.0	6850.8	6.22	–
Offshore Wind	0.03	–	0.02	–
Solar PV	0.05	–	0.04	–
CCGT	–	–	155.2	44.26
COAL with CCS	–	–	–	–
CCGT with CCS	–	–	–	–
ESS	2313.6	2230.8	10.3	10.0



(a) (b)

Fig. 2 – Heat demand by region with respect to total heat demand and transmission nodes aggregated at 110 KV. Fig. 2a shows the resulting locations of new energy storage (ESS), onshore wind (WOS) and electrolysers (ESR) for the RET + ESR case, while Fig. 2b focuses on the Dublin and MidEast Regions.

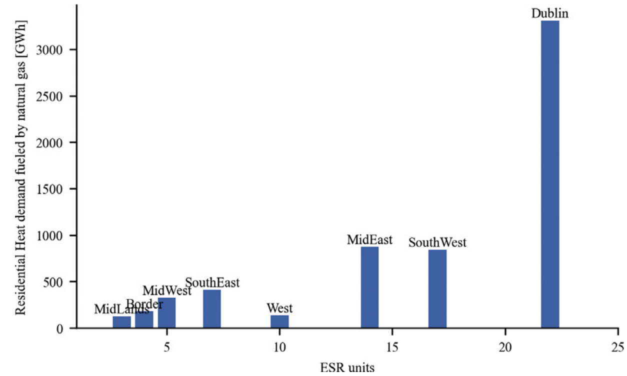


Fig. 4 – Number of electrolysers against yearly heat demand in the ROI.

onshore wind/solar plants, ESR units and battery storage for the RET + ESR scenario. The location of new onshore wind plants is distributed in all regions except the Dublin region where it is precluded due to space limitations. The Dublin region has the highest aggregated (gas-fired) heat demand reflecting a relatively strong penetration of residential gas-fired heating across the region. Other cities, such as Cork, with relatively high penetration of gas-fired residential heating in the urban area are situated within larger rural regions and therefore a relatively low aggregated heat demand from gas-fired heating. Even though new on-shore wind is precluded in the Dublin region with only electrical storage build there, as illustrated in Fig. 3, the greatest share of electrolysers are constructed in the Dublin region, as shown in Fig. 4.

Electrolysers

The number and location of the ESR units is the same in both scenarios involving electrolysers, i.e., the RET + ESR and ESR-only. The substitution of 10% of the natural gas demand for heating with hydrogen requires 82 ESR units. The ESR aggregated CAPEX is € 246 million. Fig. 4 shows the relationship between number of ESR units per region and heat demand with almost one-quarter of ESR units in Dublin. Is interesting to note that the regional distribution of the 82 units is not monotonically increasing with total heat demand; section Discussion discusses this further.

Reactive power

Transmission lines have a smaller resistance compared to reactance. In the power flow equations, this results in a stronger coupling between reactive power and voltage magnitude [59, p66]. Thus, the principal control variable to maintain voltage quality across the network is the reactive power flow. Voltage magnitude is constantly monitored to prevent the grid or sub-networks from failing. Voltage instability creates oscillations that can propagate widely leading to tripped generators and transmission lines that could result in voltage collapse and local or, in severe circumstances, system wide blackouts [60]. From a system planning perspective it is important to consider the implications in reactive power from introducing electrolysers in the power grid. In the Republic of Ireland, the Transmissions System Operator sets the voltage quality reference limits, with the lower and upper voltage thresholds set at 0.95 and 1.09 per unit (p.u.), respectively [61]. The EU's voltage quality standard requires the magnitude to be within the limits at least 99% of the time in any one week period [62]; this is approximately 87 h per year. Table 3

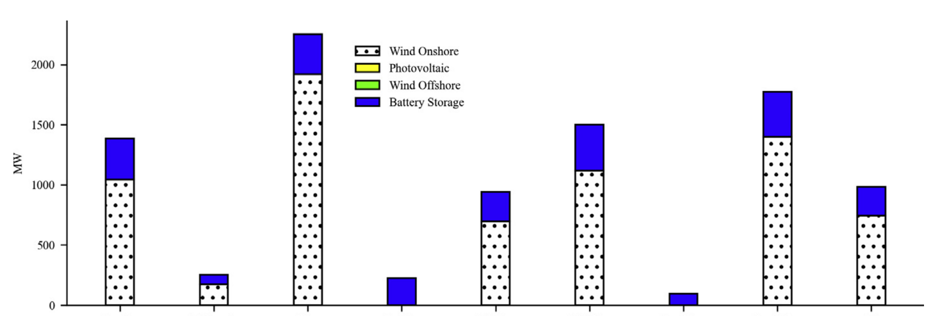


Fig. 3 – New capacity per region in the RET + ESR scenario. Onshore wind and energy storage are the most significant new capacity installed.

Table 3 – Electrolysers impact on reactive power losses and voltage magnitudes.

Policy	Q_L	$\|V\| < 0.95 \| 1.09 < \|V\|$		
	[TWh]	$\widehat{H}$ [hrs/node]	$\widehat{t}$ [hrs]	$\widehat{\lambda}_{\|V\|}$ [%]
BAU	8.42	766	15.9	–
ESR-only	8.81	967	18.8	13%

presents the yearly reactive power losses, Q_L, the total number of hours averaged over the nodes, $\hat{H}$, average duration, $\hat{}$, and the change of the average marginal costs, $\widehat{\lambda}_{|V|}$, with respect to BAU. The number of hours outside the tolerance is 18% more in the ESR-only case (18.8 h s) than in BAU (15.9 h s) but the average duration is still below the maximum permissible hours per year.

Hydrogen production

Hydrogen production is similar for both the ESR-only and ESR + RET cases. The results presented in this section are relevant to both. This study analyses the impact and potential of hydrogen for residential heating in the ROI. The highest rates of H_2 production are in the winter months. Fig. 5 shows the average production rate of hydrogen and the state of storage. It is noteworthy that the system's average storage level peaks during the summer months. The average storage level is 32% higher during the period May–September than the rest of the year. Moreover, the production rate uses the storage to increase production gradually as the autumn gives way to the winter period.

The least cost minimisation approach in ENGINE optimises power generation subject to reliability and network constraints. For the scenarios involving the ESR units, the model also optimises hydrogen production and consumption. Fig. 6 shows the capacity factor of hydrogen production for each ESR unit. The scatter plot on the left corresponds to the ratio of hydrogen produced to the maximum capacity over a one-year time period. The histogram on the right is the frequency of events on the scatter plot, with a bin width of 20%. The plots show that 65% of the ESR units have a hydrogen production utilisation of 70% or higher.

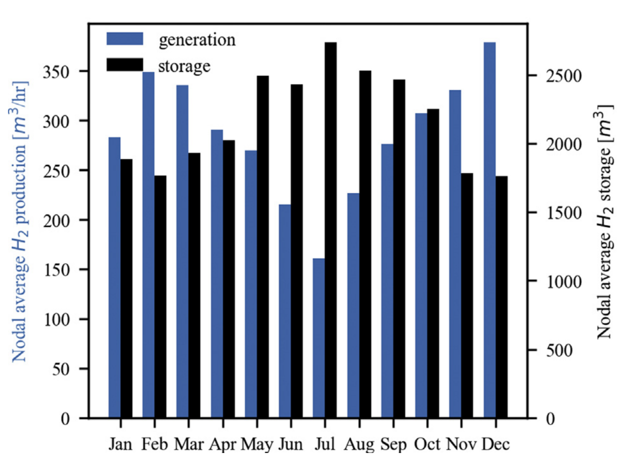


Fig. 5 – Monthly averages over nodes with ESR units. Black bars represent the hydrogen storage and blue bars the hydrogen production rate. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Curtailment

Power curtailment is one mechanism used in real-time by the system operator to maintain the grid within safe operational levels. Variable generation is curtailed to preserve the network's stability but during supply shortages load can be shed, typically at specific locations, to prevent cascading events affecting the whole network. Although the scope of this study is not the real-time balancing of supply and demand, rather long-term planning, the results provide some insight on the magnitude of flexibility needed in addition to the renewable target.

Wind curtailment

Table 4 shows yearly total wind curtailment, in TWh, under each scenario. Introducing electrolysers in the ESR-only scenario reduces wind curtailment relative to the BAU scenario by 13% to 0.625 TWh, which is consistent with the point that green hydrogen is considered an enabling technology for asynchronous renewables integration [3]. The policy target to roughly double renewable electricity generation to 70% reflected in scenario RET-only leads to a massive 726% increase in wind curtailment relative to BAU, totalling 5.957 TWh. The increase in curtailment reflects the variability of wind generation and also the ramping and minimum generation constraints of synchronous generators. If the increase in curtailment is reflected in higher rates of curtailment for specific wind farm projects it could represent a financial challenge for investors. In the RET + ESR scenario one might anticipate that curtailment declines versus the RET-only scenario but the opposite occurs. In the RET + ESR scenario there is a higher level of installed renewable capacity (7098.8 MW versus 6850.8 MW, see Table 2) and therefore greater possibilities for wind power surplus and curtailment. In the RET + ESR scenario wind curtailment is 740% higher than the BAU case. Wind capacity factors are also reported in Table 4. Capacity factors decline by approximately 5% points under implementation of the 70% renewables policy. The deployment of electrolysers has a positive but very small impact on capacity factors of <0.2% points in the ESR scenarios.

Load curtailment

The model penalises forced load outages in the objective function by minimizing the VOLL cost arising from load curtailment. In both the BAU and RET-only scenarios the yearly energy not served is 4.491 MWh. The largest load curtailment event across all the scenarios coincides with a demand peak at a substation in west Belfast over a 13-h duration. The level of load curtailment increases in the two scenarios that include electrolysers, increasing by 6% in the RET + ESR and 7% in the ESR-only scenario relative to the BAU. The additional ESR loads is directly responsible for the additional aggregate system load curtailment. Table 5 shows the expected energy not served per region for each scenario and the differences across regions and reflects the number of electrolysers installed in each region.

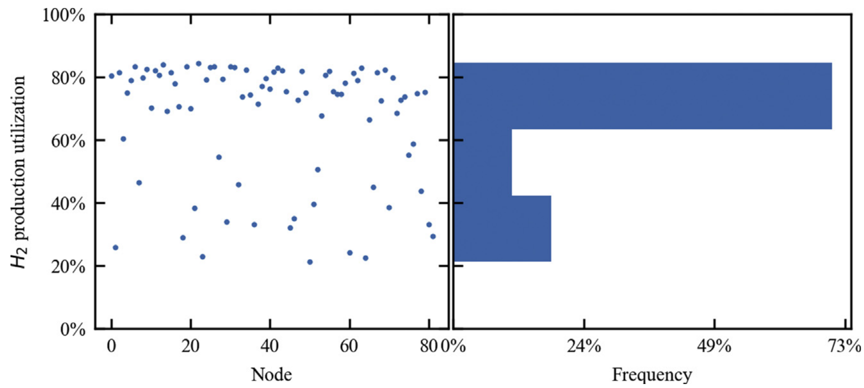


Fig. 6 – The scatter plot shows the yearly capacity factor of hydrogen generation at each node with an ESR unit. The histogram shows the frequency of events on the scatter plot.

Table 4 – Wind energy curtailment and Capacity factor.

Policy	Wind Curtailment [TWh]	Capacity Factor [%]
BAU	0.721	35
ESR-only	0.625	36
RET-only	5.957	30
RET + ESR	6.059	30

Dublin has the highest level of load curtailment but is also the region with the highest number of electrolysers and is subject to transmission congestion.

Zonal prices

In Ireland and in much of the EU, nodal prices in the power market are not operational but debate on their merits is underway [63]. The impact on zonal prices is presented here, as nodal settlement prices may be adopted in the future. Fig. 7 shows the effect of both policies on zonal prices with respect to the BAU case. Adding hydrogen for heating leads to an increase in price across all regions by between 1 and 2%, as shown in Fig. 7b. The greatest impact on zonal prices relates to the expansion in renewables generation with price falling in all regions by 77–79% relative to the BAU scenario (Fig. 7b). This large reduction in prices reflects the growing share of renewable generation and its priority dispatch. While nominally there is not much difference in prices across the two RET policies relative to the BAU (Fig. 7a v Fig. 7c), the change in standard deviation of prices is more substantial. Under the RET-only scenario the standard deviation of prices decreases by 59% relative to the BAU scenario, whereas the decline is only 45% in the RET + ESR scenario. Prior research simulating the impact of an expansion of renewable generation in the ISEM also projected mean price reductions and a reduction in price variability but at a more modest scale. In the case of expanding renewable wind capacity from 2 GW to 4 GW Curtis et al. [64] projected a 8.5% reduction in mean prices and approximately a 11% reduction in standard deviation. In the RET-only scenario here, the expansion in renewable capacity is close to 7 GW for a total renewables installed capacity of 11 GW, which shows that as the 70% RET scenario is gradually implemented its impact is likely to be non-linear.

Table 5 – Total load curtailment in MWh in each region.

	BAU	ESR-only	RET-only	RET + ESR
Border	–	0.026	–	0.024
Midlands	–	0.009	–	0.008
West	–	0.026	–	0.024
Dublin	–	0.080	–	0.072
Mideast	–	0.038	–	0.035
Midwest	–	0.023	–	0.020
Southeast	–	0.026	–	0.024
Southwest	–	0.046	–	0.042
Northern Ireland	4.491	4.539	4.491	4.534

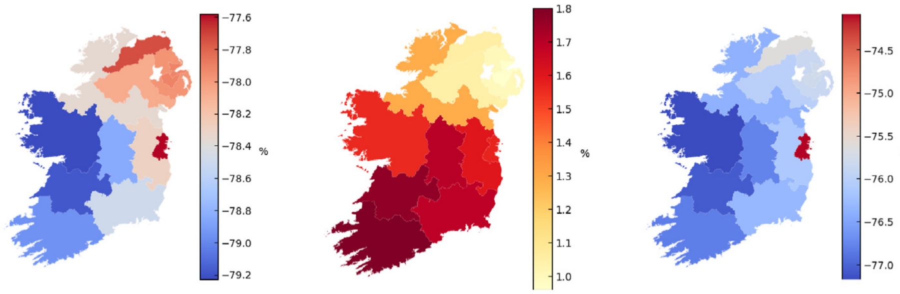
Emissions

The two principal factors affecting emissions are 1) the carbon emitted in generating electricity and 2) the carbon emissions avoided by blending hydrogen with natural gas and used for residential heating. Table 6 shows the emissions from existing and new power generation. The addition of renewable power in both cases, RET-only and RET + ESR, results in emissions reduction, primarily from existing generation, equivalent to a 30% reduction compared to the BAU case. In contrast, in ESR-only scenario emissions increase by 3% compared to the BAU, which is attributable to existing and new generation in the ratio of 97:3. Emissions savings from residential heating in the ESR scenarios total 0.11MtCO_2 per year.

Discussion

The scenario results pose a number of interesting insights not just with respect to hydrogen but with the policy target to increase renewables generation.

The ESR-only scenario can help answer whether large-scale green hydrogen production within the context of a real power system is practically feasible. While the ESR-only



(a) RET-only. (b) ESR-only. (c) RET+ESR.

Fig. 7 – Comparison of regional marginal prices with respect the BAU scenario. Note: the legend's colour gradient differs across the three panels. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Table 6 – Aggregated CO_2 emissions [$MtCO_2$] of existing and new capacity.

Policy	Existing	New	Total
BAU	12.59	0.115	12.7
ESR-only	12.62	0.408	13.0
RET-only	8.596	0.273	8.87
RET + ESR	8.630	0.284	8.91

scenario considers the use of hydrogen in residential heating displacing natural gas, the insights may be useful in other green hydrogen-use cases too, e.g. in transport. As reported in Table 2, the ESR-only scenario included new investment in thermal generation, specifically a 155 MW CCGT plant relative to just 44 MW in the BAU case. Emissions from electricity generation increased by 0.3$MtCO_2$ in the ESR-only relative to the BAU scenario. Emissions savings from natural gas displacement in residential heating totalled 0.11$MtCO_2$ so net emissions savings from ESR are negative. If green hydrogen is defined as primarily the avoidance of fossil fuels as the energy source for its extraction in this scenario the hydrogen cannot be labelled as "green". While power-to-hydrogen based on surplus or curtailed wind generation is often nominally labelled as green hydrogen, this scenario shows that this may be premature without detailed assessment of the complex interaction between electrolysers and the power system. It also suggests that when evaluating green hydrogen projects for net emissions savings (e.g. in heating, transport etc.) the net impact on the wider power system should also be incorporated.

Focusing on emissions savings in residential heating, i.e. 0.11$MtCO_2$, a relevant question is how does the cost of emissions abatement using hydrogen compare with other mechanisms to reduce the carbon intensity of the residential sector? Based on the capital investment in electrolysers and the CO_2 reductions in the two ESR scenarios the mean cost of abatement is € 114.3/tCO_2. This figure is comparable to the € 88–133/tCO_2 range estimated by the Hydrogen Council [65].[2] A marginal abatement cost curve (MACC) for a wide range of abatement measures is published in the Irish government's Climate Action Plan [66] and the € 114.3/tCO_2 estimate lies between retrofitting existing dwellings with either gas or solid fuel stoves to a high standard (i.e. a B2 rating) and using CO_2 free heating in new buildings ([66, Fig. 4.2]). On that basis the cost of power-to-hydrogen as a means to decarbonise residential heating is on the same order of magnitude as some other policy options under consideration. It should be noted that the € 114.3/tCO_2 estimate is based on a conservatively high CAPEX assumption, as discussed in section Case Study, therefore the cost could be lower or may decline with scale deployment. Unlike the decarbonisation of home heating via retrofits, the decarbonisation of the gas network by hydrogen injection necessitates substantially fewer decisions and therefore its implementation may face fewer barriers.

In the scenarios examined, renewable generation capacity increases from roughly 4 GW in the BAU scenario to 11 GW in the RET-only and RET + ESR scenarios, less than a three-fold increase whereas aggregate wind curtailment increases by more than 7-fold. Furthermore, electricity prices decline by more than 75% and wind capacity factors decline by 5% points. Facing these circumstances the subsidisation of renewable energy generation via energy markets will increasingly become financially unsustainable for renewable generators. Accordingly, the financial model underpinning new renewable generation investment will need to evolve as the policy target to roughly double renewable electricity generation to 70% is implemented. One option is to switch renewable subsidisation from an energy to a capacity basis [67] and such a policy shift may require setting RET targets in capacity rather than energy terms.

The four scenarios show very different new capacity pathways to 2030. In the ESR-only and BAU scenarios, where there is no requirement to meet a 70% renewable generation target, rather just demand growth of 17%. Consequently new capacity expansion is quite modest and primarily delivered via new thermal generation. In the ESR-only scenario, which nominally applies only in the Republic of Ireland with hydrogen injection into its gas grid, the majority of new CCGT

[2] The published range is 100–150 \$/tCO_2. The conversion to euros is considering the 2017 average exchange rate between the euro and the US dollar: 1 USD = 0.8865 EUR.

Table 7 – Aggregated energy and emissions from existing and new power capacity.

		Existing		New		Total	Total
		Conventional	Renewable	Conventional	Renewable		
		TWh	TWh	GWh	GWh	TWh	$MtCO_2$
BAU	IE	22.42	10.24	–	–	32.6	9.54
	NI	7.50	2.91	313.3	–	10.7	3.16
ESR-only	IE	22.58	10.33	358.2	19.4	33.3	9.75
	NI	7.39	2.92	751.9	0.16	11.1	3.28
RET-only	IE	14.71	8.53	–	16,115	39.3	6.69
	NI	5.25	2.73	–	2080	10.1	2.18
RET + ESR	IE	14.78	8.47	–	16,834	40.1	6.73
	NI	5.27	2.72	–	2088	10.1	2.18

capacity investment, at 68% of a total 155.2 MW, is built in Northern Ireland. Almost all of the new renewable capacity is constructed in the Republic of Ireland. The ESR-only scenario demonstrates the somewhat perverse emissions outcome that a policy option to facilitate decarbonisation of heating in one jurisdiction, achieving emissions savings of some $0.11MtCO_2$, leads to higher emissions in the other jurisdiction associated with new CCGT capacity. While the absolute changes in emissions are relatively small, the example demonstrates how interconnected electricity markets have the potential to be impacted from unilateral policy actions in other jurisdictions. A second notable outcome from the ESR-only scenario relative to the RET scenarios is that the 70% RET target is driving the expansion in renewables generation. The least cost option in the ESR-only scenario is dominated by new thermal capacity.

The scenarios also demonstrate how the 70% RET target has potential synergies with the need to reinforce the transmission network. Across the four scenarios the BAU case had the highest level of transmission line reinforcement totalling 115 km, as illustrated in Fig. 1b. Transmission infrastructure reinforcement is 76% lower in the RET-only and RET + ESR scenarios. The solutions to the RET-only and RET + ESR scenarios demonstrate that the distributed and modular characteristics of renewable electricity generation can substitute for investment in grid reinforcement. The Dublin region is also

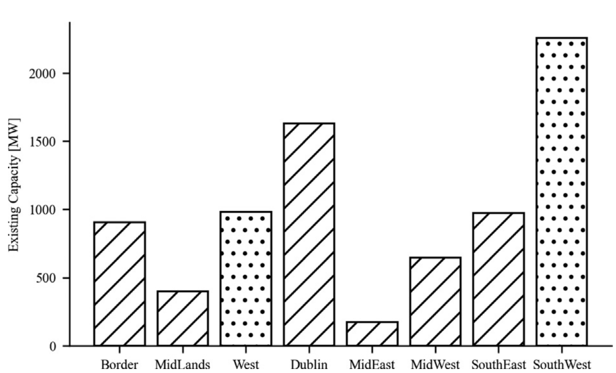


Fig. 8 – Available existing capacity per region. The existing capacity in the West region is 8%, 146%, 52% and 1% more than the Border, MidLands, MidWest and SouthEast regions respectively. The existing capacity in the SouthWest is 459% more than in the MidEast.

an interesting case, where space and planning restrictions limit new wind capacity. Almost 40% of the aggregated new PV capacity in both the RET + ESR and ESR-only cases is in Dublin where network congestion is greatest, yet grid reinforcement is 76% lower.

One motivation for deploying electrolysers is to use surplus wind energy, i.e. availing of curtailed wind generation. Comparing the RET-only and RET + ESR scenarios, there is an increase in wind generation capacity of 3.6%, while the deployment of electrolysers also leads to an increase in aggregate wind curtailment of 8%. Wind capacity factors are 30% in both RET-only and RET + ESR scenarios. Solely from a wind farm investment perspective, on the basis of negligible difference in capacity factors and similar prices, as illustrated in Fig. 7, whether the power system does or does not have electrolysers similar to the ESR deployment scenarios outlined is unlikely to influence investment decisions in wind farms. This research does not consider where an investment opportunity is a wind farm combined with an electrolyser.

The net impact of electrolysers on the power system differs substantially depending on what the reference case is. As just noted, the wind capacity factor is 30% in both RET-only and RET + ESR scenarios whereas the increase in the wind capacity factor in the ESR-only scenario is quite small. The added electricity load from the electrolysers results in an increase of 797 GWh generation from new thermal capacity in the ESR-only versus BAU scenario and a small change generation from existing thermal capacity, as shown in Table 7. This increase in conventional generation was discussed earlier in the context of increased emissions in the ESR-only scenario. Comparing RET-only with RET + ESR scenario there is no new conventional generation and just a small change in emissions. On the basis of these few scenarios, the choice of counterfactual reference scenario is critical for any policy evaluation of the deployment of electrolysers within a power system. The findings here should not be generalised to other power systems and instead bespoke modelling is necessary to evaluate the likely impact of scale deployment of electrolysers on power systems.

As the hydrogen from the electrolysers is being injected into the gas distribution network (by assumption), the *a priori* expectation might be that electrolysers are situated in areas with higher penetrations of residential gas heating. What the scenarios show is that while high heat demand is important, it is not the only factor driving electrolyser location in the least

Table 8 – Qualitative summary of the two policies in relation to the BAU. The symbols stand for broadly neutral impact (N), positive impact (+) and negative impact (–).

	Transmission	New Capacity		Curtailment		Zonal	CO_2	Wind Power
	Expansion	Renewable	Storage	Wind	Load	Prices	Emissions	Capacity Factor
ESR-only	N	–	N	+	N	N	–	+
RET-only	+	+	+	–	N	+	+	–
RET + ESR	+	+	+	–	N	+	+	–

cost optimal solutions. Fig. 4 plots the number of electrolysers against residential heat demand fueled by natural gas and shows the Dublin region matching the *a priori* expectation, i.e. a high deployment of electrolysers given its high heating demand. The other regions, with smaller populations and lower gas network penetration, all have substantially lower heat demands, however, the deployment of electrolysers is clearly not proportional to heat demand. For example, heat demand in the West region is less than 50% of that in the Midwest and Southeast regions but the number of electrolysers is up to 100% higher. Furthermore, with broadly similar heat demand in the Midlands, Border and West regions, the West region has 2–3 times the number of electrolysers. To explain this, in addition to the heat demand, the characteristics of the power system within these regions is a factor in determining deployment of electrolysers. This is illustrated in Fig. 8, which shows the installed power capacity by region. The West's capacity is higher than the Border's and therefore has relatively more power capacity to supply electrolysers. Similarly, the Southwest region has more electrolysers than the Mideast but the regions have similar heat demand and from Fig. 8 the capacity is substantially higher in the Southwest versus the Mideast hence relatively higher power capacity to supply electrolysers.

Conclusions

This research examines the impact on the power system of scale deployment of hydrogen electrolysers. While the increased load from electrolysers leads to a small increase in electricity prices (1–2%), its impact is relatively modest given that the policy ambition to dramatically increase renewable generation could lead to prices reductions of the order of 75–80%. With the extracted hydrogen displacing natural gas there is a greenhouse gas emissions improvement in the residential heating sector. In the power sector the policy to increase renewable generation is the primary factor driving emissions performance. Table 8 summarises the effect of introducing electrolysers and achieving a 70% renewable generation share in the power system.

While there may be no harmonised definition of green hydrogen [6] and numerous studies attesting to the feasibility of green hydrogen production either as stand-alone plants or within test power systems [7–9], the current analysis adds a new perspective on the potential for green hydrogen production from surplus renewable power within a real power system. The results here show that the net impact on emissions is not an unambiguous reduction. In the scenarios considered, deployment of electrolysers leads to an increase in power generation emissions both in the case of a moderate share (28% in 2018) of renewable power generation (ESR-only versus BAU scenarios) and the case of a high share (70%) of renewable power generation (RET + ESR versus RET-only scenarios), as illustrated in Table 6.

The scenario analysis also provides insights related to electricity market design within which new investments in electrolysers and renewable generation will be made. The current market mechanism for remuneration of power generation based on priority dispatch for renewables with price based on the marginal dispatched conventional generator is not likely to be sustainable with very high levels of renewable generation. The scenarios project very dramatic reductions in electricity prices and no substantive improvement in renewable (i.e. wind) capacity factors, which will undermine the viability of investment. A suggested policy option is to switch renewable subsidisation from an energy to a capacity basis.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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