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The role of power-to-gas in the future energy system: market and portfolio effects

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Abstract

Electricity systems based on renewables have an increasing demand for flexibility. This paper considers the potential of power-to-gas to provide flexibility and enhance system integration of renewables. Existing research on power-to-gas typically analyses the system effects of a predetermined power-to-gas unit without endogenising the investment decision. Moreover, insights related to market and portfolio effects of power-to-gas are rare. To this end this work presents a stochastic electricity market model. Market players considered include generating firms with different generation portfolios and different consumer groups. Firms earn revenues from an energy market, a capacity market and a feed-in premium for renewable generation. They maximise their profits by optimising the operation of existing assets and investing in new generation assets and power-to-gas. Firms with renewable generation benefit from investing in power-to-gas. While the technology itself is loss-making, power-to-gas particularly increases demand and hence prices in low-load hours. Therefore, renewable generation becomes more profitable, which justifies the investment. Metrics such as LCOE, which consider each technology in isolation, fail to capture this effect. The increase in the electricity price results in higher costs to consumers and so the overall transfer from consumers to wind generators increases in the presence of power-to-gas.

Keywords:

Electricity; wind energy; power-to-gas; stochastic market modelling; portfolio effects

1. Introduction

Modern electricity generation systems have seen a significant increase in variable renewable generation, such as wind and photovoltaic solar, in recent years, primarily in response to government targets. This in turn increases the level of variability in the electricity supply (Bertsch et al., 2016). Increased flexibility in other sources of electricity supply, and also demand, is therefore desirable in order to accommodate the increased variability. There is a wide and growing literature on this variability-flexibility interaction. Albadi and El-Saadany (2008) provide an early summary of the potential for the demand side to provide the necessary flexibility to accommodate the variation on the supply side. Palensky and Dietrich (2011) explore the extent to which smart loads and new communications devices can facilitate this new demand side response, with Siano (2014) providing a survey of the literature in this area several years later. Clastres and Khalfallah (2015) examine from an economic perspective how the price-responsiveness of consumers can be optimally

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harnessed to achieve the flexibility necessary to reduce costs while meeting demand, while Broberg and Persson (2016) perform choice experiments to determine the extent to which consumers are willing to accept external control of their electricity usage (via smart devices). Finally, De Jonghe et al. (2012) provide one of the earlier studies on the impact of variable supply and flexible demand on the entire electricity generation portfolio, from a least cost perspective, while Devine et al. (2019) and Lynch et al. (2019) perform analyses of the potential for flexible demand aggregators to participate in energy and capacity markets, respectively.

Specific technology investments are often proposed in order to accommodate this increased variability in electricity supply and power system optimisation tools are commonly used throughout the literature to determine the optimal deployment of same. Such investments include electricity storage (Barton and Infield, 2004), demand-side management (Strbac, 2008) and electricity transmission and interconnection (Lynch et al., 2012). Another technology that has the potential to accommodate surplus renewable generation on the system is power-to-gas. The power-to-gas technology uses electricity to perform electrolysis on water, splitting the water molecules into hydrogen and oxygen molecules. The hydrogen can be used directly in industrial applications, as a transport or heating fuel or injected directly into the natural gas grid (provided the total amount injected is sufficiently low). The hydrogen can also be combined with carbon dioxide to create methane. Benjaminsson et al. (2013) and Gahleitner (2013) provide useful summaries of the technical and cost characteristics of the technology, along with case studies. This paper focuses on electrolysis, or exclusively on power-to-hydrogen; however it is assumed that the hydrogen is injected directly into the gas grid as long as the total quantity does not exceed the permitted limit.

1.1. Literature review

The literature on power-to-gas can be broadly grouped into several categories. The first calculates the levelised cost of electricity (LCOE) or net present value (NPV) of power-to-gas, particularly in high renewable energy systems. Examples abound in the literature and an exhaustive review is not the focus of this paper so the focus herein is restricted to a subset of same. Lombardi et al. (2011) perform a useful summary of power-to-gas technologies, including a LCOE assessment of the costs of power-to-gas storage. However, they do not perform any system analysis. Breyer et al. (2011) perform a global 100% renewable generation study and calculate the LCOE of power-to-gas when it is co-located with both wind and photovoltaic generation. Guandalini et al. (2015) use statistical models of wind output to determine the profitability of power-to-gas under various cost characteristic assumptions, while assuming the power-to-gas unit injects hydrogen directly to the grid. They do not provide any analysis of the system-level impacts of this power-to-gas operation. Schiebahn et al. (2015) perform a LCOE and production cost analysis of power-to-gas for a German case study, again neglecting the system impacts of same. Given that these studies are focused on the LCOE or NPV of the technology in isolation, rather than considering the electricity system as a whole, there is no consideration of the potential impact of power-to-gas on the profitability of other generation technologies, or vice versa. Furthermore there are many assumptions made about the costs of the technology and the operational decisions of the power-to-gas operator.

The second strand of literature concerns specific business cases or case studies of various applications of power-to-gas. For example, Buchholz et al. (2014) analyse the business case for integrating a power-to-gas unit with a lignite fired power plant (LPP). The benefits considered focus exclusively on the LPP plant itself, for example reduced wear and tear by reducing cycling of the unit. The system impacts are again ignored. Breyer et al. (2015b) examine the integrated value chain for incorporation of power-to-gas in the specific context of a kraft pulp mill, i.e. not as part of an electricity generation system. These papers again tend to focus on the costs and revenues of the power-to-gas technology itself, potentially in conjunction

with investment in a complementary technology. However, they do not consider the system-wide effects of power-to-gas investment. Qadrdan et al. (2015), in contrast is one of the few papers to consider the business case for power-to-gas as part of an integrated electricity and gas system, in this case, that of Great Britain. However, the investment decision in power-to-gas itself is exogenously-determined - indeed; this is the case in all of the papers surveyed above.

There are several studies that consider the impact of power-to-gas within an energy system, including systems with one hundred per cent renewable generation. One example is Breyer et al. (2015a), who examine a case study of 100% renewable electricity in North-East Asia. They use a linear optimisation model with perfect foresight. Palzer and Henning (2014) and Henning and Palzer (2014) perform a greenfield analysis of the optimal expansion of a 100% renewable heating and electricity sector in Germany, which includes power-to-gas as a potential technology option. Hlusiak and Breyer (2012) perform a cost-minimisation exercise for the Allgäu region in Southern Germany where they minimise the LCOE while considering the potential for battery and long-term power-to-gas storage in reaching 100% renewable electricity supply. Moeller et al. (2014) performs a similar analysis for the Berlin-Brandenburg region. Varone and Ferrari (2015) focuses on the potential use of surplus wind generation to make synthetic fuels for the transport system, and so shifts the focus away from the power sector. A common theme to these studies is the focus on the potential for surplus renewable generation to be consumed by power-to-gas units, rather than determining the optimal operation of the entire system. This is therefore a major drawback, as the contribution of power-to-gas to market and system outcomes cannot be determined. Investments in various technologies are also typically determined exogenously, shedding no light on the optimal level of power-to-gas investment, either from a least-cost perspective or from the perspective of a profit-maximising firm.

Finally some studies do consider the optimal operation of generation units on the system, along with the power-to-gas unit(s). Examples include Jentsch et al. (2014), who use unit commitment and economic dispatch for the German power system with a fixed renewable penetration of 85%. de Boer et al. (2014) perform a similar exercise for the Dutch system, while Ahern et al. (2015) use the same methodology to examine power-to-gas in the Irish electricity system. All of these studies consider the operational decisions of the system operator only, and the level of power-to-gas capacity installed is exogenously-determined. Vandewalle et al. (2015) also perform a cost-minimisation exercise on the Belgian electricity, gas and carbon sector through an operational model, but do attempt to determine the optimal investment in power-to-gas. However the investment in power-to-gas itself is not a control variable of the model; rather the results of the operational model are used to determine the optimal investment. This ignores the effect power-to-gas investment and operation has on the system itself.

In the literature surveyed above, there is no examination the market or portfolio effects of investment in power-to-gas, namely the potential for power-to-gas investment to render another technology more or less profitable. The consideration of portfolio effects in least-cost electricity systems, rather than focusing solely on the cost of each technology in isolation, is an important new consideration given that consumers are affected not just by the average cost of electricity that they face, but also by the variability of same. The consideration of portfolio effects in electricity markets was pioneered by Awerbuch in Awerbuch and Berger (2003). This work notes that the contribution of an electricity generation technology to a generation portfolio is of value if the variable cost of its output is certain, even if it has a high capital cost. Variable renewable generation such as wind a solar provides a good example. Awerbuch expanded on this idea in subsequent publications, such as Awerbuch (2006), which stressed the importance of abandoning the focus on least cost standalone technologies, and Awerbuch and Yang (2007), which applied these methodologies

to determine the optimal European power system mix in 2020. Awerbuch focused on the variation of the investment and operational costs of generation in the papers above, but the approach was continued in the context of liberalised electricity markets based on marginal-cost pricing. For example, Roques et al. (2008) consider optimal baseload portfolios in Great Britain taking risks and returns into account, assuming various levels of correlation between electricity and fuel prices. Lynch et al. (2013) consider the risk-returns of the entire portfolio, including mid-merit and peaking units, for the electricity system of the island of Ireland. Tietjen et al. (2016) uses risk-return analysis to determine the optimal wind generation portfolio for Europe. While this literature focuses on both the risk and return of a given portfolio, it is important to consider the potential for a given technology to render another technology more or less profitable on average, as well as considering the variation of those profits.

1.2. Original contributions of this paper

This paper represents a significant advance on the state of the art by addressing several gaps in the literature. Firstly, as outlined above, there is no examination in the literature to date of the optimal level of power-to-gas investment in modern power systems. This paper, in contrast, treats power-to-gas investment as an endogenous variable, and is solved for under various market conditions such as wind penetration. Secondly, the impact of power-to-gas investment on the profitability of an electricity market player’s portfolio is a significant focus of this paper. This is in marked contrast to the literature above, which focuses exclusively on the profitability of the power-to-gas unit on a standalone basis. The impact of power-to-gas on the profitability of other power system investments, and vice versa, is therefore examined in this paper for the first time. Finally, in recognition of the fact that investment in renewable generation is driven primarily by policy decisions rather than market outcomes, the model exogenously determines the level of installed wind capacity and considers the resulting investment decisions in power-to-gas. This allows us to determine how policy-driven outcomes, such as renewable generation, and market-driven outcomes, such as power-to-gas investment decisions, interact, and the resulting costs and benefits for consumers can be identified and examined.

This paper also makes several methodological contributions. In contrast to the (mostly deterministic) cost-minimisation modelling performed in the literature to date, this model considers a stylised electricity market as a stochastic mixed complementarity problem (s-MCP), which accounts for the stochasticity of the renewable generation. The importance of stochastic modelling of variable renewable generation is well-established in the literature, with Ambec and Crampes (2012) providing a useful summary. Stochastic modelling is particularly important for the high-renewable scenarios under examination here (Devine and Bertsch, 2018). On the demand side, the model distinguishes between residential and industrial/commercial consumers, both of whom have the objective of minimising their costs. This is in contrast to much of the extant literature, where system demand is modelled as one parameter rather than distinguishing between consumer groups. On the supply side, the model considers generation firms that earn revenues from an energy market and a quantity-based capacity market. Moreover, firms earn an additional feed-in premium (FIP) on top of the market price for any renewable generation. This modelling of three different sources of electricity generation firms’ revenues is more representative of modern electricity markets and represents an important advance on the state-of-the-art. The firms’ objective is to maximise their profits. The model considers operational decisions of each of the generation firms, but also allow firms to determine their optimal investment into new technologies, including power-to-gas, as well as optimal retirement of existing units. Thus the optimal portfolio of technologies is arrived at endogenously, including the optimal investment in power-to-gas. This is in contrast to the models surveyed above, which considered operational decisions only.

2. Methodology

Table 1: Indices and sets.

$f \in F$	Generating firms
$t \in T$	Generating technologies
$p \in P$	Time periods
$k \in K$	Consumers groups
$s \in S$	Scenarios

Note: sets contain a finite amount of non-zero natural numbers.

Table 2: Variables.

Firms' primal variables	
$gen_{f,t,p,s}$	Generation from firm f with technology t in period p and scenario s
$cap_{f,t}^{bid}$	Capacity bid of firm f with technology t
$inv_{f,t}$	Investment in new generation capacity for firm f with technology t
$exit_{f,t}$	Decommissioning of old generation capacity for firm f with technology t
$gen_{f,p,s}^{P2G}$	Gas produced by firm f in timestep p and scenario s
inv_f^{P2G}	Capacity of power-to-gas firm f invests in
Consumers' primal variables	
$g_{k,p,s}^{ls}$	Load shedding from consumer group k in period p and scenario s
$g_{k,p,s}^{micro}$	Micro generation from consumer group k in period p and scenario s
$g_{k,p,s}^{PV}$	PV generation from consumer group k in period p and scenario s
Dual variables	
$\gamma_{p,s}$	System price for time period p and scenario s
κ	Unit capacity price
$\lambda^\#$	Lagrange multipliers associated with constraint $\#$ of the firms' problem
$\mu^\#$	Lagrange multipliers associated with constraint $\#$ of the firms' problem consumers' problem

Note: '.' is used as a place-holder as the subscripts for both Lagrange multipliers vary depending the on constraint.

Table 3: Parameters.

PR_s	Probability associated with scenario s
MTC_t	Maintenance cost form generating technology t
$CAP_{f,t}$	Initial generating capacity for firm f with technology t
$D_{k,p}^{REF}$	Reference demand for consumer group k in period p and scenario s
$G_{k,p}^{LS,MAX}$	Maximum load shedding for consumer group k in any time period or scenario
INT_k^{MICRO}	Micro generation capacity for consumer group k
INT_k^{PV}	PV generating capacity for consumer group k
$NORM_{p,s}^{PV}$	PV generating profile for period p and scenario s
$NORM_{f,t,p,s}^G$	Generating profile for firm f with technology t in period p and scenario s
$TARGET$	Capacity target for overall market
X_t	Feed-In premium for technology t
X^{PV}	Feed-In premium for PV
DR_t	De-rating factor for technology t
A^\cdot	Intercept associated with marginal cost functions
B^\cdot	Slope associated with marginal cost functions
$C_{k,p}^{PV}$	Marginal cost of using PV generation for consumer group k in period p
IC_t^{GEN}	Investment in generating technology t cost
CAP_f^{P2G}	Initial power-to-gas capacity
EFF	Efficiency of converting electrical energy to gas
C^{GAS}	Price of gas

Table 4: Functions.

$C_t^{GEN}(\cdot)$	Marginal cost function for technology t
$C_{k,p}^{LS}(\cdot)$	Load shedding operational cost for consumer group k in period p
$C_{k,p}^{MICRO}(\cdot)$	Operational cost of using micro generation for consumer group k in period p

In this section, the methodology is discussed. A stochastic MCP is utilised to represent an electricity market with two types of players: generation firms and electricity consumer groups. The model is very similar to the model developed in Bertsch et al. (2018). The most significant difference is the consideration of investment and operation decisions of power-to-gas units.

Firms receive revenues from energy and capacity markets as well as a FIP and seek to maximise their profits. They may hold multiple generating units of baseload, mid merit, peakload and wind technology. Firms may invest in generation capacity of any technology and may also invest in power-to-gas capacity. Firms may also earn revenues from a capacity market. As in Bertsch et al. (2018) the capacity payment mechanism considered is a quantity based mechanism. All firms are modelled as price-takers, i.e., no firm may exert market power. As the problem does not involve market power considerations, nor does it constrain any primal and dual variables together, it may be solved using a single objective cost minimisation problem (Devine, 2012). Thus, the obtained solution should correspond to an efficient equilibrium for an electricity marketplace.

Consumers minimise the cost of meeting their demand. They do so by utilising a range of possible demand-side flexibility measures, such as load shedding, PV generation or thermal micro generation. Consumer groups rather than individual consumers are modelled, in a similar manner to that outlined in (Bertsch et al., 2018), whose decisions represent the aggregate actions of consumers in these groups. Consumer groups are distinguished by different levels of demand-side flexibility capability and their demand profiles.

The stochasticity of the model arises from the uncertainty surrounding wind and PV power (Bertsch et al., 2018). Thus, each scenario in our model corresponds to different RES generation profiles, i.e. varying levels of wind and solar power availability at each point in time. Each of the generation firms and consumer groups considered have separate optimisation problems that are connected through market clearing conditions. The stochastic MCP is made up of these market clearing conditions along with the Karush-Kuhn-Tucker (KKT) conditions for optimality from each of the players.

Throughout this section the following conventions are used: lower-case Roman letters indicate indices or primal variables, upper-case Roman letters represent parameters (i.e., data, functions), while Greek letters indicate prices or dual variables. The variables in parentheses alongside each constraint in this section are the Lagrange multipliers associated with those constraints.

2.1. Firm f 's problem

Firm f maximises its expected profits (revenues less cost) by choosing the amount of generation, the quantity of capacity bid, investment in new capacity and decommissioning of existing capacity. Firms also choose the capacity of power-to-gas in which it wishes to invest and, if this quantity is non-zero, how much gas it wishes to produce (and thus how much electricity it consumes). Firm f considers revenues received from a capacity and an energy market as well as a FIP for RES generation. In addition, it also considers any revenues it earns from the gas it produces. Its costs consist of generation costs, investment costs and any costs incurred for maintaining its units. Furthermore, firm f 's costs also include the cost of generating

electricity for power-to-gas. Firm f 's optimisation problem is:

$$\begin{aligned}
\max_{\substack{gen_{f,t,p,s}, cap_{f,t}^{bid}, \\ inv_{f,t}, exit_{f,t}, \\ gen_{f,p,s}^{P2G}, inv_f^{P2G}}} \quad & \sum_{t,p,s} \left(PR_s \times gen_{f,t,p,s} \times (\gamma_{p,s} + X_t - C_t^{GEN}(gen_{f,t,p,s})) \right) - \\
& \sum_t \left(IC_t^{GEN} \times inv_{f,t} + (inv_{f,t} + CAP_{f,t} - exit_{f,t}) \times MTC_t \right) + \\
& \sum_{p,s} \left(PR_s (C^{GAS} \times gen_{f,p,s}^{P2G} - \gamma_{p,s} \times (1/EFF) \times gen_{f,p,s}^{P2G}) \right) \\
& - IC^{P2G} \times inv_f^{P2G} + \sum_t DR_t \times \kappa \times cap_{f,t}^{bid},
\end{aligned} \tag{1a}$$

subject to:

$$gen_{f,t,p,s} \leq (CAP_{f,t} + inv_{f,t} - exit_{f,t}) \times NORM_{f,t,p,s}^G, \quad \forall t, p, s, \quad (\lambda_{f,t,p,s}^1), \tag{1b}$$

$$cap_{f,t}^{bid} \leq CAP_{f,t} + inv_{f,t} - exit_{f,t}, \quad \forall t, \quad (\lambda_{f,t}^2), \tag{1c}$$

$$gen_{f,p,s}^{P2G} \leq EFF \times (CAP_f^{P2G} + inv_f^{P2G}), \quad \forall t, p, s, \quad (\lambda_{f,p,s}^3), \tag{1d}$$

where the parameter EFF represents the efficiency of converting electrical energy to gas within a power-to-gas unit while C^{GAS} represents the price of gas, and $gen_{f,p,s}^{P2G}$ represents the hydrogen produced by the power-to-gas unit. It is assumed that power-to-gas injects hydrogen directly back into the gas grid, and so the power-to-gas revenues are given by the total hydrogen produced multiplied by the gas price: $C^{GAS} \times gen_{f,p,s}^{P2G}$. Furthermore, the unit of $gen_{f,p,s}^{P2G}$ is MWh of thermal energy, rather than cubic meters or kilograms. The term $(1/EFF) \times gen_{f,p,s}^{P2G}$ calculates the electricity required to generate $gen_{f,p,s}^{P2G}$ units of hydrogen. Thus, the inputs to the power-to-gas unit are electrical MWhs of electricity and the outputs are thermal MWhs of hydrogen. This is a technology-agnostic representation of power-to-gas, and so can legitimately be applied to any unit, once the efficiency is known. No particular assumption regarding the type of electrolyser is required.

The marginal cost of generating with technology t is

$$C_t^{GEN}(x) = A_t^{GEN} + B_t^{GEN}x, \tag{2}$$

which means the overall cost of generating electricity with technology t is quadratic.

Constraints (1b) and (1c) constrain the amount of energy generated by and the capacity bid of firm f . Constraint (1d) ensures that, for each timestep and scenario, firm f cannot produce more gas than the capacity of its power-to-gas unit. The parameter CAP_f^{P2G} represents firm f 's initial power-to-gas capacity before any investment. Firm f 's optimisation problem is convex if all values for B_t^{GEN} are non-negative. The KKT conditions of firm f 's problem are discussed in Appendix A.

2.2. Consumer group k 's problem

Each consumer group minimises the cost of meeting their expected demand. As part of their optimisation problem, they may choose to (partially) shed their load or to (partially) self-generate using solar PV or thermal

micro generation. For PV generation, they receive a FIP. Load shifting or storage options on the demand side are not considered as the focus is on understanding the potential role of power-to-gas. Considering other flexibility measures would lead to distortions in this analysis. However, investigating whether demand side storage and power-to-gas are competing or complementary technologies will be examined in future research.

Consumer group k 's optimisation problem is:

$$\min_{\substack{g_{k,p,s}^{\text{ls}}, g_{k,p,s}^{\text{micro}}, \\ g_{k,p,s}^{\text{pv}}}} \sum_{s,p} PR_s \left(\gamma_{p,s} \times (D_{k,p}^{\text{REF}} - g_{k,p,s}^{\text{ls}} - g_{k,p,s}^{\text{micro}} - g_{k,p,s}^{\text{pv}}) - X^{\text{PV}} \times g_{k,p,s}^{\text{pv}} \right. \\ \left. + g_{k,p,s}^{\text{ls}} \times C_{k,p}^{\text{LS}}(g_{k,p,s}^{\text{ls}}) + g_{k,p,s}^{\text{micro}} \times C_{k,p}^{\text{MICRO}}(g_{k,p,s}^{\text{micro}}) + g_{k,p,s}^{\text{pv}} \times C_{k,p}^{\text{PV}} \right) \quad (3a)$$

subject to

$$g_{k,p,s}^{\text{ls}} \leq G_k^{\text{LS,MAX}}, \quad \forall p, s, (\mu_{k,p,s}^1), \quad (3b)$$

$$g_{k,p,s}^{\text{micro}} \leq INT_k^{\text{MICRO}}, \quad \forall p, s, (\mu_{k,p,s}^2), \quad (3c)$$

$$g_{k,p,s}^{\text{pv}} \leq NORM_{p,s}^{\text{PV}} \times INT_k^{\text{PV}}, \quad \forall p, s, (\mu_{k,p,s}^3), \quad (3d)$$

$$g_{k,p,s}^{\text{ls}} + g_{k,p,s}^{\text{micro}} + g_{k,p,s}^{\text{pv}} \leq D_{k,p}^{\text{REF}}, \quad \forall p, s, (\mu_{k,p,s}^4). \quad (3e)$$

The marginal cost functions associated with load shedding and micro generation are:

$$C_{k,p}^{\text{LS}}(x) = A_{k,p}^{\text{LS}} + B_{k,p}^{\text{LS}}x, \quad (4)$$

$$C_{k,p}^{\text{MICRO}}(x) = A_{k,p}^{\text{MICRO}} + B_{k,p}^{\text{MICRO}}x. \quad (5)$$

Constraint (3b) limits the amount of electricity consumer group k can shed while constraints (3c) and (3d) limit the amount of electricity consumer group k can self-generate from micro- and PV generation, respectively. Constraint (3e) ensures any electricity generated by consumer group k must be less than their reference demand (the demand consumers have in absence of any demand side flexibilities). In other words, constraint (3e) ensures consumer group k 's own generation cannot be used to meet other consumers' demand.

Consumer group k 's problem is convex, assuming all values for $B_{k,p}^{\text{LS}}$ and $B_{k,p}^{\text{MICRO}}$ are non-negative. Its KKT conditions are presented in Appendix A.2.

2.3. Market clearing conditions

The optimisation problems of each player are connected via the following market clearing conditions:

$$\sum_{f,t} gen_{f,t,p,s} = \sum_f (1/EFf) \times gen_{f,p,s}^{\text{P2G}} + \sum_k \left(D_{k,p}^{\text{REF}} - g_{k,p,s}^{\text{LS}} - g_{k,p,s}^{\text{MICRO}} - g_{k,p,s}^{\text{PV}} \right), \quad \forall p, s, (\gamma_{p,s}) \quad (6a)$$

$$\sum_{f,t} DR_t \times cap_{f,t}^{\text{bid}} = TARGET, \quad (\kappa). \quad (6b)$$

Equation (6a) ensures that the electricity generated equals the electricity consumed. Equation (6b) ensures that the sum of capacity bids from firms, times a derating factor¹, must equal the capacity target. The variable $gen_{f,p,s}^{P2G}$ reflects the increased electricity demand from power-to-gas operation.

As each of the players' optimisation problems are convex, the KKT conditions are both necessary and sufficient for optimality (Gabriel et al., 2012). Thus, the stochastic MCP consists of the KKT conditions of all players in addition to the market clearing conditions.

2.4. Model outputs

The outputs of the model are the optimal investment, de-commissioning and capacity bid decisions of each firm as well as the power generation from each unit for each time period and scenario. Based on these outputs, several other quantities of interest can be easily calculated as follows.

Consumer costs are the sum of the total costs incurred by consumers in the capacity and generation markets. The former is given by the total capacity in the capacity market multiplied by the capacity price κ and the latter by the total generation multiplied by the electricity price ($\gamma_{p,s}$) plus any applicable Feed-In Premium (X_t):

$$ConsumerCost = \sum_{f,t} cap_{f,t}^{bid} \times \kappa + \sum_{f,t,p,s} gen_{f,t,p,s} \times PR_s \times (\gamma_{p,s} + X_t) \quad (7)$$

Generator profits are calculated as per equation (1a). RES curtailment is calculated by subtracting the total RES generation in each hour from the total potential RES generation available, which is itself the product of the total installed wind capacity and the capacity factor at that hour. The capacity factors are calculated according to the description in section 3.3. For all these quantities, the expected value of each can be calculated as the sum across the scenarios s , weighted by the probability of each scenario PR_s .

2.5. Limitations of the model

The model is designed to be flexible in terms of the granularity of the dataset employed. In particular, the set of generation technologies (both existing and new) can in theory be increased without bound. However, computational constraints may restrict the total number of technologies considered in practice. For the purposes of this paper, as a detailed representation of the power system is not the focus of this research, the small number of technologies considered is sufficient.

The model is a MCP model and so integer variables and constraints cannot be included. This means that more technical constraints such as start costs, no load costs, minimum up and down times and minimum generation levels cannot be included as integer constraints, and instead both generator investment and output are continuous linear variables. This approach is common in the literature (see for example Hirth (2013)), but may not be appropriate at very high levels of variable generation. For a full discussion see Shortt et al. (2012). However, the linear MCP approach taken in this paper was used to investigate the potential for added power system flexibility from demand response in Lynch et al. (2019) and was found to closely replicate the results of a far more detailed model that included integer constraints, namely that found in Nolan et al. (2017). Thus, while the full technical details of the results here may not mimic day-to-day detailed power system operation, the broad results in terms of the contribution of power-to-gas to system flexibility and renewable generation integration are likely to prove robust.

¹The derating factor in this work reflects the proportion of its overall capacity a technology can provide to meet the capacity target.

3. Input data

The model described in section 2 is applied to a case study based on the future Irish power system. For this purpose, the data used are mainly for 2025 from EirGrid (2016) where it is necessary to use projections of future data, such as future aggregate demand data. However, this paper is not an attempt to replicate or predict any particular future power system. Rather, the paper presents a generally-applicable stylised future electricity market that can be populated with data from any power system or market. For the purposes of this paper, Irish data are used only where it is necessary in order to ensure our inputs have a basis in data from a real power system. Applying this methodology to a different test system would of course lead to different results, and a well-interconnected system in particular may see a lower level of power-to-gas installation. The Irish power system, with high renewable generation and limited interconnection, benefits particularly from the storage features of power-to-gas. Demand side data are described in section 3.1. The input data related to the conventional supply side and power-to-gas is described in section 3.2 and data related to renewable generation is described in section 3.3.

3.1. Demand side data

The consumer groups considered on the demand side include commercial/industrial as well as residential consumers. Figure 1 illustrates the reference demand of the industrial and residential consumer groups on a typical day. This figure shows that the residential demand profile is less flat (the peak is more pronounced) than the industrial one. Based on EirGrid (2016), the assumed total annual electricity demand of 33.6 TWh and peak demand is 5655 MW. In terms of the quantity target for the capacity market, this is calculated as 1.2 times the system peak demand similar to Devine et al. (2019), i.e. $TARGET = 1.2 \times 5655 \text{ MW} = 6786 \text{ MW}$.

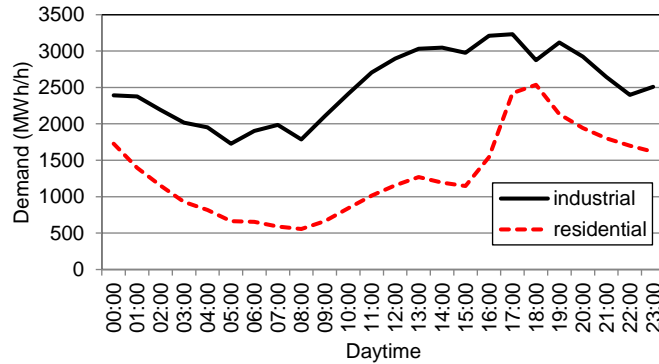


Figure 1: Reference demand of industrial and residential consumers on a typical day

3.2. Conventional power generation and power-to-gas data

On the supply side, three generic thermal technologies are considered, baseload, midmerit and peak, and utility-scale onshore wind turbines. Generation assets from the Irish power system are aggregated and categorised accordingly. Firms are assumed to be capable of investing in new thermal generation technologies, which have higher efficiencies than the existing portfolio. Table 6 shows the relevant characteristics of each unit. The annuity is calculated using the lifetimes assumed. The maximum capacity values for each technology are broadly based on EirGrid (2016). The initially installed capacity by technology is presented in Table 5. There is no power-to-gas in the initial portfolio.

Table 5: Initial generation portfolio ($CAP_{f,t}$).

Technology	Baseload	Mid merit	Peakload	Wind
Capacity (MW)	3944	916	504	4800-7680

In the portfolio analysis that follows, the existing generation assets in the table above are divided between five firms. The first firm is an integrated firm, and owns approximately half of the generation assets of each technology type. Firms 2-5 are specialised firms, and own the remaining baseload, mid merit, peaking and wind generation capacity, respectively.

Our model considers quadratic cost functions for the conventional generators as described in section 2.1, i.e. the marginal costs at the intercept increase with the power output of each generator according to the marginal cost slope $B_t^{\text{GEN}} = 0.000213$ (see Grigg, 1996). Table 6 shows the marginal power generation costs at the intercept, for further details see Bertsch et al. (2018).

There are large variations in the literature for investment costs and operational expenditures of power-to-gas units. The literature surveyed in considering these characteristics are noted and discussed in the introduction². For the electrolysis, reported values range from €300/kW (Breyer et al., 2011) to €1000/kW (Taljan et al., 2008) or even higher. Similarly, assumptions around the efficiency vary between 65% (Breyer et al., 2015b) and 90% (Yildiz and Kazimi, 2006). In this paper, the focus was on electrolysis only and assumed investment costs of €600/kW and operational expenditures of around 2% of the specific investment per year. Within the wide range of values that appear in the literature, these assumptions can be considered moderate, which seemed reasonable rather than using values at the upper or lower end of the range. These values translate into annualised specific investment costs of €43,589/MW y and fixed O& M costs of €10,897/MW y (Table 6). Moreover, an efficiency of 70%, based once again on the extensive literature survey performed, and a gas price of €18.00/MWh_{th} are assumed, which is relevant for the revenue side and operational decisions of the power-to-gas units. The implications of these cost and efficiency assumptions on the results are discussed in section 4.1.

Table 6: Techno-economic input data of supply side and power-to-gas technologies.

Technology	Annuity of specific invest (IC_t^{GEN}) (€/MW y)	Fixed O&M costs (MTC_t) (€/MW y)	Marginal power gen. costs at intercept (A_t^{GEN}) (€/MWh _{el})	Spec. CO ₂ emissions (t CO ₂ /MWh _{el})	Lifetime
Existing baseload	-	41,667	48.87	1.17	-
Existing mid merit	-	27,778	41.10	0.36	-
Existing peakload	-	23,148	63.38	0.56	-
New baseload	110,769	41,667	31.58	0.78	40
New mid merit	67,268	27,778	34.00	0.30	30
New peakload	40,363	23,148	50.50	0.45	20
Power-to-gas	43,589	10,897	0	0	30

3.3. Renewable power generation data

The variable sources of renewable electricity generation considered in this paper are wind and solar PV. In order to perform a stochastic analysis, it is necessary to consider a range of renewable power production

²The specific papers considered when arriving at the cost and efficiency assumptions in this paper are, in no particular order, Breyer et al. (2015b); Ahern et al. (2015); Breyer et al. (2011, 2015a); Palzer and Henning (2014); Hlusiak and Breyer (2012); Moeller et al. (2014); Vandewalle et al. (2015); Pleßmann et al. (2014); Heffels (2015); Taljan et al. (2008); Yildiz and Kazimi (2006); Schiebahn et al. (2015). Future work will consider a wider range of input parameters for power-to-gas units.

series, one for each of the stochastic scenarios s considered (there are six in total). Note that wind and solar PV are not only variable but also uncertain, and furthermore their uncertainties are correlated since both depend on the meteorological conditions. It is therefore important to take these correlations into account when generating input data for the stochastic MCP. By using historical wind and PV data as a basis for the analysis, the spatial and temporal correlations between wind and PV are preserved. The task at hand is therefore choosing a set of historical wind and PV data series and a set of associated probabilities that can be considered representative of the potential wind and solar output in any given year, assuming the year in question is not so far in the future as to render recent historical data as unrepresentative of potential future wind and solar output. In other words, long run climate changes are ignored when choosing wind and solar output.

The historical data considered are based on hourly MERRA2 reanalysis data (Bosilovich et al., 2016) on surface incoming shortwave flux, air temperature and wind speed for the years 1981 to 2015 inclusive. These data were then transformed to time series of wind and solar capacity factors. For wind, the transformation is based on the method outlined in Cradden et al. (2017) and Cannon et al. (2015) and the wind speed to capacity factor curve by Ofgem (2013). For solar PV, the transformation follows Ruppert et al. (2016) and Schwarz et al. (2018) using parameters for Ireland described in Bertsch et al. (2017). The hourly wind and solar capacity factor time series of 35 years, generated from the temperature and wind speed data from 1981 to 2015, were then clustered into six annual time series, each of which occurs with a predetermined probability. These time series and their associated probabilities are chosen such that they are representative of the 35 year period, and correspond to the scenarios s in the model. The chosen time series and their probabilities of occurrence are summarised in Table 7. Details of the renewable data generation and the clustering procedure are described in Bertsch et al. (2018).

Table 7: Representative years chosen for RES scenarios and corresponding probabilities of occurrence (see Bertsch et al., 2018).

Year	1983	1998	2001	2003	2004	2015
Probability of occurrence	0.486	0.286	0.086	0.086	0.029	0.029

Our assumptions in relation to the installed RES-E capacity are based on EirGrid (2016). The system studied includes 50 MW of solar PV capacity, which are installed on the demand side in this study. Moreover, the power system described by EirGrid (2016) includes 4800 MW of installed wind capacity, which are assumed to be installed and operated on the supply side. In order to meet the long-term RES-E and decarbonisation targets beyond 2025, the installed wind capacity will need to be further increased (Slednev et al., 2017). Therefore, in order to analyse how increasing levels of wind capacity affect optimal investment decisions in the power system, in particular in power-to-gas, the model is run several times while exogenously increasing the wind capacity in 10% steps (in relation to the 4800 MW installed, i.e. steps of 480 MW). Consequently, endogenous wind investment decisions are not considered. Overall, a range of 4800 MW - 7680 MW of wind on the system is considered, which corresponds to a capacity of 85% - 136% of the system peak load respectively. Note that the installed PV capacity is not varied in this paper.

4. Results

The results presented here are subdivided into two sections. In the first instance, the impacts at system and market level of the installation of power-to-gas technologies is examined. Thereafter, the impact at the level of the individual firm is examined, in terms of the changes to the profitability of the specific generation portfolio of each firm.

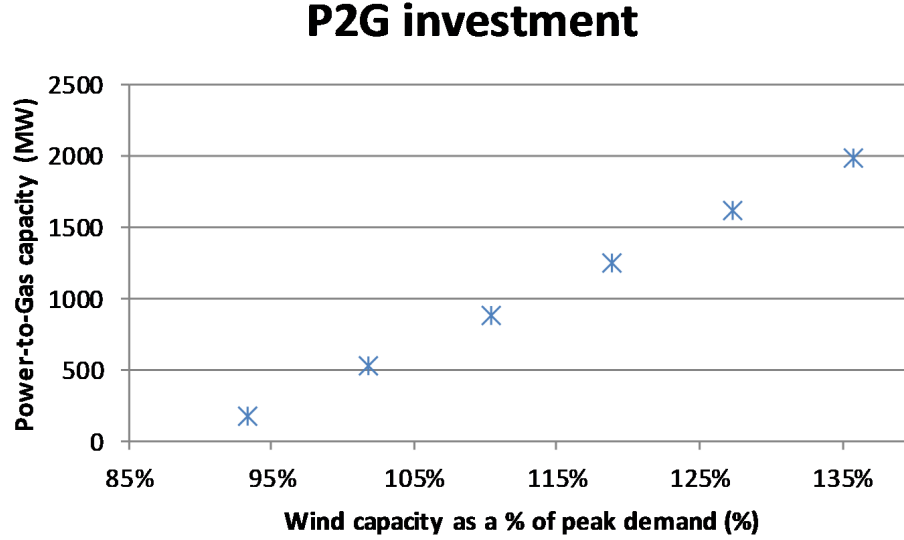


Figure 2: Optimal investment in power-to-gas technology (MW_{el}) under various installed wind capacities

4.1. System and market effects

Figure 2 shows the optimal investment in power-to-gas technology as determined by the model under all the different exogenously-chosen installed wind capacities. At lower levels of wind penetration than those displayed in Figure 2 there is no investment in any power-to-gas capacity, but once the wind capacity exceeds approximately 5280 MW (corresponding to 93% of the system peak load and a wind penetration of roughly 50% of demand) there is positive investment. This result concurs with previous literature on the topic (Heffels, 2015). The corresponding production of hydrogen ranges from 60,000 cubic metres to 1.1M cubic metres over the course of the study (which corresponds to one year), depending on the wind penetrations and power-to-gas capacities (which are shown in Figure 2).

The linear relationship between power-to-gas investment and wind capacity is a consequence of modelling the investment and output decisions of the firms as continuous linear variables. Including discontinuities in the firms' decision variables, such as modelling investment on a per unit basis, or including start costs and no load costs in the dispatch decisions, would most likely alter the linear relationship between installed wind capacity and power-to-gas investment. Altering the investment cost and/or the assumed efficiency of the power-to-gas technology would shift the curve up or down in relation to the y-axis but would not change the shape of the curve. Finally, imposing a limit on the amount of hydrogen that can be injected to the grid may impose a cap on the total installed capacity of power-to-gas, although in those cases it may prove economic to have yet higher levels of installed power-to-gas capacity if the possibility of bottling and selling hydrogen and/or further conversion of hydrogen to methane were considered. Further work will examine this potential.

Figure 3 shows the costs and revenues associated with investing in power-to-gas (when considering the technology's profits in isolation) for the scenario where the installed wind capacity on the system equals 127% of the peak demand. Under this scenario, the optimal investment in power-to-gas is approximately 1,600 MW_{el}.

The purchase of electricity to operate the power-to-gas plant yields revenue for the plant as the electricity price becomes negative whenever the amount of wind generation available is greater than the demand. At these times, the marginal cost of production is the marginal cost of wind, which is minus twenty-three euro

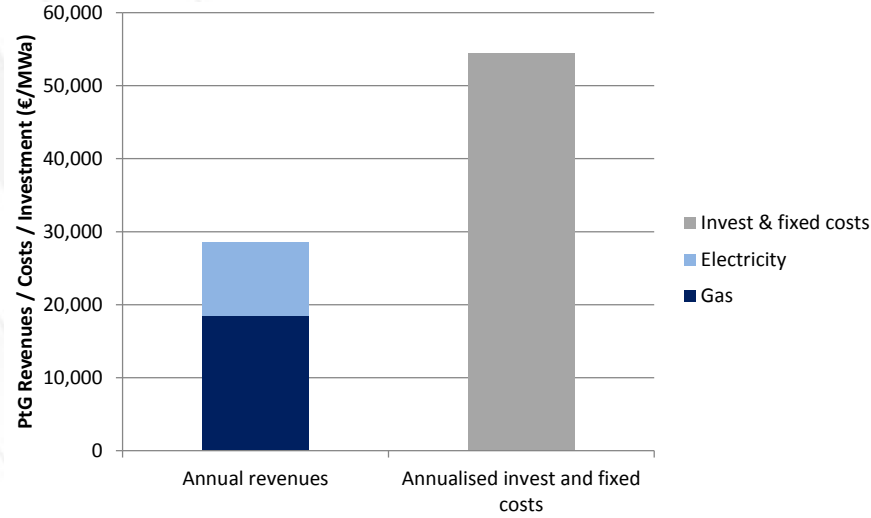


Figure 3: Cost and revenues associated with power-to-gas unit

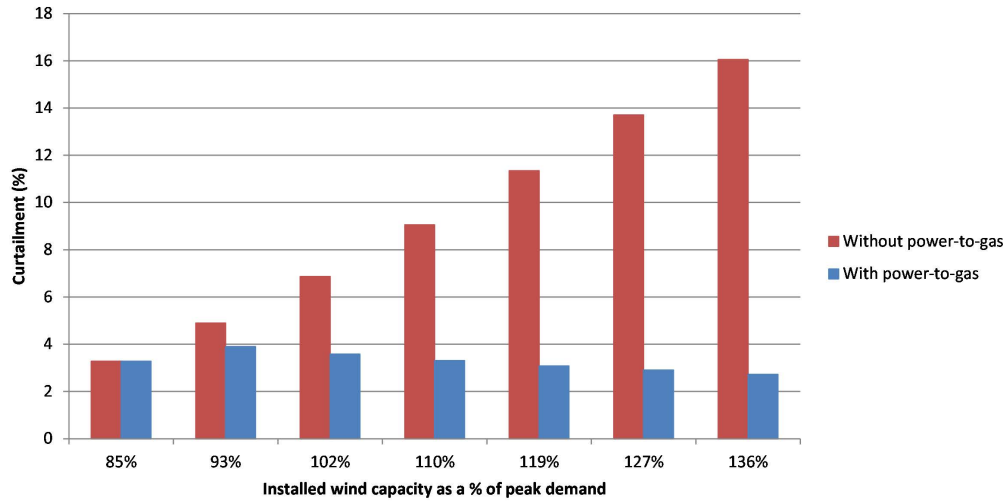


Figure 4: Wind curtailment with and without power-to-gas investment

per megawatt hour (due to wind receiving a FIP over and above the market price). Consumption of electricity during these hours therefore yields revenue for the power-to-gas plant owner. The power-to-gas unit also earns revenue from selling the hydrogen they produce. Because this paper assumes that the hydrogen is injected and sold directly back to the gas grid, the price received by the power-to-gas plant per unit of hydrogen sold is equal to the wholesale price of natural gas in €/MWh_{th}. Future work will consider the possibility of selling hydrogen on hydrogen markets, for use in industrial applications, or of converting to methane and selling the methane in the ETS or non-ETS sector.

In spite of this, the sum of the revenue from selling renewable gas at the wholesale price of gas and the revenue from consuming electricity is less than the annual capital costs of investment in power-to-gas, and so power-to-gas is a loss-making technology. Given the positive investment in power-to-gas, market or portfolio effects must render it an efficient investment. This result underlines the importance of examining investment in power-to-gas, and indeed any technology, in the context of the entire portfolio of technologies, rather than restricting focus to the profitability of the technology on a stand-alone basis.

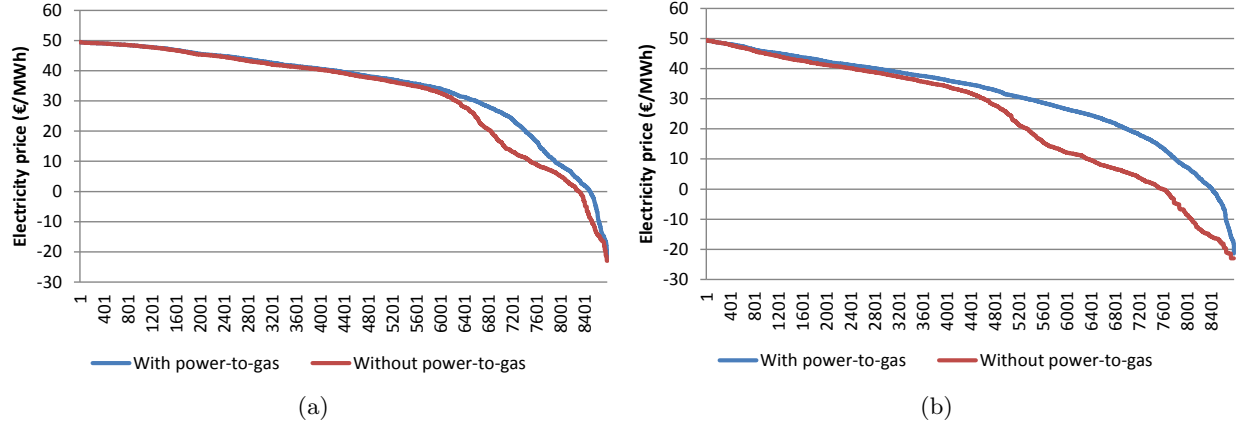


Figure 5: Price duration curves with and without power-to-gas

The model was also run without the option of investment in power-to-gas in order to isolate the impact of same. Figure 4 shows the difference in wind curtailment for the cases with and without investment in power-to-gas at each level of installed wind. In the absence of power-to-gas, the level of wind curtailment increases with the level of wind installed on the system. When allowing the players to invest in power-to-gas, however, the level of wind curtailment stays more or less at a constant level.

Figure 5 shows the market price duration curves with and without power-to-gas for levels of installed wind capacity equalling around 100% of the peak load (a) and around 135% of the peak load (b). Unlike storage technologies, which increase off-peak demand and reduce peak demand, power-to-gas only does the former by using electricity for power-to-gas production during periods of low (net) demand. Thus the upper end of the price duration curve is unchanged but off-peak prices increase significantly. This in turn increases the profits of technologies with the lowest marginal costs that generate at times of low net demand, in particular wind generation.

4.2. Firm and portfolio effects

now examine the effects of the changes to renewable integration and electricity prices seen above on generation profits. The profitability of each conventional technology type per megawatt installed is shown in Figure 6 for each of the levels of wind penetration considered. The seven shades of bars correspond to the seven different wind penetration levels chosen, with darker colours corresponding to lower wind penetrations. The profitability per megawatt installed of the existing technologies increases as wind increases. This is a consequence of retirement decisions. Installed wind capacity crowds out conventional technologies and so the revenues for each technology are distributed over a smaller total installed capacity, boosting the revenues per megawatt installed.

In the case of wind, the profit per megawatt installed decreases as the total amount of wind installed increases. This is to be expected given standard diminishing returns arguments. However, the addition of power-to-gas increases the profit per megawatt of wind relative to the case where there is no investment in power-to-gas (Figure 7). This is due to the increase in off-peak prices induced by the power-to-gas unit.

Given the technology-specific results above, it stands to reason that firms that have wind capacity as part of their generation portfolios will benefit the most from the presence of power-to-gas on the system. Figure 8 shows the profits per megawatt of installed capacity that accrue to each firm, assuming each firm was the firm to invest in power-to-gas. In other words, Figure 8 shows the profits calculated as the difference between the

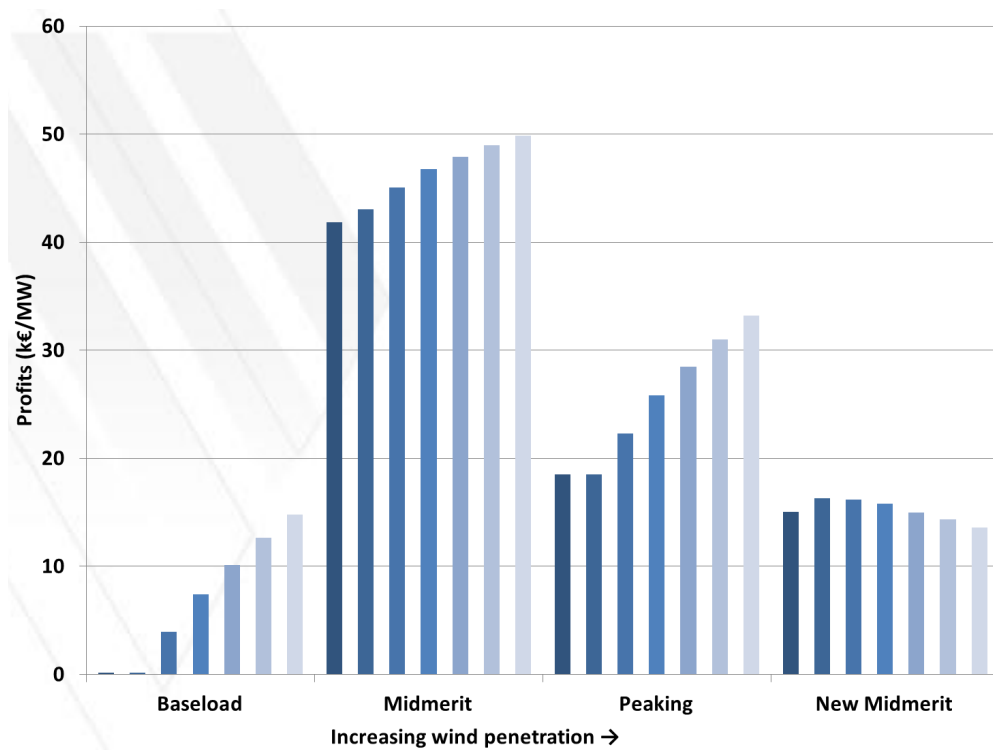


Figure 6: Profitability of each conventional technology per megawatt installed for each wind level

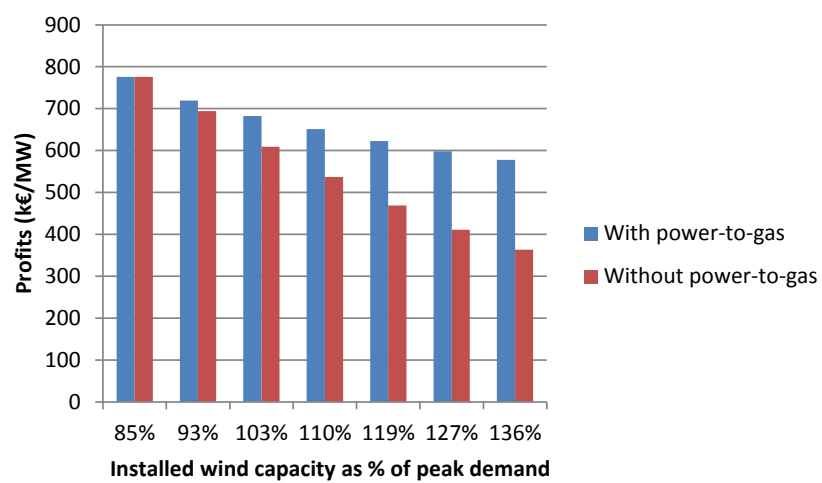


Figure 7: Profitability of wind per megawatt installed for each wind level

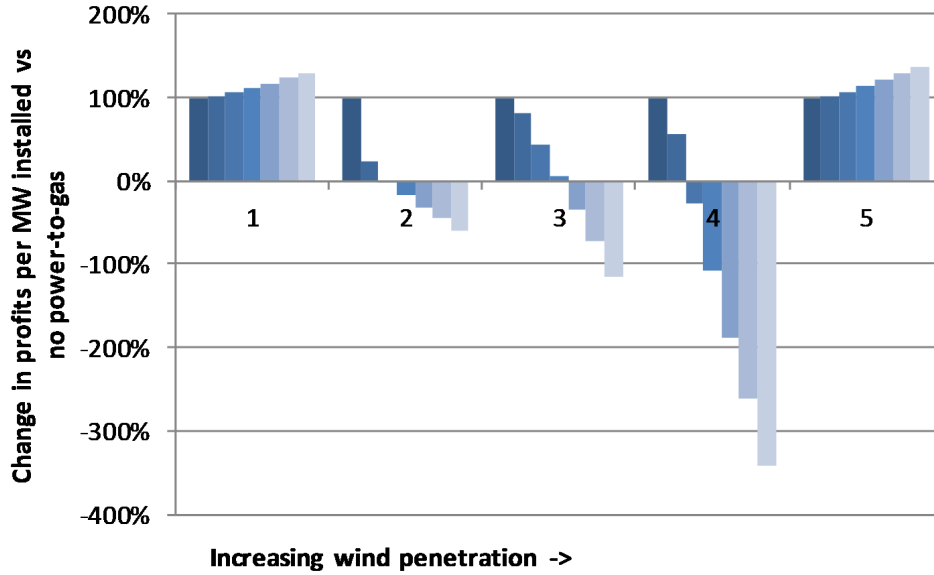


Figure 8: Profitability of each firm relative to the case with no power-to-gas

firm's revenues from the energy and capacity market revenues plus the revenues from power-to-gas operation, and the firm's generation capacity investment costs and operational costs plus the power-to-gas investment cost. As above, the seven shades of bars correspond to the seven different wind penetration levels.

As expected, firms one and five, which have wind capacity in their portfolios, see higher profits per megawatt installed for all levels of wind and power-to-gas capacity. The increase in their wind generation's profitability more than offsets the loss-making power-to-gas investment. The firms that have only conventional generation in their portfolios, however, see lower profits relative to the case where there is no investment in power-to-gas. This is because the investment cost of power-to-gas is greater than the boost in revenues from power-to-gas operation itself along with the extra revenues gained by other technologies as a result of the higher off-peak prices induced by power-to-gas.

Figure 9 shows the total cost incurred by consumers at each level of installed wind capacity, both with and without power-to-gas. These costs include energy and capacity payments paid by consumers in each market along with any subsidy payments to wind generation. Any savings from self-consumption of solar generation are also accounted for in the calculation. Consumer costs decrease with increasing levels of wind generation due to the lower electricity prices induced by wind. However, power-to-gas increases off-peak electricity prices and so increases consumer costs. Thus power-to-gas investments facilitate a transfer from electricity consumers to wind capacity owners over and above the FIP payments wind generators receive from consumers.

5. Discussion

There are several new contributions that the results above make to the literature. The importance of considering the impact of a particular technology on the generation portfolio, rather than considering the costs and benefits of the technology in isolation, is highlighted by this work. This holds both in relation to firm portfolios and market portfolios. Metrics such as Levelised Cost of Electricity (LCOE) exhibit significant weaknesses as a means of determining the relative strengths and weaknesses of generation technology

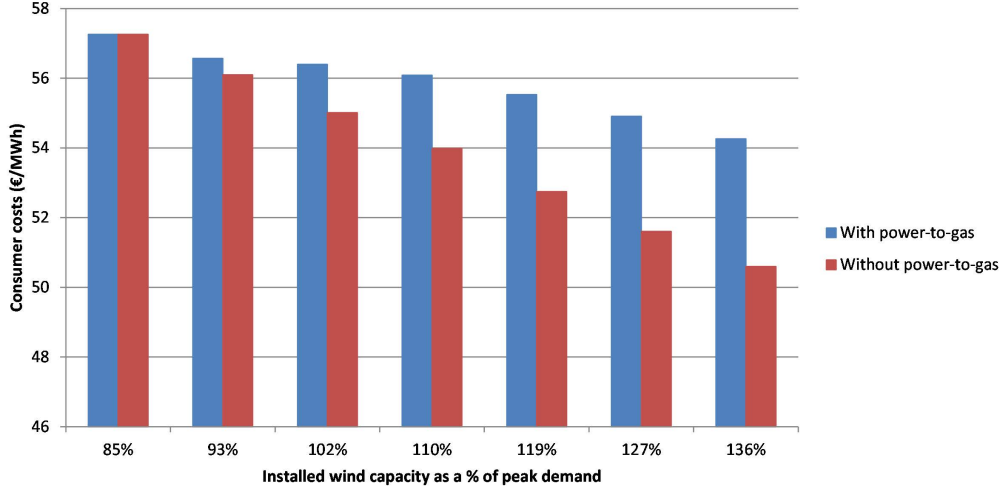


Figure 9: Total cost incurred by consumers at each level of installed wind capacity

investments (Joskow, 2011). In spite of this, such metrics are still widely used, with Musi et al. (2017); Lai and McCulloch (2017); Clauser and Ewert (2017) and Geissmann (2017) providing only recent examples. The use of net present value to determine whether to invest in a particular technology is also a poor metric as it does not consider the potential for one technology to impact on the profitability of another technology held by a given firm.

The fact that negative prices arise in our model drives the results, at least to some extent. These negative prices incentivise investment in power-to-gas, which in turn raises market prices and thus consumer costs (Figure 9). Thus the subsidy paid by consumers to wind generators leads to them paying yet higher electricity prices, and there is a greater total transfer from consumers to wind power producers in the presence of power-to-gas compared to a scenario with no power-to-gas. This is in addition to the carbon cost already incurred by consumers.

Our model does not include a carbon credit for the production of renewable gas. However, the inclusion of same may increase investment in power-to-gas, and thus electricity prices, even further. Thus the total transfer from consumers to wind power producers depends not only on the subsidy for wind generation but also on the whole electricity generation portfolio and on the interaction of various policy instruments. Interactions between carbon pricing and renewable subsidy schemes have been studied in the literature (see for example Brown et al. (2018) and Abrell and Weigt (2008)), but to our knowledge this effect has not been studied in the context of a specific technology such as power-to-gas, nor have the distributional implications between consumers and producers been studied. This has important implications for policy-makers considering optimal renewable subsidisation and carbon taxation and may be the focus of further work.

For simplicity, it was assumed that the gas is sold back onto the gas grid, and thus avoided the inclusion of the costs of storing and transporting hydrogen for use in industry and elsewhere. However, hydrogen can also be used to make carbon-neutral methane, which can be sold in the non-ETS sector as well as being injected into the gas grid and used in the power generation sector. In Ireland, the carbon tax that applies in the non-ETS sector (currently €20) is less volatile than the ETS price, and so carbon-neutral gas in the non-ETS sector would enjoy a greater or smaller price premium versus natural gas compared to the premium that would apply in the ETS sector. Regardless the potential for power-to-gas to reduce carbon emissions

by producing carbon-free gas has implications not considered here.

There is of course potential for competing technologies to crowd out the investment opportunities for power-to-gas. For example, storage technologies that, like power-to-gas, increase off-peak electricity generation, but also reduce peak generation, reduce the potential impact of power-to-gas on wind owners' profits. In particular, consumers may have an incentive to invest in storage technologies, as they can reduce their exposure to peak prices as well as increasing their off-peak price exposure, and so may incur lower costs than those incurred with power-to-gas investment. This paper focused on power-to-gas only in order to fully examine the interaction between power-to-gas and other aspects of the power generation sector. However the trade-offs between power-to-gas versus other potential generation investments should be further explored and will be the focus of future work.

This paper considered optimal investments in a one-year framework. However expanding this work to a repeated game may yield further insights as the timing of investments is important. Given that investments in power-to-gas may render potential storage investments by consumers and other firms less profitable and vice versa, there may be an optimal time to invest in each technology. Similarly, the presence of power-to-gas on the system benefits all players that own wind generation, with the greatest net benefit going to firms that own wind but do not own power-to-gas, and so do not incur the cost of the power-to-gas investment. There is thus an option value of waiting inherent in power-to-gas investment, as a firm's optimal strategy would be to invest in wind given that a rival firm invests in power-to-gas. Future work may explore these possibilities. Moreover, this work modelled all firms as price-takers; however in reality electricity markets are characterised by oligopoly. The presence of price-makers in the market may change the optimal level of investment in each technology, including power-to-gas, as price-making behaviour in the energy market would raise prices, rendering all generation investments more profitable. The divergence of power-to-gas investment, if any, when price making behaviour is introduced may also inform discussion on whether there is an external cost or benefit to power-to-gas investment, and therefore whether a tax or a subsidy is justified. Further work will consider the implications of price-making behaviour on the results presented here.

6. Conclusion

This paper presented a stochastic mixed complementarity model to understand what level of power-to-gas is optimal, what determines this level, and which market player(s), if any, have an incentive to invest in this technology. Generation firms maximise their profits from an electricity market and consumers minimise their cost of electricity usage. The model endogenously determines optimal investment decisions and operational decisions of generation and power-to-gas technologies.

Power-to-gas investment occurs once the wind penetration exceeds roughly 50% of electricity demand and increases with wind penetration. However, power-to-gas itself is a loss-making technology. Nevertheless, firms with renewable generation in their portfolio have an incentive to invest in power-to-gas because power-to-gas increases the electricity demand in hours of low net demand and, hence, increases electricity prices in those hours. The resulting increase in profits from renewables outweighs the losses the firms make from the power-to-gas investment. These findings underline the importance of considering portfolio and market effects of technology investments rather than considering the profitability of investments in isolation. Metrics such as LCOE are incapable of reflecting the portfolio effects captured by this methodology.

Renewable curtailment stays more or less constant in the presence of power-to-gas, but increases with the level of wind capacity on the system if firms do not have the option to invest in power-to-gas. Power-to-gas thus has the ability to accommodate renewable generation. However, these wider benefits of power-to-gas are

paid for by electricity consumers, whose costs increase in the presence of power-to-gas. Future research should therefore include competing technologies (e.g., distributed storage technologies) as possible investments on the demand side.

Appendix A. Karush-Kuhn-Tucker conditions

This appendix presents the Karush-Kuhn-Tucker (KKT) conditions for optimality for the two types of players modelled in this work. These conditions, along with the market clearing conditions (6), make up the mixed complementarity problem. The ‘perp’ notation $0 \leq a \perp b \geq 0$ is equivalent to $a \geq 0$, $b \geq 0$ and $a \cdot b = 0$.

Appendix A.1. Firms’ KKT conditions

The firms’ KKT conditions include all those from Appendix A.1 of Bertsch et al. (2018) in addition to:

$$0 \leq gen_{f,p,s}^{P2G} \perp -PR_s(C^{\text{GAS}} - \gamma_{p,s} \times (1/EFF)) + \lambda_{f,t,p,s}^3 \geq 0, \quad \forall f, p, s, \quad (\text{A.1})$$

$$0 \leq inv_f^{P2G} \perp IC^{P2G} - \sum_{p,s} EFF \times \lambda_{f,p,s}^4 + \lambda^5 \geq 0, \quad \forall f, \quad (\text{A.2})$$

$$0 \leq \lambda_{f,p,s}^3 \perp -gen_{f,p,s}^{P2G} + EFF \times (CAP_f^{P2G} + inv_f^{P2G}) \geq 0, \quad \forall f, p, s. \quad (\text{A.3})$$

Appendix A.2. Consumers’ KKT conditions

The consumers’ KKT conditions are

$$0 \leq g_{k,p,s}^{\text{ls}} \perp -PR_s(\gamma_{p,s} - \frac{\partial C_{k,p}^{\text{LS}}}{\partial g_{k,p,s}^{\text{ls}}}) + \mu_{k,p,s}^1 + \mu_{k,p,s}^8 \geq 0, \quad \forall k, p, s, \quad (\text{A.4})$$

$$0 \leq g_{k,p,s}^{\text{micro}} \perp -PR_s(\gamma_{p,s} - \frac{\partial C_{k,p}^{\text{MICRO}}}{\partial g_{k,p,s}^{\text{micro}}}) + \mu_{k,p,s}^4 + \mu_{k,p,s}^8 \geq 0, \quad \forall k, p, s, \quad (\text{A.5})$$

$$0 \leq g_{k,p,s}^{\text{pv}} \perp -PR_s(\gamma_{p,s} + X^{\text{PV}} - C_{k,p}^{\text{PV}}) + \mu_{k,p,s}^5 + \mu_{k,p,s}^8 \geq 0, \quad \forall k, p, s, \quad (\text{A.6})$$

$$0 \leq \mu_{k,p,s}^1 \perp -g_{k,p,s}^{\text{ls}} + G_k^{\text{LS,MAX}} \geq 0 \quad \forall k, p, s, \quad (\text{A.7})$$

$$0 \leq \mu_{k,p,s}^2 \perp -g_{k,p,s}^{\text{micro}} + INT_k^{\text{MICRO}} \geq 0 \quad \forall k, p, s, \quad (\text{A.8})$$

$$0 \leq \mu_{k,p,s}^3 \perp -g_{k,p,s}^{\text{pv}} + INT_k^{\text{PV}} \times NORM_{p,s}^{\text{PV}} \geq 0 \quad \forall k, p, s, \quad (\text{A.9})$$

$$0 \leq \mu_{k,p,s}^4 \perp -g_{k,p,s}^{\text{ls}} - g_{k,p,s}^{\text{micro}} - g_{k,p,s}^{\text{pv}} + D_{k,p}^{\text{REF}} \geq 0 \quad \forall k, p, s. \quad (\text{A.10})$$

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