The effect of electricity markets, and renewable electricity penetration, on the levelised cost of energy of an advanced electro-fuel system incorporating carbon capture and utilisation

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Abstract

Power-to-Gas (P2G) is a technology that converts electricity to gas and is termed gaseous fuel from non-biological origin. It has been mooted as a means of utilising low-cost or otherwise curtailed electricity to produce an advanced transport fuel, whilst facilitating intermittent renewable electricity through grid balancing measures and decentralised storage of electricity. This paper investigates the interaction of a 10MW$_e$ P2G facility with an island electricity grid with limited interconnection, through modelling electricity purchase. Three models are tested; 2016 at 25% renewable electricity penetration and 2030 at both 40% and 60% penetration levels. The relationships between electricity bid price, average cost of electricity and run hours were established whilst the levelised cost of energy (LCOE) was evaluated for the gaseous fuel produced. Bidding for electricity above the average marginal cost of generation in the system (€35-50/MW$_e$h) was found to minimise the LCOE in all three scenarios. The frequency of low-cost and high-costs hours, analogous to balancing issues, increased with increasing shares of variable renewable electricity generation. However, basing P2G systems on low-cost (less than €10/MW$_e$h) hours alone (999 hours in 2030 at 60% renewable penetration) is not the path to financial optimisation; it is preferential to increase the run hours to a level that amortises the capital expenditure.

Keywords:

Power-to-gas (P2G); Levelised cost of energy (LCOE); Renewable Energy Storage; Electricity Market; Electrofuel; Optimisation.

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1. Introduction

The impact of climate change and the harmful nature of fossil fuels are well established. In response to this the European commission has set a target of at least an 80% reduction in greenhouse gases (GHGs) by 2050 relative to 1990 levels, with the ultimate goal of keeping climate change below 2°C [1,2]. It is estimated that achieving such a target will require a 75-80% share of low carbon technologies in the power sector [1]. Wind, and increasingly solar, will make up the majority of this variable renewable electricity (VRE) generation, as they are the current state of the art technologies available at the required scale. The EU have also encouraged the need for sustainably-produced third generation (advanced) biofuels, which must hold at least a 3.6% share of energy in transport by 2030 [3]. Transport is a particularly difficult sector to achieve emissions reductions in; the EU suggest anything from a potential increase of 20%, to a reduction of 9% in transport emissions by 2030 in their roadmap to a low carbon economy in 2050 [1]. However, heavy goods vehicles and captive fleets are especially suited to early adoption of renewable gaseous fuels where growing restrictions on particulate emissions, more predictable vehicle usage, stronger influence of policy, and increasing deployment of refuelling infrastructure facilitate the uptake of compressed natural gas (CNG) vehicles [4,5].

Increasing shares of VRE in the electricity mix can give rise to issues of grid balancing, stability, curtailment, and an increased need for storage, potentially affecting security of supply [6–9]. Large scale and flexible energy storage options are seen as a means of reducing these effects [10–12]. Presently deployed solutions such as pumped hydro storage are insufficient should significant dispatch down of VRE be avoided as they are limited by geography, and currently installed capacities are much less than the anticipated future requirements [13–15].

Power-to-Gas (P2G) has been proposed as a technology that can provide a storage mechanism for VRE and ultimately can produce an advanced transport fuel, that will help satisfy the EU target of 3.6%. P2G is a process whereby electricity is used to generate hydrogen (H_2) via the electrolysis of water, and this hydrogen can then be combined with CO_2 to produce methane (CH_4) via a Sabatier reaction ($CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$). Thus, P2G changes the energy vector, storing electricity in the form of methane, also known as gaseous fuel from non-biological origin. The technology does not require the favourable geography of other electricity storage options [10] and offers superior storage capacity and discharge times since the gas is of similar quality to natural gas and can be injected in to the natural gas grid, where it can access available markets [16]. It is intended that the fuel produced be used in the transport sector, and not for heating or power generation, as the availability of alternatives or low round trip efficiency of these routes make it inappropriate, especially considering the difficulties in decarbonising transport [4]. The ability of P2G to rapidly ramp up and down demand allows P2G to utilise difficult to manage electricity that may otherwise be curtailed [17–20]. Therefore, it can in theory provide ancillary grid balancing services that enable further integration of VRE into the electricity mix [4,21]. It may also receive a fee for this service, aiding its economic viability. Furthermore, P2G can be positioned as a novel biogas upgrading solution, utilising its CO_2 content, increasing the sustainability of biogas plants, potentially offsetting some of the capital required, and promoting a circular economy [18,22].

Many technology reviews and studies are available which detail the working principles, relative advantages and disadvantages, and trends in P2G technologies [18,19]. Wide scale deployment of P2G will be largely dependent on the cost of the gas produced and how it compares to competing advanced transport fuels. Previous work by the authors found the levelised cost of energy (LCOE) of a P2G system to be dominated (56%) by electricity costs and highly sensitive to changes in capacity factor (run hours) [23]. This paper aims to demonstrate that the figures for run hours and electricity cost are dependent on the market in which the P2G plant is engaged and are largely determined by the electricity bid price, that is, the maximum amount the plant is willing to pay for electricity at any given time (€/MW_eh). To test this, a P2G system will be modelled as a large flexible consumer within an electricity market, represented by the Irish grid with limited interconnection, in 2016 and simulations of the 2030 market at different penetrations of VRE.

The relationships between a P2G system, its bid price, and the resultant effect on LCOE will be examined. This work advances upon previous research where values for electricity cost and run hours were fixed or independent of one another [20,24–26]. The operational impact and effects of curtailment on P2G have been studied previously [10,13,27] but not with the intention of observing the impact on the financial viability of P2G, as in this study. In this work, the bid price, which the facility has control over, will be optimised to minimise the cost of the produced gas. To the best of the authors' knowledge this has not been done before.

The objectives of the paper are to:

- Examine electricity market data for trends that will affect P2G viability.
- Investigate the interactions between the electricity market and the LCOE of a P2G system modelled as a large flexible consumer.
- Examine the theory that P2G can be run economically off otherwise curtailed electricity, at different levels of VRE penetration on an island grid.
- Identify the optimum bid strategy that minimises the LCOE of gaseous fuel from non-biological origin.

2. Methodology

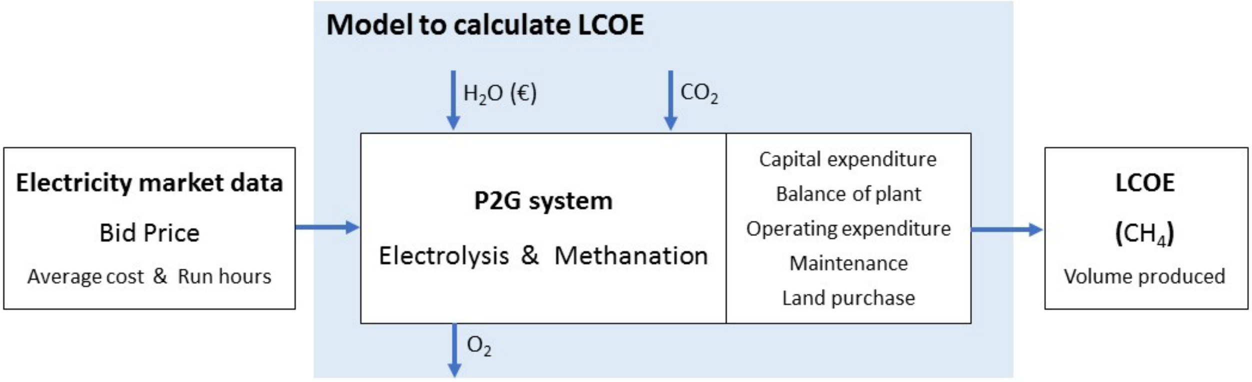


Figure 1. Inputs and outputs of the model used to calculate LCOE.

2.1 P2G model to calculate LCOE

In a previous study by the same authors, a model of a P2G system was built in order to calculate the LCOE (equation 1) for a range of cost scenarios and time periods [23]. This process or "Model to calculate LCOE" is indicated in Figure 1. The LCOE, or breakeven selling price of the gas, was chosen as the key metric as it accounts for the project capital and allows for easy comparison with other fuels. It is derived using a bespoke discounted cash flow model in MS Excel®. Firstly, the most suitable technologies for electrolysis and methanation were identified; details of these calculations and explanations of rationale can be found in McDonagh et. al [23]. Secondly, the specifications of the chosen technologies (polymer electrolyte membrane (PEM) electrolysis and catalytic methanation) were fed into the model such that capital expenditure (CAPEX), balance of plant (BoP), operating expenditure (OPEX), maintenance, and other associated costs could be accounted for. The model runs for 30 years (including 3 years commissioning, 1 year decommissioning at a cost of 20% CAPEX) at a discount rate of 7%, during which time the electrolysis stack and the methanation unit are replaced three times and once respectively. Again, a more detailed description can be found in a previous paper [23], wherein the model used fixed values for average electricity cost and run hours (€35/MW_eh and 6500 respectively) analogous to a P2G system operating in the 2020 Irish electricity market at a bid price of €50/MW_eh. In this paper however, the electricity market data affects the LCOE as the average cost of electricity and the run hours are dependent variables fed into the model. In Equation 1, "Costs" then consist of the items detailed in Figure 1 and this paragraph.

$$LCOE = \frac{\sum_{i=0}^{n} \frac{Costs\ in\ year\ i}{(1+Discount\ rate)^i}}{\sum_{i=0}^{n} \frac{kWh\ of\ gas\ produced\ in\ year\ i}{(1+Discount\ rate)^i}} \tag{1}$$

The P2G system then consisted of a 10MW$_e$ PEM electrolyser, which was considered more suitable than an alkaline electrolysis cell (AEC) and solid oxide electrolysis cell (SOEC). McDonagh et. al [23] also contains detailed analysis of the technologies and their applicability to P2G, and concluded that given the superior efficiency of PEM in the time period being assessed it would be justified to pay up to 46.7% more in CAPEX under base conditions, and still minimise LCOE. Other factors considered were the ability to quickly ramp up and down (allowing for grid service provision), OPEX, technology readiness level, and purity of hydrogen [18,24,28,29]. Similarly, catalytic methanation (CM) was chosen over biological methanation (BM) due to faster rates of production and lower specific energy consumption, despite its higher capital cost [18,30,31]. Also included was a small volume of hydrogen storage to act as a buffer for the dynamic operation of the electrolysers and methanation reactors [19,31,32].

The effect of incentives or valorisation of the oxygen produced during electrolysis will not be considered in this paper, nor will parameters beyond the control of the P2G operator. The perspective is that a P2G plant has been built and is operating in the 2030 Irish electricity market thus, measuring the effect of changes on the LCOE is sufficient to examine the relationships and observe whether optimisation is being achieved. The 2030 base scenario identified in McDonagh et al. [23] yielded an LCOE of €105/MWh and is used as the reference scenario in this paper (Table 1). In the same scenario, approximately 60% of the LCOE consisted of electricity costs as reported in McDonagh et al. [23], therefore changes in the interaction with the electricity market will have a large bearing on the LCOE.

Table 1. Economic assumptions in the model

	Electrolysis	**Methanation**	**Note**
CAPEX (€/kW$_e$)	700	140	1. BoP, OPEX, and Component Replacement given as decimal fractions of CAPEX. 2. Plant runs for 30 years. 3. Electrolysis stack replaced in years 10, 17, and 24. 4. Methanation catalyst replaced in year 15. 5. "Land Capital" costs of €(18.7(kW$_e$ of electrolysers) + 331313) for facilities greater than 1MW includes for additional costs E.g. H_2 storage, planning, etc [23]. 6. Figures are in 2016 euros.
BoP	0.15	1	
OPEX	0.032	0.057	
Component replacement	0.32	0.8	
Electrical demand	4.66 kWh/m^3 H_2	0.13 kWh/m^3 CH_4	

2.2 Source of carbon dioxide

The envisaged system is capable of utilising any source of CO_2 that has been sufficiently scrubbed of impurities and potential catalytic poisons such as chlorine compounds or hydrogen sulphide [18,31]. Many potentially low-cost and relatively pure sources have been identified including CO_2 from industrial processes (including biogenic sources should upgrading already be in place), or biogas (mixtures of CH_4 and CO_2 from biological processes), where direct utilisation avoids the significant cost of traditional upgrading. Previous works have investigated the possibility of utilising various sources of CO_2 such as that from distilleries, wastewater treatment plants, cement production facilities, and others, and found them to be suitable and abundant [33,34]. This means that provided the facility is appropriately located, and the electrolysers appropriately sized, producing sufficient hydrogen is the limiting factor. As P2G costs have been shown not to scale significantly above 1MW, the economics of these potentially small facilities do not differ greatly, any increases seen would be more than offset by the availability of cheap CO_2 [35].

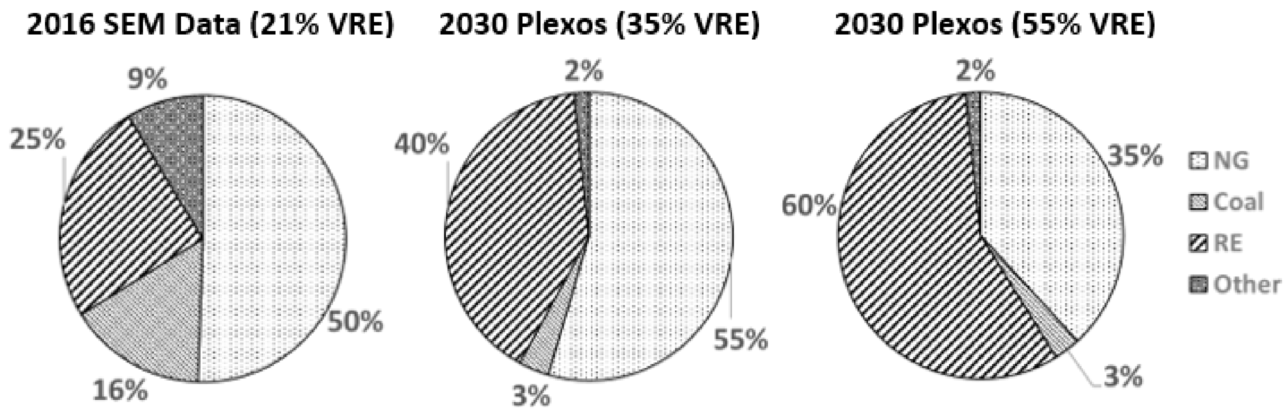
The model does not include an explicit cost of CO_2 as this would make the LCOE site specific and does not affect the results in terms of evaluating whether optimisation is being achieved in the systems interaction with the grid, as the paper intends. Further to this, a study from ENEA Consulting used a highly conservative figure of €50/ton of CO_2 transported at 10 bar and found it added a maximum of 4.5% (€8/MWh) to the LCOE. Sensitivity analysis showed that varying this figure between €20 and €80/ton resulted in a ±3% change to the LCOE [28].

The ideal source of CO_2 is biogenic and located close to the P2G facility such that the product gas has a lower carbon intensity, as would be the case if P2G were used as a novel biogas upgrading method for an anaerobic digestion (AD) system [36,37]. It is also relatively pure thus, avoiding the high energy penalty associated with direct air capture or capture from flue gases [33]. It is anticipated that in the time period analysed, AD systems will become much more prevalent.

2.3 Electricity Market Data

The system marginal price (SMP) can be considered as the hourly or half-hourly island wide wholesale price of electricity. It includes for the cost required to meet the forecast demand and additional costs associated with start-up or operating as a reserve that a generator will need to recover (costs known as uplift). In general, the SMP is low when there is more than sufficient generation capacity online to meet demand. When the amount of generation online to meet demand is scarce, the resulting SMP is higher. The SMP is set by the marginal costs of the last generator online to meet demand. In Ireland this is often gas fired generation. The SMP is also influenced by zero marginal cost VRE which tends to supress the SMP in times of high VRE production. In times of excess VRE generation, curtailment may take place. Current electricity market rules offer VRE priority dispatch on the electricity grid, therefore curtailment of VRE is often a last resort. In analysing the electricity market data, it is proposed that very low SMPs (less than €10/MW_eh) can be equated with curtailment and high VRE production; strong positive correlation has been found between increased shares of VRE and the periodic availability of low-cost electricity [38]. For the purposes of this study, information for the half hourly SMP of electricity for 2016, available for download from the single electricity market (SEM) operator [39], was collected and organised in spreadsheets.

To determine the SMP in 2030, PLEXOS models of the electricity market were developed. PLEXOS Integrated Energy Model is a power systems modelling tool used for electricity market simulations [40]. The power systems model develops an hourly SMP for the Irish electricity market based on current rules, and it has been benchmarked against historic market data and has been validated by the regulator to reproduce realistic results. The model uses deterministic mixed integer linear optimisation to minimise the costs of the electricity dispatched including for fuel costs, start-up costs, penalties for unserved energy, and a penalty cost for not meeting reserve requirements [41]. The model optimises thermal generation (fossil fuel and renewable), VRE, pumped storage, interconnection, as well as reserve classes subject to operational and technical constraints [27,42]. Also included are constraints on the unit operation of each power plant including minimum and maximum generation, minimum and maximum up and down time and the system ramp up and down rates, as well as a system level constraint consisting of an energy balance equation ensuring supply meets regional demand at each period [27]. Two PLEXOS models were tested, at 40% and 60% renewable electricity (RE) respectively. Thus, as outlined in Figure 2, three models in total were examined.



NG – Natural Gas, RE – Renewable Energy, VRE – Variable Renewable Energy

Figure 2. Details of the three electricity market models used in this study and the levels of RE and VRE in each.

Renewable energy (% RE) is calculated as delivered MW_eh of electricity from all renewable sources, as a percentage of total delivered electricity. Variable renewable energy (% VRE) then only includes intermittent sources (wind, solar, and wave), and not those that are dispatchable and therefore do not contribute to the fluctuations in supply that would affect price (CHP, co-firing of biomass, and hydropower). The "Other" portion of these charts consists mainly of peat with small volumes of heavy fuel oil, both of which are dispatchable thermal generators.

These represent the current (2020) and future (2030) targets for Ireland [43]. The vast majority of this RE will be provided by wind and other intermittent sources. The 40% RE scenario is representative of a case where the rate of new installed RE capacity does not increase drastically beyond the levels seen today. The 60% RE scenario requires the rate of additional installed capacity of RE to substantially outpace that of increasing demand. Both scenarios are feasible and therefore their implications on P2G worthy of investigation.

2.4 Calculating run hours and average cost of electricity from the models

In this study, the envisaged system engages in the electricity market without priority as a large consumer, a similar purchaser approach was used to model charging electric vehicles [44]. This means that the consumption of electricity is technology neutral and that P2G will compete for energy (against storage or interconnection for example) as it would in a functioning electricity market. The P2G plants are assumed to be ideally flexible and the model does not include constraints or costs for start-up and shut-down. No mechanism or widespread precedence has been set that would allow a plant to consume energy, even that which would otherwise be curtailed, without engaging in the electricity market. This also means that as of now P2G cannot directly benefit from its ability to provide grid balancing services and receive “free” electricity, with some rare exceptions [45,46], though this is the subject of much discussion [10,14,47–49]. Thus, the bid price of the plant directly informs the number of runs hours. The formulae in equations 2, 3 and 4 were used to extract figures for run hours and average cost of electricity.

$$Run\ Hours\ (2016) = \frac{\sum Half\ hourly\ intervals\ for\ which\ SMP < Bid\ price}{2} \quad (2)$$

$$Run\ Hours\ (2030) = \sum Hourly\ intervals\ for\ which\ SMP < Bid\ price \quad (3)$$

$$Average\ Electricty\ Cost = \frac{\sum SMP\ of\ Intervals\ for\ which\ SMP < Bid\ Price}{Resultant\ Annual\ Run\ Hours} \quad (4)$$

3. Results and discussion

3.1 Electricity market data relevant to P2G

Figure 3 illustrates for how many hours in the year (2016 or 2030) electricity was available at a given price (€/MW_eh). As expected there is a significant jump between €30/MW_eh and €45/MW_eh in all three datasets, the approximate range of the marginal cost of the large generators in the system. This implies that generation and demand are relatively matched for the majority (>5500 hours) of the year, limiting the opportunities for P2G to take advantage of system imbalances. At certain times, the SMP was also greater than €300/MW_eh (typically less than 0.5% of the year) but this data was excluded in order to avoid skewness of the graph. An SMP of over €300/MW_eh corresponds to times when demand significantly exceeded production.

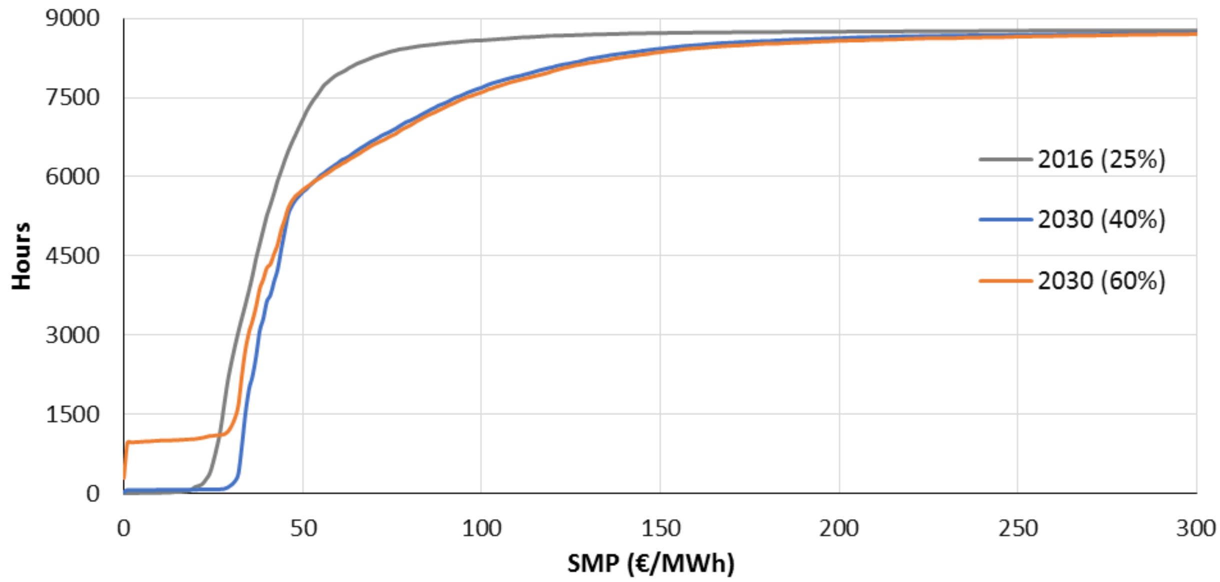


Figure 3. Cumulative number of hours for which electricity is available at a given SMP

Table 2. The average SMP throughout the year for each of the electricity markets tested

Electricity market	**2016 (25%)**	**2030 (40%)**	**2030 (60%)**
Average SMP (€/MW$_e$h)	41.83	58.91	56.08

Table 2 gives the average system marginal price in each of the scenarios tested. For a number of reasons, the costs in 2016 are lower than those of the 2030 models. Within the 2030 models some of the increased electricity costs can be attributed to a projected increase in the use and price of natural gas, carbon taxes, and increased uplift costs. Natural gas traded at an unusually low average of €2.27/GJ plus shipping and charges in 2016 [50] and is included in the model at €3.84/GJ. It accounts for 43% of generation in 2016, 54% in 2030 (40% renewable penetration scenario), and 38% in 2030 (60% penetration scenario) [43]. The cost of coal falls from €2.77/GJ [51] to €1.58/GJ but accounts for only 3% of generation in 2030 compared to 17% in 2016 [43]. The carbon tax increases from €5.34/tonne [52] to €33/tonne whilst the uplift costs increase substantially from €3/MW$_e$h to approximately €56/MW$_e$h. These costs are reflected in the SMP, and as the LCOE of a P2G facility is a function of the electricity market as a whole, it will also increase. It must also be noted that the average SMP is an incomplete measure of whether P2G LCOE will increase as the bid price methodology (outlined in section 2.4) aims to take advantage of periods of lower cost electricity, and switch off during high cost periods. It is not possible to accurately infer the LCOE from an average SMP, hence the need for further examination of the electricity market.

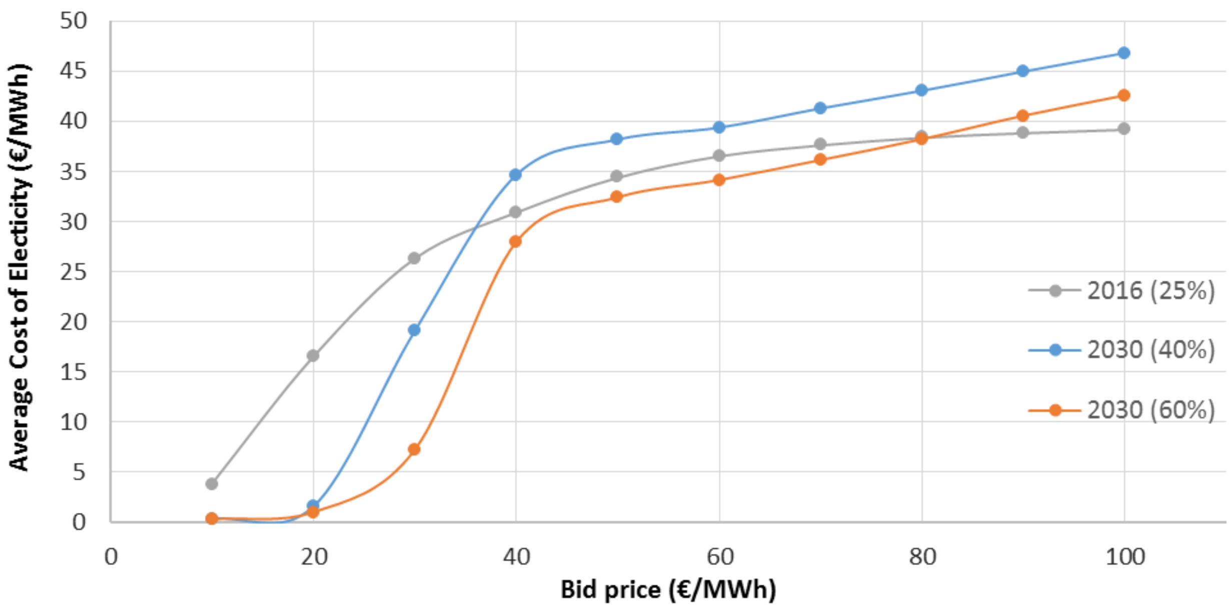


Figure 4. Change in average cost of electricity with increasing bid price

Figure 4 shows that the average price paid for electricity does not vary linearly with increasing bid price. At low bid prices there are very few run hours available, consisting of mostly near zero cost energy associated with difficulties in balancing the network. This is seen as the low, almost flat parts of the graph between €0-20/MW$_e$h. As the bid price is increased the number of hours during which the plant will now run increases rapidly. As higher price electricity is incorporated, the average cost increases. The large increase is then simply due to the plant moving from consuming a few hours of low cost energy, to a much greater number of hours of energy at a significantly higher cost. The sharp rise at ca. €30/MW$_e$h corresponds to the jump in cumulative run hours around the average marginal cost of generation, noted in Figure 3. However, above ca. €50/MW$_e$h the numbers of additional units of electricity purchased now make up a less significant portion of the total and thus, despite their high cost do not affect the average to the same extent.

The exception being the 2016 data whose hourly prices were not so concentrated around the average marginal cost of production and where the lower levels of VRE penetration did not lead to these periods of low-cost energy resulting from grid imbalances. This leads to a more gradual increase in average cost versus bid price.

Similarly, Figure 5 shows that increasing the system bid price increases the run hours non-linearly. Again, a sharp rise occurs at ca. €30/MW$_e$h corresponding to the large increase in cumulative run hours seen in Figure 3. The available run hours are greater in 2016 (25%) despite the smaller share of VRE as the cost of electricity is lower, therefore the bid price will be above the SMP for more of the time. Hours with SMP greater than €100/MW$_e$h also occur much less frequently in 2016 (25%) than in either 2030 model. Only at bid prices less than €25/MW$_e$h are there notably more run hours in the 2030 (60%) model than in either of the others. This implies that penetration levels of 60% RE are required in order to see substantial periods of low-cost energy due to difficulties in integrating VRE [8]. This also suggests that the existence of such low-cost periods (as seen in the 2030 (60%) model) does not necessarily increase the total hours a system will run for; an overall lower average cost of electricity does this to a greater extent.

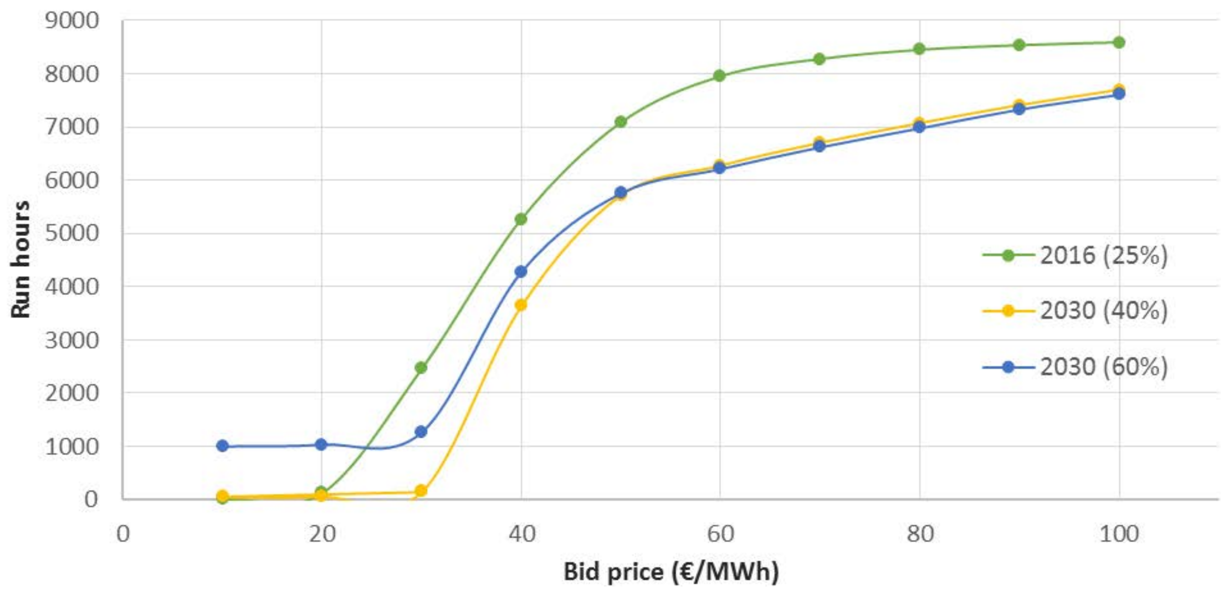


Figure 5. Change in run hours with increasing bid price

This paper attempts to investigate the interactions between the bid price of a P2G system and its LCOE by looking at the effect on both run hours and electricity cost (inputs for the discounted cash flow model). Previous studies have shown that the electricity cost and run hours are highly sensitive parameters in determining the LCOE of P2G system [24,28,53–55]. The author's previous work explicitly identifies them as the two most sensitive process inputs [23]. This leads to the possibility of optimising the bid price (the parameter a P2G facility operator ultimately has control over and the one under investigation) to minimise the LCOE of a system. Other parameters such as curtailment, interconnection, and market rules are reflected in changes in the SMP, and hence the average cost of electricity and run hours. Thus, run hours and average price of electricity are sufficient to ascertain whether optimisation is occurring with respect to bid price. To the best of the authors' knowledge this has not been examined previously.

3.2 P2G interactions with the electricity market and effect on LCOE

Figure 6 outlines the increase in LCOE with the increase in average cost of electricity. For instance, increasing the average cost of electricity from €10/MW$_e$h to €40/MW$_e$h, a 300% increase, produces a 90% increase in the LCOE (from €60/MWh to €114/MWh). This increase in electricity cost is considerable and can be equated to an increase in electricity bid price from €28 to €60/MW$_e$h, beyond the average marginal cost of generation.

In Figure 7 a non-linear relationship between run hours and LCOE is illustrated. Increasing the run hours from 2000 to 8000, again a 300% increase, produces a 51% decrease in LCOE (from €200/MWh to €98/MWh). This jump in run hours is not unrealistic and could be observed with modest increases in electricity bid price. Consequently, in many cases, the drop in LCOE associated with increasing run hours may potentially outweigh the rise due to increases in the average cost of electricity.

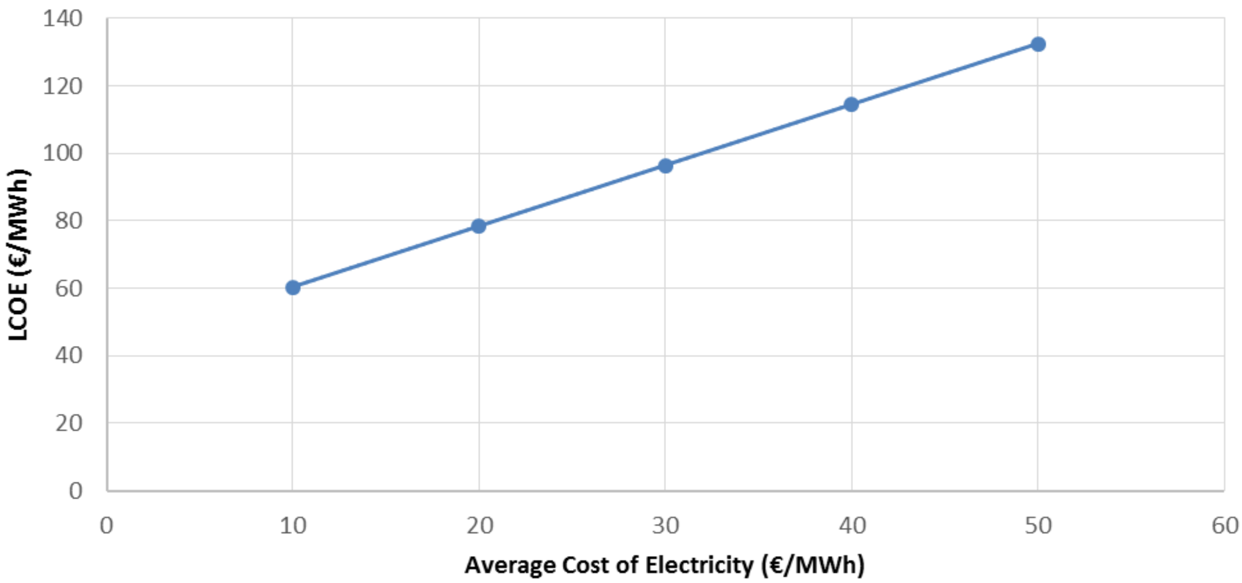


Figure 6. Change in LCOE with increasing cost of electricity and fixed run hours of 6500 per year

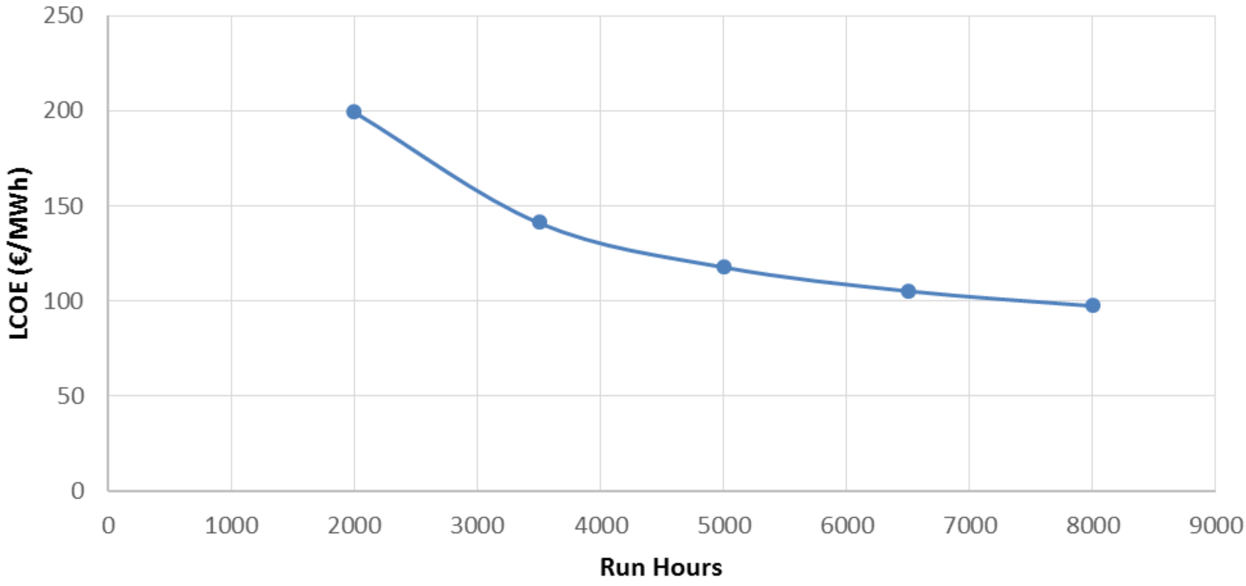


Figure 7. Change in LCOE with increasing run hours and a fixed cost of electricity of €35/ MW_eh

3.2.2 Combined effects on the LCOE of P2G

The combined effects of the parameters investigated in (Figures 4-7) culminate in the sharp drop in LCOE seen in Figure 8. This is a result of the dramatic increase in cumulative run hours between €30 and €45MW_eh (seen in Figure 3) relative to increasing SMP. Thus, it is proposed that it is far more economical, in terms of minimising LCOE, to increase the system bid price and hence its capacity factor. The drop in LCOE with increasing bid price implies that lower capacity factors will not be sufficient to amortise the project debt given the smaller quantities of gas produced. At bid prices greater than €50/MW_eh the majority of affordable energy has been captured, and so the cost is no longer compensated for by additional run hours. At these higher bid prices, the LCOE remains steady or begins to rise slightly. The bid price that minimises the LCOE is found to be approximately €50/MW_eh in this case.

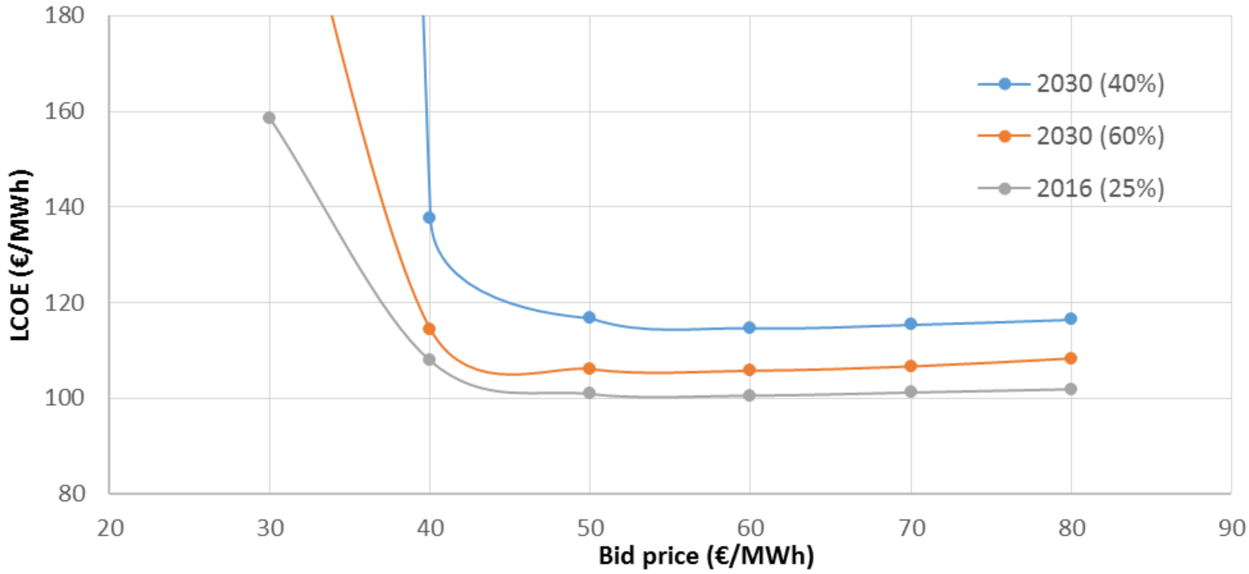


Figure 8. Change in LCOE with increasing bid price including for associated variation in run hours and average cost of electricity

Table 3. The LCOE of a P2G system bidding €50/MW$_e$h in each of the three electricity markets including its market interactions

Electricity market		**2016 (25%)**	**2030 (40%)**	**2030 (60%)**
Resultant values of a €50/MW$_e$h bid price	Run hours	7080	5714	5756
	Average cost of electricity (€/MW$_e$h)	34.41	38.16	32.39
LCOE (€/MWh)		**100.90**	**116.85**	**106.08**

The LCOE was 5% higher when using the market data of the 2030 (60%) model, and 16% higher when using the 2030 (40%) model as compared to the recorded data for 2016 (25%). As Table 3 indicates, the 2016 (25%) average cost of electricity was higher than in 2030 (60%), but the run hours were much greater, compensating for this. As stated previously this is partially due to the lower prices of natural gas, carbon, and uplift compared to the 2030 models, leading to more sustained periods of electricity under the bid price.

Also contributing to this is the volatility of the SMP in the models. As well as increasing shares of VRE resulting in more hours of low-cost energy, hours of high-cost energy also become more prevalent. The SMP decreases when generation exceeds demand, and increases when demand exceeds supply. The frequency of both of these scenarios increases with additional VRE [6]. Defining high-cost as greater than €100/MW$_e$h, it is evident from Figure 3 that in 2016 (25%) this occurs for 180 hours, 1065 hours in 2030 (40%), and 1152 hours in 2030 (60%).

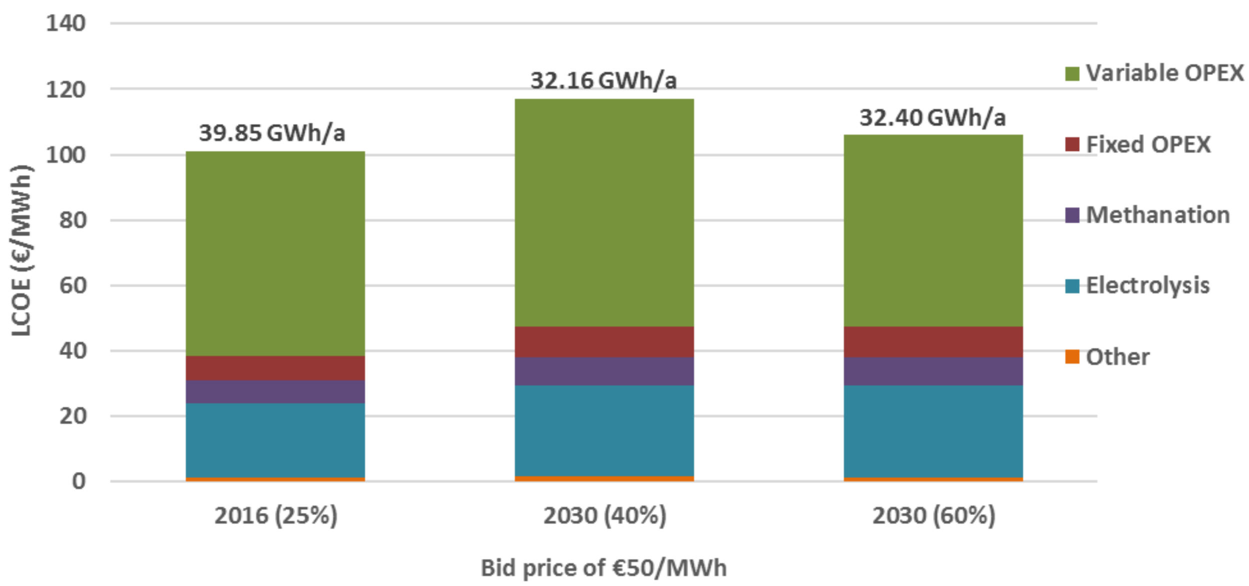


Figure 9. LCOE breakdown of a P2G system bidding €50/MW$_e$h in three electricity markets including for annual gaseous fuel output

In Figure 9 the variable OPEX, which dominates the LCOE, consists almost entirely of electricity costs. At higher production levels of gas, the LCOE falls and the contribution of capital expenditure (methanation, electrolysis, and other) diminishes. This again demonstrates that the increased capacity factor associated with a higher bid price leads to a more economical system. As capital costs fall the economic viability of P2G will still be largely dependent on affordable electricity. Access to electricity at a final purchase price of close to €25/MW$_e$h for more than 6,000 hours appears unlikely in the Irish electricity market by 2030. Thus, it will be difficult for gaseous fuel from non-biological origins to achieve further cost reductions. Charges additional to the SMP (such as grid connection and taxes) will add to costs, however, incentives to produce an advanced renewable fuel may well more than offset these costs. Biomass sources such as wood chips are already close to competing with heating oil on a cost basis and so the environmental credentials can justify the switch; however, the same cannot be said for P2G derived gas as a transport fuel. The low market value of natural gas hampers the development of P2G and carbon is not sufficiently priced to create an economic impetus for change. However, legislation requiring decarbonised bus fleets, directives mandating advanced transport fuels, and the requirement to reduce carbon intensity by 2050 to 20% of present levels will lead to gaseous fuel from non-biological origin competing with advanced biofuels (which at present are not as commercial) and electricity as a source of propulsion, which is not expected to be practicable for heavy goods vehicles and inter-city bus fleets [56].

The strategy identified here, bidding above the marginal cost of generation, has been shown to minimise LCOE by optimising run hours and electricity costs. It has the advantage of also producing larger volumes of gas than strategies predicated upon low-cost energy analogous to curtailment. In the event that increased gas production becomes more valuable, such as in the event incentives per unit of renewable fuel produced become available, this advantage becomes more significant. Scope would then exist to further increase the bid price, producing more gas, without considerable increases being made to the LCOE. This is true for all three models tested.

3.2.3 Running solely on low-cost or otherwise curtailed electricity

Previous literature has often assumed that P2G may only operate at times of excess or low-cost electricity (defined in this paper as less than €10/MW_eh), capitalising on market fluctuations largely due to the feed in priority of RE [25]. However, this work has shown that opportunities for P2G to take advantage of balancing issues and hence low-cost energy are limited. In the 2030 (60%) model 999 hours at an average cost of €0.28/MW_eh are available, the most of all three models, due largely to the increased mismatch between VRE production and demand. This would still result in an uncompetitive LCOE of €273/MWh due to the low volume of gas produced (5.62 GWh/a). In the 2030 (40%) and 2016 (25%) scenarios only 58 and 12 hours of low-cost energy are available at average costs of €0.37/MW_eh and €3.77/MW_eh respectively, making running solely on low-cost energy entirely unfeasible in these markets. This highlights that increasing the share of RE to 60% increases the availability of low-cost energy (from 58 hours to 999 hours between the 35% and 55% VRE penetration scenarios in 2030), but not to the levels required to produce competitive P2G derived gas. P2G then can be said to be an increasingly attractive solution as the share of VRE grows, but only consuming in times of surplus VRE is not proposed to be a viable business model. The availability of large quantities of surplus electricity is symptomatic of an inefficient electricity network and thus is a resource that one aims to minimise.

Real world data may provide somewhat higher quantities than those modelled, as demand and generation will not be so well forecast, but not to the point where sufficient quantities become available [42]. Operating the plant only during these periods would not allow for amortisation of the capital expenditure. Consequently, a compromise must be found between amortisation and running the plant only during the cheapest hours. This phenomenon is essentially independent of the size of the system. The volume of gas a larger system would produce, in attempting to capitalise on the low-cost electricity, would be proportional to the increased capital cost of the system. The economies of scale associated with P2G are not sufficient for this to be economically viable due in part to their modular nature [24].

4. Conclusion

The effect on the LCOE of a P2G system when it interacts with the electricity market was examined. Three electricity markets at different shares of RE (25, 40, and 60%) consisting mostly of VRE were analysed for their interactions with a 10MW$_e$ P2G facility. It was noted that the available run hours and average cost of electricity do not increase proportionally. Thus, it was found that increasing the bid price to beyond the average marginal cost of generation, approximately €35-50/MW$_e$h here, minimised the LCOE. Increased shares of VRE led to more hours of both high-cost (greater than €100/MW$_e$h) and low-cost (less than €10/MW$_e$h) electricity, but the number of low-cost run hours resulting from this was found to be insufficient to sustain a P2G facility alone. The bid strategy that minimised LCOE also produced the highest volumes of gas, ideally placing it to take advantage of incentives should they become available. Overall it was established that the viability of P2G relies on the availability of affordable energy for long periods of time and not positioning itself to take advantage of periods of low-cost energy.

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