TIME BASED APPROACH FOR LCOE AND NPV WITH APPLICATION TO GAS POWER AND HYDROGEN

Alexandre CHAILAN, General Electric Gas Power – Belfort, France,
alexandre.chailan@ge.com

Vincent BERTRAND, CRESE, Université de Franche-Comté,
vincent.bertrand@univ-fcomte.fr

Preliminary version – June 2021

Abstract

This paper explores the effect of combining a gas turbine power plant (GTPP) with electrolyzer and storage facilities for hydrogen (H_2) in the same location. We investigate how the co-location may provide new opportunities for the GTPP owner, through the ability to generate new products (in addition to the sales of electricity) that may increase the profitability for both assets: sales of H_2 and, ultimately, additional flexibility services that can be generated with the co-location. We also consider the ability of GTPP to co-fire H_2 together with NG. The paper relies on LCOE and NPV calculations, which are typical indicators for decision makers in the power industry. We use a time-based approach (named after considering historical operational data from gas-fired power plant) that enable implementing calculations on an hourly basis (compared with the 'conventional' approach for LCOE and NPV), in order to derive the energy quantities that serve to compute the LCOE and NPV. Results show that hydrogen appear to be non-competitive in most cases, with increased values for LCOE and negative NPV. Moreover, none of the incentives we consider (namely carbon pricing, lump-sum grant based on CAPEX, and subsidy that decreases the price of H2 when it is bought and increase the perceived price when it is sold) allow making hydrogen competitive with consistent values. Among the main obstacles is the decisions rule we assumed to determine the sizing of electrolysis and storage. The rule only considers the hydrogen the GTPP needs at peak times, which leads to over-dimensioning the hydrogen facilities. This results in high LCOH and, in turn, high LCOE for the GTPP. One solution to overcome this barrier would consist in giving more weight to the objective of having low LCOH in the sizing rule. Another avenue to increase competitiveness relies on adding new products that we did not implement in this preliminary version of the paper. First of all, we want to assess the benefit that may arise from including the revenues generated by grid flexibility services. We leave this for the next version of this paper.

1 Introduction

The low-carbon energy transition is a new challenge for power systems due to the global need for decarbonation and the need to develop more renewable energy systems (RES). Accordingly, variable renewable energy sources (VRES), such as wind and solar, have rapidly grown over the last decade, due to the combined effects of climate-energy policies and drop in investment costs. This trend is likely to continue, and VRES are expected to account for a high share of future electricity generation.

The variable nature of RES power generation creates a new set of constraints for electricity networks. They need to include more and more back-up facilities (through enhanced energy storage) and flexibility services to meet continuous supply/demand balance and support grid stability. Among stability and flexibility service suppliers, conventional dispatchable power plants such as gas turbines power plants (GTPP) play an important role. Together with storage and demand response (DR), the dispatchable systems provide stability and the up- and down-ward reserves that are needed to enable high penetration of VRES.[1]

In this context, hydrogen (H_2) appears as a promising energy vector at the crossroads of electricity storage, DR, and dispatchable generation (for example when used as a fuel for GTPP, see section 2.2). However, similarly to others storage options (*e.g.* battery, solar thermal or compressed air energy storage), its cost competitiveness remains a huge hurdle in spite of significant progress that has been made. High investment costs for energy storage require high operation rates to reach competitiveness (CGE, 2019).[2] Dispatchable generation is then still required along with energy storage and DR to ensure system stability and flexibility in response to VRES growth. As such, H_2 can also be seen as an option to reduce carbon emissions from dispatchable GTPP, through carbon abatements from co-firing hydrogen with natural gas (NG) (see section 2.2). This would support grid decarbonization target both through direct CO_2 reduction from dispatchable generation and indirect enabling of higher VRES penetration. Literature in this area indeed reports that CO_2 emissions are reduced when conventional

[1] Demand response can be defined as a modification in the withdrawal of electricity from the grid (due to changes in consumption) compared with normal patterns without DR. It usually consists in reduction of power demand (with or without postponement) at times of high electricity prices or when the electricity system is under pressure and requires activating some reserves to modify withdrawal. In a more general acknowledgement, DR also encompasses actions on demand that are able to increase withdrawal of electricity if needed (such as what can be made with electrolysis in our case).

[2] This is particularly relevant in the case of hydrogen, which tends to exhibit more economies of scale due to a large array of devices involve in the process, form the first conversion of electricity into H_2 (through electrolysis) to the last one that consists in turning H_2 into electricity to feed the grid (ARENA, 2018).

dispatchable assets are used to back VRES up (*e.g.* Chui *et al.*, 2009; Delarue *et al.*, 2009; Valentino *et al.*, 2012; Gutiérrez-Martín *et al.*, 2013; Aliprandi *et al.*, 2016; Squalli, 2017). Actual carbon abatements are, however, limited considering that one additional MWh of VRES electricity displaces less than one MWh of conventional dispatchable electricity.[3] At the opposite end of the spectrum, other papers report increased CO_2 emissions with the growth of VRES (*e.g.* Gutiérrez-Martín *et al.*, 2013). This is generally explained by the need to back VRES up with conventional gas-fired generation, where fast-reacting open-cycle gas-fired power plant with low efficiency sometimes substitutes higher efficient combined-cycle gas turbines.[4]

In the last few years, the question of feasibility of 100% renewable-electricity systems has also been extensively discussed in a growing literature. This appears to be a controversial topic.[5] A common feature emerges from most of the papers though: highly penetrated renewable-electricity systems are not achievable (neither technically nor economically) without maintaining dispatchable generation for flexibility and grid stability. GTPP fueled by biogas, green hydrogen are then viable options to balance supply/demand[6] as well as act as storage option through power-to-gas / gas-to-power (*e.g.* Bogdanov *et al.*, 2019). Dispatchable generation may also be required to meet winter peak demand (*e.g.* Elliston, 2012).

The question of coupling[7] VRES, storage, and dispatchable generation systems seems of importance. Only very few contributions though were found to deal with benefits from such coupling in the literature. Associated papers usually focused on how to avoid/reduce VRES curtailment and increase operating rates employing dispatchable/storage systems (Bogdanov and Breyer, 2016; Gulagi *et al.*, 2018; Fasihi and Beyer, 2020). Appropriate coupling between

---

[3] For example, Aliprandi *et al.* (2016) estimates that 1 kWh from VRES displaces approximately 0.8 kWh from conventional power in the Italian power system.

[4] One can also mention here the recent paper by Morales-España *et al.*, (2021), which argue that considering that maximizing generation from VRES always lower CO_2 emissions is a misconception. The authors identify situations in which priority dispatch given to VRES can lead to increased CO_2 emissions (and higher costs for the whole electricity system) due to 1) network constraints that create inefficient redispatches elsewhere in the merit-order, 2) increased needs for back-up capacities and replacement reserves (that are less efficient than units that would be involved otherwise). To avoid these inefficient operations of power systems, Morales-España *et al.*, (2021) argue that, instead of VRES curtailment being seen as a measure of last resort to preserve system security when necessary, VRES should always be optimally dispatched through markets, based on their true cost (reflecting the burden for the power system as a whole), thus maximizing the value of VRES to the system rather than their output.

[5] The interested readers can refer to Heard *et al.* (2017) and Hansen *et al.* (2019) for two opposite literature reviews with contrasted conclusions.

[6] Although not mentioned in this paper, low-carbon fuels in general (including blue hydrogen, synthetic methane) and NG coupled with Carbon Capture and Storage (CCS) could be an option as well.

[7] By 'coupling assets', we mean assets can interact with each other while 'co-locating them' means having them in the same location.

those solutions were also found to help minimize the global need for dispatchable capacity (Fasihi and Beyer,2020).

Those papers do not deal with how new products (such as grid flexibility services in addition to sales of electricity) with added economic value can be generated from such coupling. To the best of our knowledge, no previous work has considered such effects. This is the focus of the present paper. It aims to analyze how combining and co-locating a GTPP with a hydrogen production plant (fed by electrolysis) may generate more value compared to separate plants. The paper especially looks at typical products from such plants (electricity and hydrogen sales) and investigates how value can be created from their coupling (co-firing H_2 with NG, additional flexibility services).

The paper uses a business-oriented approach to analyze the value of hydrogen in gas power and assess the leverages and incentives to make such case profitable. We rely on LCOE (Levelized Cost of Energy) and NPV (Net Present Value) calculations, which are typical indicators for decision markers in the power industry. Our approach considers hourly price profiles (time-based approach, TBA) instead of conventional yearly averages (conventional approach). Such approach can better model the full flexibility that could be raised from co-locating hydrogen production and gas power plant.

Given the co-located equipment we assumed (*i.e.* GTPP with electrolysis and hydrogen storage tanks), we introduce *vectors* of products (*e.g.* sales of electricity, hydrogen, and grid flexibility services) and of price incentives (*e.g.* carbon pricing or subsidy for hydrogen). All of this creates *contextual sets*, reflecting different typical business cases for the plant owner. Next, we apply a *set of strategies* (mapping different decision rules) on contextual sets, which drives the LCOE and NPV values. Prices and incentives were finally leveraged to determine the boundaries of profitability compared to a baseline case.

Preliminary results (Section 3.1.3) show how the considered (TBA or conventional) approach can impact overall LCOE and NPV calculations. The model was structured to run considering electricity sales from a GT peaker plant on top of which we add onsite production of hydrogen. Further products such as flexibility services integration still require some work to be included. The present paper should be seen as a first step of a wider research program that will continue investigating this question with other cases through TBA and microeconomic modelling. [8]

[8] We present here a preliminary version of this paper for the 2021 IAEE conference.

The remainder of the paper is organized as follows. Section 2 gives a brief overview about the technological background related to hydrogen for the power industry. Section 3, we introduce the method, data, and scenarios. Section 4 presents the results and discussions. Section 5 concludes.

2 Technology brief

2.1 The basics of hydrogen production

Recent interest in cleaner forms of hydrogen can be explained by the historical and most common hydrogen production process, namely steam methane reforming (SMR), which is very carbon intensive.

Indeed, in 2016, about 95% of worldwide hydrogen production came from either natural gas (SMR) or (through gasification of) coal (IRENA, Hydrogen from Renewable Power: Technology Outlook for the Energy Transition, 2018). On average, every kilogram of hydrogen produced leads to emission of about 9.5 kg of CO_2, and 22.5kg of CO_2 when using NG and coal, respectively (IRENA, Hydrogen: A renewable energy perspective, 2019). Current hydrogen production today contributes to about 830 million t-CO_2 emitted[9] into the atmosphere every year (IRENA, Hydrogen, 2018).

Hydrogen can also be generated as a by-product from other processes. Indeed, hydrogen is a byproduct of the chlor-alkali process used to produce caustic soda and chlorine which accounts for about 5% of the worldwide production of hydrogen (IRENA, Hydrogen from Renewable Power: Technology Outlook for the Energy Transition, 2018).

Finally, water electrolysis fed by electricity is the production pathway receiving increased interest. In electrolysis, an electric current passes through a water molecule and split it into oxygen (O2) and hydrogen (H2) (see Eq. 1). This process is as carbon-intensive as the electricity it is fed with. It can be seen as low to zero carbon if fed with VRES such as wind and solar power. This is why it gathers so much interest today.

$$H_2O = H_2 + \frac{1}{2}O_2 \qquad \textit{Eq. 1}$$

Depending on how it is produced, hydrogen can be sorted by color summarized on Table 1 (General Electric, 2021), with indications on carbon footprint for each color.

Color	Production ways	Hydrogen carbon intensity
Black	Coal gasification	Very High
Grey	Steam Methane Reforming (SMR)	High

[9] Units from International System (SI) have been considered in this paper. t-CO_2 then refers to metric tonnes of CO_2.

Blue	SMR coupled with Carbon Capture and Storage (CCS)	Low
Turquoise	Methane pyrolysis	Low to very low
Green	Electrolysis using VRES electricity	Low to very low
Pink	Electrolysis using nuclear electricity	Very low

Table 1 - Hydrogen colors by production ways

Hydrogen, just as electricity, is an energy carrier. It contains energy that can be used in different ways, and while an abundant molecule, it is not (or barely) naturally occurring by itself, thus the need to manufacture it. Once produced, it can feed many different applications:

- Mobility: hydrogen can be used in fuel cell electric vehicles (FCEV) as a fuel powering the vehicle. It can be used for private (individual car) and public (bus, train) and freight transport (trucks, cargo) and even in aviation in the long run (Shell, 2017). Hydrogen can also power ships.
- Industrial sectors: hydrogen is used as a raw material or feedstock in different processes (Hydrogen Europe, Decarbonise Industry).
  - Chemicals such as ammonia, methanol, some polymers (e.g. polyurethane or nylon) or resins are produced using hydrogen.
  - Refineries: hydrogen is used in hydrogenation processes (hydro-cracking) to produce lighter crudes
  - Metal processing industry: hydrogen can be used for direct reduction of iron ore in the steel industry. Although it is not the mainstream way of producing iron[10], direct reduction (using green hydrogen) could lead to consistent decrease in CO_2 emission from this sector since it would replace either coke or natural gas.
- Building heat: hydrogen can also be used as a fuel for heating buildings.
- Last hydrogen can be used as a fuel in the power industry.

[10] Iron ore being generally reduced using coal or coke in blast furnaces

2.2 Hydrogen & electricity

In the power industry, hydrogen can be (co-)fired in gas turbines (GT), engines or used in fuel cells (FC) to generate electricity. This occurs through combustion in a gas turbine and as an electrochemical reaction in a fuel cell. Both can be represented by Eq. 2 below.

$$H_2 + \frac{1}{2}O_2 = H_2O \qquad \text{Eq. 2}$$

One of the main differences between a FC and a GT lies in the amount of power they can generate due to size and scale of the technology. Current FC power goes from kW-scale up to smaller MW-scale (DOE, 2015) while gas turbines capacity can reach hundreds of MW. Just as for gas turbines, FC can use hydrogen or other gas as a fuel to generate electricity (and heat for Combined Heat and Power (CHP) plants).

The interest of hydrogen combustion is that it does not produce CO_2 but water vapour[11] [12] (see Eq. 2).

GT manufacturers have extensive experience in burning hydrogen blended with natural gas in gas turbines at levels up to 90%-vol and more (General Electric, 2019). By way of illustration, a 40 MW GTPP operating with high-level of hydrogen is shown on Figure 1.

Figure 1 - 6B.03 gas turbine currently burning ~ 70%-vol hydrogen in a refinery in South Korea

---

[11] Direct emissions (i.e. from combustion equation shown on Eq. 2) are considered here. Practically, the-carbon intensity of electricity produced through a fuel-fired turbine will be as low carbon as the fuel (hydrogen or other) is.

[12] Pollutants such as NOx can also be produced depending on GT operating conditions, technologies and NOx abatement systems installed.

3 Methodology, data and scenarios

3.1 LCOE, NPV & LCOH approach

LCOE and NPV are usually calculated using yearly averaged values for inputs such as electricity, natural gas, and carbon prices. The (so-described) 'conventional' approach seems to be inefficient to capture the whole complexity of co-locating hydrogen production and gas-fired power plant. A *time-based approach* (named after considering historic operational data from actual gas-fired power plant in models) has been preferred.[13] Both methods are explained and compared in this section (Graham, P. 2018).

3.1.1 Conventional approach

In what has been called here the 'conventional approach' for calculation of LCOE (electricity), NPV and LCOH (hydrogen), yearly averaged values are usually considered (see Eq. 3, Eq. 4 and Eq. 5).

$$LCOE = \frac{\sum_{i \in Year} \sum_{j \in Components} \frac{Cost_j(i)}{(1+r)^i}}{\sum_{i \in Year} \frac{OH(i) * LF_{GT}(i) * Power_{GT}}{(1+r)^i}} \qquad \text{Eq. 3}$$

with

$Cost_j(i)$: Costs related to GTPP component j during year i

$OH(i)$: Amount of GTPP operating hours during year i

$LF_{GT}(i)$: GTPP yearly load factor during year i

$Power_{GT}$: Nominal GTPP power output in MW

and

$$Components = \{Gas\ Turbine\ Power\ Plant;\ Electrolyser\ plant;\ Hydrogen\ Compression\ and\ Storage\ plant\}$$

$$Year = [0; 1; \dots; Lifetime]$$

$$r: Discount\ rate$$

[13] See Graham (2018) for a presentation of some alternative methods to extend the conventional LCOE approach.

$k \in Sub - Periods$: k considered sub-period (e.g. Sub-Periods = [0, 1, …, 8760] considering 8760 hours a year)

Note that when we refer to 'GTPP', 'Electrolyzer plant', and 'Hydrogen Compression and Storage plant', we have included all components, costs associated to these systems. For example, GTPP costs cover gas power plant construction, permitting, installation & commissioning, EPC, owner's costs as well as component manufacturing costs & shipment.

Similarly, for NPV calculation, Eq. 4 is usually considered.

$$NPV = \sum_{i \in Year} \frac{(CF_i)}{(1+r)^i} - \sum_{j \in Components} CAPEX_j \qquad \text{Eq. 4}$$

with

CF_i: Net Cash Flow (after tax) over the year (i), considering revenues and expenses from all components

$CAPEX_j$: Investment cost related to component j

Last, for LCOH calculation, Eq. 6 is considered.

$$LCOH = \frac{\sum_{i \in Year} \sum_{j \in Components} \frac{Cost_j(i)}{(1+r)^i}}{\sum_{i \in Year} \frac{H2_{production}(i)}{(1+r)^i}} \qquad \text{Eq. 5}$$

with

$H2_{production}(i) = OH(i) * LF_{H2}(i) * \frac{Power_{H2}}{Elec_{H2}^{cons}}$: Yearly hydrogen production in kg-H_2 or GJ-H_2

$Cost_j(i)$: Costs related to Hydrogen production plant component[14] j during year i

$OH(i)$: Amount of hydrogen production plant operating hours during year i

$LF_{H2}(i)$: Hydrogen production plant yearly load factor during year i

$Power_{H2}$: Hydrogen production plant power capacity in kW

$Elec_{H2}^{cons}$: Electricity consumption to produce 1 kg-H_2 (or 1 GJ-H_2) in kWh/kg-H_2 or kWh/GJ-H_2

[14] Typically, electrolyzer, hydrogen storage tank or hydrogen compressor are hydrogen production plant components.

In this approach, some opportunities - such as arbitrating between burning hydrogen in the gas turbine and selling it depending on the market price- may be complicated to consider. Indeed, some of the benefits from co-locating hydrogen and electricity production (*e.g.* arbitrating between different use of the plant) require a finer consideration such as time profiles for some inputs.

The Time-Based-Approach (TBA) includes changes in power, NG and carbon prices over time (e.g. hourly) instead of considering yearly averaged values.

3.1.2 Time-based approach

Eq. 6, Eq. 7 and Eq. 8 show the formula for calculating LCOE, NPV and LCOH respectively using the 'time-based approach'.

$$LCOE = \frac{\sum_{i \in Year} \sum_{j \in Components} \frac{Cost_j(i)}{(1+r)^i}}{\sum_{i \in Year} \frac{\sum_{k \in Sub-Periods} OH(k,i) * LF_{GT}(k,i) * Power_{GT}}{(1+r)^i}} \qquad \text{Eq. 6}$$

with

$$Cost_j(i) = \sum_{k \in Sub-Periods} Cost_j(k,i)$$

$Cost_j(k,i)$: Costs related to GTPP component j during year i and sub-period k

$OH(k,i)$: GTPP operating hours during sub-period k during year i

$LF_{GT}(k,i)$: GTPP load factor during year i averaged over the sub-period k

and

$$NPV = \sum_{i \in Year} \frac{(CF_i)}{(1+r)^i} - \sum_{j \in Components} CAPEX_j \qquad \text{Eq. 7}$$

with

$$CF_i = \sum_{k \in Sub-Periods} CF(k,i)$$

$CF(k,i)$: Cash Flow after tax over the sub period k from year i

$CAPEX_j$: Investment cost related to component j

Last, for LCOH calculation, Eq. 8 is considered.

$$LCOH = \frac{\sum_{i \in Year} \sum_{j \in Components} \frac{Cost_j(i)}{(1+r)^i}}{\sum_{i \in Year} \frac{\sum_{k \in Sub-Periods} H2_{production}(k,i)}{(1+r)^i}} \qquad \text{Eq. 8}$$

with

$$Cost_j(i) = \sum_{k \in Sub-Periods} Cost_j(k,i)$$

$Cost_j(k,i)$: Costs related to hydrogen production plant component[14] j during year i and sub-period k

and

$$H2_{production}(k,i) = OH(k,i) * LF_{H2}(k,i) * \frac{Power_{H2}}{Elec_{H2}^{cons}}$$

$OH(k,i)$: H_2 production plant operating hours during sub-period k during year i

$LF_{H2}(k,i)$: H_2 production plant load factor during year i averaged over the sub-period k

$Power_{H2}$: Hydrogen production plant power capacity in kW

$Elec_{H2}^{cons}$: Electricity consumption to produce 1 kg-H_2 (or 1 GJ-H2) in kWh/kg-H_2 or kWh/GJ-H_2

The Time-Based-Approach (TBA) includes changes in power, NG and carbon prices over time (e.g. hourly) instead of considering yearly averaged values. In practical terms, a year is subdivided into sub-periods. This is shown in Eq. 6, Eq. 7 and Eq. 8 through the introduction of sub-period index k. Sub-period division can be of different forms:

1. Either it subdivides the whole year. For instance, the year is divided into equal sub-period (ex: quarter, month, day, hour, *etc.*, or week as per Figure 2). Inputs are then considered for each sub-period (one input value – say, electricity price - for each quarter, month, …).
2. Or, it represents a typical profile for the considered inputs over the whole year. For instance, the year can be modelled by considering typical weekly values over one month (as per Figure 3). The ‘standard’ month is then replicated all year long.
3. Or, a combination of typical profiles with probability of occurrences. For example, a typical month with weekly values can be considered for each season (see Figure 4).

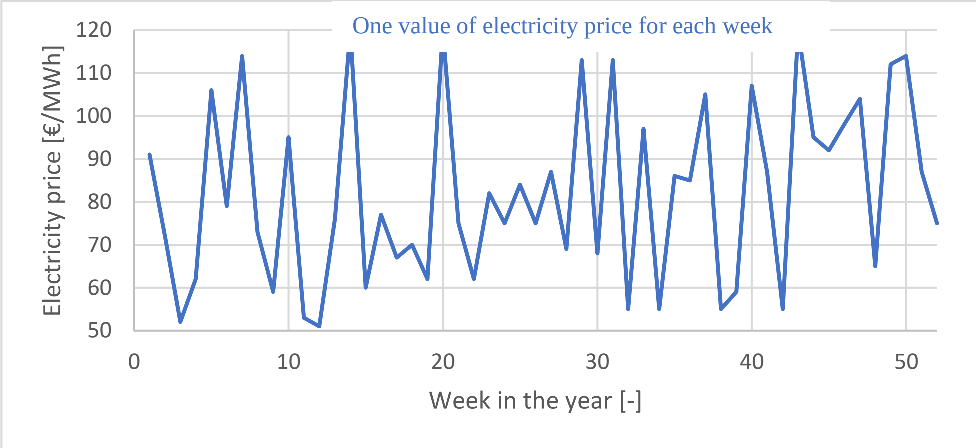

Figure 2 - Example of electricity profile prices for subperiod division 1

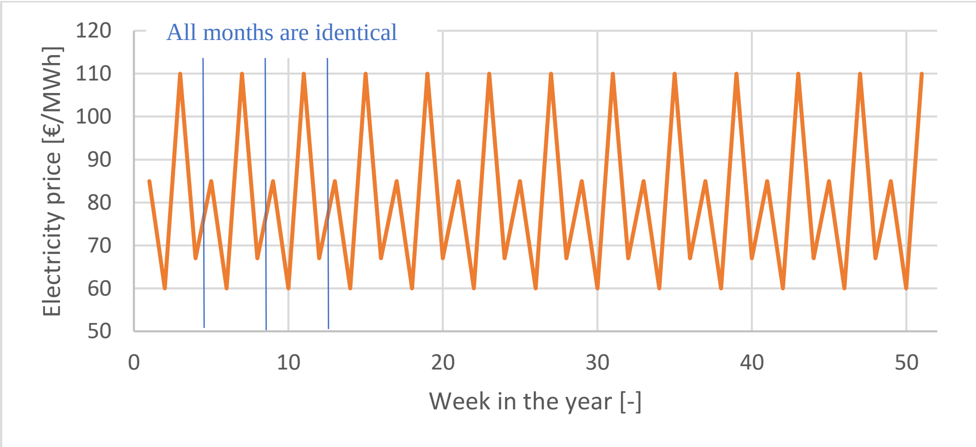

Figure 3 Example of electricity profile prices for subperiod division 2

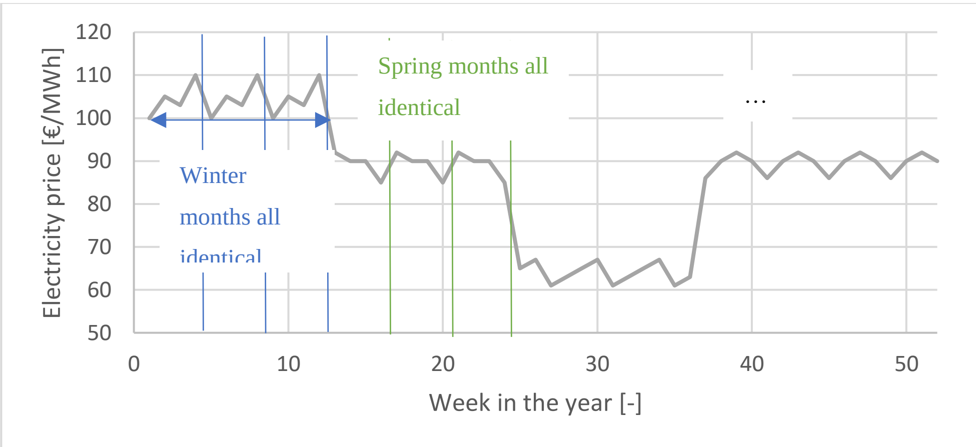

Figure 4 Example of electricity profile prices for subperiod division 3

3.1.3 Method comparison & simplified example

The two methods described above (conventional and time-based) have been compared over one simple example.

We consider a GTPP running at baseload (nominal capacity) by day (when electricity and NG price are high) while shut off by night (when prices are low). A constant volumetric H_2 proportion of 5% (by volume) - bought externally - is blended with natural gas.

For time-based approach, we considered price profiles as per given on Figure 5 (and in Appendix 0). We have considered day and night variations in NG and electricity prices[15] and financial data in Table 3. Contributions from NG costs on LCOE, and from NG costs and electricity revenues on NPV are shown on Table 2. Such contributions were calculated isolating NG costs (or electricity revenues) in LCOE and NPV formulas.[16] The same has been done for H2 and CO2 contributions on LCOE and NPV.

For the sake of simplification, we neglected components costs such as gas turbine power plant CAPEX and O&M costs and only consider NG and electricity prices varying every hour over the day while H_2 and CO_2 constant costs. The second sub-division period presented above has then be used here: a typical day with hourly variations.

For conventional approach, we averaged the same values over the day and proceed to calculations.

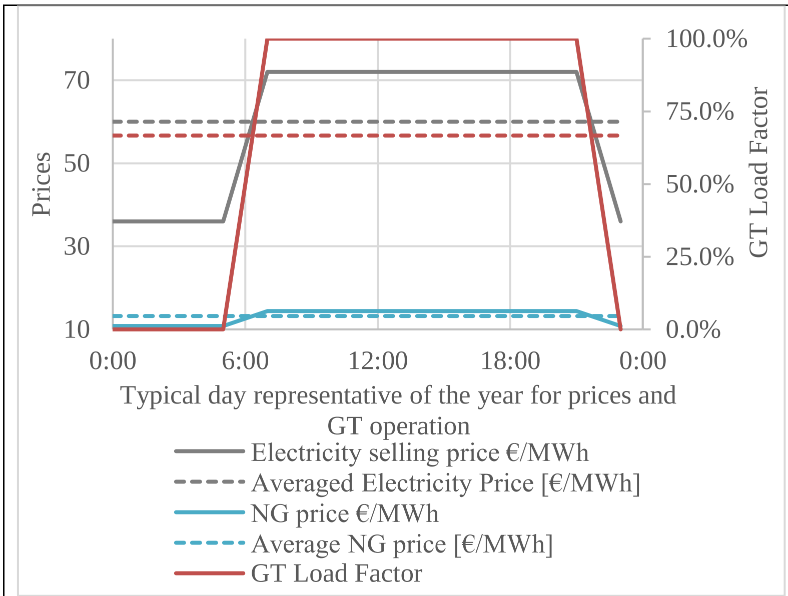

Figure 5 – Simplified example of electricity price and GT operating hours (OH) profiles that can be considered in LCOE and NPV calculations using the time-based approach (continuous line) vs the yearly values conventionally used (dashed lines)

	Conventional Approach	Time-based Approach
LCOE [€/MWh]		
NG	45.46	49.21
CO_2	12.25	
H_2	7.54	
Total	**65.25**	**69.00**
NPV [M€]		
NG	-258.96	-280.29
CO_2	-69.75	
H_2	-42.95	
Electricity	398.73	471.00
Total	**27.06**	**78.00**

Table 2 - Table showing contribution of fuels (NG, H_2), CO_2 costs and electricity revenues on LCOE and NPV for the two approaches[17]

[15] For this specific example, CO2 price of 20€/t was considered.
[16] Concretely, 45.46 €/MWh of total 65.25 €/MWh LCOE value are due to NG related costs for conventional approach (see Table 2). Another way to see it is that 69.7% of LCOE value is due to NG purchase.
[17] For the illustration, impacts from other costs on LCOE and NPV values are assumed similar considering one method or the other (ex: CAPEX costs do not depend from chosen year subdivision).

Data	Value	Unit
Discount rate	10%	-
Lifetime	20	years
Tax rate	21%	-
Escalation rate	2%	-

Table 3 - Financial assumptions considered for simplified example

From Table 2, one can see that

- 45.46 €/MWh out of total 65.25 €/MWh LCOE value calculated with the conventional approach, (*i.e.* 69.7% of total LCOE) are due to natural gas purchase. It is slightly higher for the TBA.
- The difference on LCOE NG contributions between the two methods is about 8% (3.75 €/MWh). It is transferred on the total LCOE.
- On NPV side, NG related costs reduces NPV by 258.96 M€ in the conventional approach. Similarly, a non-negligible difference is observed between conventional and TBA approach on the NG (-21.33 M€) and electricity (72.27 €) contribution of NPV.

Concretely, NG costs and electricity revenues have been underestimated using the conventional approach because hourly variations in NG and electricity prices were not captured. Using a TBA on historic profiles should help better capture real value of LCOE and NPV.

Of course, the example given here is extremely simplified. But one should keep in mind that in practice, most of these economic inputs may vary every hour or second. Real systems are much more complex, and differences coming from economic inputs may be balanced, or in certain cases, drive financial indicators (LCOE, NPV or other) to an extreme value.

Considering in advance price evolution and averaging on the expected operation of the plant is an option but could be a complicated exercise. Plus, considering a plant with several products to sell (e.g. electricity and hydrogen)[18], the benefits of the time-based approach is ultimately to help looking for the operability optimum of such plant for a given context with inputs varying

[18] Such observation is also valid for other products (such as oxygen when hydrogen is produced from electrolysis), services (such as grid ancillary services) and consumable items (such as NG, CO_2, water…)

over time[19]. In other terms, it is to determine what time is best to produce and sell electricity and what time is for producing and selling hydrogen.[20] This was done through contextual sets and decision rules.

3.2 Contextual sets & decision rules for time-based approach

The time-based approach makes sense when there are significant input shifts during the period being examined. This approach allows captures operational and input profile changes that are otherwise smoothed or overlooked by the conventional approach.

To fully benefit from such approach, we introduce a conceptual framework that consists in creating ***contextual sets*** reflecting different typical business cases for the plant owner (see section 3.2.1). Next, once the contextual sets have been defined, we consider a ***set of strategies*** mapping decisions rules and strategies the plant owner could apply on the contextual set in order to increase value (see section 3.2.2).

3.2.1 Contextual set

Each contextual set includes three different vectors, as follows.

- ***Vector of equipment***, gathering a family of equipment co-located. These are physical components interacting with each other. They are limited in numbers to restrict the scope of the contextual set at hand. For the present paper, we have narrowed the vector of equipment with the following: GTPP, hydrogen production plant consisting of an electrolyzer, compressor and storage system.[21]
- ***Vector of products***, showing the products that the vector of equipment can produce and sell. In the case of this paper, given the vector of equipment mentioned just before, we assume that the vector of products is made of the following items: sales of electricity, hydrogen, and grid flexibility services.[22]
- ***Vector of prices and incentives***, define the economic context associated with the vectors of equipment and products that are considered. This includes prices and policy instruments that give incentives (*e.g.* carbon pricing, subsidies for storage or H_2 generation,

[19] For instance, this can be done on historical profiles.
[20] Or what time is best for providing a service or buying a certain consumable item.
[21] The vector could be modified with additional devices compared with those we consider for this paper. For example, one may include VRES, others dispatchable power systems, fuel cell, batteries, *etc.* This translates into more contextual sets to investigate.
[22] Here again, the vector can be modified. As an illustration, with the same vector of equipment as for this paper, we may add products such as: sales of oxygen (by-product form electrolysis), heat generation and sales (when considering combined heat and power systems), remuneration for inertia provided to the grid, *etc.*

representative revenue for grid flexibility services). Each price can either determine a revenue (when considering an output that is sold) or a cost (when associated with an input for one or several devices). For example, natural gas is seen as a cost for the GTPP while electricity produced is a revenue. The first one reduces NPV while the latter increases it. There are also situations in which some of the commodities we consider can be both input and output, so that the corresponding price determine both costs and revenues. For example, when electrolysis is run with electricity from the grid (rather than being directly fueled by the co-located GTPP), the price of electricity sets both a cost (from the electrolyzer point of view) and a revenue (from the GTPP point of view). The elements we include in the vector of prices and incentives for this paper are summarized in Table 4 below (together with the component of others vectors).[23]

Vector of equipment	**Vector of products**	**Vector of prices and incentives**
- GTPP system - Electrolyzer system - Storage system for hydrogen	- Sales of electricity - Sales hydrogen - Sales of grid flexibility services	- Prices for electricity, H_2 - Carbon pricing - Representative subsidy for H_2 generation - Representative revenue for grid flexibility services

Table 4 - Items to be included in the vectors for the contextual sets

Vectors with elements given in Table 4 can then be combined to generate different contextual sets. One should note that the approach shown here can be applied to different combination of elements (other than shown on Table 4) and more generally when products from different sectors are co-located in the same site (or when synergies between sectors are expected).

Before going forward in the presentation, the treatment of H_2 co-firing in GTPP has to be discussed. This concerns situations in which self-generated H_2 can either be sold or burnt in the GTPP. In this case, each amount of H_2 that is burnt in the GTPP entails an opportunity cost associated to having fewer H_2 to be sold. Hence, whereas self-consumption of H_2 is not directly

[23] As before with other vectors, one can modify the element to include more prices and incentives in the vector.

considered as a product (given that we implicitly defined products as outputs that can be sold), it still has value in our calculations. It either reduces or increases cost associated with running GTPP under co-firing (depending on the situation and NG and CO_2 prices that H_2 will substitute) and increase or decline in the value of NPV.

3.2.2 Strategy set

Once the contextual sets have been defined, we have to introduce decision rules that give criteria to determine how different combinations between equipment, products, and prices/incentives may modify the load profiles of devices (compared with the baseline with historical data) and prioritize how to operate them.

Each association of specific decision rules creates a set of strategies. Next, we can shape pairings of contextual sets and sets of strategies, which lead to different modifications in operating times and specific costs and revenues. Finally, LCOE and NPV values are derived for each pairing. This is illustrated by Figure 6.

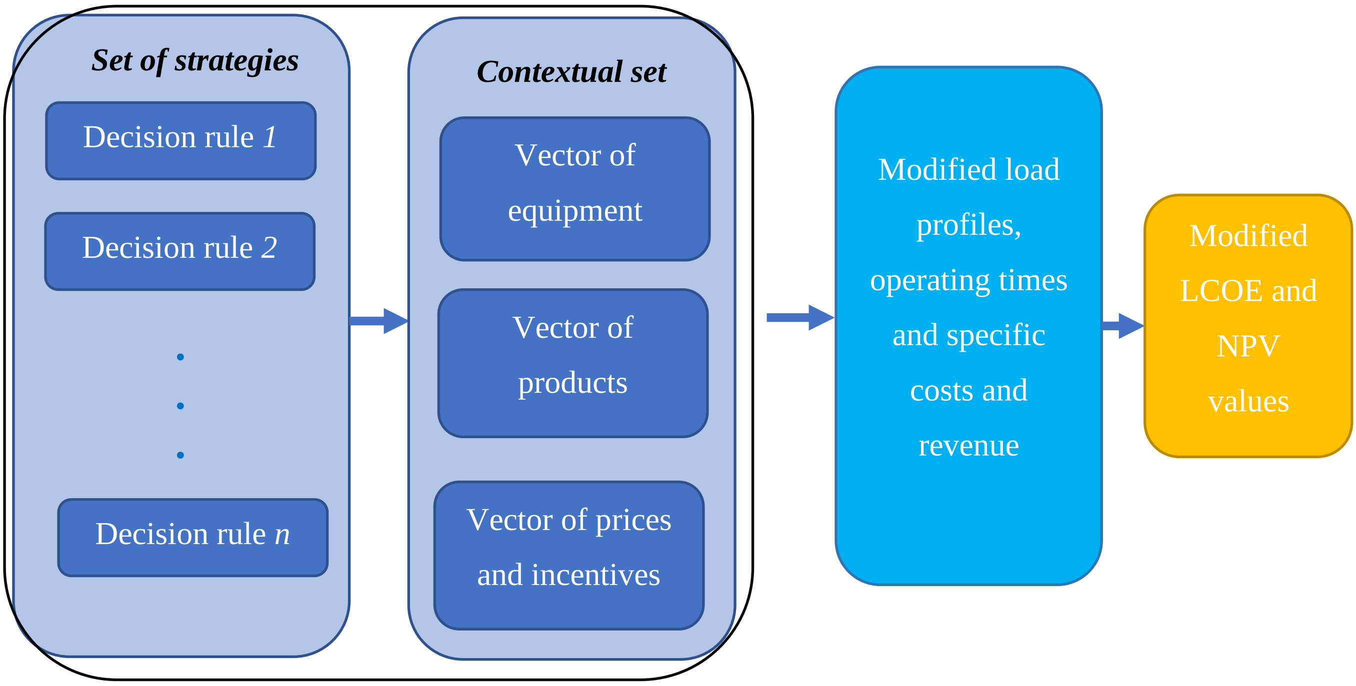

Figure 6 - Operating Diagram showing how contextual sets & sets of strategies influence indicators calculation.

The set of strategies is be made of items such as:

- Assumed exogenous orderings among elements in the vectors of products, each one reflecting some ways to prioritize between the products that are considered by the plant owner.

- Storage rule that enables determining when H_2 has to be stored and when it can be removed from storage to be sold, with the constraint of having enough H_2 to run the GTPP under co-firing at the required periods. [24]
- Assumed periods during which the electrolyzer can generate H_2 (given the storage rule).

In all cases, decision rules may reflect underlying preferences for the plant owner (*e.g.* prioritizing electricity over flexibility services) or technical requirements (*e.g.* assuming that electrolysis can only happen at night, to avoid excessive pressure when fueled from the grid).

3.3 Scenarii

3.3.1 Baseline

For the specific case study, a gas-fired power plant utilizing a GE 9E.03 [25] running with 100% methane has been considered as *Baseline* scenario. It is assumed the gas turbine operates as a peaker plant[26] running about 200 hours a year. Considered profile of operation is shown on Figure 7.

The following profile is assumed as reference profile and is considered for the whole remaining lifetime of the plant.[27]

---

[24] Such storage rule implies that the GTPP load profile and the percentage of co-fired H_2 fully determine the way H_2 is stored and removed from storage (and more generally the sizing of both electrolysis and storage capacities, see section 3.3.4).
[25] 129.1MW power and 32.3% efficiency, LHV - heat rate of 10 942 kJ/kWh-LHV were considered.
[26] A peaking power plant (or 'peaker') runs specifically at high electricity demand time. It is different from base load power plant which runs to meet minimum electricity demand.
[27] One should note that for confidentiality reasons, this profile has been inspired from existing profiles but does not represent an existing power plant operation profile.

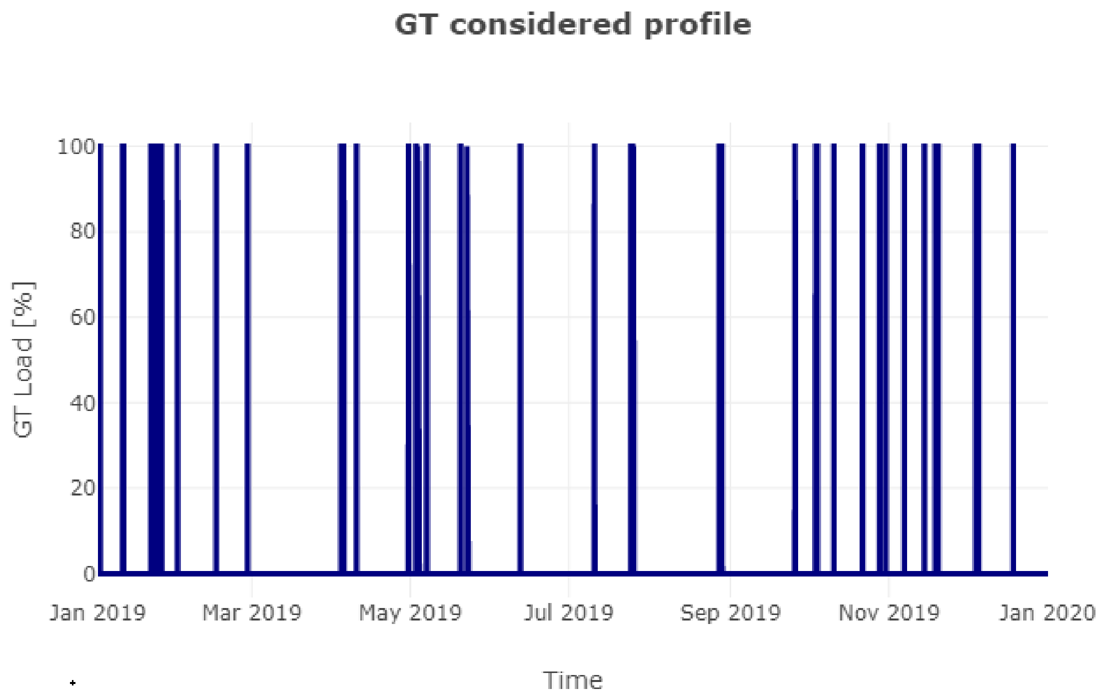

Figure 7 - Simplified GT Profile considered (time step of 1 hour)

In addition, the plant is assumed to be 30% hydrogen capable which means it is capable of burning up to 30% hydrogen by volume blended with NG.

Please note the results are later shown relatively to this *Baseline*.

3.3.2 Baseline with external H_2 co-firing

We will call *Baseline with external H2 co-firing* the baseline case where 30%-vol H_2 are blended in NG. In this case, low-carbon hydrogen is purchased outside of the plant at fixed price given on Table 5. It is then blended with natural gas onsite.

Burning blended natural gas with hydrogen enables reducing plant emissions[28]. Blending 30%-vol H2 in natural gas reduces direct CO2 emissions by about 11.4% (General Electric, 2019).

3.3.3 Co-location of hydrogen production plant

The purpose of the paper is to understand under which circumstances co-locating and coupling hydrogen production plant with the gas-fired plant could make sense based on NPV and LCOE calculation compared to baselines set.[29]

[28] 30%-vol H2 blended in natural gas reduces direct CO2 emissions by about 11.4%.
[29] By ‘coupling assets’, we mean assets can interact with each other while ‘co-locating them’ means having them in the same location. Co-locating GTPP and electrolyzer can make it possible to combine them when needed (*e.g.* plugging the electrolyzer on the GT) and analyze possible synergies between them.

To do so, as per section 3.2, the contextual set shown on Table 4 has been considered.

- The GTPP can generate electricity and provide flexibility services to the grid.
- A hydrogen production system, based on electrolysis, with compressor and high-pressure storage system is installed on the plant. It can produce hydrogen to be either burnt in the GT (blended with NG) or sold. The system produces hydrogen using grid-electricity[30] by night when the GT is not running[31]. Flexibility services can be provided by the system.
- The indicators to optimize are the Net Present Value (NPV) and Levelized Cost of Electricity (LCOE). Although Levelized Cost of Hydrogen (LCOH) could be considered as well.

From these assumptions, we need to size the hydrogen production plant so it can provide enough hydrogen to the GT based on operating profile in Figure 7 (see section 3.3.4).

3.3.3.1 H_2 production for GT consumption only

In this scenario, we assume that the hydrogen production plant is used to produce hydrogen only to be consumed by the GT at the required proportion (30%-vol).

The goal of this scenario is to ensure GT can run when called, while decarbonizing part of its electricity production.

3.3.3.2 H_2 production for GT consumption and external sales

In this scenario, we complement hydrogen production for GT needs with additional H_2 production to be sold. This is done to maximize plant revenues.

Once hydrogen produced, it can be used in the GT. It can also be sold providing it does not jeopardize gas power plant fuel supply.

The following strategy has then been adopted to prioritize products among the plant

1. Electricity production is prioritized. As the plant is a GT peaker, it has been assumed it is critical for the grid. The priority lies in producing enough hydrogen to cover the GT needs (in assumed hydrogen proportion, 30%-vol).

[30] French electricity carbon footprint was of 35.7 gCO2/kWh in 2019 (considering CO_2 emissions of 19.2 Mt-CO_2 and electricity production of 537.7 TWh) (RTE, 2019)
[31] We have assumed operation by night, so the system is unlikely to be solicited under grid stressful events.

2. Once GT needs filled, additional hydrogen production can be made available for sales to maximize plant revenues.[32]

3.3.4 Preliminary results & equipment sizing

For the scenario with co-location of hydrogen production and the GTPP, the hydrogen production plant components were sized such that the GT's hydrogen needs would be covered at 30%-vol hydrogen proportion. In other terms, the minimum storage system size required to comply with the required GT profile (and hydrogen proportion) was searched. A backward induction has been used to do so.

Figure 8, Figure 9 and Figure 10 illustrate this method. They have been plotted for an electrolyzer size of 20MW[33]. The minimum storage size to comply with GT requirements is in this case is 60.6 tonnes of hydrogen.

In short, starting from the end of the year backwards, we have estimated cumulative GT hydrogen needs and couple them with hydrogen production profile[31]. Curves shown on Figure 8 and Figure 9 establish the tactical moments to produce hydrogen so GT calls from Figure 7[34] can be met. The minimum storage size to cover GT needs for a given electrolyzer capacity was then established.

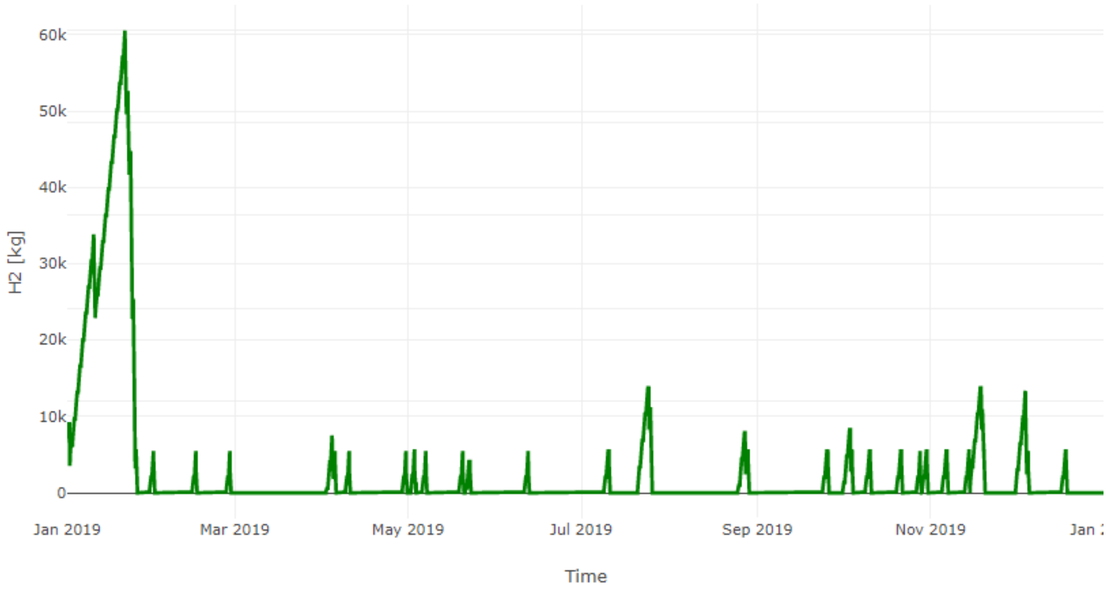

Figure 8 - Backwards cumulative GT hydrogen requirements

[32] Hydrogen is sold when storage tank is full and no GT needs coming.
[33] 20 MW electrolyzer has been considered for this illustration.
[34] Considering 30% -vol H_2.

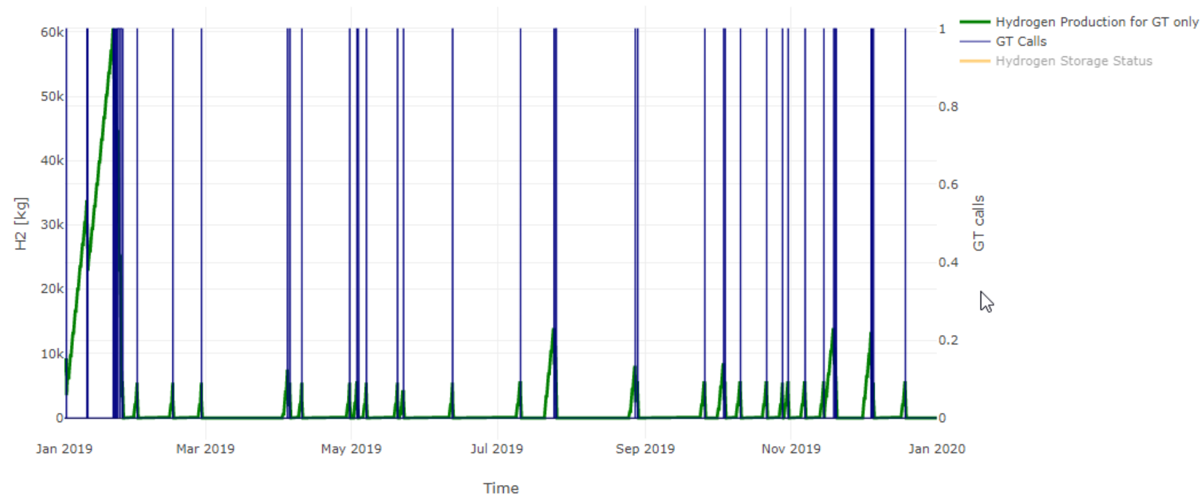

Figure 9 - GT profile & backwards-established cumulative GT hydrogen requirements to comply with such profile

We have ensured the ability of such storage size to fill GT calls for considered hydrogen production rate and profile. This is shown on Figure 10.

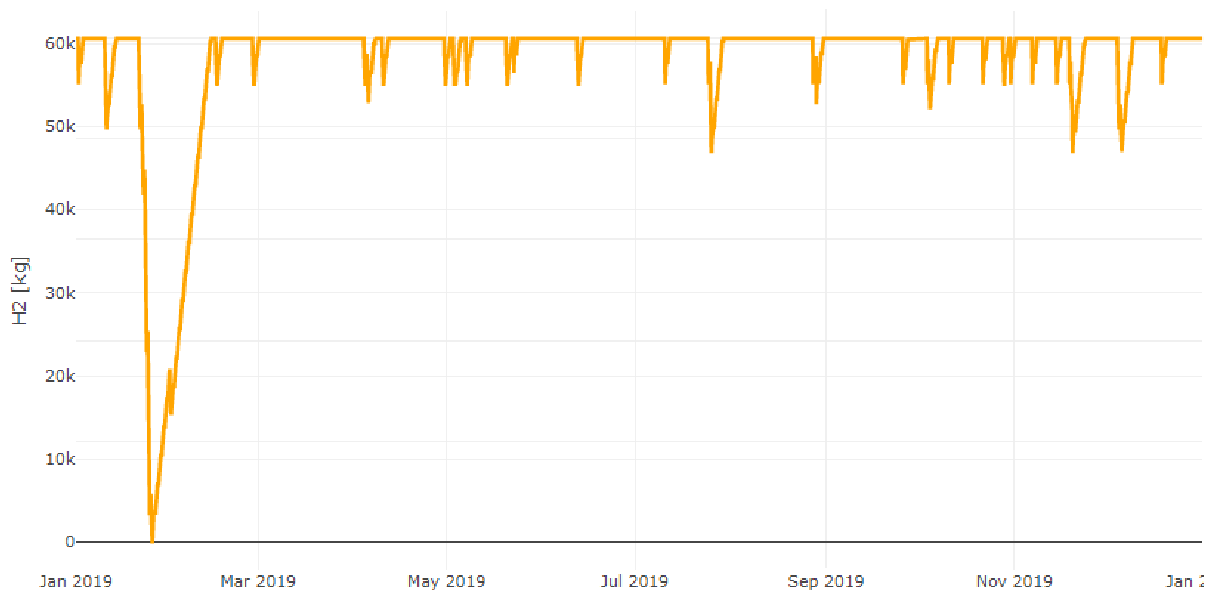

Figure 10 - Hydrogen storage profile over time

In the graphs above, the minimum storage size to comply with GT requirements is of 60.6 tonnes of hydrogen for 20 MW electrolyzer capacity.

The natural next step after was to find the best tradeoff between electrolyzer and storage sizes, ensuring GT considered profile can be met[35]. Figure 11 was plot for different electrolyzer sizes

[35] At 30%-vol H_2 only based on local hydrogen production plant.

using the method describe above. It shows minimum storage size required for given electrolyzer capacity and associated investment costs for the hydrogen production plant.

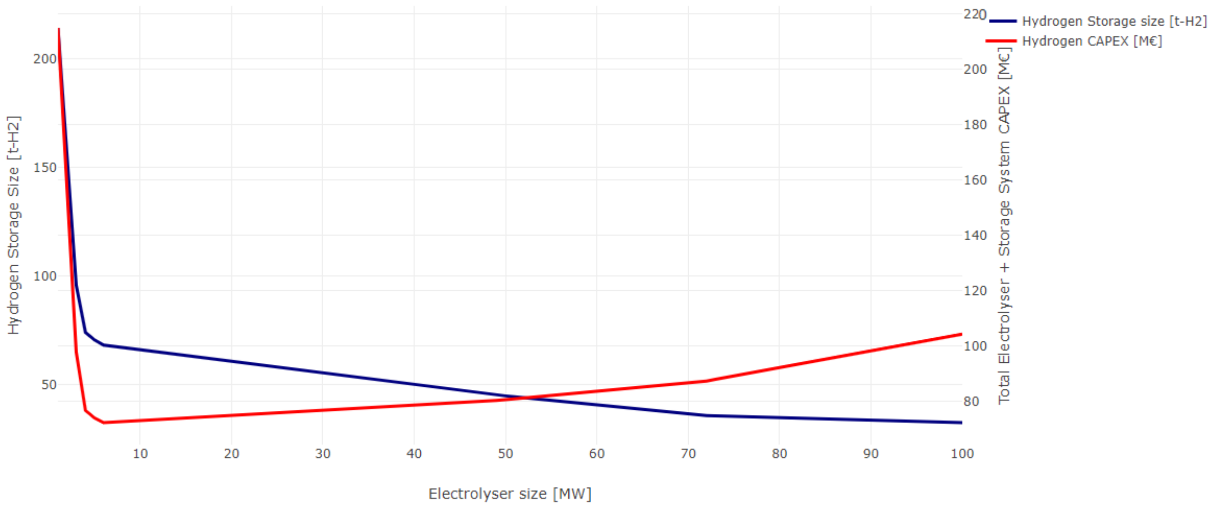

Figure 11 – Hydrogen production plant CAPEX optimization ensuring GT profile coverage[36]

The lowest investment cost combination of electrolyzer size and storage size was retained for the study (6MW electrolyzer size[37] and 68.1 tonnes for storage one). Considered investment costs from appendix 0 were considered.

3.4 Assumptions & data

3.4.1 Price data

Price data shown on Table 5, Figure 12 and Figure 13 have been considered. Data sources and considered steps are gathered on Table 6. We consider 2019 as year of reference for those data in France.

[36] Investment costs from appendix 0 were considered.
[37] Producing 115.2 kg-H2/hr assuming 52.1 kWh of electricity consumed per kilogram of hydrogen produced.

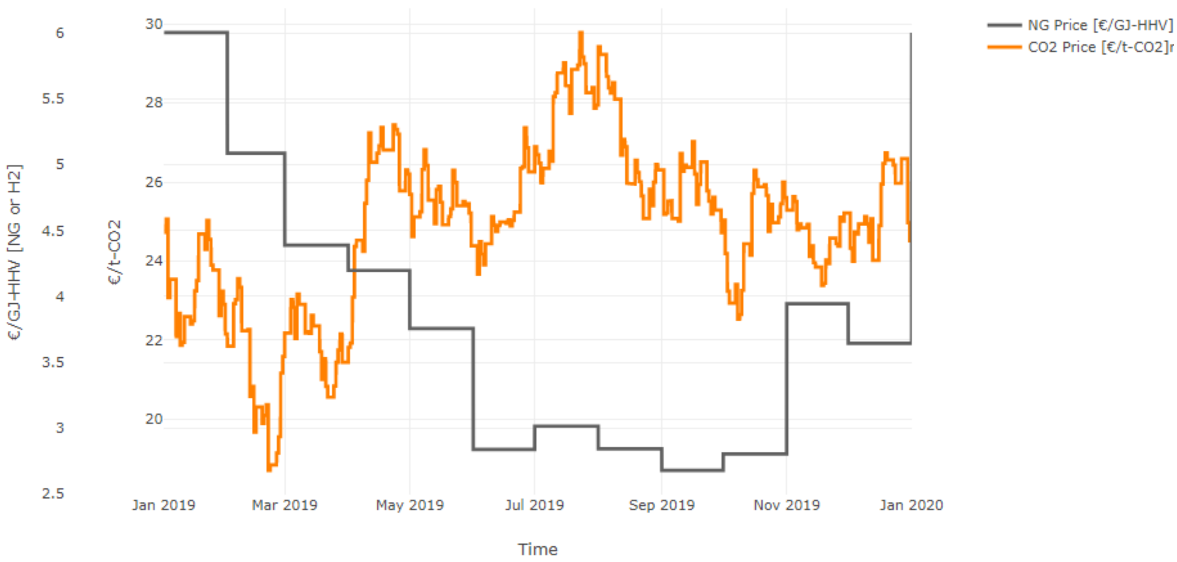

Figure 12 - NG and CO_2 profiles considered

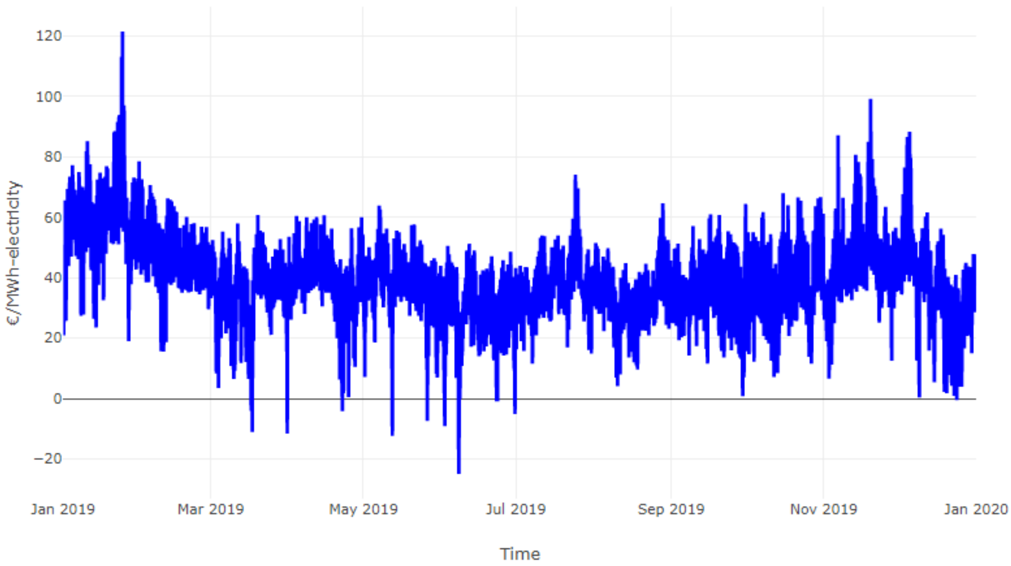

Figure 13 - Electricity Price Profile considered (time step of 1 hour)

For water and hydrogen price, we first considered constant prices as per shown on Table 5.

Resource	**Value**	**Unit**
Hydrogen	4.68[38]	€/kg-H_2
Water	0.004	€/L

Table 5 - Hydrogen and water prices considered

[38] Typical green hydrogen LCOH lies between 2.6 and 6.3 €/kg-H_2 (IEA, Global LCOH production by techno, 2020).

Economic data	**Data accuracy**	**Source**
Electricity price	Hourly	(ENTSOE Transparency Platform, France 2019)
NG price	Monthly	NG spot price (PEG Nord) in 2019 in France (Vattenfall, 2019)
CO_2 price	Daily	EUA price from Carbon Price Viewer from (Sandbag, 2019)
Water price	Yearly	Own assumption
H_2 price	Yearly	Own assumption

Table 6 - Economic data sources

Cost parameters considered for the study are shown in Appendix 2.

3.4.2 Other assumptions

Other assumptions and a few clarifications are presented in this section.

Regarding the GTPP, the choice of SC GT peaker was motivated by two reasons:

1. The duty cycle of a peaker plant is different from baseload-running plant. Indeed, a peaker cycle is more uncertain because it is mainly based on electricity price variations due to the need for balancing the differences in electric supply and demand. Building a business case around a peaker GTPP co-fired with hydrogen (and understanding which levers to implement to make it profitable) may help decarbonize such assets while reducing uncertainty associated with a carbon-producing business model.
2. By definition, peakers run a low number of operated hours a year and then require less volume of fuel than baseload-running machines on a yearly basis. This naturally leads to smaller electrolyzer and storage capacity and then lower associated costs in colocation scenarios.

In LCOE and NPV calculations, investment and operation costs that are similar between the scenarios have not been considered. For instance, GTPP investment costs are assumed similar between all scenarios. They have been set aside in this study.

About the hydrogen production plant, degradation of storage capacity was not considered. Energy required for compression before storage was assumed constant as per shown in Appendix 0. Whereas we haven't considered degradation mechanisms occurring in electrolyzer stacks, we tried and accounted for them in variable O&M costs[39].

[39] Considering 100,000 hours of lifetime for electrolyzer stack and assuming 45% CAPEX cost for stacks, we reached variable O&M costs of 3.9 €/[MW.hr] assuming 0.872M€/MW for electrolyzer CAPEX costs (IEA, Global LCOH production by techno, 2020)

4 Results & discussion

4.1 Raw results

Scenarios described in section 3.3 have been run and are presented on Table 7. Results are shown relatively to the *Baseline* case.

	$\Delta\, \boldsymbol{NPV} = \boldsymbol{NPV}[\boldsymbol{scenario}] - \boldsymbol{NPV}[\boldsymbol{Baseline}]$	$\Delta_{\%}\, \boldsymbol{LCOE} = \frac{\boldsymbol{LCOE}[\boldsymbol{scenario}] - \boldsymbol{LCOE}[\boldsymbol{Baseline}]}{\boldsymbol{LCOE}[\boldsymbol{Baseline}]}$	**LCOH**
Baseline with H_2 co-firing	-10.7	+60%	NA
H_2 production for GT consumption	-76.9	+ 542%	42.1
H_2 production for GT consumption & external sales	-71.3	+ 303%	31.8
Units	*M€*	*%*	*€/kg-H_2*

Table 7 - Results shown relatively to baseline scenario

A few observations can be made:

- *Baseline case with H_2 co-firing* will lead to lower NPV values (10.7M€ below the one from *Baseline* scenario) and higher LCOE (60% higher than *Baseline* one)
- Scenarios with hydrogen production show even lower NPV (~ 70M€ lower) and higher LCOE values (~300 or even 540% higher).
- When applicable LCOH values are very high compared to market trends (IEA, Global LCOH production by techno, 2020)

One can note that all scenarios studied are less profitable than *Baseline* one. However, they all help reduce GT emission by 11.4%. One can wonder under which set of incentives they could become profitable.

4.2 Incentives

For each scenario considered, we have determined the level different kind of incentives should reach to make the business case as profitable as *Baseline* case. In other terms, we have determined which values such incentives should reach so scenarios reach same NPV value as the baseline.

The following incentives were considered:

- An investment related subsidy in M€ received when project starts.
- Hydrogen breakeven price in €/kg-H_2
- CO_2 breakeven price in €/t-CO_2 assumed as constant

Results are shown in Table 8.

	Baseline with H_2 co-firing	**Onsite H_2 production for GT consumption only**	**Onsite H_2 production for GT consumption and external sales**	***Units***
Investment subvention	10.7	76	71	*M€*
Hydrogen price	0.74	NA[40]	60.3	*€/kg-H_2*
CO_2 price (EUA)	624	~5400	~4000	*€/t-CO_2*

Table 8 - Breakeven values of different incentives for the three scenarios compared to Baseline

A few observations can be stated:

- Amounts of investment subsidy required for the scenarios compete with *Baseline* one goes from tens of M€ when H_2 is delivered to the plant (e.g. bought externally) and rises to more than 70M€ when it is produced onsite.
- Hydrogen buying price of 0.74€/kg-H_2 is required to make *Baseline with H_2 co-firing* as profitable as *Baseline* scenario.
- H_2 selling price of 60.3 €/kg-H_2 is required to make scenario with *Onsite H2 production for GT consumption and external sales.*
- CO_2 prices to reach to make scenarios more competitive go from more than 600€/t-CO_2 for *Baseline with external H*2 up to several thousands of €/t-CO_2 when hydrogen is produced onsite. As comparison, CO_2 price was of 24.87€/t-CO_2 in average in 2019.

[40] Hydrogen price incentive is applicable only when hydrogen is bought or sold which is not the case for scenario with *H_2 production for GT consumption only*.

4.3 Discussion

First, LCOH on Table 7, are quite high under the set of data and assumptions considered. This is mainly due to the equipment sizing method used: hydrogen production plant components capacity have been sized based on GT hydrogen needs only (see section 3.3.4). One can now see this does not lead to LCOH optimization. Sizing hydrogen production plant for GT power generation needs only does not appear as a profitable choice. Instead, LCOH minimization should be pursued when doing so. In general, prioritizing one sector (Power Generation in our case) over another (hydrogen production) can compromise final optimization. As one of the next steps for our model, we plan to include LCOH as a parameter when sizing hydrogen plant capacities. This should lead to lower final LCOH value and improvements on LCOE. NPV should increase as well for scenario *Onsite H_2 production for GT consumption and external sales*. If sized only for LCOH optimization, one should see LCOH value close to current hydrogen price[41]. A tradeoff between GT needs and LCOH would then have to be made in order to maximize NPV.

Second, in our calculations, only two products have been considered: electricity and hydrogen sales. In real terms, a GTPP – especially a peaker – can provide other products including flexibility services (among others primary & secondary frequency responses to the grid, blackstart capability). On its side, hydrogen production plant can also provide flexibility services (such as interruptibility). These new flexibility products alone would not necessarily change the relative results presented here. However, considering synergies between co-located objects (GTPP, H_2 production plants) could enhance them. Such integration could help improving the business cases for scenarios *Onsite H_2 production for GT needs only* and *Onsite H_2 production for GT consumption and external sales*. Several flexibility services should be added to the model. Study of possible synergies between components (from flexibility standpoint) is planned too.

Last, one can conclude from Table 8 that an incentive mechanism considered alone does not bring sufficient revenue to make H_2 a profitable option for the studied gas peaker power plant. Alone, carbon price or incentives on hydrogen does not seem sufficient to fill the gap between the considered scenarios (modeled H_2 and CO_2 prices needed to fill the gap are far from current

[41] When hydrogen is produced through electrolysis.

market prices[42][38]). It would rather likely require activating several mechanisms of incentives to avoid costly incentive amount.[43]

Among the next steps, we also plan to explore the impacts from other incentive mechanisms (for instance on energy storage) and how incentives could be coupled to help improve the associated business cases.

5 Conclusion

This paper explored the effect of combining a GTPP with electrolyzer and storage facilities for hydrogen, in the same location. We investigate how the co-location may provide the plant owner with the ability to generate new products (in addition to the sales of electricity) that may increase the profitability for both assets. To the best of our knowledge, no previous work has considered such effects.

The paper uses a business-oriented and time-based approach to analyze the opportunities for considered devices, created by the sales of H_2 and, ultimately, the additional flexibility services that can be generated with the co-location[44]. We also consider the ability of GTPP to co-fire H_2 together with NG. The approach relies on LCOE and NPV calculations, which are typical indicators for decision markers in the power industry. Importantly, the time-based approach (named after considering historical operational data from GT power plant) provides decomposition of data with sub-periods. Such approach enables us to consider the full flexibility we can benefit from co-location. Concretely, this enable us to implement calculations on an hourly basis, using hourly values for prices and GTPP profiles, in order to derive the energy quantities that serve to compute the LCOE and NPV. By contrast, the 'conventional' approach is not able to capture the whole complexity of combining hydrogen production and GT power plant in the same location.

Overall, results show that that hydrogen appear to be non-competitive in most cases, with increased values for LCOE and negative NPV. Moreover, none of the incentives we consider (namely carbon pricing, lump-sum grant based on CAPEX, and subsidy that decreases the price of H_2 when it is bought and increase the perceived price when it is sold) allow making hydrogen

[42] Typical green hydrogen LCOH lies between 2.6 and 6.3 €/kg-H2 (IEA, Global LCOH production by techno, 2020).
[43] Under the considered assumptions and set of data (France, 2019)
[44] We present here a preliminary version of this paper for the 2021 IAEE conference.

competitive with consistent values. Among the main obstacles is the decisions rule we assumed to determine the sizing of electrolysis and storage. The rule only considers what the GTPP needs at peak times, which leads to over-dimensioning the hydrogen facilities. This results in high LCOH and, in turn, high LCOE for the GTPP. One solution to overcome this barrier would consist in giving more weight to the objective of having low LCOH in the sizing rule. Another avenue to increase competitiveness relies on adding new products that we did not implement in this preliminary version of the paper. First of all, we want to assess the benefit that may arise from including the revenues generated by grid flexibility services.

Beyond, this paper can be seen as first step in a more general project that will continue investigating the opportunities associated with combining and co-locating storage, electrolysis and power generation. This is a question that deserves more investigations using further contextual cases through TBA (with more products, devices, incentives, *etc*.), as well as more comprehensive methodology such as microeconomic modelling to analyze investment decisions and dispatching. We leave this for future research.

Acronyms

Acronym	Description
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CCS	Carbon Capture and Storage
DR	Demand Response
ENTSO-E	European Network of TSO - Electricity
EPC	Engineering, Procurement & Construction
EU ETS	European Union Emission Trading System
EUA	European Union Allowances
FC	Fuel Cell
GT	Gas Turbine
GTPP	Gas Turbine Power Plant
H_2	Hydrogen
HHV	Higher Heating Value
IEA	International Energy Agency
kW	kilo Watt
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
LHV	Lower Heating Value
MW	Mega Watt
NG	Natural Gas
NPV	Net Present Value
OH	Operating Hours
O&M	Operations & Maintenance
OPEX	Operational Expenditure
RES	Renewable Energy Systems
SC GT	Simple Cycle Gas Turbine
SMR	Steam Methane Reforming
TBA	Time Based Approach
TSO	Transmission System Operator
VRES	Variable Renewable Energy Sources

References

Aliprandi, F., Stoppato, A., Mirandola, A., 2016. Estimating CO2 emissions reduction from renewable energy use in Italy. *Renewable Energy*, 96(A), p 220-232.

ARENA (Australian Renewable Energy Agency), 2018. *Comparison of dispatchable renewable electricity options*. Rapport.

Bogdanov, D., Farfan, J., Sadovskaia, K., Aghahosseini, A., Child, M., Gulagi, A., Oyewo, A.S., Barbosa, L.S.N.S., Breyer, C., 2019. Radical transformation pathway towards sustainable electricity via evolutionary steps. *Nature Communications*, 10(1077).

CGE, 2019. *Stockage stationnaire d'électricité – Synthèse et recommendation du theme de l'année 2018 de la section ICM du CGE*. CGE (Conseil Général de l'Économie), French Ministry of the Economy and Finance.

Chiu, C.L., Chang, T.H., 2009. What proportion of renewable energy supplies is needed to initially mitigate CO_2 emissions in OECD member countries? *Renewable and Sustainable Energy Reviews*, 13(6-7), p 1669-1674.

Delarue, E.D., Luickx, P.J., D'haesleer, W.D., 2009. The actual effect of wind power on overall electricity generation costs and CO_2 emissions. *Energy Conversion and Management*, 50(6), p 1450-1456.

DoE, 2009. Hydrogen and Fuel Cells Program Record.

DOE, 2015. Fuel Cell Technologies Office.

ENTSOE Transparency Platform. (France 2019). France. Retrieved from https://transparency.entsoe.eu/transmission-domain/r2/dayAheadPrices/show?name=&defaultValue=true&viewType=GRAPH&areaType=BZN&atch=false&dateTime.dateTime=06.05.2021+00:00|CET|DAY&biddingZone.values=CTY|10YFR-RTE------C!BZN|10YFR-RTE------C&resolution.val

Fasihi, M., Breyer, C., 2020. Baseload electricity and hydrogen supply based on hybrid PV-wind power plants. *Journal of Cleaner Production*, 243(18466).

General Electric, 2021, Jeffrey Goldmeer, John Catillaz. GEA34805. Hydrogen as a fuel for gas turbines - A pathway to lower CO2. Retrieved from https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf

General Electric, 2019, Jeffrey Goldmeer. GEA33861 - Hydrogen power generation: Fuel-flexible gas turbines use hydrogen as an enabler for a low or reduced carbon energy ecosystem. Retrieved from www;ge.com: https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf

Graham, P., 2018. *Review of alternative methods for extending LCOE calculations to include balancing costs*. Technical report, CSIRO, Australia.

Gulagi, A., Bogdanov, D., Breyer, C., 2018. The role of storage technologies in energy transition pathways towards achieving a fully sustainable energy system for India. *Journal on Energy Storage*, 17, p 525-539.

Gutiérrez-Martín, F., Da Silva-Álvarez, R.A., Montoro-Pintado, P. 2013. Effects of wind intermittency on reduction of CO_2 emissions: the case of the Spanish power system. *Energy*, 61, p 108-117.

Hansson, J., Berndes, G., Johnsson, F., Kjärstad, J., 2009. Co-firing biomass with coal for electricity generation – An assessment of the potential in EU27. *Energy Policy*, 37(4), 1444–1455.

Heard, B.P., Brook, B.W., Wigley, T.M.L., Bradshaw, C.J.A., 2017. Burden of proof: a comprehensive review of the feasibility of 100% renewable-electricity systems. *Renewable and Sustainable Energy Reviews*, 76, p 1122-1133.

Hydrogen Europe. Decarbonise Industry. Retrieved from Hydrogen Europe: https://hydrogeneurope.eu/decarbonise-industry

Hydrogen Europe. Hydrogen Production. Retrieved from Hydrogen Europe: https://hydrogeneurope.eu/hydrogen-production-0

Hydrogen Europe. Zero emission Mobility. Retrieved from Hydrogen Europe: https://hydrogeneurope.eu/zero-emission-mobility

IEA, 2020. Global LCOH production by techno. Retrieved from https://www.iea.org/data-and-statistics/charts/global-average-levelised-cost-of-hydrogen-production-by-energy-source-and-technology-2019-and-2050

IEA, 2020. Natural Gas Fired Power.

IEA, 2018. Hydrogen. Retrieved from Irena: https://www.iea.org/fuels-and-technologies/hydrogen

IRENA, 2018. Hydrogen from Renewable Power: Technology Outlook for the Energy Transition. Retrieved from https://www.irena.org/publications/2018/Sep/Hydrogen-from-renewable-power

IRENA, 2019. Hydrogen: A renewable energy perspective. Retrieved from https://www.irena.org/publications/2019/Sep/Hydrogen-A-renewable-energy-perspective

Morales-España, M., Nycandera, E., Sijm, J., 2021. Reducing CO2 Emissions by Curtailing Renewables: Examples from Optimal Power System Operation. Working paper.

RTE, 2019. Bilan électrique 2019.

Sandbag, 2019. Carbon Price Viewer. Retrieved from https://ember-climate.org/data/carbon-price-viewer/

Shell, 2017. Shell Hydrogen Study - Sustainable mobility through fuel cells and H2. Retrieved from https://www.shell.com/energy-and-innovation/new-energies/hydrogen/_jcr_content/par/keybenefits_150847174/link.stream/1496312627865/6a3564d61b9aff43e087972db5212be68d1fb2e8/shell-h2-study-new.pdf

Squalli, J., 2017. Renewable energy, coal as a baseload power source, and greenhouse gas emissions: Evidence from U.S. state-level data. *Energy*, 127, p 479-488.

Valentino, L., Valenzuela, V., Botterud, A., Zhou, Z., Conzelmann, G., 2012. System-wide emissions implications of increased wind power penetration. *Environmental Science & Technology*, 46(7), p 4200-4206.

Vattenfall, 2019. Marché de gros du gaz naturel - France. Récupéré sur https://www.vattenfall.fr/professionnels/le-mag-energie-pro/marche-de-l-energie?page=3

Weigt, H., Ellerman, A.D., Delarue, E., 2013. CO_2 abatement from renewables in the German electricity sector: Does a CO2 price help? *Energy Economics*, 40(1), 149–158.

Appendix 1 - Data used for comparison conventional and time-based approach

	Time-based method			Conventional method			Identical for both methods	
Time	**GT Load Factor**	**Electricity price**	**NG price**	**GT Load Factor**	**Electricity price**	**NG price**	**CO_2 price**	**H_2 buying price**
	%	***€/MWh-elec***	***€/MWh-HHV***	***%***	***€/MWh-elec***	***€/MWh-HHV***	***€/t***	***€/MWh-HHV***
00:00:00	0%	36	10.8	66.6%	60	13.2	20	36
01:00:00	0%	36	10.8	66.6%	60	13.2	20	36
02:00:00	0%	36	10.8	66.6%	60	13.2	20	36
03:00:00	0%	36	10.8	66.6%	60	13.2	20	36
04:00:00	0%	36	10.8	66.6%	60	13.2	20	36
05:00:00	0%	36	10.8	66.6%	60	13.2	20	36
06:00:00	**50%**	**54**	**12.6**	66.6%	60	13.2	20	36
07:00:00	100%	72	14.4	66.6%	60	13.2	20	36
08:00:00	100%	72	14.4	66.6%	60	13.2	20	36
09:00:00	100%	72	14.4	66.6%	60	13.2	20	36
10:00:00	100%	72	14.4	66.6%	60	13.2	20	36
11:00:00	100%	72	14.4	66.6%	60	13.2	20	36
12:00:00	100%	72	14.4	66.6%	60	13.2	20	36
13:00:00	100%	72	14.4	66.6%	60	13.2	20	36
14:00:00	100%	72	14.4	66.6%	60	13.2	20	36
15:00:00	100%	72	14.4	66.6%	60	13.2	20	36
16:00:00	100%	72	14.4	66.6%	60	13.2	20	36
17:00:00	100%	72	14.4	66.6%	60	13.2	20	36
18:00:00	100%	72	14.4	66.6%	60	13.2	20	36
19:00:00	100%	72	14.4	66.6%	60	13.2	20	36
20:00:00	100%	72	14.4	66.6%	60	13.2	20	36
21:00:00	100%	72	14.4	66.6%	60	13.2	20	36
22:00:00	**50%**	**54**	**12.6**	66.6%	60	13.2	20	36
23:00:00	0	36	10.8	66.6%	60	13.2	20	36

Appendix 2 - Cost parameters considered in the study [a]

Section	**Quantity**	**Value**	**Unit**	**Assumption based source**
Financials	Discount rate	10%	-	Own assumption
	Tax rate	21%	-	Own assumption
	Lifetime	20	Years	Own assumption
	Global escalation rate	2%	-	Own assumption
Gas	Volumetric gas composition	70% CH_4 30% H_2	%-vol	Own assumption
Hydrogen production plant	Electrolysis plant CAPEX costs	0.72	M€/MW	Current electrolyzer CAPEX from (IEA, Global LCOH production by techno, 2020)
	Electrolysis plant Fixed O&M costs	2.2%	%-CAPEX/yr	Current electrolyzer Fixed OPEX from (IEA, Global LCOH production by techno, 2020)
	Electrolysis plant Variable O&M costs	3.9	€/(MW.hr)	Recalculated considering (IEA, Global LCOH production by techno, 2020)
	Electrolyzer plant electricity consumption	52.1	kWh-elec/kg-H_2	Current electrolyzer efficiency from (IEA, Global LCOH production by techno, 2020)
	Electrolyzer H_2 production	115.2	kg-H_2/hr	Model-determined
	Storage & compression plant CAPEX costs	1	M€/t-H_2 stored	Own assumption

[a] Constant conversion rate of 0.82 €/$ has been assumed.

	Storage & compression plant Fixed O&M costs	2%	%-CAPEX/yr	Own assumption
	Storage size	68.1	t-H_2	Model-determined
	Compression + storage electricity consumption	3	kWh/kg-H_2	Own assumption (DoE, 2009) [b]

[b] In the quoted study, estimated energy to compress & fill hydrogen storage varies between 1.7 and 6.4 kWh/kg-H2 due to different types of compressors and different filling conditions for vehicle storage applications. For 350 bar compression pressure, an energy use between 2 and 4 kWh/kg H2 can be assumed. We considered 3 kWh/kg-H2 in the present study.