Gas turbines in a carbon-neutral society
10th International Gas Turbine Conference
11-15 October 2021

Paper ID Number: 32-IGTC21

DECARBONISATION OF GAS TURBINE BY BURNING HYDROGEN PRODUCED LOCALLY BY ELECTROLYSIS

Camila Torres Moncayo / EDF DTEAM INGEUM

1 Place Pleyel, 93200, Saint-Denis, France
+33 143693548
camila-maria.torres-moncayo@edf.fr, jean-louis.meyer@edf.fr, thierry.le-guevel@edf.fr

ABSTRACT

This study deals with the conversion of a 125 MW peak load Gas Turbine from gas or domestic fuel to hydrogen, and considers the equipment required for this purpose. The problem is studied from an end-user perspective considering that the turbine has been changed or retrofitted previously. The study only refers to H2 equipment.

The study tries to respond to the following question: the path to 100% hydrogen in new turbines seems technologically promising. But is it technically feasible for a real industrial turbine and is it economical viable if we take into account the global costs?

A big challenge in scaling from small hydrogen blends to 100% is the big quantity of electricity needed for electrolytic hydrogen production and important storage needed. This paper only considers the case of onsite electrolytic hydrogen production and on site tank storage.

A set of 6 cases were studied for this note. They vary three parameters: Hydrogen-blended (30% H2 and 70% natural gas) or 100% hydrogen power generation project ; Storage capacity: providing 50 hours, 120h or 25 hours of operation and finally refilling time of the storage capacity: for a period of 1 month or 4 months of electrolyser operation.

For the various case studies, the following technical parameters were roughly sized: capacity of electrolysers in MW, storage capacity in tones, cryogenic pumping and vaporizing flow in Nm3/h.

CAPEX and OPEX costs were estimated for each case study.

It is important to precise that costs are treated at a macro scale. In a real project, other important costs should be added as the integration engineering, site works, commissioning, and obviously the conversion of the GT itself.

Aside from the cost aspects, this study also identifies the technical aspects of equipment associated with a project of this type, and analyzes feasibility based on market capabilities today. It provides elements to consider such as the ground installation to be expected if one wishes to install this equipment in an industrial site as well as elements of regulatory constraints and industrial risks that may be binding.

Scope of the study

The paper presents a pre-feasibility study that sizes the adequate H2 production systems based on alkaline electrolysis technology, H2 storage solutions (gaseous and liquefied), pumping and regasification to be installed in order to adequately feed one GT.

Different scenarios are exposed based on H2 proportion in the gas turbine (100% H2 and mixed fuel 30% H2 co-fired with natural gas), and storage capacity needs which depend on specified autonomy and the number of hours of operation of the gas turbine.

The study attempts to show cost estimates at a macro scale, associated to the introduction of H2 equipment in an industrial existing site and some elements to be considered referring to equipment footprint and industrial risks.

Emphasis is placed on H2 equipment, the conversion of the existing gas turbine in a H2 gas turbine is out of the scope of work.

Summary of main results and findings

- Of six case studies performed, only two cases (2 and 6) would be potentially viable technically from the perspective of the suppliers of electrolysers and storage. These cases were estimated at ±50% between €30 and €40 million for study case 2 and between €20 and €25 million for study case 6.

- Nevertheless, costs of the two projects are extremely high regarding other decarbonization options.
- In general, thinking of a turbine supply with an electrolyser operating at the same time to ensure the necessary production of H2 is not possible taking into account the large quantities of H2 required for a GT of this size and especially because the start of the turbines is done at peak load. It would therefore be illogical to supply the electrolysers with energy at this time.
- Storage and filling time impact the hydrogen production capacity: the longer the filling time, the smaller the installed production capacity for the same storage capacity. The larger the storage, the more installed production capacity. It is therefore necessary to find a good compromise between these two parameters for each project.
- The costs of electrolysers represent an important part of the CAPEX for a project. These costs are constantly evolving and the definitive estimation should be done on a project specific way. Values are not to take in consideration for all projects.
- Since the reduction in CO2 emissions is not proportional to the volume of hydrogen in natural gas, one can think that only a turbine burning blending with a high proportion of hydrogen or 100% H2 has a real environmental impact.
- The industrial risks associated with a hydrogen production and a storage facilities are significant and can impact the realization of an industrial project on site.

INTRODUCTION

In a context of decarbonisation of electrical facilities, turbine suppliers are actively working to enable gas-turbine operations with 100% Hydrogen or mixtures of natural gas and hydrogen. Hydrogen power generation announcements have picked up rapidly since 2019.

From the ETN Report "The path towards a zero-carbon gas turbine" (2020) it is indicated that the development of retrofit solutions for existing natural gas turbines will be a key enabler for the implementation of the hydrogen gas turbine technology and that first steps can initially be achieved with relatively small modifications to existing combustors, allowing co-firing of hydrogen to significant fractions (>30 %). Increased field experience would enable further developments, such as new types of combustors allowing up to 100% of hydrogen.

For most manufacturers, it's more than just the turbines, they are making big bets on integrated hydrogen packages that span hydrogen production, storage, and combustion.

Key components of an integrated package are: electrolysers, hydrogen storage solutions with related compressors and hydrogen-capable gas turbine.

Considering the big quantities of hydrogen required for combustion, hydrogen compression and storage in on-site tanks can only be considered for pilot projects using small turbines.

Energy storage to underground salt caverns is a good way of resolving this problem, but the geological location is not always adapted, that's why this kind of storage was not considered in the study.

The mass calorific value of hydrogen is the highest of all existing fuels, which explains the interest in the energy industry. For example, the natural gas LHV (Lower Heating Value) is about 50,000 kJ/kg, while the H2 LHV is almost 120,000 kJ/kg.

Table 1: comparing volume and mass parameters of natural gas vs hydrogen

	Natural Gas	H2
LHV in mass (kJ/kg)	50 020	119 930
LHV in volume (kJ/Nm3)	35 514	10 800
Volumic mass - under normal termperature and pression conditions (kg/Nm3)	0,71	0,09

For end users of turbines, like EDF, which is one of the lowest CO2 emitters per MWh product, the energy transition represents an opportunity to actively contribute to the development of innovative solutions adapted to the climate emergency. EDF has decided to position itself on the new business of decarbonized H2, produced by electrolysis of water powered by non-CO2-emitting electricity sources.

With that in mind, it is interesting to evaluate the technical feasibility and associated costs of an on-site H2 installation which allows the combustion of large quantities of H2, in a real industrial case study.

This note examines the technical-financial feasibility of setting up upstream means of feeding the GT: production of H2 by alkaline electrolysis, liquefaction, liquid storage (LH2) with cryogenic pumping and regasification for different cases.
The equipment shown in the figure below corresponds to the main part of a project of this kind in terms of CAPEX and OPEX costs and also in terms of implementation and industrial risks.

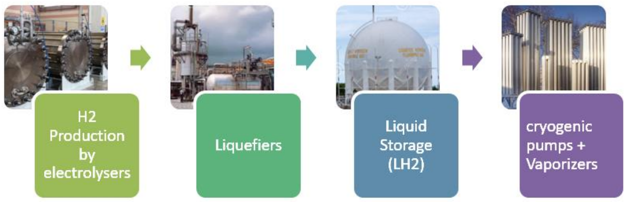

Figure 1: equipment studied for a Hydrogen GT Project

Case studies

Six case studies are presented in this note and should be read as follows:

1) Feeding the GT with 100% H2 fuel, on-site storage that can provide 50 hours of operation to the GT, the storage is filled during a period of 1 month of operation of the electrolyser in 9 hours per day. **(*H2 100%; 50 hours; 1M*)**

2) GT supplied with 30% H2 fuel, on-site storage provides 50 hours of operation, this storage is filled during a period of 1 month of operation of the electrolyser in 9 hours per day. **(*H2 30%; 50 hours; 1M*)**

3) GT supplied with 100% H2 fuel, on-site storage provides 120 hours of operation, this storage is filled during a period of 4 months of operation of the electrolyser in 9 hours per day. **(*H2 100%; 120 hours; 4M*)**

4) GT supplied with 30% H2 fuel, on-site storage provided 120 hours of operation, this storage is filled during a period of 4 months of operation of the electrolyser in 9 hours per day. **(*H2 30%; 120 hours; 4M*)**

5) GT supplied with 30% H2 fuel, no on-site storage planned. **(*H2 30%; 0 hours; 0M*)**

6) GT supplied with 30% H2 fuel, planned on-site storage that can provide 25 hours of operation, this storage is filled during a period of 1 month of operation of the electrolyser in 9 hours per day. **(*H2 30%; 25 hours; 1M*)**

The study does not take into account:
- The feasibility and costs associated with the modifications on the GT to be made to adapt it to the H2 supply to replace gas (or domestic fuel oil).
- The feasibility and costs of connecting the site to the natural gas network in the event of H2/natural gas mixing.

NOMENCLATURE

CAPEX: Capital Expenditure
GT: Gas Turbine
H2: Hydrogen
OPEX: Operating Expenses

STUDY RESULTS

EDF Gas Turbines

A reflection has been carried out on the GT of EDF assets that could be conducive to the conversion to Hydrogen. Although this paper is not interested in the technical feasibility of adapting conventional gas turbines to burn another fuel such as Hydrogen, the study considers the technical data associated with GT at the an EDF site, only for the surface of this site that could accommodate new equipment. Technical assumptions taken are the following:
-Power: 125 MWe,
-Average efficiency: 34% (considered the same for natural gas or hydrogen in this study)
-Operating hours: 150 h
-Annual operating profile: 50% of the total energy provided by the GT is given in winter (February and March).

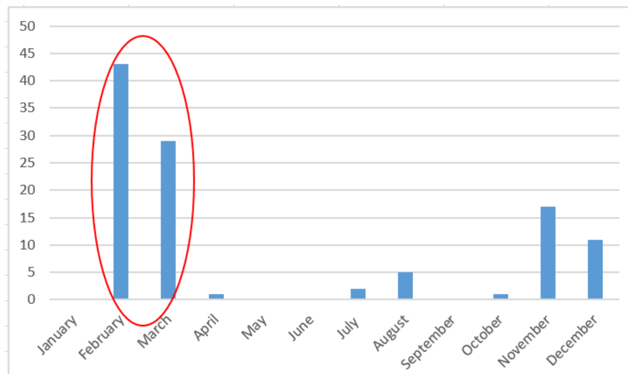

Figure 2: Operating hours of the GT (case study) on an average year

This leads to the definition of the storage capacity to be estimated. The study incorporates three possibilities: 25 hours, 50 hours, or 120 hours.

Operation Strategy

The following operation strategy options were considered:
-The electrolyser is considered to run for 9 hours a day. Indeed, in order to save OPEX costs, it is considered that the electrolyser would operate between 9 pm and 6am (in which the cost of electricity is reduced).
-The Refilling time of the storage capacity is defined for a period of 1 month or 4 months of electrolyser operation.
-Regarding some of the information about H2 Turbines development, the case studies consider a percentage of H2 content in the fuel: either a mixture of 30% H2 and 70% natural gas, or 100% H2.
- The configuration of combustion is a dual-fuel natural gas / H2 or liquid fuel / H2

Technical synthesis results

The following table summarizes the results of the sizing of the main equipment for each case described previously.

Table 2: Table indicating results of design parameters results: H2 flow needed for the GT, electrolyser capacity, liquefier capacity, liquid storage capacity and cryogenic pumping and vaporizers operating pressures and flows

Equipment	1) H2 100% ; 50h ; 1M	2) H2 30% ; 50h ; 1M	3) H2 100% ; 120h ; 4M	4) H2 30% ; 120h ; 4M	5) H2 30% ; 0h	6) H2 30% ; 25h ; 1M
H2 flow needed to feed the Turbine	116 000 Nm3/h	13 000 Nm3/h	116000 Nm3/h	13 000 Nm3/h	13 000 Nm3/h	13 000 Nm3/h
Electrolyzer capacity	21 400 Nm3/h 107 MW	2 500 Nm3/h 12 MW	12 800 Nm3/h 64 MW	1 400 Nm3/h 7 MW	13 400 Nm3/h 67 MW	1 200 Nm3/h 6 MW
Liquefier capacity	18	2	11	1,2	-	1
Liquid Storage capacity	525 t	60 t	1260 t	145 t	0 t	30 t
Cryogenic pumping + vaporizers	1 bar → 35 bar 116 000 Nm3/h	1 bar → 35 bar 13 000 Nm3/h	1 bar → 35 bar 116 000 Nm3/h	1 bar → 35 bar 13 000 Nm3/h	30 bar → 35 bar 13 000 Nm3/h	30 bar → 35 bar 13 000 Nm3/h

H2 Production

Electrolyser technologies

Today, there are three electrolysis technologies to produce H2 by electrolysis: alkaline, PEM and High Temperature. Details on the difference in processes will not be developed in this study.

Sizing of H2 production equipment and sensitivity variables

- Cases of a 100% H2 GT (study case 1 and 3)

For cases where the fuel supplying TAC (125MWe) is 100% H2, the feed rate is almost 116,000 Nm3/h. This makes it possible to quickly draw a first conclusion for this case: the production of H2 cannot be done simultaneously in relation to the need for the TAC. Indeed, if we take into account that a 20 MW H2 production facility produces 4,000 Nm3/h, it would take 29 such installations to meet the instantaneous need and this represents more energy than the TAC could produce and would lead to prohibitive CAPEX.

- Cases of a 30% H2 GT (study case 2,4,5 and 6)

If the Gas Turbine (125 MW) is fueled of 30% H2 and 70% Natural Gas, the H2 flow required is about 13,000 Nm3/h. This is almost 9 times less than the 100% H2 rate (so non-proportional, this is explained by the H2 volume pCI and its density). We also sized the borderline case (case 5) where H2 production is simultaneous to the consumption of GT and there is no on-site storage. Installed production capacity (in Nm3/h and MW).

The installed capacity of an electrolyser corresponds to the volume in normal cubic meters per hour, but in general we speak of installed MW, which correspond to the electrical consumption of the electrolyser (without the auxiliaries) to produce the desired flow. For alkaline electrolysers we assumed a production of 200 Nm3/MW.

The installed capacity will be sized by the storage required for a defined range (50 hours for case 1 and 2; 120h for case 3 and 4) and by the time it is filled.

Consequences of storage and filling time on installed production capacity

Storing fuel smoothens production over time and thus reduces installed capacity compared to instant production without storage. The longer the filling time, the smaller the installed production capacity for the same storage capacity. The larger the storage, the more installed production capacity. It is therefore necessary to find a good compromise between these two parameters, which meet the annual need for supply of the GT. Based on the study cases, it was considered that:

- The 50-hour storage is done during a one-month operating period of the electrolyser (daily production of 9 hours corresponding to the 9pm to 6am slot). For example, production is done during the month of January, this storage is consumed during the period of February (but renewed simultaneously to be operational for the month of March). Then the electrolyser can run for another month to ensure the need for the rest of the year. In this case, the electrolyser will only operate 3 months a year to meet the annual requirement. - The storage of 120 hours is done in a longer period, of 5 months distributed in non-winter periods (with the same assumption of daily production of 9 hours/day). In this case, the electrolyser can fill the storage in the period from April to July, operating on non-maximum charge for 4 months. This could allow you to buy electricity at a lower price.

Electricity consumption and water consumption

The electrolysis process requires water and electricity for the electrochemical reaction to separate the H2O molecule to occur inside the electrolyser. The two inputs of the process are therefore electricity and demineralized water. Electricity consumption corresponds to the kWh consumed by Nm3 products. It increases linearly with the use of electrodes. An electrical consumption of between 4.5 kWh/Nm3 and 6 kWh/Nm3 can be considered depending on the supplier. Water consumption (potable or demine) is estimated at 0.9 l/Nm3. This equates to just under 2 l/Nm3 of raw water.

H2 Production CAPEX Costs

Manufacturers aim to reach prices of 1 million euros /MW for large installations (from 20 MW) in the near future and to further reduce prices for bigger installations. The CAPEX costs estimated take a conservative estimation of almost 2 million euros/MW. This data remains very important for the business plan and should be verified and updated to a specific project.

H2 Production OPEX Costs

For the OPEX costs associated with the production of H2, one can consider only one aspect:

- Electrical consumption represents the sizing item: 90% of the costs excluding heavy maintenance, the other 10% being associated in particular with the consumption of water and the reagents necessary for its demineralization.

Water consumption costs are not detailed in this note. The cost of electricity consumption depends on the price of electricity and the consumption of electrolysers.

Storage

General information

Storage techniques for hydrogen are diverse:

- Storage in the form of compressed gas.

This application would not be suitable for on-site production given the excessive volumes. Hydrogen gas can be compressed and stored up to significant pressures (400-1000 bar) for mobility applications.

- Liquid hydrogen (LH2).

It is a proven technology but used in the space industry and for the delivery of a few high-capacity service stations. Since the liquefaction temperature is -253 degrees Celsius (or 20.3 K) in the atmosphere, the liquefaction energy required is important, as is the need for the use of adequate insulation to avoid uncontrolled evaporation (Boil-off).

- Liquid Organic Hydrogen Carriers (LOHC).

A technology currently under industrial deployment, but not mature enough at the moment for such amounts of H2.

Sizing

The quantities of storages of the different cases of study are shown in the following table:

Table 3 : Table indicating, for each of the 6 case studies: the hours of autonomy of the turbine in hours, the storage capacity in tons, the storage capacity in Nm3, the storage capacity in m3 to 700 bar, the storage capacity by volume in m3 of liquid H2.

CASE N°	Turbine hours of autonomy (h)	Storage Capacity in tons	Storage Capacity in Nm3	Storage Capacity in m3 at 700 bar	Liquid Storage Capacity in m3
1) H2 100% 50h 1M	50	525	6 000 000	12 000	7 000
2) H2 30% 50h 1M	50	60	700 000	1 400	800
3) H2 100% 120h 1M	120	1260	14 000 000	29 000	17 000
4) H2 30% 120h 1M	120	145	1 600 000	3 400	2 000
5) H2 30% 0h	0	0	0	0	0
6) H2 30% 25h 1M	25	30	335 000	700	400

For this study, we have therefore chosen to develop the solution involving liquid hydrogen.

Storing hydrogen in liquid form has the advantage of significantly reducing the volume of storage as well as the pressure of hydrogen. In fact, the density of liquid hydrogen at 1 bar is worth about 70.9 kg/m3 (density reached by hydrogen gas at a pressure of 1,800 bar), which allows to store about 2.4 kWh/l.

Liquid hydrogen is stored in double-insulated cryogenic tanks whose purpose is to limit heat exchange by minimizing both thermal conduction between the gas inside and the environment, and also to protect it from thermal radiation.

Boil-off

Hydrogen vaporization enthalpy is very low. Thermal insulation should be excellent for the storage of liquid hydrogen. The unintended evaporation of H2, which corresponds to a weight loss of 0.5 to 1% per day, or even between 0.3 and 2% depending on the technology used, is one of the main issues of storing hydrogen in its liquid form.

LH2 Storage CAPEX costs

The study considers a rough estimation given by a potential supplier, of 100 k€/ton.

LH2 Storage OPEX costs

The cold maintenance of the LH2 tanks is done through a Liquid Nitrogen Shield. OPEX costs for tank maintenance are not reported in this study. But they are considered to be negligible compared to the overall balance.

H2 Liquefaction

General information

The hydrogen liquefaction process has significant constraints:

The temperature of hydrogen liquefaction is -252.85 degrees Celsius. Cooling the gas to such a temperature requires a significant energy consumption (8-14 kWh/kg for large installations) which contributes to a significant additional cost. A supplier contact indicates that they are capable of building more efficient installations (in the order of 6.5 KWh/Kg) but that a hypothesis of 10 KWh/Kg remains reasonable. These high electricity consumptions explain in particular the fact that this storage solution is not used in hydrogen stations with electrolyser, and that this choice of supply is only attractive for large quantities of delivery (in order to make the "fixed" costs associated with delivery and packaging profitable).

- The design of the heat insulation of the liquefactor should be effective in avoiding (or minimizing) any vaporization. A classic solution is to perform vacuum insulation of the liquefactor's cold box.

-The liquefactor works at a pressure of about 20 bar (which would be suitable for H2 gas products under pressure such as some supplier’s technology, but a compressor should be added if hydrogen gas is produced at atmospheric pressure). For small liquefactors (capacity - 2 t/day), the most common technology is helium.

Sizing

The maximum capacity of the liquefactor, which is crucial for the purchase of a liquefaction unit, must be calculated in relation to the peak operating period, which corresponds to the one in which the required storage is produced.

Table 4: Table indicating, for each of the 6 case studies: the hydrogen storage capacity in tons, the duration of each cycle of liquefaction in months and the maximum capacity of liquefier considered in tons/day.

Case n°	H2 Storage Capacity (tons)	Liquefaction time (month)	Maximum capacity of liquefier (tons/day)
1) H2 100% 50h 1M	525	1	18
2) H2 30% 50h 1M	60	1	2
3) H2 100% 120h 4M	1 260	4	11
4) H2 30% 120h 4M	145	4	1,2
5) H2 30% 0h	0	0	-
6) H2 30% 25h 1M	30	1	1

H2 liquefaction CAPEX costs

The largest world's capacity of liquid hydrogen production is located on the North American continent (Canada - USA). In addition, Air Liquide announced in 2018 that it has signed an agreement with FEF (First Element Fuel Inc., a leader in hydrogen infrastructure in the United States) and plans to build a liquid hydrogen production plant dedicated to the mobility market. The plant is expected to be completed in 2022 (project duration estimated at 3 years), at an estimated cost of $150 million and a production capacity of 30 tons per day. As far as Europe is concerned, only four liquefaction units exist to date. The unit in Leuna-Germany is the most recent project in Europe, and it costed about 20 million euros for liquefaction of a capacity of 5 tons per day. These references provide a general picture of the costs of such installations and to place them between 4 to 5 million euros per ton of liquid hydrogen produced daily.

H2 liquefaction OPEX costs

Operating costs are related to energy consumption due to liquefaction. The consumption ranges from 8 to 14 kWh/kg. This consumption is quite high and it is very penalizing for this type of storage.

Cryogenic pumping and vaporization

General information

Pumping is necessary to increase the pressure of the LH2 to the pressure needed to power the TAC which operates at about 32 bar. Cryostar, a Linde-based company, offers cryogenic pumps adapted to speeds of up to 900 kg/h (at a rough estimation of 250K euros according to Linde). The pumping system can be installed next to the tank with a fairly small footprint. Linde indicates that for the flows of cases 1 and 3 (116,000 Nm3), a range of pumps of a higher flow should be developed. For the other cases, they indicate that pumping this flow is feasible.

In other hand, vaporizers transform the liquid hydrogen to gas prior the feeding of the GT.

CAPEX and OPEX costs

Pumping and evaporation facilities are now adapted to the smallest flows (13,000 Nm3/h) in cases 2, 4, 5 and 6 and involve investment costs in the order of 5.5 million euros. For the higher speeds (160,000 Nm3/h) in cases 1 and 3, the costs amount to 18 million euros, and technically the equipment is not developed for such flows. Linde says they should develop more suitable ranges in case the market for this type of pumps and evaporators develops.

Global Costs per case

Following figures show the global CAPEX distribution by equipment and by case study.

It is important to note that the costs of a real project should also include the engineering integration of those equipment in a real site and works. The numbers are just a rough estimation of equipment to be committed.

a) We considered a high cost of H2 production of about 2M€/MW, but the tendency is that the costs of electrolysers will drop significantly.

b) We considered a low cost of H2 (optimistic vision) for projects on the future

Case study n°1: Feeding the GT with 100% H2 fuel, on-site storage that can provide 50 hours of operation to the GT, the storage is filled during a period of 1 month of operation of the electrolyser in 9 hours per day. (H2 100%; 50 hours; 1M) → **project estimation is beyond 200 M€ for this case**

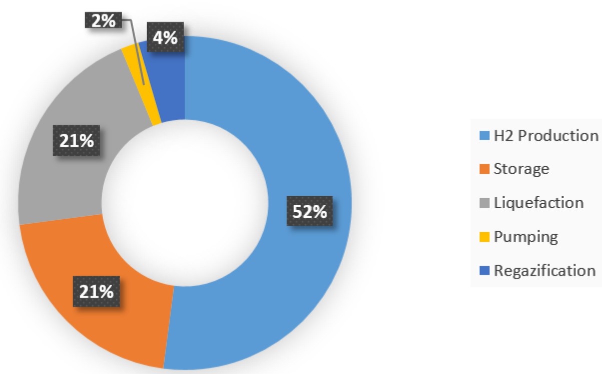

Figure 3: Project cost allocation graph for case 1 and assumption a)

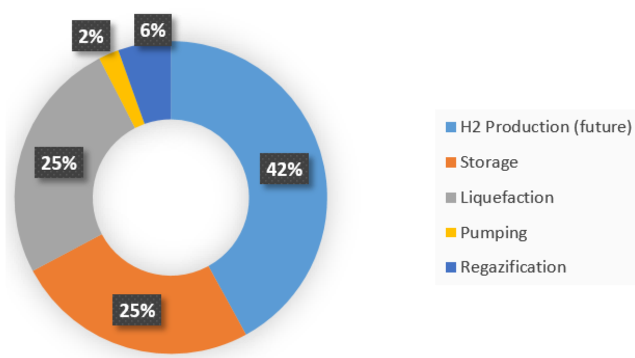

Figure 4: Project cost allocation graph for case 1 and assumption b)

Case study n°2: GT supplied with 30% H2 fuel, on-site storage provides 50 hours of operation, this storage is filled during a period of 1 month of operation of the electrolyser in 9 hours per day. (H2 30%; 50 hours; 1M) → **project estimation for case 2 is 30 M€ to 40M€ (±50%)**

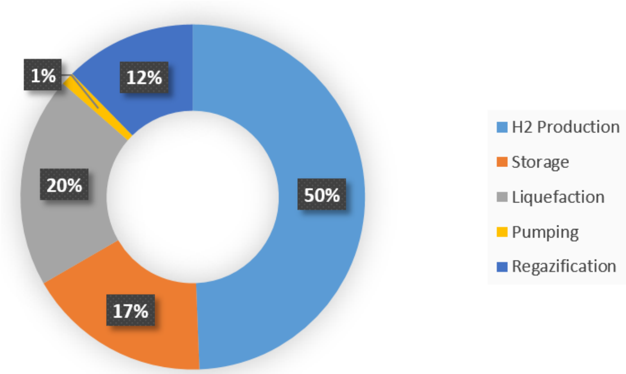

Figure 5: Project cost allocation graph for case 2 and assumption a)

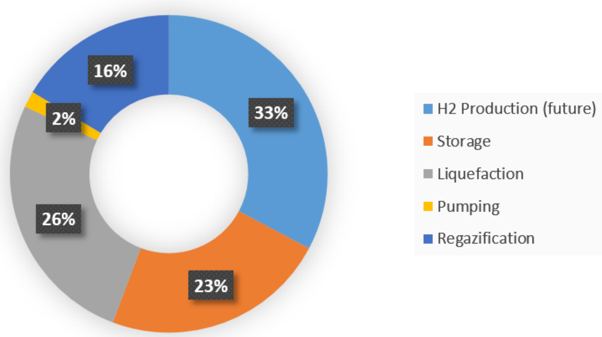

Figure 6: Project cost allocation graph for case 2 and assumption b)

Case study n°3: GT supplied with 100% H2 fuel, on-site storage provides 120 hours of operation, this storage is filled during a period of 4 months of operation of the electrolyser in 9 hours per day. (H2 100%; 120 hours; 4M) **→ project estimation for case 3 is beyond 200 M€**

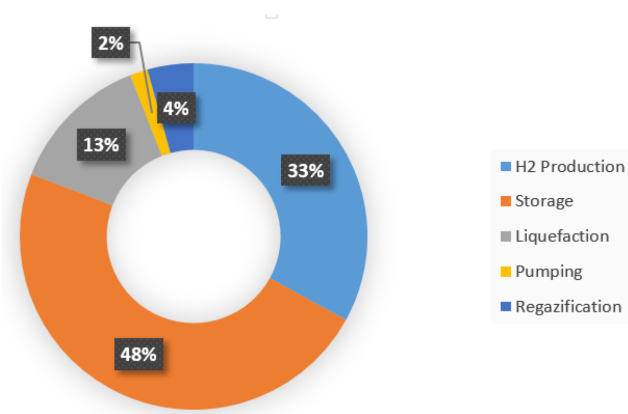

Figure 7: Project cost allocation graph for case 3 and assumption a)

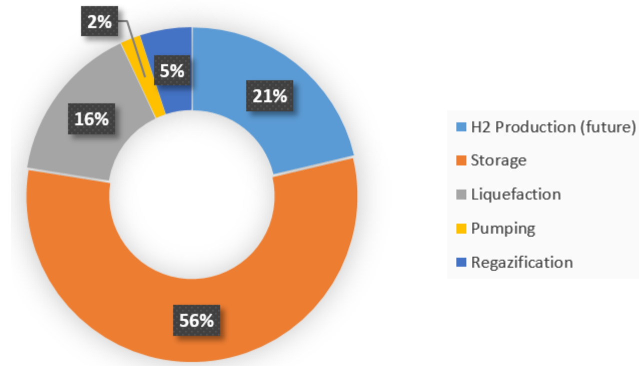

Figure 8: Project cost allocation graph for case 3 and assumption b)

Case study n°4: GT supplied with 30% H2 fuel, on-site storage provided 120 hours of operation, this storage is filled during a period of 4 months of operation of the electrolyser in 9 hours per day. (H2 30%; 120 hours; 4M) **→ project estimation for case 4 is 35 M€ to 45M€ (±50%)**

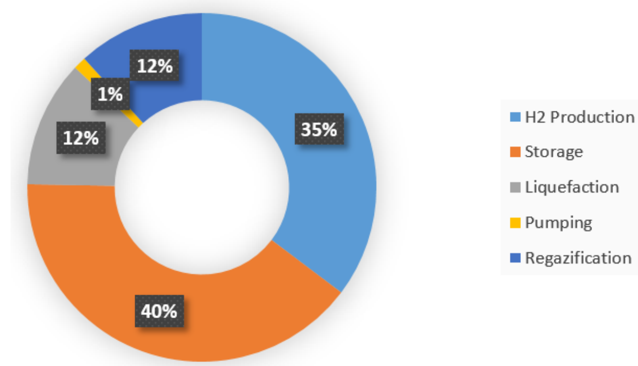

Figure 9: Project cost allocation graph for case 4 and assumption a)

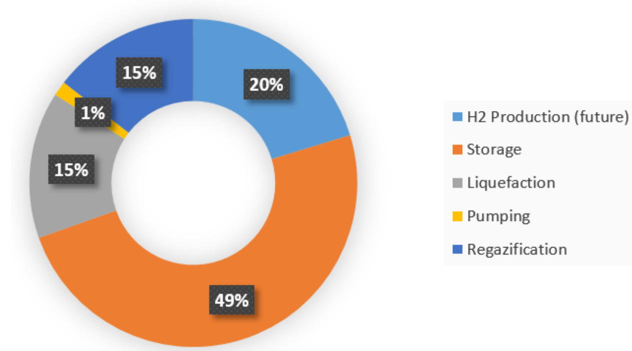

Figure 10: Project cost allocation graph for case 4 and assumption b)

Case study n°5: GT supplied with 30% H2 fuel, no on-site storage planned. (H2 30%; 0 hours; 0M) **→ project estimation for case 5 is 70 M€ to 100M€ (±50%)**

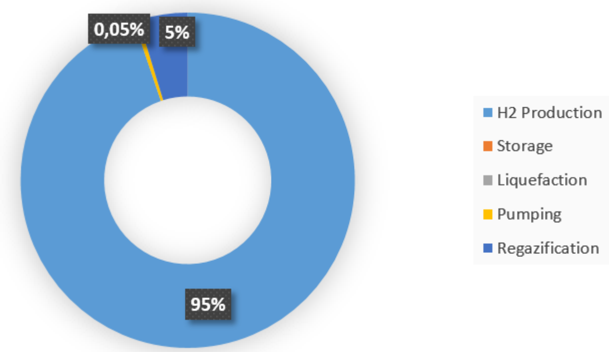

Figure 11: Project cost allocation graph for case 5 and assumption a)

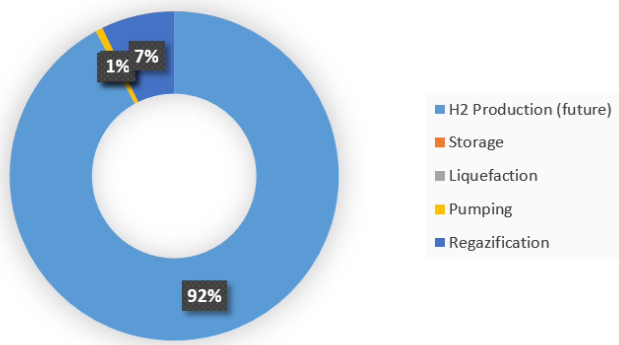

Figure 12: Project cost allocation graph for case 5 and assumption b)

Case study n°6: GT supplied with 30% H2 fuel, planned on-site storage that can provide 25 hours of operation, this storage is filled during a period of 1 month of operation of the electrolyser in 9 hours per day. (H2 30%; 25 hours; 1M) → **project estimation for case 6 is 20 M€ to 25M€ (±50%)**

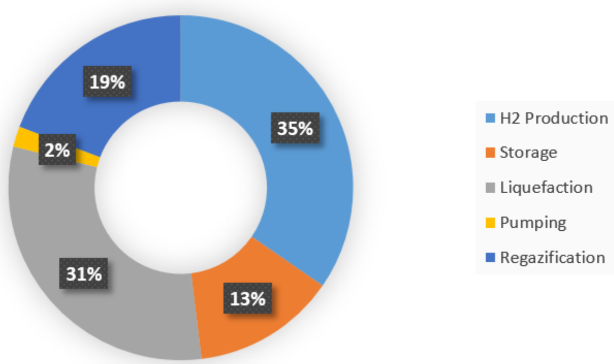

Figure 13: Project cost allocation graph for case 6 and assumption a)

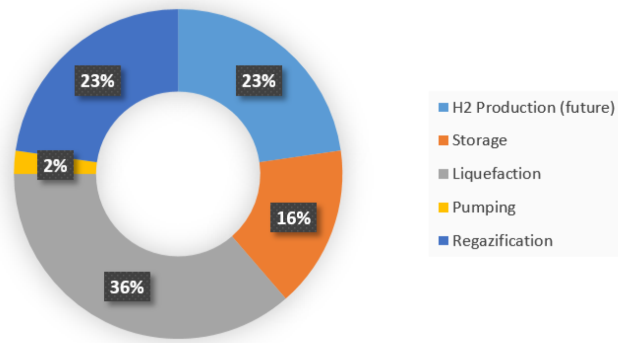

Figure 14: Project cost allocation graph for case 6 and assumption b)

CONCLUSIONS OF TECHNICAL-ECONOMICAL STUDY

Economic conclusions

CAPEX Costs-In cases n°1 and n°2, where the storage is sized for 50h of TG functioning, the production of H2 is the more expensive equipment (≈50% of total CAPEX). The storage and liquefaction are almost equivalent and represent around 20% each.

-In cases 3 and 4, storage is almost 3 times larger and carried out over a longer period (4 months), which reduces production capacity. In this case, storage accounts for about half of the total CAPEX, and production drops to 30%.

-Case n°5 is a borderline case, where the electrolyser is operating at the same time as the GT, which would make no sense for a real project. But it establishes that in this case, the production must be of a very large capacity. It represents almost all CAPEX costs.

-Case n°6 represents a 25-hour storage of the GT's operation, which represents only just over 10% of the total CAPEX. In this case, it is observed that liquefaction takes on a larger proportion, close to the costs represented by production (31% and 35% respectively).

OPEX costs

The main OPEX costs of this type of project are related to the energy consumption of hydrogen production by electrolysis, as well as liquefaction, which is a very energy-intensive process.

H2 Production

Concerning the hydrogen production required for a GT, alkaline electrolyser technology can currently meet the needs for case 2, 4 and 6 corresponding to capacity between 2 and 12 MWe, and in the near future to the capacity for larger facilities (above 60 MWe). The aim for manufacturers is to increase capacity, which currently is about 20 MWe for the largest facilities in Europe, to 100 MWe, or even 700 MWe installed. Costs will tend to go down. The cost of the MW is expected to be less than one million euros in the next years. The OPEX costs are mainly related to electricity consumption. On this matter, the choice of the electrolyser must also take into account the electrical performance, the manufacturer's guarantees on the degradation of the energy performance of the electrolysers over time, as well as the price of the kWh consumed according to the project and other more specific variables not addressed on this very generic study (time range of electricity consumption, impact of the charge rate on the performance of the electrolyser).

Finally, it is important to point out that in order to be consistent with the ambition of decarbonize gas turbines, it is necessary to ensure that the hydrogen production is also powered by non-CO2-emitting electricity, i.e. renewable energy or nuclear energy.

Liquid H2 Storage

The only viable option to date for storing large amounts of H2 is liquid hydrogen. The storages planned for all case studies are theoretically feasible (but in practice, the largest liquid storage built worldwide is 225 tons, operated by NASA). The two viable cases of study to date, compared to what is done in the market for the industry, are case 2 (60 tons), case 4 (145 tons) and case 6 (30 tons) estimated at 7 million and 17 million and 3.5 million respectively. CAPEX storage prices would tend to remain fairly stable considering that this market would not grow as much as expected for H2 electrolysis production systems, since liquid H2 applications do not concern industry or transportation markets whose gas solutions are now preferred. Aerospace is the preferred user of liquid H2. OPEX prices are considered negligible compared to other items in this study.

Liquefaction

The market for liquefiers is quite small. Indeed, the manufacturers Linde and Air Liquide have the only references on the European market. Preferred users of liquefiers are quite specific and there is no expected large increase in this market for industry or mobility (a hypothesis that remains to be verified in the years to come). Liquefiers CAPEX are in the order of 4 million euros/tonne.day for capacities of 15 tons per day and are expected to be lower for larger capacities. OPEX prices are linked to the electrical consumption of liquefaction.

Problem of boil off Gas (BOG)

The problem of boil off must be taken into account in the business plan. In fact, the annual energy consumption spent to liquefy the BOG (Liquid H2 which vaporizes on the tank by uncontrolled and unwanted temperature exchanges with the ambient temperature) is between 1 to 4 times the total storage capacity, which implies, for a storage of 60 tons, an additional annual energy expenditure of between 35K and 145K. (This is not taken into account in the totals displayed in the summary table)

Cryogenic pumping and evaporators

Pumping and evaporation facilities are now adapted to the smallest flows (13,000 Nm3/h) of cases 2, 4, 5 and 6 and involve investment costs about 5.5 million euros. For the higher flows (160,000 Nm3/h) in cases 1 and 3, the costs amount to 18 million euros, and technically the equipment is not developed for such flows.

As hydrogen is an extremely flammable gas, its presence in large quantities generates sources of risk to be studied.

It is recommended to carry out a study to define the major dangerous phenomena to be modelled, and to conclude on the viability of the installation of such equipment on an industrial site.

Then, it will be essential to carry out an ATEX study and a hazard study that will establish the possible domino effects in a specific site. Given the regulations that apply to these different case studies in France, the planning for validation of such a project could take significant delays longer than 2 years.

CO2 emission reduction

It is important to note that the relation between the volumetric content of H2 in the fuel is not linear with respect to CO2 emissions. This can explain why the 30%H2-70%CH4 mixture reduces CO2 emissions by only 10% as figure below shows.

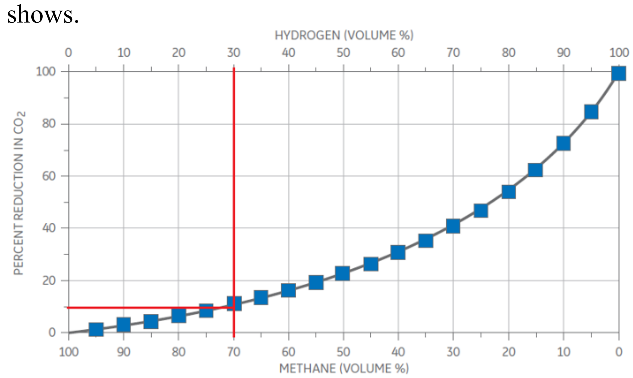

Figure 15: evolution of percent reduction in CO2 vs hydrogen volume on a blended methane based fuel.

In addition, it is also important to point out that in France, the priority sectors to reduce CO2 emissions are transport and buildings. Indeed, the gas turbines of the current fleet operate very few hours in the year to ensure peak periods (about 150 hours per year). One would therefore think that the CO2 emission savings made from the conversion of this type of means will have very little benefit.

Equipment footprint

The ground surface area of H2 production facilities at this stage can be estimated by comparison with other existing projects. It is considered that there is some proportionality between the installed capacity and the surface area occupied. Large-capacity facilities (starting at 20 MW) are able to mutualize auxiliary facilities (including transformers/redressers and demineralized water production), allowing optimization compared to smaller capacities. However, each project will have to study its implementation according to the constraints of each site and adapt accordingly.

For liquid storage of H2, the preferred geometry corresponds to spheres when the quantity exceeds 60 tons.

Linde indicates that for storages of 60-70 tons or less, they generally provide horizontal cylindrical storages.
Following table summarizes results of estimated footprint of production and storage (other equipment and minimum safety distance need to be included, not studied in this note).

Table 5: Table indicating, for each of the 6 case studies the minimum footprint required to install the equipment of production and storage of H2 on site

	1) H2 100% ; 50h ; 1M	2) H2 30% ; 50h ; 1M	3) H2 100% ; 120h ; 4M	4) H2 30% ; 120h ; 4M	5) H2 30% ; 0h	6) H2 30% ; 25h ; 1M
Minimum footprint (Production + Storage)	7 000 m2	1 000 m2	5 000 m2	1 500 m2	3 500 m2	600 m2

Industrial risks
As hydrogen is an extremely flammable gas, its presence in large quantities generates sources of risk to be studied. In a first approach, the dangerous phenomena associated with large H2 storage are:
- BLEVE (Boiling Liquid Expanding Vapour Explosion)
- Tank pressurization resulting in a burst of capacity
- Evaporation of a slick of Liquid Hydrogen (explosive cloud)

It is recommended to carry out a study as soon as the equipment is sized, to be able to define the major dangerous phenomena to be modeled for each project and be able to conclude on the viability of installing such equipment at one of the sites of the EDF thermal park. Secondly, it will be essential to carry out a hazard study that can establish the possible domino effects in a specific site, combined with ATEX zoning.
Depending on the results of the impact assessment, a two-year delay between the idea and execution for such a project should be considered.

CONCLUSIONS
- Only 2 cases would be potentially viable technically in a supplier point of view, even if really challenging taking into account the industrial risks associated to the storage of important volumes of H2.
- Cost efficiency: costs of the two projects are extremely high regarding other decarbonization options.
- In general, thinking of a turbine supply with an electrolyser operating at the same time to ensure the necessary production of H2 is not possible taking into account the large quantities of H2 required for a GT of this size and especially because the start of the turbines is done at peak load. It would therefore be illogical to supply the electrolysers with energy at this time.
- Storing fuel smoothens production over time and thus reduces installed capacity compared to instant production without storage. The longer the filling time, the smaller the installed production capacity for the same storage capacity. The larger the storage, the more installed production capacity. It is therefore necessary to find a good compromise between these two parameters for each project.
- It is important to precise that storage capacity and filling time chosen are adapted to the operation of the case study. The same turbine operated in another conditions will necessarily have a different number of hours of operation and a different distribution in the year. The conclusions of this study are therefore site specific.
- For some turbines operating daily and few hours a day, storage can be less than the values shown in this study and therefore, gas compression and gas storage should be preferred rather than liquefying and storing liquid hydrogen, because of important impacts on costs (CAPEX and OPEX).
- The costs of electrolysers represent an important part of the CAPEX for a project. These costs are constantly evolving and the definitive estimation should be done on a project specific way. Values are not to take in consideration for all projects.
- Since the reduction in CO2 emissions is not proportional to the volume of H2 in natural gas, we can think that only a turbine burning blendings with a high proportion of H2 or 100% H2 has a real environmental impact.
- The industrial risks associated with an H2 production and storage facility are significant and can impact the realization of an industrial project on site.

REFERENCES

1) ADEME, Technical Report “Rendement de la chaîne Hydrogène ”, (2020)
2) Afhypac, Technical Report “Les données de bases physico-chimiques sur l’Hydrogène”, (2013)
3) ETN “The path towards a zero-carbon gas turbine” (2020)