# H2 readiness of gas-fired power plants-technical, regulatory and economical requirements

Eurelectric position paper

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**transforming** the energy system to make it more responsive, resilient and efficient. This includes increased use of renewable energy, digitalisation, demand side response and reinforcement of grids so they can function as platforms and enablers for customers, cities and communities;

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**innovating** to discover the cutting-edge business models and develop the breakthrough technologies that are indispensable to allow our industry to lead this transition.

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## KEY MESSAGES

- With an ever-increasing share of variable renewables in the energy system there will be the need for additional flexible and dispatchable electricity supply. Hydrogen-ready gas-fired power plants, both retrofits and newbuilds, may offer such benefits to the system.

- The definition of an H2-ready gas-fired power plant requires that, in a final stage, it can be operated with 100% hydrogen combustion. In interim stages, however, existing facilities may run on pure natural gas or blends with different mixtures as various degrees of readiness may be allowed.

- H2-readiness should be linked to plans for sufficient provision of hydrogen including the ability to obtain adequate grid connectivity. Now, manufacturers must establish definitions and technical specifications to meet with market necessity in a timely fashion.

- An investor venturing to build a new H2-ready gas-fired power plant will need certainty of planning, application for permits and authorisation in line with the Industrial Emissions Directive (IED) to allow for operation with both gas and hydrogen, as well as blends thereof.

- To make investments economically viable provided relatively few operating hours, additional incentives beyond the energy-only market may be required such as awarding capacity payments.

# 1. Introduction

The European objective to reduce emissions and reach decarbonisation objectives requires the exponential growth of decarbonised power generation and electrification. With an ever-growing share of variable renewables, such as wind and solar, whose output also varies with seasons, there is a need for flexible and dispatchable electricity supply. This may be derived from different sources. One option is hydrogen-ready gas-fired power plants (H2-ready) that may be both retrofits and newbuilds. Ultimately, such H2-ready facilities should aim for 100% hydrogen burnups but before reaching this stage various degrees of H2-readiness may be allowed. Yet, manufacturers must move fast to establish definitions and technical specifications to meet with the necessities of the market in a timely fashion.

Different technologies and strategies can be used to cover the residual load in the short term, such as storage, demand-side management measures, grid extensions and others. With decarbonisation efforts going forward, a relatively small share ofthe power sector will rely on gas and their associated dispatchable generation to balance the power system. Hydrogen will count for 3-4% and biomethane for 2-8% of the total electricity generation[1] required to meet the EU power demand in 2050, complementarily to other dispatchable sources, such as hydropower, nuclear, battery storage and others.

Overall, the main challenge comes when talking about seasonal flexibility where the technologies available are limited and many of them are still technically immature. In the energy system of the past, this was not called for since thermal generation (principally fuelled by coal and natural gas) was providing the necessary seasonal flexibility. But today the question is gaining much more significance. One option is gas-fired power plants which respect environmental standard and can be reconverted to run with hydrogen.

Since new gas-fired plants should regularly be aligned with EU taxonomy regulation, CO2 emissions might be limited. Based on the Commission Delegated Regulation (EU) 2022/1214 amending Delegated Regulation (EU) 2021/2139 as regards economic activities in certain energy sectors, CO2 emissions of a new plant should be either lower than 100 gCO2e/kWh (based on life cycle analysis [LCA]), or, for plants whose construction permit is granted before 31 December 2030, should not exceed 550 kg $CO_2$/kW over its life-cycle (20 years).Such a plant must be operated with 100% renewable and/or low-carbon gaseous fuels from 31 December2035, onwards.  In addition, it should lead to a reduction in emissions of at least 55% of greenhouse gasses (GHGs) compared to existing solid or liquid fossil fuel-based power plants to be replaced.

Options differ for how to generate clean electricity with gas-fired power plants. The first one is to have gas-fired power plants running with hydrogen or biomethane. This is an optimal solution to sustain benefits in terms of the flexibility with a dispatchable source. However, the supply of hydrogen or biomethane may be limited in particular in the early years before 2035 due to shortcomings of the nascent hydrogen market. This will certainly require a speeding up with the recent adoption of the Hydrogen and Decarbonised Gas Market Package as well as with competing use cases.[2] Therefore, plants might transitionally run on either natural gas or biomethane as well as on blends with differing shares of clean hydrogen co-firing before switching to pure hydrogen. If plant operation cannot comply with taxonomy regulation requirements this might cause higher financing costs to secure

[1] Exact figure depending on the scenarios in Eurelectric Decarbonisation Speedways, 2023

[2] As an example, 800 MW of CCGT powered by hydrogen might consume 40 t H2/h. If it operates for 3000 Flh a year it will need 120 kt of H2 a year, equivalent to the production of 2.7 GW of electrolysers operating 4,000 hours a year.

investments or with regards to CO2 emissions allowances. Alternatively, the gas-fired power plant could run with natural gas and carbon capture and storage (CCS) to capture emissions.

Given the Member State interest in rolling-out a hydrogen route, gas-fired power plants that would switch to hydrogen must be hydrogen-ready from an engineering perspective. But a clear definition and description of the related technical requirements for these plants is still missing. Such a description is nevertheless urgently needed, e.g. to specify prequalification for auctions, tenders or funding. This paper aims to fill this gap.

## 2. Definition of H2 readiness

An H2-ready gas-fired power plant is being defined as a plant which can finally be operated – depending on one or more retrofits – **on 100% hydrogen combustion**. In interim stages, it might run on pure natural gas or on blends with different mixtures (e.g. 30%, 50%, 70%) of natural gas and hydrogen. Which blend is being applied depends *inter alia* on the gas/H2 grid whether hydrogen is supplied via blending in the existing gas grid[3], or as pure hydrogen via a separate grid and the plant has two grid connections (one for gas andone for H2). If the plant operator can make a choice what mix is to be used, they should, whenever possible, comply with taxonomy requirements.

However, H2 readiness should be linked on plans to afford sufficient availability of hydrogen and ability to connect to the adequate grids. Availability of required electrolysers and hydrogen storage in the neighbourhood of the power plant cannot be the responsibility of plant operators. When operating 10 GW of gas-fired plants running on H2, they would need the output of up to 30 – 35 GW of electrolysers. Therefore, a direct import or transport of hydrogen to consumption sites, via new or methane-retrofitted H2 infrastructure, seems more suitable to feed such plants.

For existing plants, different layers of "readiness" might additionally apply. "Partial readiness" means that these plants are able to adapt to 10%, 30%, 50% or 80% (volumetric ratio) hydrogen at some point in time during their operational lifetime. So far, however, very few plants would be able to comply with 100% hydrogen during their operational lifetime. For others, it might be more economic to erect a new gas plant rather than to retrofit the existing one. This must be assessed on a case-by-case basis.

H2 readiness does not discriminate against a specific technology – it includes all gas turbine technologies, combined heat & power (CHP), gas motors, fuel cells and/or heat boilers. Thus, to prove H2 readiness, the entire system including all plant components (and auxiliary systems) which are needed to operate the plant must be capable of using hydrogen, (e.g. including in ramping-up & down times). However, derivates (e.g. ammonia [NH3]) are not considered in this paper.

## 3. Technical requirements

A new gas-fired power plant is considered H2-ready if it can be operated with pure hydrogen after (one or more) retrofit procedures throughout its technical lifetime, whatever the operating cycle and load profile. Thereby, for new plants, the technical plant design should be designed for 100% hydrogen operation from the outset or be retrofittable as far as best available technology allows. Specifically, the different physical and chemical properties of hydrogen and methane, particularly regarding density and calorific value, must be considered when upgrading existing technologies. This also means it is not straightforward to draw direct conclusions about the effective CO2 reduction from the hydrogen content in percentage% by volume. Therefore, the equivalence consideration via the heat input (thermal firing capacity [TFC]) is a suitable measure of decarbonisation for equal plant output. For example, a share of 30% hydrogen by volume in the fuel gas mixture corresponds to a share of 11.4% of the firing thermal capacity leading to CO2 savings of 11.4%[4].

Still, the challenge is that the relevant technical prerequisites for H2-ready gas-fired power plants are being gradually created on the part of the plant manufacturers. These prerequisites include *inter alia*:

- the safety (e.g. explosion protection measures)
- the combustion behaviour (as a result of deviating heating value, combustion temperature and flame speed)
- emission levels (e.g. burner design, NOx reduction technologies required)
- the material to hamper H2 vapourisation (e.g. fuel lines, boiler material)
- the handling of the fuel volumes (e.g. space requirements and/or increased volume flow and gas speed in current pipelines)
- the H2 availability (e.g. storage, import, infrastructure, gas mixing station)
- the CO2 reduction (non-linear to volumetric ratio of natural gas and H2).

These chemical specificities differentiate the H2-ready plants from conventional natural gas power plants. A concrete example: Depending on the specific H2 content, the fuel gas system and the burner is designed for the increased fuel gas volume flow (factor 3.3 greater), the changing combustion temperature (~+ 200 °C higher in case of H2 burning, thus requiring an adapted cooling concept) and the changed material stress. The latter requires careful selection of the materials used, which are suitable for hydrogen; this applies to both pipes and seals. The possibility to use current pipelines must be carefully assessed whether they are capable of meeting these requirements. If not run with pure hydrogen, a gas mixing station is also required, for which the necessary space must be provided. This needs space which has to be reserved when designing the plant – buildings must be larger than for a plant fired only with natural gas.

Since hydrogen is more explosive (i.e. detonics) than natural gas, H2-ready gas plants require additional security measures to protect against explosion or prevent flame flashbacks. These measures might include e.g.:

- venting at the highest point in a building since H2 has a much lower density than air and unlike natural gas, hydrogen therefore accumulates in high points
- larger protection zones due to the lower density and stronger explosive effects
- additional prevention against electrostatic charge as the minimum ignition energy is much lower

Thereby, it also has to be taken into account that the hydrogen flame is hardly visible in daylight and can only be perceived by the development of heat.

Also, emissions from hydrogen combustion differ from natural gas, particularly for NOx, as peak temperatures are higher for hydrogen combustion. Depending on the full load hours, additional measures for flue gas scrubbing must be taken or at least planned as a

[4] Vgbe Factsheet “H2 readiness of gas turbine plants”, 2022

preventive measure. The plant should at least be designed so that selective catalytic reduction device (SCR) can be retrofitted. However, primary measures to reduce emissions should be exhausted as far as possible. At 100% H2 combustion, increased water vapour in the flue gas is to be expected. Due to this higher water vapour content, normalisation to dry NOx leads to a disadvantage with H2 combustion – this fact has to be taken into account when setting the emission limit values.

The availability of hydrogen determines the operation mode. In the beginning, an H2-ready gas plant needs a connection to the gas grid. If it switches to 100% H2 combustion, a connection to an H2 grid with sufficient, flexible H2 supply must be guaranteed simultaneously. In the future H2 network, all major consumers are to meet at sufficiently high pressure to operate gas turbines without additional fuel gas compressors (50 to 60 bar).

This regularly implies that a sufficient hydrogen source is connected to the same grid, too. Storage on site would not be relevant in most cases and may not be sufficient to allow relevant operation time. A dispatchable hydrogen supply solution including storage is key if green hydrogen is used since this will be produced in times of high renewable energy source (RES) feed-in when the gas plant is not running. Otherwise, there is a high risk of longer standstills. A technical risk occurs if a blend is used, and the grid operator cannot ensure a constant ratio of H2 (cf. gas quality stability) in a blend or a blend with a share of H2 higher than 2%. Otherwise, the plant needs two grid connections, one for gas and one for H2 to produce the relevant blend on-site. This is also relevant if the gas plant cannot be started with pure hydrogen only, but also needs natural gas to start.

All these technical issues still have to be further evaluated by the original equipment manufacturers (OEMs) as part of their research and development (R&D) activities. Currently, the TRL (technological readiness level) of gas turbines is 4 – 5 only. Vgbe expects that gas turbines which are capable of 100% H2 will be available at large scale from 2030 onwards.

Gas motors are today easier to develop and will be available from 2025 onwards. In order to scale up technology, electricity generators team up with OEMs starting test operation. A global first test of a 100% renewable hydrogen running was successfully operated by ENGIE in October 2023 on an existing gas turbine (12 MW SGT-400 Siemens unit) on the premises of a paper mill in France in the scope of the HyFlexPower demonstration project.[5] As another example, RWE will test a 34 MW Kawasaki H2 gas turbine from 2025/2026 onwards in Lingen scaling up from a 1 MW plant already in operation in Kobe (Japan) since 2018.

For existing plants, the challenges to switch to a fuel mix with more than 20% hydrogen are significant. Fuel switch must be assessed case by case. Existing gas turbines need a larger combustion chamber with new combustion technology and modified cooling concept when the H2-share increases to more than 50 Vol-% H2. Additional flue gas treatment (for NOx) may be required, with additional space needed. Such a modernisation often requires relatively large investments, and therefore a case by case decision if advantageous compared to a new plant. As such, OEMs should develop retrofit programs to adapt existing plants to growing shares of hydrogen.

If the construction of H2-ready gas-fired power plants is put out to tender, the operators must provide proof of H2 readiness. For as long as technological concepts for such plants are not proven in detail at large scale, plant manufacturers must give a guarantee on the option to switch to hydrogen which is then being used to fulfil this prequalification criteria.

[5] See https://www.engie.com/en/news/hyflexpower

However, although the design still has to be further developed given the work in progress of the OEMs, first assessment to calculate full cost in order to prepare for calls for tender are already available.

Commissioning of new H2 ready gas-fired power plants or repurposing existing gas-fired plants to hydrogen will require (additional) investment. For example, Aurora has assessed the expected total cost of conversion in 2030.[6] According to their analysis, converting gas turbines to blend 30% H2, will require an investment of €70/kW and an additional €125/kW to adjust to 100% H2 combustion – €195/kW in total. Fixed operating and maintenance costs are also expected to increase with approximately 10% due to increased need for safety measures. Cost for new H2 ready gas-fired power plants is estimated in another study by Aurora[7]: CapEx for H2-ready combined-cycle gas turbines (CCGTs) are assumed with €860/kW, whereas CapEx for H2-ready open-cycle gas turbines (OCGT) is estimated at€617/kW.

## 4. Regulatory requirements

A new plant needs permits and authorisation based on the rules set by the IED. To get planning certainty, the plant operator of a new-build will try to apply for a permit which allows operation with both fuels – gas, hydrogen and any possible blend. To do so, a sufficiently detailed description of the plant is required, although some features might still be missing. Such an authorisation should not be put into question; if requirements change, if preload and total load of air pollutants increase due to other emission sources or if technology develops before the planned fuel switch.

Therefore, both emissions and immissions have to be adequately regulated on top of the CO2 monitoring and management:

- Emission regulation:
    - For 100% H2, higher NOx-emissions and more water vapour in flue gas has to be expected compared to gas. This should be considered when defining emission thresholds – simply implementing the threshold for gas also for hydrogen does not reflect the differences: due to the increased water vapour loading, the "dry" NOx emissions would be calculated as too high in the normal procedure (correction factor is 1.372).
    - Currently, no specific emission limits for H2 combustion are foreseen in the IED. In the next revision of the Best Available Technique Reference Document for Large Combustion Plats (BREF LCP), specific requirements for hydrogen combustion (including blends) should be evaluated and then be implemented in the next Best Available Technique (BAT) conclusions. These requirements should differentiate between new-build, retrofitted existing plants (which might not be able to install an SCR) and operation mode (e.g. plants with < 1,500 operating hours per year for which regulation is based on emission loads instead of Emission Limit Values (ELVs)).
- Immission regulation:
    - New plants or fuel switch might have influence on **immissions**, e.g. in nature protection areas (e.g. NOx, NH3, formaldehyde).

[6] See Aurora study „Decarbonising The Dutch Thermal Gas Fleet", Oct 2023, p. 48.
[7] Aurora study „Ready for hydrogen? Outlook on new reliable capacity in Germany", Dec. 2023.

- In addition, compliance with the tightened requirements from the Ambient Air Quality Directive must be ensured, thus bringing the new plant also in line with the Zero Pollution Strategy affords higher flue gas scrubbing efforts.
- However, this should only be assessed once for the original permit. If an authorisation is granted, the operator should have a binding right to switch to hydrogen.

Hydrogen is at the core of the recently adopted Hydrogen and Decarbonised Gas Market Package. Based on this upcoming new legal framework, rules for access to the existing gas grid are to be adapted or even newly designed for the new hydrogen grid. In general, the existing rules for gas grid access and grid use have proven their worth and will therefore also apply to the new hydrogen grid.

Since hydrogen might be a scarce resource in the beginning, a pivotal point to be considered is the granting of non-interruptible access to hydrogen grid by H2 fired power plants. This will ensure that they will be supplied with hydrogen in particular during a *Dunkelflaute* (no wind and cloudy weather) in which they are urgently needed to ensure security of supply. If there is a hydrogen supply shortage at times when an electricity supply emergency situation occurs, electricity generation from hydrogen should be prioritised for such protected, critical power plants (i.e. protected *vis-à-vis* H2 disruption risk), compared to other hydrogen use cases for the same reason.

This is also valid for the access to storage capacity or H2 supply flexibility in general: hydrogen combustion plants will synchronously not run at times when electrolysers are operated. Electrolysers need high renewable electricity generation whereas H2 fired gas plants will run at times of RES shortage. Therefore, the hydrogen has to be stored or handled through flexible assets in order to make it available for the plants when needed. If hydrogen combustion is operated with imports, the same holds true. If hydrogen is imported via ships, this intermittent supply has to be stored or handled, too. If it is imported via pipeline, it should be handled to allow a dispatchable or flexible supply, too, to be available when needed.

In addition to the electrical grid connection, the possibility of district heating extraction, and thus, more efficient use of the fuel, must also be considered, as the use of H2 in a CHP plant is much more useful than in a pure power generation plant.

## 5. Financial requirements

Investments in new H2-ready gas-fired power plants must be economically viable. Given low operating hours, revenues from the energy-only market may not suffice to finance these investments. Therefore, additional incentives are necessary to ensure timely system adequacy through reliable capacity, including H2-ready plants.

To support investments and award capacity payments on a market-basis, various factors need to be considered when investing in H2-ready plants: Firstly, regardless of technology, awarded capacities must ensure timely investments and be able to provide decarbonised power in the long term, (i.e. technical H2-readiness has to be fulfilled as a prequalification criteria, for instance, e.g. via a guarantee from the plant manufacturer or via an assessment of a certification body).

Relevant regulatory authorities may designate so called 'go-to-areas' for locating H2-ready gas fired plants taking into account when an H2 grid connection will be available in due time (e.g. based on H2 grid development plans) and be favourably located from a power grid perspective in terms of a 'power system-friendly' location.

Consideration could be given to introducing a capacity mechanism – either centralised or decentralised – to bridge any financial gaps. New or retrofitted plants could be granted longer-term contracts to ensure they can recover their investment costs compared to existing plants.

Eurelectric pursues in all its activities the application of the following sustainable development values:

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