



Ultra-low emission flexible plants for blue hydrogen and power production, with electrically assisted reformers

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ABSTRACT

This study investigates the potential of natural gas-based plants designed to produce blue hydrogen and decarbonized electric power, conceived to operate flexibly depending on the electricity price. This paper considers plants based on fired-tubular reforming (FTR) and auto-thermal reforming (ATR) technologies, with MDEA-based pre-combustion CO₂ capture process and partial electrification of the reformer, designed to achieve CO₂ capture efficiency higher than 95 %. Heat and mass balances for the chemical and power island are evaluated at both full and part load to define the corresponding operating maps. With pre-combustion CO₂ capture only, FTR plants can achieve CO₂ capture rates higher than 90 %, H₂ production efficiency of 73–74 % and power generation efficiency of around 47 %. Reformer electrification allows increasing overall capture efficiency to 95 %. Plants based on ATR can approach 95 % capture efficiency without electrification and achieve H₂ efficiency similar to FTR but higher electric efficiency, close to 51 %. An economic analysis is performed to assess profitability of the plants under electricity price scenarios with different penetration of renewables. The economic analysis shows that flexible plants may be profitable in future scenarios with high penetration of renewables and high price variance, resulting in IRR around 10–17 % for hydrogen selling prices of 2.0–2.5 €/kg, natural gas price of 9 €/GJ and carbon tax of 100 €/tCO₂.

1. Introduction

“Blue” hydrogen produced from natural gas with CO₂ capture and storage (CCS) can support the initiation of a low carbon hydrogen market [1], contributing to the decarbonization of industry and hard to electrify transport sectors [2]. For blue hydrogen to be truly low-carbon, high CO₂ capture rate and natural gas supply chain with very low methane leakage are essential [3–5].

Antonini et al. [6] assessed and compared Fired Tubular Reforming (FTR)¹ and Auto-thermal reformer (ATR)-based plants with CO₂ capture from shifted syngas. According to their work, only the ATR-based processes with high CO₂ separation efficiency (>95 %) could achieve capture rates of 93–98 %. More recently, an IEAGHG study [7] compared different blue hydrogen production plants, namely: (i) Fired Tubular

Reforming-based process (referred to as SMR in the cited report) with post-combustion capture, (ii) ATR-based plant with Gas heated reformer (GHR), also referred to as Low Carbon Hydrogen (LCH), (iii) Electrified Steam Methane Reformer (ESMR), and (iv) Partial Oxidation (POX) process. The four plants feature CO₂ capture rates of 90 %, 93.6 %, 98.6 % and ~88 %², respectively.

As of today, four industrial plants produce hydrogen from FTR with CO₂ capture, namely Port Arthur (Air Products), Quest (Shell), Tomakomai (JCCS Ltd/METI) and Port Jerome (Air Liquide) [8]. These plants feature relatively low overall CO₂ capture efficiencies, as the economic driver for CO₂ capture was not associated to the minimization of CO₂ emissions. New blue hydrogen projects are being proposed in Europe and North America, mostly based on ATR and aiming at CO₂ capture rates of higher than 95 % (a list of the existing and announced blue H₂ projects is available in the [supplementary information - SI](#)).

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¹ Steam methane reforming (SMR) and fired tubular reforming (FTR) are often used as synonyms in the literature. In this work, we use the FTR acronym in order to refer to the technology rather than to the chemical reaction.

² In the original reference [7], a 100 % capture rate is claimed for the POX-based plant. However, from the discussion in the report, this value is obtained by neglecting the uncaptured carbon in the CH₄ delivered together with the H₂ product, after methanation of the residual CO and CO₂. From the balance tables, it is possible to back-calculate 181 kg of captured CO₂ per GWh of natural gas input, corresponding to an actual CO₂ capture rate (defined as the ratio between the carbon in the captured CO₂ and the carbon in the inlet natural gas) of about 88 %.

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Nomenclature			
ASU	Air separation unit	IEA	International Energy Agency
ATR	Auto-thermal reformer	IRR	Internal Rate of Return
CEPCI	Chemical Engineering Plant Cost Index	LCH	Low Carbon Hydrogen
CAC	CO ₂ Avoidance Cost	LHV	Lower Heating Value
CMRE	CO ₂ mitigation rate of electrification	LT	Low Temperature
COE	Cost of electricity	MDEA	Methyl diethanolamine
COH	Cost of hydrogen	NG	Natural gas
CC	Combined Cycle	NGCC	Natural gas combined cycle
CCR	Carbon capture ratio	NPV	Net present value
CCS	Carbon capture and storage	PSA	Pressure swing adsorber
CCUS	Carbon capture, utilization and storage	POX	Partial Oxidation
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortization	PtHE	Power to Hydrogen Efficiency
ESMR	Electrified Steam Methane Reforming	PV	Photovoltaics
FTR	Fired tubular Reformer	S/C	Steam to carbon ratio
GHR	Gas Heated Reformer	SC	Steam cycle
GSR	Gas Switching Reforming	SI	Supplementary Information
GT	Gas turbine	SMR	Steam methane reforming
HB	Hydrogen boost	SPECCA	Specific Primary Energy Consumption for CO ₂ Avoided
HPT/IPT/LPT	High/Intermediate/Low pressure turbine	T&S	Transport and Storage
HT	High Temperature	TCR	Total capital requirement
HRSR	Heat recovery steam generator	TIT	Turbine inlet temperature
IC	Intercooled	TOT	Turbine outlet temperature
		TPC	Total plant cost
		TRL	Technology readiness level
		WGS	Water gas shift

The application of CCS in power plants working in the mid-merit market or as peakers would cause a very high cost of electricity, due to the high capital intensity of CCS and the low capacity factor [9]. Several studies were conducted on power generation from natural gas (NG) with commercially available pre-combustion CO₂ capture technologies, assessing how CCR around 85–93 % were achievable by accepting an efficiency penalty around 8–14% points with respect to unabated operation [10]. From a cost of electricity (COE) perspective, pre-combustion capture is less competitive than post-combustion capture in combined cycles [10–12]. However, opportunities for pre-combustion capture systems arise from flexible operation in energy markets with high penetration of renewables, where natural gas fired power plants may provide balancing services to the grid [13] and contribute to reduce the total system cost [14].

To the authors' knowledge, only a few studies in the open literature have focused on combining the concepts of flexible power and hydrogen production plants with CCS. Szima et al. [15] proposed to couple the Gas Switching Reforming (GSR) technology with a Combined Cycle (CC) for production of decarbonized hydrogen and power. The results of the study suggest that in presence of a large market for clean hydrogen, a flexible solution for blue hydrogen and power can justify the investment risks. Cloete et al. published two studies on flexibility considering the interrelation between GSR plants with variable renewable sources and its impact on the energy system [16,17]. Results in [16] suggest that such a flexible plant coupled with wind and PV can help phasing out unabated technologies already with a carbon tax around 60 €/tCO₂. In [17], Cloete et al. modelled an energy market based on renewables, taking into account costs of infrastructures and storage for electricity and hydrogen. The study found that scenarios including blue hydrogen can achieve lower total annual costs for the overall system (27–31 % decrease with respect to the scenario without CCS).

The purpose of this study is to investigate the potential of new "Powdrogen" polygeneration plants to co-produce low-carbon hydrogen and dispatchable low-carbon power, featuring economic advantages compared to the separated power and hydrogen generation with CCS. The Powdrogen concept consists in coupling a chemical island based on either an FTR or an ATR, with a H₂-fired gas turbine combined cycle to

flexibly produce blue hydrogen and/or electricity. In a previous paper by the same authors [18], technical aspects related to the thermal integration between the heat recovery in the chemical island and in the combined cycle have been assessed. By feeding a single steam turbine with steam generated by heat recovery in the chemical island and in the gas turbine heat recovery steam generator, a Capex reduction may be obtained thanks to the adoption of a single larger steam turbine. Startup time of the combined cycle can also be decreased as the steam turbine is kept warm even when the gas turbine is off, due to the steam produced in the chemical island. On the other hand, such thermal integration entails a reduction in the plant turndown ratio and efficiency losses due to the adoption of a sub-optimal design of the turbine, needed to manage major variations of the steam flow rate between power production mode and hydrogen production mode. In this paper a non-integrated configuration, with a steam turbine for the steam raised in the chemical island and a separate steam turbine for the CC, is considered.

This work presents a comprehensive analysis of Powdrogen plants, alongside with the assessment of the potential of the partial electrification of the reformer. The study focuses on FTR- and ATR-based plants designed to operate with high carbon capture ratios, assisted by the introduction of an electrified section to enhance methane conversion and/or hydrogen production.

In summary, the novelty of this work consists in:

1. Analyzing and comparing FTR- and ATR-based plant configurations designed to achieve high CO₂ capture efficiencies (>90–95 %) by pre-combustion CO₂ removal only;
2. Assessing the impact on the techno-economic performance of partially electrified reforming aimed at reducing CO₂ emissions and/or increasing H₂ production;
3. Defining the maps of operating region of flexible Powdrogen plants;
4. Evaluating the economic performance indicators of the Powdrogen plants.

2. Plant concept

The assessed Powdrogen plants are composed by different sections

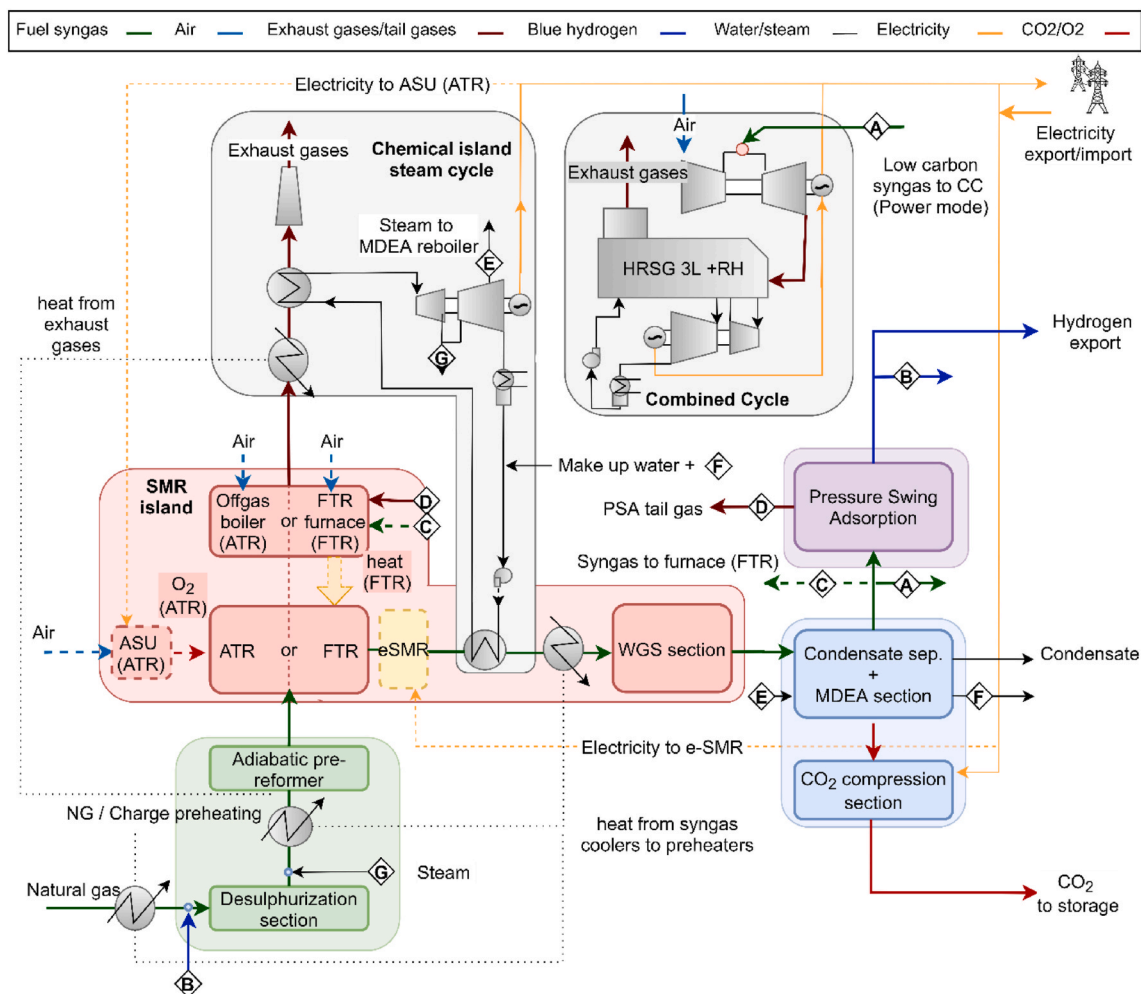


Fig. 1. Block diagram of the “Powdrogen” plants assessed in this work. Dashed lines represent components and streams present only in specific configurations and/or operating modes while black dotted lines represent heat exchanged from exhaust gas and syngas cooling to preheat NG and charge to reformer.

(or islands) for syngas production via SMR, CO₂ separation, hydrogen purification and power generation (Fig. 1):

- SMR island: natural gas is desulfurized and mixed with steam to be converted into a syngas rich in H₂ and CO by a steam reforming process based on an adiabatic pre-reformer followed by either a fired tubular reforming (FTR) with hydrogen-fired furnace or an autothermal reforming (ATR). Both FTR and ATR reactors may be followed by an additional electrified steam methane reforming (eSMR) reactor to enhance methane conversion. Steam reforming is followed by the Water Gas Shift (WGS) section, composed by a high temperature (HT-WGS) and a low temperature (LT-WGS) reactor. Heat is recovered from both exhaust gases and syngas cooling to preheat the charge (NG + H₂O mixture) to the reformer and to produce steam. The SMR island of the ATR-based plant include the air separation unit (ASU) and the PSA off-gas boiler.
- CO₂ separation: H₂-rich (above 90 % vol.) syngas is obtained after CO₂ separation by chemical absorption with MDEA-based solvent. This stream can be used as fuel in the combined cycle for electricity production or purified and delivered to the market as “blue” hydrogen. The separated carbon dioxide stream is compressed and sent to storage as supercritical CO₂.
- Hydrogen purification: impure H₂ after CO₂ separation is purified in a conventional PSA unit, to obtain high purity hydrogen. The low-pressure PSA off-gas stream is used as fuel in the FTR furnace or in a boiler for steam generation in the ATR-based plants.

- Steam cycle: steam raised by recovering heat in the SMR island is used for: (i) steam reforming, (ii) solvent regeneration in the reboiler of the MDEA-based CO₂ capture section and (iii) power generation in a steam cycle. Make up water is supplied to compensate for the steam needed to form the reformer charge.
- Combined cycle: impure H₂ after CO₂ separation may be burned in an advanced H-class gas turbine assumed to run on H₂-rich (>90 % molar) fuel mixtures. The gas turbine is coupled with a triple pressure and reheat heat recovery steam cycle.

Independently of the technology, the capacity of the SMR island is assumed such that the H₂-rich syngas output exactly fits the fuel demand of the H-class gas turbine running at full load. Accordingly, Powdrogen plants can work in different operating modes: (i) hydrogen production mode, where the produced hydrogen is totally exported and the combined cycle is off; (ii) power generation mode, where all the H₂-rich syngas is burned in the GT and no H₂ is exported, (iii) polygeneration mode, where hydrogen is partly burned in the GT, which operates at part-load, and partly exported as blue hydrogen, (iv) electrified mode, in which the SMR island consumes electricity to drive the reforming reaction and hydrogen is the only product. For a complete description of the plant sections and of the main assumptions adopted for the calculation of the mass and energy balances, the reader is addressed to the SI.

Residual direct CO₂ emissions from blue H₂ plants are associated to three sources: (i) unconverted CH₄ from the reformer, (ii) unconverted CO from the WGS section and (iii) uncaptured CO₂ from the CO₂

Table 1
Main features of the Powdrogen plants assessed in this work.

	FTR	FTR-Plus	e-FTR	ATR
Reforming temperature, °C	890	950	950/1050	1050
Reforming pressure, °C	32.7	32.7	32.7	32.7
Steam to carbon ratio,	3.4	3.4	3.4	1.5
Pre-reforming inlet temperature, °C	490	490	490	490
HT-WGS inlet/outlet temperature, °C	340/415	340/427	340/435	320/440
LT-WGS inlet/outlet temperature, °C	195/220	195/200 ^a	195/200 ^a	195/250
CO ₂ separation efficiency, %	95 %	99 %	99 %	99 %
PSA H ₂ recovery efficiency	89 %	95 %	95 %	95 %

^a cooled WGS reactor.

separation unit. In order to increase the overall CO₂ capture rate, the following measures may be taken:

- i. To increase CH₄ conversion in the reformer by increasing the reformer exit temperature. This issue is relevant in FTR, whose exit temperature is limited by the stress resistance of the reactor material, leading to much higher methane slip than ATR. The achievement of very high reforming temperatures is facilitated by an electrified section, that warms up the reacting syngas via electric heating from inside the reactor, without overheating the pressure-resistant shell [19,20].
- ii. To improve CO conversion in the WGS section by reducing the LT-WGS exit temperature. This may be achieved via a cooled reactor [21] or by multiple (two or more) intercooled LT-WGS reactors.
- iii. To design the CO₂ removal process from syngas for very high CO₂ separation efficiencies (>99 %). Such high separation efficiency combined with high hydrogen recovery (>99.9 %) can be achieved by proper process configuration (two-stage absorption with semi-lean and lean solvent and high-pressure flash gas recirculation to the absorber) and is a common practice since decades in ammonia production plants [21,22].

In FTR-based plants, that normally operate with reforming exit temperature close to 900 °C, more than 10 % of the carbon in the feedstock remains allocated as unconverted CH₄, preventing to achieve >90 % of overall CO₂ capture rate in FTR-based plants relying only on CO₂ removal from syngas. Conversely, commercial ATR, thanks to the higher operating temperature (>1000 °C) allowed by the internal fuel oxidation, can easily achieve CH₄ conversion well above 95 %, which explains why ATR are the preferred technology for blue H₂ plants aiming at high CO₂ capture efficiency. A quantitative analysis on the impact of the reforming process parameters on methane conversion and residual CO₂ emissions is discussed in the SI.

In this work, the partial electrification of the reforming process is conceived as a way to:

1. Enhance the reformer exit temperature to increase CH₄ conversion in FTR-based reformer, achieving >90 % CO₂ capture efficiency with pre-combustion capture only.
2. Improve the flexibility of the plant by boosting H₂ production by activating electric heating in low electricity price periods, both in FTR- and ATR-based plants.

2.1. Selected plants

As anticipated in the Introduction, different Powdrogen steam cycle configurations have been compared in a previous paper [18]. In this work, a non-integrated steam cycle design has been assumed, which appears preferable for plants expected to operate for most of the time in hydrogen mode and for plants built by retrofitting existing natural gas fired combined cycles, where a heat recovery steam cycle already exists.

This study compares the following four different Powdrogen plants, operating with the process parameters summarized in Table 1:

1. The FTR plant, which adopts conventional technologies and operating parameters, similar to those typically assumed in literature studies and aligned to commercial hydrogen plants in operation in refining and chemical industry.
2. An improved FTR-based process (FTR-Plus), featuring improved design to increase the CO₂ capture efficiency, namely: (i) higher reformer exit temperature (950 °C vs. 890 °C) to improve methane conversion; (ii) cooled LT-WGS section, with fixed outlet temperature of 200 °C (vs. 220 of the FTR case) [21,23] and (iii) increased CO₂ separation efficiency of the MDEA section (99 % vs. 95 % [21, 22]). Also, this plant features improved H₂ recovery in the PSA unit (95 % vs. 89 % of conventional plants), which should be achievable with optimized cycles and increased number of pressure equalization steps [24].
3. The FTR-based plant including an additional electrified reforming (e-FTR) section with maximum outlet temperature of 1050 °C (i.e. the same outlet temperature achieved in ATR).
4. The ATR-based plant with conventional reforming temperature and S/C ratio, adiabatic WGS reactors and gas treatment section with 99 % CO₂ capture efficiency and 95 % of H₂ recovery in the PSA unit as in the FTR-Plus process.

In all cases, the size of the chemical island has been set to exactly supply the H₂-rich fuel for the selected gas turbine at full load. It has to be remarked that different sizing criteria could involve larger or smaller hydrogen production capacity compared to the GT, depending for example on the expected hydrogen demand or on the availability of additional sources of hydrogen for power generation, e.g. green H₂ from storage [25], or the possibility to co-fire natural gas in the combined cycle.

3. Methods

AspenPlus® process simulation software with the NRTL-RK thermodynamic model [26,27] was used to evaluate the heat and mass balances of the chemical island of all the plants. All the chemical reactors were calculated at chemical equilibrium, with CH₄ as an inert in the WGS reactors.

The H₂-fired gas turbine was calculated with the in-house code introduced in [28]. The cooled expansion model [29,30] was calibrated on selected GT data [18], as presented in SI.

The following operating modes have been considered for the flexible Powdrogen plants:

- Hydrogen mode: all the hydrogen produced in the plant is delivered as output product and the combined cycle is off. This is selected as the nominal operating mode for the Powdrogen plant, that defines the design specifications of the process units, of the heat exchangers in the chemical island and of the chemical island steam cycle.

- Power mode: the chemical island works at full load and the whole H₂-rich gas produced is burned in the gas turbine. The only output from the plant is electricity, since the PSA unit is bypassed, and no hydrogen is exported. Given the size of the selected gas turbine, this operating mode sets the capacity of the chemical island, i.e. the maximum syngas flowrate produced at full load for both power and hydrogen mode.
- Minimum power mode: the plant operates in polygeneration mode, producing both hydrogen and electricity. The chemical island operates at full load. Part of the syngas produced is burned in the combined cycle which works at minimum load and the remaining syngas is sent to the PSA for co-production of high purity hydrogen.
- Electrified mode: the reformer reactor is partially electrified, with an electric resistance that heats up the syngas downstream or within the main FTR and ATR reactors, leading to reduced CO₂ emissions and/or increased hydrogen production. The electrified reformer in FTR-based plants is conceived to increase the final outlet temperature up to 1050 °C, to increase methane conversion. In ATR-based plants, the outlet temperature is kept constant (1050 °C) with respect to nominal operation and electric heating enhances hydrogen production by reducing the amount of oxygen injected in the ATR.

The calculation of the heat and mass balances of flexibly operated plants requires off-design modelling approach, as described in the SI.

3.1. Key performance indicators

The technical performance of the plants is evaluated with the following indexes:

- The hydrogen production efficiency (η_{H_2}), defined as the ratio between the lower heating value (LHV) chemical power output of the exported hydrogen and the LHV power input of natural gas (Equation (1)).

$$\eta_{H_2} = \frac{\dot{m}_{H_2} \cdot LHV_{H_2}}{\dot{m}_{NG} \cdot LHV_{NG}} \quad (1)$$

- The equivalent H₂ production efficiency ($\eta_{H_2,eq}$) (Equation (2)) considers the “equivalent” natural gas input, that includes the credits from electric power export \dot{P}_{el} (or the indirect natural gas consumption associated to power import, if \dot{P}_{el} is negative), accounted by assuming a reference combined cycle efficiency $\eta_{el,ref}$ of 63 %, taken as a representative value of generic state-of-the-art large-scale combined cycle [31].

$$\eta_{H_2,eq} = \frac{\dot{m}_{H_2} \cdot LHV_{H_2}}{\dot{m}_{NG} \cdot LHV_{NG} - \frac{\dot{P}_{el}}{\eta_{el,ref}}} \quad (2)$$

- The net electric efficiency (η_{el}) (Equation (3)) is calculated as the ratio between the net electric power output over the natural gas LHV power input.

$$\eta_{el} = \frac{\dot{P}_{el}}{\dot{m}_{NG} \cdot LHV_{NG}} \quad (3)$$

- The specific CO₂ emission can be calculated referring to hydrogen (E_{H_2}) (Equation (4)) or electric energy (E_{El}) (Equation (5)) output,

depending on the operation mode. The specific emission considers only the direct CO₂ emitted at the plant stack.

$$E_{H_2} = \frac{\dot{m}_{CO_2,emitted}}{\dot{m}_{H_2} \cdot LHV_{H_2}} \left[\frac{g_{CO_2}}{MJ_{H_2}} \right] \quad (4)$$

$$E_{El} = \frac{\dot{m}_{CO_2,emitted}}{\dot{P}_{el}} \left[\frac{kg_{CO_2}}{MWh_{el}} \right] \quad (5)$$

- The carbon capture ratio (CCR) is defined as the molar ratio between the captured CO₂ and the carbon entering with natural gas as described in Equation (6).

$$CCR = \frac{\dot{n}_{CO_2,stored}}{\dot{n}_{C,GN}} \quad (6)$$

- The Specific Primary Energy Consumption for CO₂ Avoided (SPECCA) represents the energy consumption associated to the avoidance of one CO₂ emission mass unit with respect to a reference plant without CO₂ capture. In Hydrogen mode (Equation (7)), it is defined as the ratio between the increase in specific equivalent fuel consumption ($1/\eta_{H_2,eq}$) and the reduction of equivalent CO₂ emission with reference to a FTR plant without CCS ($\eta_{H_2,eq,ref} = 79.65 \%$, $E_{H_2,eq,ref} = 73.44 \text{ g}_{CO_2}/MJ_{H_2}$, see the SI). In Power mode (Equation (8)), it is defined as the ratio between the incremental heat rate ($3600/\eta_{el}$) and the specific CO₂ emission reduction with respect to a reference natural gas combined cycle without CCS ($\eta_{el,ref} = 63 \%$, $E_{el,ref} = 325.6 \text{ kg}_{CO_2}/MWh$).

$$SPECCA = \frac{\frac{1}{\eta_{H_2,eq}} - \frac{1}{\eta_{H_2,eq,ref}}}{E_{H_2,ref} - E_{H_2}} \left[\frac{MJ_{LHV}}{kg_{CO_2}} \right] \quad (7)$$

$$SPECCA = \frac{\frac{3600}{\eta_{el}} - \frac{3600}{\eta_{el,ref}}}{E_{el,ref} - E_{el}} \left[\frac{MJ_{LHV}}{kg_{CO_2}} \right] \quad (8)$$

- In electrified reforming operating mode, the Power-to-H₂ efficiency (PtHE) (Equation (9)) is defined as the ratio between the marginal hydrogen LHV power output and the additional electric power consumption with respect to the baseline operation with electric heating off.

$$PtHE = \frac{(\dot{m}_{H_2,elec} - \dot{m}_{H_2,base}) \cdot LHV_{H_2}}{\dot{P}_{el,elec} - \dot{P}_{el,base}} \quad (9)$$

- The CO₂ mitigation rate of electrification (CMRE) (Equation (10)) is defined as the ratio between the reduction of CO₂ emission in the electrified operation and the additional electric power consumption with respect to the baseline operation with electric heating off, assuming that the increased electricity consumption does not involve additional CO₂ emissions (i.e. that the consumed electricity is zero-emissions).

$$CMRE = \frac{\dot{E}_{H_2,elec} - \dot{E}_{H_2,base}}{\dot{P}_{el,elec} - \dot{P}_{el,base}} \left[\frac{kg_{CO_2}}{MWh_{el}} \right] \quad (10)$$

Table 2
Powdrogen plants performance in hydrogen and power mode.

	FTR	FTR-Plus	e-FTR	ATR
HYDROGEN MODE				
NG thermal input, MW	1635	1710	1662	1419
Hydrogen output, MW	1220	1220	1220	1044
Hydrogen output, Nm ³ /h	410,176	410,176	410,176	351,003
Chemical island turbine output, MW	59.01	77.04	87.15	88.14
Electric consumption, MW	–	–	77.58	–
CO ₂ compression, MW	25.32	30.38	31.22	26.25
ASU electric consumption, MW	–	–	–	35.33
Other auxiliaries, MW	11.37	11.82	11.54	6.77
Net electric output, MW	22.31	34.84	–33.18	19.79
Specific net electric output, kWh/kg _{H2}	0.609	0.952	–0.906	0.632
Hydrogen production efficiency, %	74.59	71.33	73.42	73.57
Eq. Hydrogen production efficiency, %	76.24	73.71	71.16	75.24
Carbon capture ratio, %	78.88	90.52	95.75	94.13
Specific emission g _{CO2} /MJ _{H2}	16.16	7.58	3.30	4.55
Specific emission kg _{CO2} /kg _{H2}	1.94	0.91	0.40	0.55
SPECCA, MJ/kg _{CO2}	0.98	1.54	2.14	1.07
POWER MODE				
NG thermal input, MW	1635	1710	1662	1419
Fuel thermal input to GT, MW	1224	1222	1222	1210
Gas Turbine power output, MW	521.5	520.5	520.3	515.0
Bottoming cycle power output, MW	255.4	255.0	254.9	247.3
Chemical island turbine output, MW	57.69	76.65	87.93	26.00
Electric reformer consumption, MW	–	–	77.58	–
CO ₂ compression, MW	25.36	30.40	31.23	26.26
ASU electric consumption, MW	–	–	–	35.42
Other auxiliaries, MW	11.11	11.71	11.51	4.12
Gross power output, MW	834.6	852.2	863.1	788.3
Net power output, MW	798.1	810.0	742.8	722.5
Net electric efficiency, %	48.80	47.36	44.70	50.90
Carbon capture ratio, %	78.51	90.58	95.77	94.22
Specific emission kg _{CO2} /MWh _{el}	91.10	40.89	19.43	23.30
SPECCA, MJ/kg _{CO2}	7.09	6.63	7.64	4.49

4. Technical results

4.1. Results

Table 2 shows the performance of the four assessed Powdrogen plants in hydrogen mode. The FTR case exhibits the highest hydrogen production efficiency 74.59 % and the lowest carbon capture ratio 78.88 %. The FTR-Plus achieves a higher CCR, which increases up to 90.52 % and a reduction of the specific direct emissions from 1.94 to 0.91 kg_{CO2}/kg_{H2}. On the other hand, hydrogen production efficiency reduces by about 3.3% points, due to the increased fuel consumption in the FTR furnace to achieve the higher reforming temperature. The higher fuel consumption in the FTR furnace increases steam generation in the syngas cooling section, leading to a higher net electric power output (see Table 2).

In the e-FTR plant, electrification allows exceeding 95 % CO₂ capture rate and reducing specific emissions to 0.40 kg_{CO2}/kg_{H2}. Hydrogen production efficiency also rises to 73.42 %, but the plant becomes a net importer of electricity, causing a reduction of the equivalent hydrogen production efficiency (71.16 % vs. 73.7 % of the FTR-Plus plant) and an increase of SPECCA (2.14 vs. 1.54 MJ/kg_{CO2}). The net electricity consumption of the e-FTR plant corresponds to less than 3 % of the hydrogen LHV energy output, or to about 0.9 kWh/kg_{H2}. This is a much lower consumption than expected for a fully electrified reformer (~10 kWh/kg_{H2}, from authors' estimations confirmed by data from IEAGHG report [7]) or than ~35–55 kWh/kg_{H2} of electrolytic hydrogen [32,33].

Finally, the ATR-based plant achieves comparable hydrogen production efficiency (73.57 %) and emissions (0.55 kg_{CO2}/kg_{H2}) to the e-FTR plant. On the other hand, the plant remains a net electricity exporter, leading to high equivalent hydrogen production efficiency (75.24 %) and low SPECCA (1.07 MJ/kg_{CO2}), comparable with the FTR plant.

Table 2 also shows the performance of the Powdrogen plant when operated in power mode. The ATR shows the highest net electric efficiency (50.90 %), 2–3% points higher than FTR and FTR-Plus, keeping much lower CO₂ emissions (23.3 vs. 40.9–91.1 kg_{CO2}/MWh). So, efficiency of the ATR-based plant is comparatively better than FTR-based plants when operated in power mode. The reason for this result is that in hydrogen mode the PSA off-gas of the ATR plant is inefficiently (from an exergy analysis perspective) burned in a boiler to produce steam, while in power mode the PSA is bypassed and all the syngas is supplied to the combined cycle.

Operations in power mode also explain the different fuel input between FTR-based plants and ATR. In FTR-based plants, a significant fraction of decarbonized syngas (6.7–11.3 %) feeds the reformer furnace. The natural gas input must be increased proportionally compared to an ATR with the same flow rate of syngas directed to the combined cycle. Operating in H₂ mode, the syngas fraction used in the furnace significantly decreases because most of the heat is supplied by burning the PSA off-gas. This explains why the H₂ output of the FTR-based plants exceeds the one of ATR.

In power mode, the e-FTR plant operates with the lowest net electric efficiency (44.70 %) due to the electricity consumed in the chemical island. On the other hand, it achieves the lowest specific emissions (19.43 kg_{CO2}/MWh_{el}) although at the expense of a higher SPECCA (7.64 vs. 4.49 MJ_{LHV}/kg_{CO2} of the ATR-based plant).

Obtained results are aligned with other studies presented in literature. The ATR plant in hydrogen mode can be compared with benchmark case with MDEA (labeled ATR + HT + LT, CCR = 98 % for the CO₂ separation unit) investigated by Antonini et al. [6]. In our case, due to different assumptions for the steam cycle (higher steam pressure and temperature of 100 bar and 540 °C vs. 43 bar and 400 °C, and lower condensation pressure 0.04 bar vs. 0.05 bar) the plant has a positive electric output. Conversely, the slightly lower hydrogen production efficiency (73.6 % vs. 76.7 % of Antonini et al.) is due to: (i) a lower CH₄ conversion due to lower ATR outlet temperature at fixed S/C ratio and, (ii) a higher LT-WGS inlet temperature (210 °C vs 180 °C), leading to a lower CO conversion.

The FTR base case can be compared with 1B case from IEAGHG report [34] having a comparable process flow concept. In this study, we obtain a higher carbon capture ratio (ca. 78 % vs. 67 %), a higher specific electric production (0.61 vs. 0.17 kWh/kg_{H2}) and a higher hydrogen production efficiency (74.6 % vs. 69.7 %) due to differences in the process design and operating parameters (e.g., the adoption of a second LT-WGS reactor that both increases CCR and η_{H2}, a higher S/C ratio of 3.4 vs 2.7 of case 1B, a different design of the cooling line of the reformed syngas and furnace flue gas, an improved steam cycle). Although there are notable differences in the process configuration, performance of the FTR-Plus plant can instead be compared to the 90 % CCR FTR case from the IEAGHG report [7]. The latter presents a natural gas fired furnace and an additional MEA-based CO₂ removal unit treating the furnace flue gas. The FTR-Plus plant exhibits a higher hydrogen production ratio of 71.3 % compared to 69 % and slightly lower specific emissions (0.91 vs. 1.0 kg_{CO2}/kg_{H2}) with higher specific electric production (0.95 vs. –1.1 kWh/kg_{H2}).

To account for greenhouse gas emissions associated to methane leakage from the natural gas supply chain, which are potentially the highest contributors of indirect GHG emissions, Fig. 2 shows the equivalent emissions from each plant in hydrogen mode and power mode as a function of the CH₄ leakage, with 20-year and 100-year global warming potential of CH₄ (GWP20 = 89.5 kg_{CO2,eq}/kg_{CH4}, GWP100 = 29.8 kg_{CO2,eq}/kg_{CH4}). The graphs are built according to the procedure from Romano et al. [35]. The total equivalent consumption of natural gas is computed considering the direct NG consumed by the plant and the indirect natural gas consumed to supply electricity to the plant (assumed to be produced by a combined cycle with 90 % CO₂ capture and electric efficiency η_{el} = 50 %, indicatively the same performance indexes of the Powdrogen plants in power mode). The

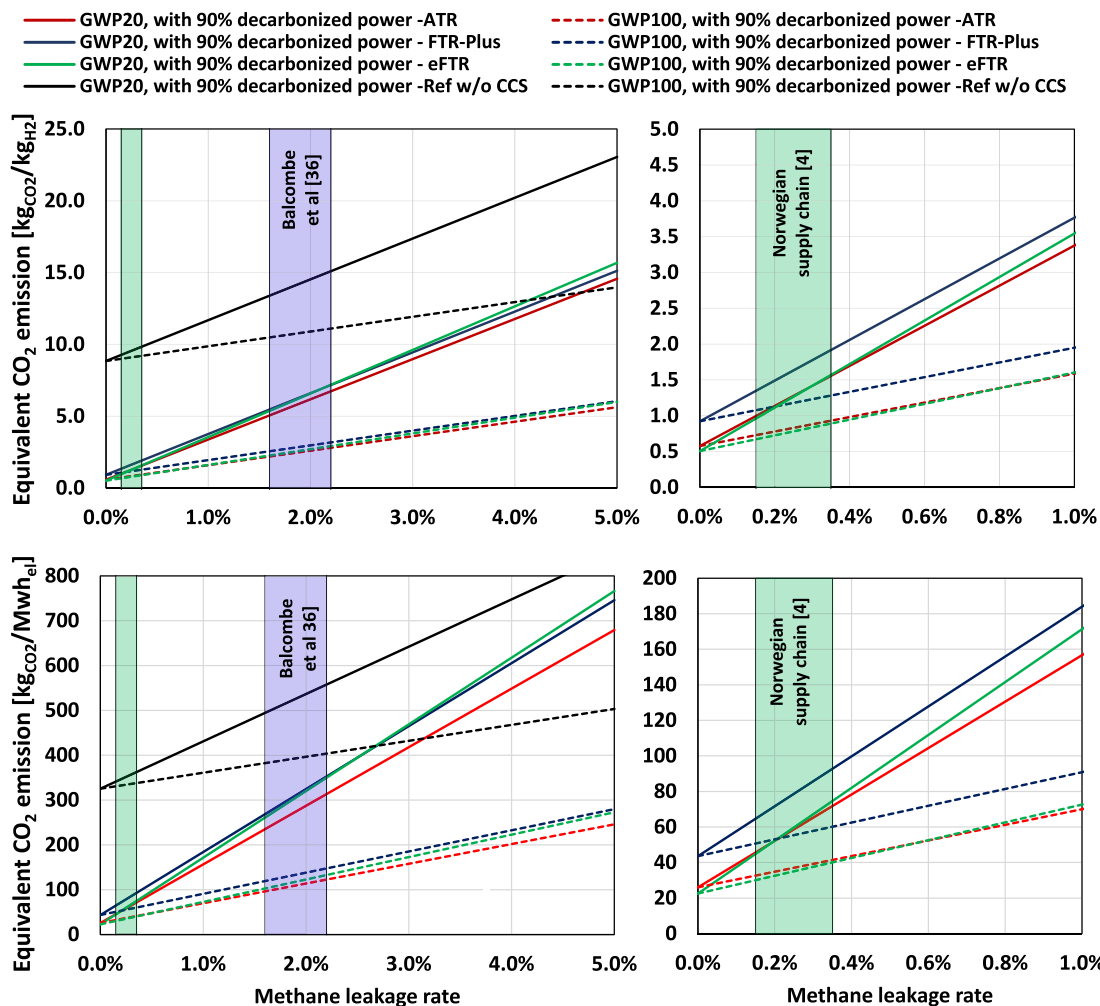


Fig. 2. Equivalent emissions for the ATR, FTR-Plus and e-FTR as a function of CH₄ leakage from value chain for hydrogen mode (top chart) and power mode (bottom chart) operation, assuming 90 % decarbonized electricity for NG production, process and transport. Line patterns refer to different global warming potential: GWP20 (solid lines) and GWP100 (dashed lines). Charts on the right hand side zoom in on the low methane leakage region. Literature data ranges are taken from [4,5,36].

equivalent emissions related to NG production, processing and transport are assumed equal to 0.37 g_{CO2}/MJ_{NG} (i.e. a 90% reduction compared to the current emissions is assumed, through implementation of CCS or other renewable energy sources in the supply chain [35]) and included in the balance. Among the three plants, ATR and e-FTR cases show the lowest specific emissions in a wide range of methane leakage rates. The slope of the e-FTR plant line is more pronounced, as this plant is more affected by the higher methane leakage rates, due to NG-based power import. Under these assumptions, the plants meet the European green taxonomy target of 3 kg_{CO2}/kg_{H2} for leakage rates lower than 1.5–2%. The leakage rates depend on the implementation, on the whole NG supply chain, of appropriate measures aiming to limit the unwanted release of methane into the atmosphere. Shaded regions in Fig. 2 refer to literature data on NG supply chain leakages: 1.6–2.2% are the mean and median values of the range assessed by Balcombe et al. [36], while the lower range of the Norwegian supply chain (0.15–0.35%) is taken from [4], where reported emissions are mostly due to the distribution and storage phases, while the extraction phase entails an average value of about 0.012 % [5]. This latter range can be taken as representative of a well-designed and maintained NG supply chain, in line with the recommendations of most advanced legislations. On the other hand, emission-intensive supply chains, as recently measured by Chen et al. [37] for Permian Basin wells with average values above 9 %, are not

compatible with any sustainable use of NG, included blue hydrogen production.

4.1.1. Flexible electrified operations

The e-FTR process can be designed aiming at flexible plant operations, exploiting the possibility of tuning the thermal power provided by combustion and electricity, depending on the relative electricity, hydrogen and CO₂ prices. Table 3 shows the performance of the e-FTR plant operated under different operating modes, identified by the syngas exit temperatures from the combustion-heated and the electric-heated sections respectively. Cases 950–1000 and 950–980 refer to a reduction in electric heating consumption, while keeping a fixed exit temperature from the combustion-heated section of 950 °C. Case 950–980 represents a nearly zero power output case, involving the use of the internally produced electricity only, with near zero electricity export. Conversely, in cases 900–1050 and 850–1050, the reformer heat duty is progressively shifted from combustion to electric heating, to exploit low electricity price. Each of these cases represents an off-design calculation of the baseline e-FTR 950–1050 case (i.e. 950 °C at combustion section exit and 1050 °C at electrified reforming section exit). This is why the results of the 950-950 case (where the electrically heated reformer is off) in this table are similar but not identical to the FTR-Plus case.

When the temperature at the exit of the electrified section is reduced,

Table 3
e-FTR plant performances in hybrid off-design operation.

	950-1050 (e-FTR)	950-1000	950-980	950-950	900-1050	850-1050
HYDROGEN MODE						
Fired tubular ref outlet temp., °C	950	950	950	950	900	850
Electrified ref outlet temp., °C	1050	1000	980	950	1050	1050
NG thermal input, MW	1662	1662	1662	1662	1662	1662
Hydrogen output, MW	1220	1215	1210	1203	1284	1364
Hydrogen output, Nm ³ /h	410,176	408,495	406,814	404,460	431,693	458,590
Electric consumption, MW	77.58	43.37	27.42		134.9	206.8
Net electric output, MW	-33.18	-10.55	0.99	21.73	-91.14	-199.1
Specific net electric output, kWh/kg _{H2}	-0.906	-0.289	0.027	0.602	-2.365	-4.864
Hydrogen production efficiency, %	73.42	73.14	72.82	72.37	77.27	82.11
Eq. Hydrogen prod. efficiency, %	71.16	72.41	72.89	73.90	71.09	68.99
Carbon capture ratio, %	95.75	94.03	92.90	90.53	95.76	95.78
Specific emission g _{CO2} /MJ _{H2}	3.30	4.66	5.57	7.47	3.13	2.93
Specific emission kg _{CO2} /kg _{H2}	0.40	0.56	0.67	0.90	0.38	0.35
SPECCA, MJ/kg _{CO2}	2.14	1.83	1.72	1.48	2.15	2.75
CMRE, kg _{CO2} /MWh _{el}	331.6	381.5	400.3	-	175.3	100.6
PtHE, %	30.96	37.17	33.75	-	71.76	72.91
POWER MODE						
Net power output, MW	742.8	761.7	767.8	783.3	-	-
Net electric efficiency, %	44.70	45.84	46.21	47.14	-	-
Carbon capture ratio, %	95.77	94.06	92.94	90.58	-	-
Specific emission kg _{CO2} /MWh _{el}	19.43	26.64	31.42	41.07	-	-
SPECCA, MJ/kg _{CO2}	7.64	7.15	7.06	6.76	-	-

Table 4
ATR plant performances in hybrid off-design operation.

	ATR	HB1	HB2
NG thermal input, MW	1419	1703	1419
Hydrogen output, MW	1044	1326	1241
Hydrogen output, Nm ³ /h	351,003	445,814	417,236
Electric consumption, MW		99.3	252.3
ASU electric consumption, MW	35.33	35.46	17.73
Net electric output, MW	19.79	-57.21	-206.3
Specific net electric output, kWh/kg _{H2}	0.632	-1.438	-5.539
Hydrogen production efficiency, %	73.57	77.88	87.44
Eq. Hydrogen prod. efficiency, %	75.24	73.94	71.05
Carbon capture ratio, %	94.13	92.81	91.96
Specific emission g _{CO2} /MJ _{H2}	4.55	5.26	5.24
Specific emission kg _{CO2} /kg _{H2}	0.55	0.63	0.63
SPECCA, MJ/kg _{CO2}	1.07	1.42	2.23
CMRE, kg _{CO2} /MWh _{el}	-	-38.7	-13.0
PtHE, %	-	90.23	87.13

H₂ production efficiency and specific CO₂ emissions change with a nearly linear trend with respect to the net electric consumption. In this region, the power-to-hydrogen efficiency is rather low (always below 40 %, i.e. much less than water electrolysis), indicating that electrification is here mostly functional to reduce CO₂ emissions rather than increasing H₂ production. This is confirmed by the high CO₂ mitigation rate of electrification (i.e. the CMRE index, evaluated with respect to the non-electrified 950-950 base case), ranging between 330 and 400 kg_{CO2}/MWh, i.e. indicating that using low-carbon renewable or nuclear electricity to heat the reformer allows avoiding roughly the same emissions as substituting the power generated by a natural gas fired combined cycle or, from another (unpreferable) perspective, that using the electricity produced in a combined cycle to run such electrified reformer would be CO₂ neutral as far as direct emissions are concerned.

When the temperature at the exit of the combustion-heated section is reduced keeping the temperature at the exit of the electrified section fixed at 1050 °C, hydrogen production is increased, as a lower flow rate of H₂-rich syngas is burned in the FTR furnace. Reducing such temperature to 850 °C (850–1050 case), leads to +13 % of hydrogen output and to +10% points of NG to hydrogen efficiency compared to the 950-950 case. The power to hydrogen efficiency (LHV based) is over 70 %, i.e. slightly higher than mid-term perspective efficiency of low temperature electrolysis systems [33]. CO₂ capture efficiency is not affected, but

specific emissions reduce as a consequence of the higher H₂ output. The CMRE index reduces to 100 kg_{CO2}/MWh in the 850–1050 case, indicating that in this region the impact of shifting the reformer energy input from H₂-based fuel combustion to electric heating would mainly increase H₂ output rather than reduce CO₂ emissions.

In all the cases, shifting the reforming heat source from H₂ fuel to electricity has a negative impact on the equivalent H₂ production efficiency and SPECCA. These indexes are defined by considering natural gas fired combined cycles with CO₂ capture as the reference technology for power generation. Using electricity in the reformer is accounted by these indexes like the NG-to-electricity-to-heat energy conversion path, which has to be avoided because highly inefficient.

A similar analysis can be conducted in power mode: reducing the reformer electric input involves a reduction of the carbon capture ratio by up to 5.2 % points, a doubling of the specific emissions (from 19.4 to 41.1 kg_{CO2}/MWh), an increase of the net electric efficiency by 2.44 % points and a decrease of SPECCA from 7.64 to 6.76 MJ/kg_{CO2}. Cases 900–1050 and 850–1050 are not simulated in power mode because the increase in the reformer electric consumption does not lead to any positive effect even in terms of CO₂ emission reduction.

Table 4 shows the performance of the ATR plant when operated in two different “hydrogen boost” (HB) electrified operating modes.

1. The first option (HB1) assumes to increase by 20 % the natural gas input at constant O₂ flow rate to the ATR. The additional heat required to achieve the target 1050 °C reformer outlet temperature is provided via electric heating. In this operating mode, the S/C ratio is kept constant and equal to 1.5.
2. The second option (HB2) considers a fixed natural gas input and 50 % reduction of the O₂ feed to the ATR, compensated by electric heating.

In both cases, the O/C ratio in the ATR reduces, causing a variation of syngas composition. In the HB2 case, the S/C ratio is increased from 1.5 to 1.8 to have an almost constant syngas flowrate (114.9 kg/s vs. 107.6 kg/s, -6.4 %) and make enough steam available in the reformer even if the oxygen flow rate is halved, resulting in a decrease of the steam generated by partial oxidation of the charge. Overall, the additional steam supplied offsets the lack in steam generation from methane oxidation. Adopting a steam to carbon ratio of 1.8 is also functional to keep stable the temperatures in the charge preheating and in the syngas

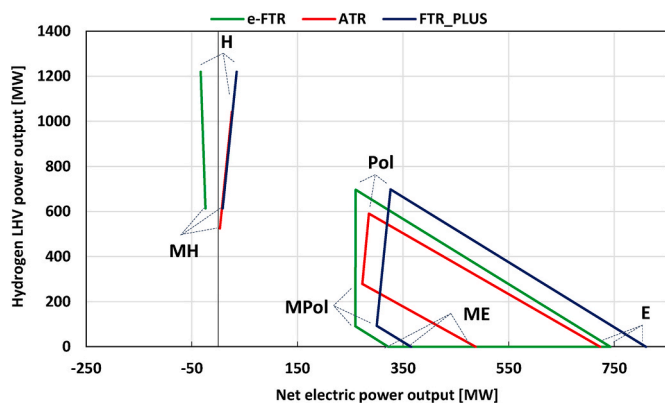


Fig. 3. Operating map of Powdrogen plants.

Table 5
Operating points of the flexible powdrogen plants.

Operating point	H	MHt	Pol	MPol	E	ME
Reformer load, %	100	50	100	50/70 ^a	100	50/70 ^a
Combined cycle status	off	off	min. load	min. load	full load	part load
Syngas final use	PSA	PSA	PSA/CC	PSA/CC	CC	CC

^a Assumed ATR minimum load = 70 %.

cooling sections (maximum difference 10 °C).

Both operating modes have the main effect of boosting hydrogen production. In both operating modes the combined cycle is off. H₂ production efficiency increases significantly: +4.3% points and +13.9 in HB1 and HB2, respectively. On the other hand, CCR decreases by 1.3–2.2% points, as the reduction in O/C ratio implies a reduction in CH₄ and CO conversion due to the lower H₂O content in the syngas and thus a lower steam to CO ratio in the WGS. Overall, the specific emissions slightly increase from 0.55 to 0.63 kgCO₂/kgH₂ and the SPECCA consequently worsens. The PTHE is high in both cases (87–90 %) meaning that electric heating is nearly fully converted into LHV chemical energy. Finally, following the increase in CO₂ specific emission, CMRE is slightly negative. Looking at the process parameters considered in this study, electrification of the ATR-based plants is essentially useful to increase the H₂ output.

4.2. Operating maps

The operating maps of the flexible powdrogen plants considered are shown in Fig. 3. The map shows the region of hydrogen and electricity outputs in which the e-FTR, FTR Plus and ATR plants can operate. Each vertex of the region represents one of the aforementioned operating points, also resumed in Table 5. On the left-hand side of the chart, the hydrogen and minimum hydrogen mode (labeled “H” and “MH”) are represented. The straight lines represent the points where the plant can tune the hydrogen export from maximum to minimum load (assumed equal to 50 % of the reformer capacity). Point “E” identifies the power mode, where steam reformer and combined cycle run at full load and no hydrogen is exported from the plant. In the polygeneration point (Pol), the reformer works at nominal condition, while the GT operates at minimum load (assumed 30 % of the GT power output at full load). In this operating point, 57 % of the nominal hydrogen output is exported. In the point “MPol” the reformer and the GT are both operated at minimum load. Provided that at the assumed minimum load of the chemical island the hydrogen produced exceeds the GT fuel demand at minimum load, a limited hydrogen output occurs in the “MPol” operating point. In the “ME” point, the chemical island operates at the minimum load, no hydrogen is exported and all the H₂-rich syngas is delivered to the GT that runs at part load (about 40–64 % of nominal load for FTR and ATR-based plants, respectively).

When the combined cycle is on, the ATR shows a lower range of hydrogen export for a given electric power output compared to FTR plants. This happens because the PSA operates at partial load (poly-generation mode) or is turned off (power mode) when synthesis gas is fed to the GT. The steam produced by the boiler powered by the PSA off-gases decreases. This causes a strong reduction (–40 %) of the steam flow rate to the steam turbine of the chemical island. To avoid operating this steam turbine below its minimum load, the chemical island turn-down ratio is limited to 70 % (instead of 50 % of the FTR cases), causing the chemical island minimum load line (i.e. the bottom red line connecting ME and MPol points) to be higher than the corresponding lines of the FTR cases. This drawback could be mitigated by sending steam generated in combined cycle to the turbine of the chemical island.

In case of electrified plants, the maps can be extended by considering the operating points achievable by tuning the reformer electrification, as shown in Fig. 4.

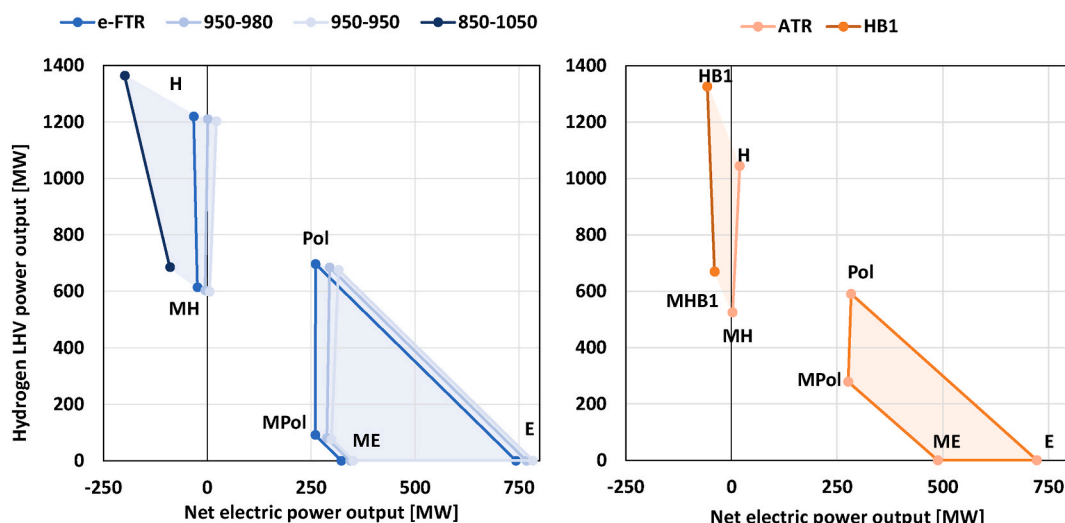


Fig. 4. Operating maps of the e-FTR (left) and ATR (right) electrified plants.

Table 6
Capital cost breakdown.

	FTR-Plus		e-FTR		ATR	
	[M€]	[%]	[M€]	[%]	[M€]	[%]
Air separation unit	–	–	–	–	163.9	13.8
Sulfur guard bed	2.3	0.2	2.2	0.2	2.0	0.2
Pre-reformer	5.1	0.4	5.0	0.4	4.0	0.3
Reformer	147.3	12.1	170.5	13.7	39.6	3.3
PSA off-gas boiler	–	–	–	–	16.3	1.4
Water Gas Shift reactors	20.1	1.6	19.7	1.6	13.4	1.1
Syngas coolers and cooling system	81.6	6.7	81.1	6.5	61.2	5.2
MDEA acid gas removal	48.9	4.0	49.8	4.0	34.8	2.9
CO ₂ compression and drying	92.7	7.6	94.4	7.6	77.7	6.5
PSA	34.0	2.8	34.0	2.7	31.0	2.6
Hydrogen compressor	15.4	1.3	15.4	1.2	12.5	1.1
Steam turbine and Generator	52.7	4.3	56.2	4.5	55.8	4.7
Feedwater and Miscellaneous	200.3	16.4	200.1	16.0	155.2	13.1
BOP Systems						
Combined cycle	519.9	42.6	519.9	41.6	519.9	43.8
Total plant cost M€	1220		1248		1187	
Specific TPC €/kW _{el}	1508		1680		1641	
Specific TPC €/kW _{H₂-exp}	1000		1023		1138	
Specific TPC (excl. CC cost) €/kW _{H₂-exp}	574		597		640	
Total capital requirements, M€	1586		1630		1542	

5. Economic analysis

5.1. Method

The economic analysis is performed according to the approach described in the IEAGHG report [34]. The total plant cost (TPC), defined as the installed cost of the plant including project contingencies, is calculated from [38,39], updated to 2020 with Chemical Engineering Plant Cost Index (CEPCI) and scaled to the proper size (the reader is addressed to SI for further information on cost estimation method). Given the size considered for the FTR-based plants, two parallel reforming trains were adopted [8]. Moreover, considering that data in [38] refer to a FTR with NG burners while this work considers a H₂-fired furnace, the capital cost of the section is increased by 14 %, based on estimates from [34]. Since no information is available in the open literature on existing electrified reforming section cost, this value was assumed to be 50 % of the cost of a fired tubular reforming section of equal thermal power. The lower expected cost is justified by the much more compact geometry as no furnace is needed [40] and by the lower cost of the shell materials, assuming internal resistive heating.³

The breakdown of the total capital cost is shown in Table 6. The Total capital requirement (TCR) is then calculated considering startup costs, spare part costs, owner's cost, interest during construction and working capital [34].

The cost of the syngas generation section is higher for FTR-Plus and e-FTR than for ATR due to higher materials costs and unfavorable economies of scale, also caused by the adoption of two reforming trains. On the other hand, the cost of the ASU is higher than the FTR cost, with a Capex share of 14 % of the ATR plant TPC. The Capex share of the combined cycle is about 40 % in all the configurations, which highlights the potential benefit achievable in retrofitting projects on existing

³ The assumption on the eSMR cost may be compared with the data in the IEAGHG study [7], where the specific Capex of an eSMR-based plant is estimated to be about 35 % less (676 vs. 1031 €/kW_{H₂,LHV}) than a conventional FTR plant with CO₂ capture of equal capacity (300 MW_{H₂,LHV}). Considering that the cost share of the main H₂ generation section including CO₂ separation is about 50 % of the total plant cost [34], 50 % of Capex reduction for the sole reforming section represents a more conservative assumption compared to the IEAGHG study.

Table 7
Fuel, water, power and CO₂ unit costs.

Variable costs	Unit	Cost
Natural gas	€/GJ _{LHV}	9
Raw water	€/m ³	0.20
Electricity selling/purchasing price	€/MWh	60
CO ₂ transport and storage cost	€/t _{CO₂ stored}	10
CO ₂ emission cost	€/t _{CO₂ emitted}	100

combined cycle power plants. Regarding the specific TPC for H₂ production (i.e. excluding the CC cost) the FTR plants present a lower cost (574–597 €/kW_{H₂, LHV}) compared to the ATR plant (640 €/kW_{H₂, LHV}). The ATR plant cost is in line with the aggregated cost of the IEAGHG study (966 €/kW_{H₂, LHV} with capacity of 300 MW_{H₂} [7]), applying an overall scale factor of 0.7. The lower cost of the FTR-based system in this work compared to the IEAGHG study (1031 €/kW_{H₂, LHV} with capacity of 300 MW_{H₂} [7]) is to be attributed partly to the larger size and partly to the absence of a post-combustion flue gas capture section [38].⁴

The fixed operating costs include annual maintenance cost (1.5 % of TPC), direct labour cost (60'000 € with 150 employees), administrative and support labor cost (30 % of the direct labour plus the maintenance labour cost assumed as 40 % of the overall maintenance cost).

Table 7 shows the fuel, water, power and CO₂ unit costs. Table 8 shows the assumed financial parameters.

The study is based on Discounted Cash Flow analysis. Depreciation was not considered, since the results are reported on the Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) basis.

6. Results

The Cost of Hydrogen (COH) and the Cost of Electricity (COE) were evaluated as the break-even selling prices for the two products. The first index was evaluated assuming that the plant runs in hydrogen mode throughout the year, while the second one considers that the plant always runs in power mode. The cost breakdown is shown in Fig. 5 for FTR-Plus, e-FTR and ATR cases. In all cases, the highest share is due to natural gas consumption, followed by Capex. The e-FTR plant shows a slightly higher COH (2.30 €/kg_{H₂}), while the ATR has the lowest COE (100.8 €/MWh_{el}). The e-FTR features the highest COE (111.0 €/MWh_{el}), caused by the intrinsic inefficiency of self-consuming electricity to heat the reformer when electricity is the plant product. The COH can be compared with data from IEAGHG [7], where values of 2.61 and 2.62 €/kg_{H₂} are reported for FTR and ATR, respectively. A significant difference (more than 0.4 €/kg_{H₂} difference) is due to the lower CO₂ T&S cost assumed in this study (10 €/t_{CO₂}, representative of a low-cost and large-scale developed infrastructure [41–43] vs. 55 €/t_{CO₂}). Capital expenditures are greater in this study (0.46 vs. 0.37 €/kg_{H₂} for the FTR in [7]) due to the presence of the CC, which outbalances the positive impact of the larger plant scale. Finally, the different NG price assumed (9 vs. 6 €/GJ) results in higher feedstocks cost compared to the IEAGHG study (1.52 €/kg_{H₂} vs. 1.30 €/kg_{H₂} for FTR and 1.47 €/kg_{H₂} vs. 1.16 €/kg_{H₂} for ATR).

As for power generation cost, the computed COE for the ATR case is higher than those reported by other studies [10,11] for NGCC with post-combustion and pre-combustion capture (69 €/MWh_{el} and 70–74 €/MWh_{el}, respectively). This is mostly due to the higher NG cost assumed in this study (9 vs. 6.5 €/GJ_{NG, LHV}). With a 6.5 €/GJ_{NG, LHV} cost, the COE would reduce by about 17.7 €/MWh_{el}, reaching a value of around 83 €/MWh_{el}. The remaining difference is due to: (i) the presence

⁴ The IEAGHG report does not give a breakdown of the Capex, while the NETL report [38] taken as a reference for cost estimation in this paper shows a percentage weight of 35 % of the total Capex cost associated to the post-combustion flue gas capture section.

Table 8
Financial assumptions.

Financial input parameters	
Currency	€ 2020
Construction period	3 years
Capital expenditure curve	20/45/35 % (1st,2nd,3rd year)
Interest during construction	8 %
Plant lifetime	25 years
Capacity factor (Hydrogen and Power mode)	86 % (7500 equivalent hours)
Finance	100 % Financial leverage
Discount rate	8 %
Inflation rate	2 %
Owner's cost	7 % of TPC

of the capital expensive ASU for the ATR-based system (ii) the lower net electric efficiency, (iii) the higher specific cost for the combined cycle assumed as 675 €/kW_{el} in this study (vs. 630 in €/kW_{el} [11]) and (iv) other different assumptions (e.g. different discount rate).

Fig. 6 shows the sensitivity analysis performed on the COE and COH for the three Powdrogen plants against two reference FTR and CC plants without CO₂ capture. Given the high CCR achieved, sensitivity to the CO₂ emission cost is limited. With respect to unabated plants, the breakeven carbon tax (i.e. the cost of CO₂ avoided) is around 74–83 €/t_{CO2} for hydrogen production and around 88–120 €/t_{CO2} for power production. In hydrogen mode, a sensitivity on the electricity price has been carried out, showing the opposite trend between the e-

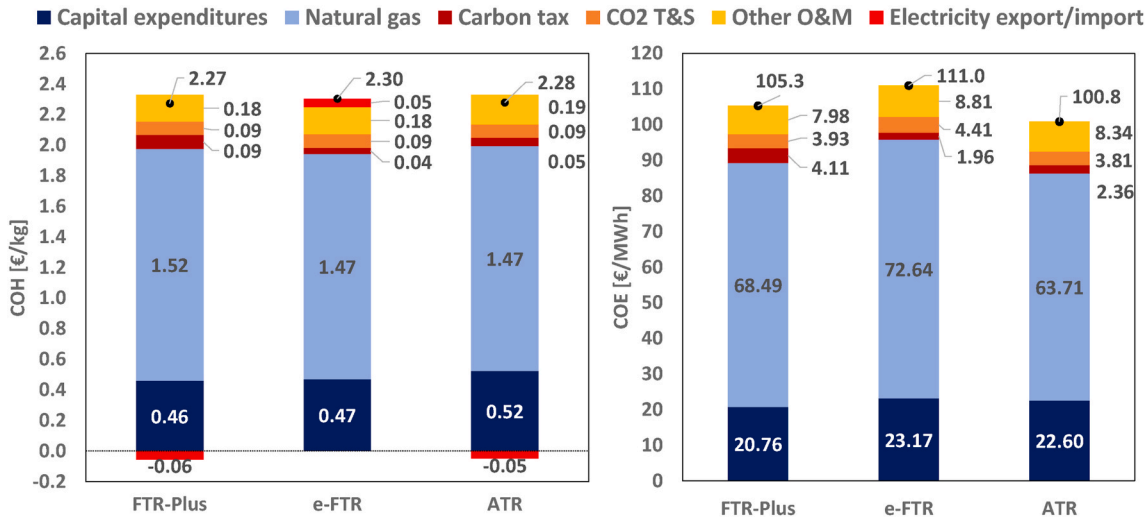


Fig. 5. COH (left) and COE (right) breakdown for FTR-Plus, e-FTR and ATR plant.

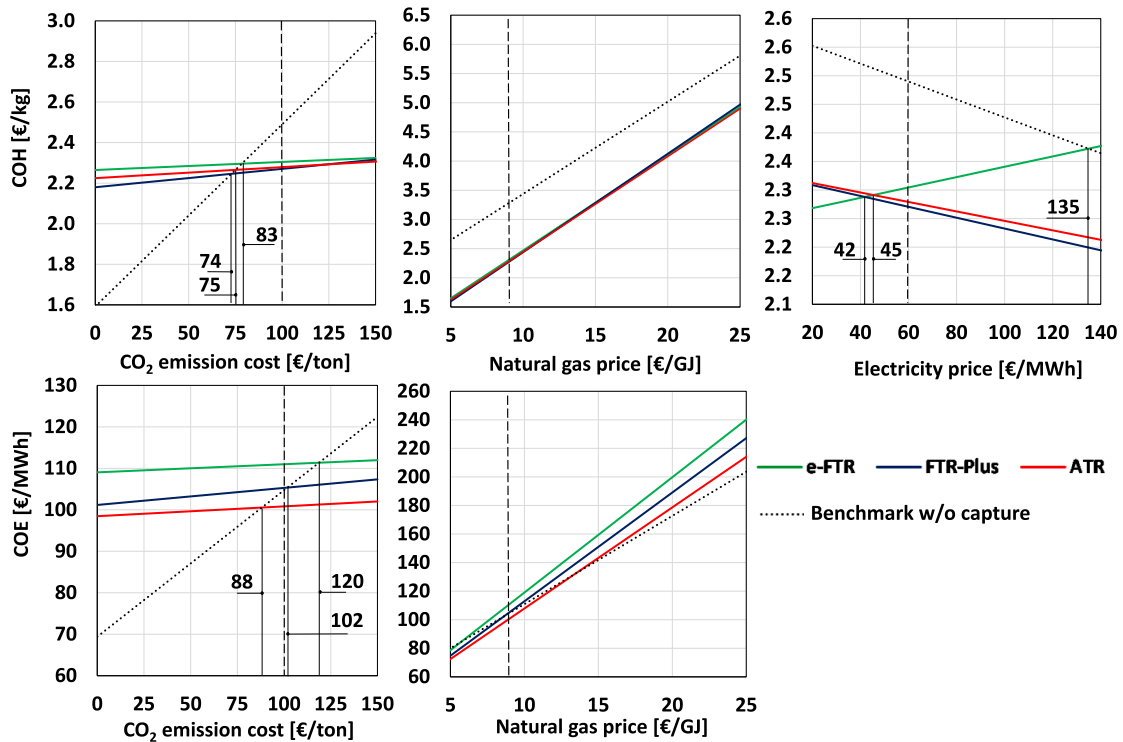


Fig. 6. Sensitivity analyses of COH (top) and COE (bottom) for FTR-Plus, e-FTR and ATR plants and of benchmark FTR and CC plants without CO₂ capture. Vertical dashed lines represent the assumed baseline value for the considered variable.

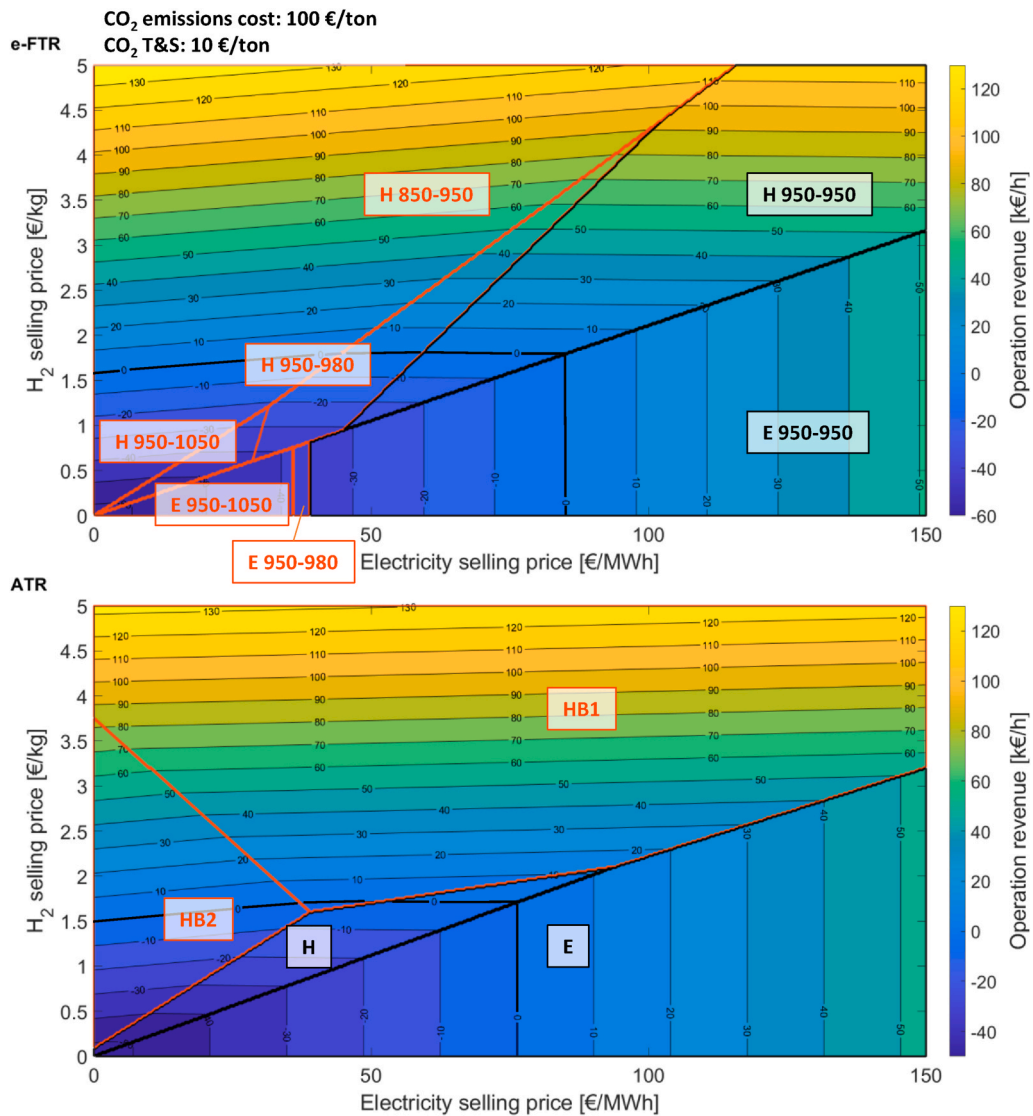


Fig. 7. Operational profits for e-FTR and ATR as a function of electricity price.

FTR plant (power importer, becoming the lowest cost option for electricity price below 40 €/MWh) and the other plants (power exporters).

Fig. 7 shows the maps of the optimal operating regions based on gross profit, for the flexible e-FTR and ATR plants as a function of electricity and H₂ selling prices, for the imposed CO₂ emissions costs of 100 €/ton_{CO2}. For every couple of electricity and hydrogen selling prices, the gross profit for each operating mode is assessed.

The graph also shows the iso-profit lines (in k€/h). For negative profits, the plant should be shut down, unless shut-down and start-up costs are higher than the cost of operating with negative profit for a certain time period. With a CO₂ emission cost of 100 €/t_{CO2} (but the same considerations are valid for higher carbon tax prices given the small sensitivity to carbon emission costs), it is possible to identify four profitable operating modes for the e-FTR case. With high electricity price and low hydrogen price, the plant operates in power mode, with electric heating off (E 950-950). Oppositely, with high H₂ selling price and low electricity price, the plant operates in hydrogen mode, with high electrification (H 850-950). In the intermediate region of high selling prices of both electricity and hydrogen, the flexible Powdrogen plant operates in hydrogen mode, but with reduced electric heating (H 950-980, i.e. neutral electricity balance) or no electric heating (H 950-950, i.e. moderate power export). With low electricity and hydrogen selling prices, the plant would operate with negative profits (or would be

switched off). In this region, the optimal operating modes correspond to maximum reforming firing (950 °C FTR exit temperature) and post-electrification on, to reduce CO₂ emissions, as the benefit of lower cost associated to CO₂ emission justifies the increased electric consumption. The optimal operating regions of the ATR plant are similar to the FTR plant. The power mode (E) operating region is more profitable with respect to the e-FTR at same electricity price due to the higher net electric efficiency. At low electricity selling price, the plant operates in HB2 mode, earning profits for H₂ prices higher than 1.5 €/kg. The non-electrified hydrogen mode (H) operating region is narrow and comprised between intermediate hydrogen and electricity selling prices of 1.7 €/kg (with electricity selling price 55–78 €/MWh) and 2.1 €/kg (with electricity selling prices around 90 €/MWh). If hydrogen price increases, the most profitable operating mode is HB1.

Finally, an economic analysis was carried out combining the performance of the flexible Powdrogen plants with electricity price duration curves (Fig. 8). The electricity price curves refer to the Danish electricity market, selected because it features high penetration of variable renewables. Different price scenarios are considered: the real one referring to year 2019 retrieved from Nord Pool [44], and future projections assessed by the Danish ENTSO-E (Energinet) and described by Butera et al. [45]. The analysis is conducted on the “2035-B” and “2040” cases, considered representative of an electricity market strongly

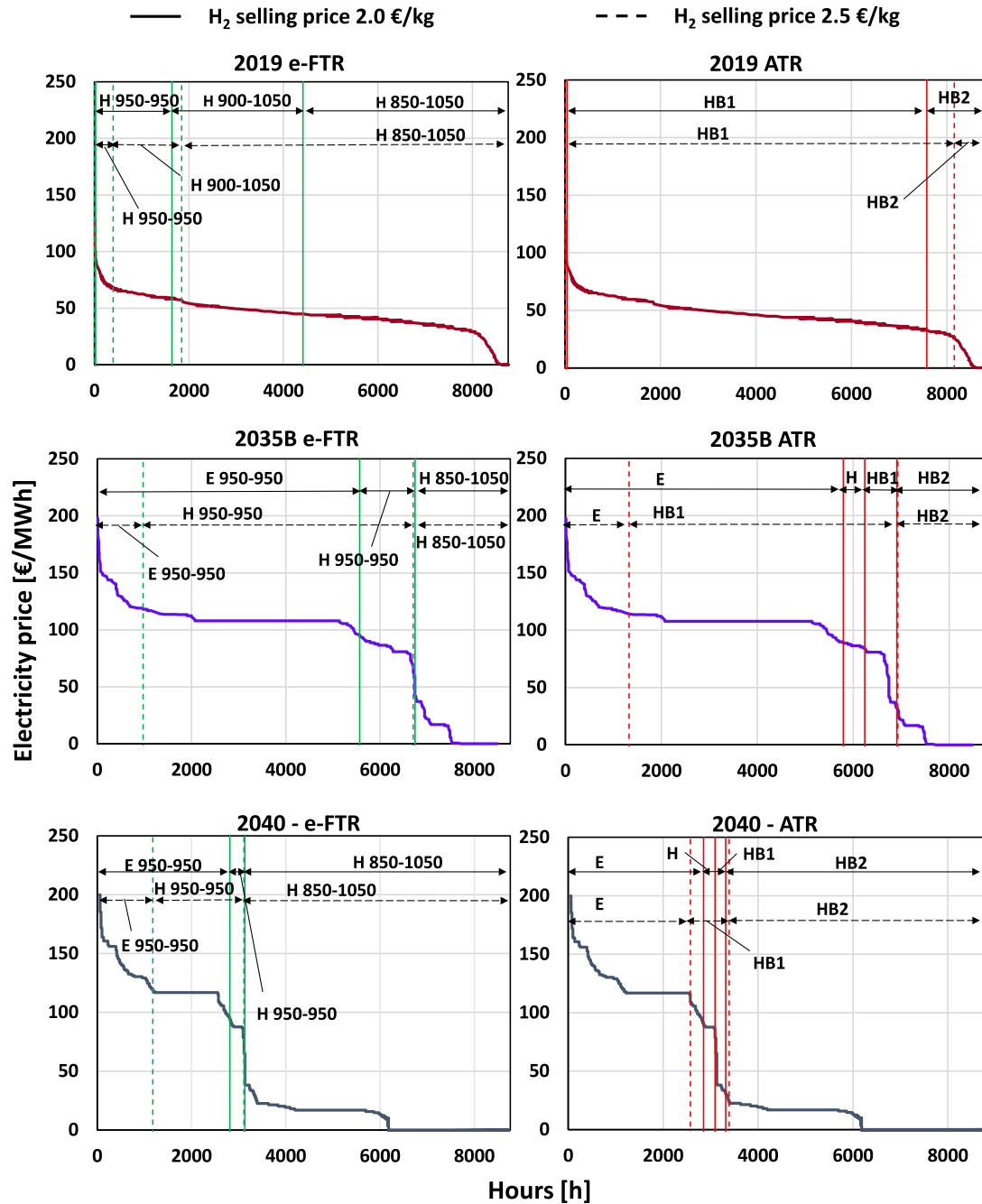


Fig. 8. Electricity price duration curves in “2019”, “2035-B” and “2040” scenarios for flexible e-FTR (left) and ATR (right) Powdrogen plants, with details on operating modes. Areas comprised between solid vertical lines refer to hydrogen selling price of 2 €/kg. Areas comprised between dashed lines refer to hydrogen selling price of 2.5 €/kg.

penetrated by renewable energy sources (mainly wind power). According to these scenarios, the average yearly electricity price is expected to increase in the future (85.1 €/MWh in 2035-B scenario and 50.7 €/MWh in the 2040 scenario, vs. 45.1 €/MWh in 2019). The number of hours with zero price increases (1240 h and 2580 h, vs. 140 h in 2019). The average price of the 2000 highest-cost hours increases (132.7 €/MWh in 2035-B scenario and 123.4 €/MWh in the 2040 scenario vs. 63.9 €/MWh in 2019). Two hydrogen selling prices have been considered, namely 2 and 2.5 €/kg and a fixed carbon tax of 100 €/t_{CO2}.

For case “2019” and for the two hydrogen prices assumed, both plants never operate in power production mode due to the absence of high electricity prices periods. The low yearly average electricity price of

45.1 €/MWh allows the plant to operate mostly in electrified hydrogen mode: the e-FTR runs 18.5 % of the time in hydrogen mode (H 950-950), and progressively switches the electric heater on, working 31.7 % of the time in H 950–1050 and 49.6 % of the time in H 850–1050 modes. If the hydrogen price increases to 2.5 €/kg, the profits connected to the additional hydrogen produced are such that the plant operates most of the time (8370 h, i.e. when the electricity price is lower than 68 €/MWh) with the electric heating activated. The ATR operates almost entirely in HB1 mode (7540 h, 86.3 % of the time) and switches to HB2 (1180 h, 13.5 % of the time) when the electricity price is lower than 32 €/MWh. When the hydrogen selling price increases to 2.5 €/kg, the HB1-HB2 breakeven price drops to 24 €/MWh, with small effects on the time distribution of the

different operating modes.

In the “2035-B” scenario, with hydrogen selling price of 2 €/kg, the e-FTR Powdrogen plant operates mainly in Power mode (E 950–950), for about 5570 h, i.e. when the electricity price is above 95 €/MWh. It works in hydrogen mode with no reformer electrification (H 950–950) for about 1170 h and turns the electric heating on (H 850–1050) when electricity price decreases below 58 €/MWh, working in this condition for the remaining 2020 h. For a hydrogen selling price of 2.5 €/kg (dashed lines), the operation time in Power mode decreases significantly (970 h, i.e. when electricity price is higher than 118 €/MWh), while time in hydrogen mode increases significantly (5730 h). The electrified reformer is activated for electricity price below 64 €/MWh. Due to the steepness of the price curve in that price range, the operating hours in H 850–1050 are very similar to the low hydrogen selling price case (2020 h).

The ATR-based Powdrogen plant with 2 €/kg hydrogen selling price operates predominantly in Power mode (E, 5790 h, i.e. 66.1 % of the time). For electricity price below 89 €/MWh, the plant switches to hydrogen mode (H). When electricity price reduces below 82 €/MWh, electric heating is switched on and the plant operates in Hydrogen boost mode (21.1 % in HB2 and 7.6 % in HB1). Despite having a lower PtHE (87.1 % vs. 90.2 % of HB1) and a lower hydrogen production, the HB2 operating mode is preferable at lower electricity prices due to the lower natural gas consumption. When hydrogen selling price increases to 2.5 €/kg, the operating time in Power mode decreases significantly (1320 h, i.e. 15.1 % of the time), as this operating mode becomes competitive for electricity price above 114 €/MWh. Below this price, it becomes economically beneficial to switch to electrified hydrogen mode HB1 (5600 h, 64.0 % of the time), switching to HB2 mode for the remaining 1830 h (20.9 % of the time) with electricity price below 24 €/MWh.

In the “2040” scenario, the increase of low electricity price hours leads to a significant increase of the operating time in electrified hydrogen mode (H 850–1050 for FTR plant and HB2 for the ATR-based plant). Compared to the 2035 scenario, the operating time in power mode reduces for hydrogen selling price of 2 €/kg and slightly increases for hydrogen price of 2.5 €/kg. This different trend is due to the price curve shape in the high electricity price region. In all the cases, due to the reduced size of the plateau with intermediate electricity prices in the 100–120 €/MWh range, the number of operating hours in non-electrified hydrogen mode reduces significantly in the 2040 scenario.

Starting from the distribution of the operating modes in the different scenarios, it is possible to evaluate the revenues for the typical reference year and thus the Net Present Value (NPV) alongside with the IRR, as shown in Table 9. The ability to produce and sell electricity or hydrogen depending on their price allows the plants to achieve a positive NPV at

the end of lifetime in all cases considered, exception made for year 2019 in the lower hydrogen price scenario.

7. Limits of the study

The following notations allow the reader to better understand the technical and economic context within which this study was developed:

- The technology of hybrid and flexibly operated reformers requires experimental validation. Also, the operating range (e.g. 20 % increase gas throughput achievable by electrification) is an arbitrary assumption that needs experimental validation on specific reformer design.
- A high degree of uncertainty is related to the estimated Capex of tubular reformers with increased outlet temperature and for electrified reformers. No solid literature reference is available to support the assumed costs.
- The economic analysis of the different scenarios assumes that the chemical island of the Powdrogen plants always operates at full load and that the electricity and hydrogen produced can be sold on the market. This involves the existence of a hydrogen market with proper infrastructure and storage facilities size, capable to receive all the H₂ produced by the plant, independently of the hydrogen supply profile.
- The economic analysis has been carried out with reference to year 2020, before the 2022–2023 high inflation period. This may involve a general underestimation of Capex values.
- The economic analysis is based on the electricity price curves of the day-ahead market and does not take into account additional revenues that may arise from operations on more profitable markets, such as the intra-day and balancing markets.
- For sake of simplicity, electricity from renewables has been considered CO₂-free. On a LCA basis, it entails a burden of CO₂ emissions depending on the location and features of the power generation mix and on the supply chain of the technologies (e.g., PV, wind). Literature reports scattered values for the LCA of green electricity and recent work has been dedicated to updating the emission databases for e.g. PV based green electricity and hydrogen production [46,47].

8. Conclusions

This study assessed the technical and economic performance of “Powdrogen” plants for low-carbon hydrogen and electricity production from natural gas, designed to achieve carbon capture ratios of 90–95 %, by pre-combustion CO₂ capture techniques only.

The study showed that:

Table 9

Results of the economic analysis of flexible e-FTR and ATR Powdrogen plants for scenarios 2019, 2035B and 2040.

Average electricity price, €/MWh	2019		2035 B		2040	
	e-FTR	ATR	e-FTR	ATR	e-FTR	ATR
	45.1		85.0		50.5	
Hydrogen selling price = 2 €/kg_{H2}						
Power/Hydrogen/Electrified hydrogen mode time share, %	0.3/18.5/81.3	0.5/0.0/99.5	63.6/13.4/23.1	66.1/5.1/28.8	32.1/3.6/64.3	32.6/2.8/64.7
Electricity produced, GWh/y	19.63	30.06	4363	4193	2205	2065
Electricity consumed, GWh/y	−1118	−675.0	−402.2	−420.3	−402.2	−1136
Net electricity production, GWh/y	−1098	−644.9	3961	3773	1803	929
Hydrogen production, GWh/y	11469	11483	4182	3660	8078	7317
Net present value, M€	−607.3	−391.8	351.4	634.6	541.5	705.7
Internal rate of return, %	4.00	5.49	9.87	11.3	10.8	11.7
Hydrogen selling price = 2.5 €/kg_{H2}						
Power/Hydrogen/Electrified hydrogen modetime share, %	0.1/4.5/95.5	0.1/0.0/99.9	11.1/65.4/23.5	15.1/0.0/84.9	13.4/22.1/64.3	29.4/0.0/70.6
Electricity produced, GWh/y	3.83	3.18	767.1	955.6	923.7	1858
Electricity consumed, GWh/y	−1509	−591.1	−405.6	−698.8	−1123	−1154
Net electricity production, GWh/y	−1505	−587.9	361.5	256.6	−199.1	704.1
Hydrogen production, GWh/y	11791	11583	9757	9727	10065	7763
Net present value, M€	1358	1556	1441	1543	1956	1982
Internal rate of return, %	14.3	15.3	14.6	15.2	16.6	16.8

- Powdrogen plants based on fired tubular reformers (FTR) can achieve capture rates higher than 90 % by pre-combustion CO₂ separation only, if a combination of technologies is adopted: high reformer exit temperature (950 °C), H₂-fired furnace, low exit temperature from the LT-WGS reactor and high efficiency MDEA-based CO₂ separation unit. Post-electrification of the reformer would allow reaching 95 % CO₂ capture efficiency, with an e-FTR exit temperature of 1050 °C.
- Powdrogen plants based on ATR can approach 95 % capture efficiency by combining a conventional reformer with a low exit temperature LT-WGS reactor and a high efficiency CO₂ separation process.
- Hybridization of reformer process by partial electrification offers the opportunity of operational flexibility in both FTR and ATR-based Powdrogen plants. In FTR-based plants, post-electrification may be adopted to reduce CO₂ emissions and to increase H₂ output, with a power-to-hydrogen conversion efficiency of up to around 72 %. Partial electrification of ATR allows increasing the H₂ output either by reducing O₂ input or by increasing the natural gas input, with power-to-hydrogen conversion efficiency of 87–90 %.
- Compared to advanced non-electrified FTR-based Powdrogen plant (i.e. FTR-Plus case), ATR-based Powdrogen plants have similar natural gas-to-hydrogen production efficiency when operated in hydrogen mode (73–74 %), higher electric efficiency in power mode (50.9 % vs. 47.4 %), higher CO₂ capture rate (94.2 % vs. 90.6 %) and lower SPECCA. From the economic perspective, similar cost of hydrogen (~2.3 €/kg) and cost of electricity (100.8 vs. 111.0 €/MWh) have been estimated for ATR and FTR-based processes, with superior economic indicators for the ATR-based plants for the considered plant size.
- The relative selling price of hydrogen and electricity and, by a lower extent of the cost of CO₂ emission, determines the optimal operating mode of a flexible Powdrogen plant. The integration in the high-renewable Danish electric grid of year 2019 (taken as example of a future evolution of the grid mix representative also of other EU countries) and of future 2035 and 2040 scenarios from the literature have been assessed. Powdrogen plants would operate in power mode, hydrogen mode and electrified hydrogen mode for variable periods of time, depending on the electricity price curve shape. In future 2035–2040 scenarios, featuring higher price variance (i.e. long periods with high price electricity over 100 €/MWh as well as long periods with low price below 30 €/MWh), Powdrogen plants would tend to operate predominantly in power mode (selling electricity at high price) and in electrified hydrogen mode (increasing H₂ output by consuming low-price electricity).
- With hydrogen selling price of 2 €/kg and 2.5 €/kg, the economic analysis results in negative NPV in the 2019 electricity price scenario and positive NPV in the future scenarios, with internal rate of returns of 10–11 % and 14–17 %.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.ijhydene.2023.10.159>.

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