Economic assessments of gas switching technology

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Summary

In the GaSTech project, UBB was investigated two Gas Switching Technologies were chosen for techno-economic assessments: Gas Switching Reforming (GSR) and Gas Switching Combustion (GSC). The economic assessments for GSR/GSC plant were done base on mass and energy balance received from project's partners: NTNU, SINTEF and UPM.

Two primary GSR-based plants were designed and thoroughly assessed: the GSR-CC plant for power production and the GSR-H2 plant for hydrogen production. The GSR-CC power plant is compared to two benchmarks: an NGCC power plant with no CO_2 capture and the same NGCC plant with post-combustion MEA CO_2 capture. A standard baseload economic assessment at a capacity factor of 85% revealed that the two CO_2 capture plants show similar results (around 74 €/MWh) , with the LCOE in the case of the GSR plant being slightly higher. However, GSR achieved an identical COCA (60.86 €/tone) to the MEA plant because of its higher CO_2 avoidance rate. However, a more realistic mid-load scenario at a capacity factor of 45% reversed this outcome. When assuming an average electricity price of €60/MWh and a €1.35/kg hydrogen price, the GSR plant outperformed the MEA benchmark, showing an annualized investment return that is about 5 %-points higher. This advantage increased with higher CO_2 prices due to the very high CO_2 avoidance of the GSR plant.

Three high efficiency CCS concepts based on integrated gasification combined cycles (IGCC) was compared to standard IGCC power plants without and with CO_2 capture: 1) gas switching combustion (GSC), 2) GSC with added natural gas firing (GSC-AF) to increase the turbine inlet temperature, and 3) oxygen production pre-combustion (OPPC) that replaces the air separation unit (ASU) with more efficient gas switching oxygen production (GSOP) reactors. Relative to a supercritical pulverized coal benchmark, these options returned CO_2 avoidance costs of 38.7, 24.3 and 42.8 €/ton (including CO_2 transport and storage), respectively. Despite the higher fuel cost and emissions associated with added natural gas firing, the GSC-AF configuration therefore emerged as the most promising solution.

List of abbreviations

ACF	Annual cash flow
ASU	Air separation unit
CCS	CO_2 capture and storage
CEPCI	Chemical engineering plant cost index
CLC	Chemical looping combustion
COCA	Cost of CO_2 avoidance
COT	Combustor inlet temperature
EPCC	Engineering, procurement and construction cost
GS	Gas Switching
GSC	Gas switching combustion
GSC-AF	GSC power plant with added natural gas firing
GSOP	Gas switching oxygen production
GSR	Gas switching reforming
HRSG	Heat recovery steam generator
IGCC	Integrated gasification combined cycle
LCOE	Levelized cost of electricity
LHV	Lower heating value
MEA	Monoethanolamine
NG	Natural gas
NGCC	Natural gas combined cycle
NPV	Net present value
O&M	Operations and maintenance
OC	Oxygen carrier
OPPC	Oxygen production pre-combustion power plant
PS	Process contingency
PSA	Pressure swing adsorption
PT	Project contingency
SMR	steam methane reforming
S/C	Steam to carbon
TIC	Total install cost
TIT	Turbine inlet temperature
TOC	Total overnight cost
TOT	Turbine outlet temperature
TPC	Total plant cost
U	Overall heat transfer coefficient
WGS	Water-gas shift

1 Introduction

The global power sector faces a key challenge in the 21st century: achieving rapid emissions reductions despite strong demand growth[1]. The target set at the Paris Climate Agreement [2] is to limit global average temperature increase to "well below 2 °C" by the end of the century. The models presented by the Intergovernmental Panel on Climate Change (IPCC) requires zero or even negative emissions from the power sector to comply with the 2 °C target [3]. Five main channels for greenhouse gas reduction are generally considered in global energy analyses (e.g. IEA [1]): energy efficiency, renewable energy, nuclear power, fuel switching, and CO_2 capture and storage (CCS).

Among these pathways, CCS is arguably the most promising for drastic emissions reduction for three main reasons: 1) CCS retrofits can achieve emissions reductions from plants that have already been built, 2) CCS can be applied to sectors other than electricity such as direct industrial emissions or clean fuels, and 3) CCS can achieve negative emissions through bio-CCS or direct air capture. Unfortunately, the deployment of CCS is lagging far behind the trajectory required by the Paris Climate Accord [4], mostly because of economic and political challenges. However, the added cost of CCS can be minimized through more advanced CO_2 capture processes. Lowering the energy demand for the CO_2 separation process presents one promising pathway towards lower operating and capital costs of CCS plants.

Chemical looping combustion (CLC) offers a way to substantially reduce this energy penalty, leading to considerable reductions in the CO_2 avoidance cost [5]. The low energy penalty of CLC relative to other CO_2 capture technologies has led to extensions of the chemical looping principle to other CO_2 and energy intensive processes such as reforming [6], air separation [7] and hydrogen production through the steam-iron process [8]. One important challenge with CLC is scale-up under pressurized conditions. To overcome this challenge, novel reactor concepts were proposed which can improve the scalability of pressurized chemical looping technology. Examples include the rotating reactor [9], packed bed CLC [10] and the gas switching technology (GST) investigated in this proposal [11]. In gas switching technology, the solid oxygen carrier is kept in one reactor and alternately oxidized with air and reduced by the fuel. Such a simple standalone bubbling fluidized bed reactor promises to be substantially easier to scale up and pressurize than the interconnected dual circulating fluidized bed CLC configuration. To maintain continuous operation, a coordinated cluster of several dynamically operated gas switching reactors can be used in the same plant [12].

The gas switching technology was first applied to combustion, where it was experimentally demonstrated in lab scale reactors under atmospheric and pressurized conditions [13-15]. This concept is also being extended to methane reforming where atmospheric demonstration of the GSR was completed successfully [16]. A gas switching variant of this principle, called gas switching oxygen production (GSOP), was recently proposed to displace the ASU in a pre-combustion CO_2 capture IGCC configuration [17]. This oxygen production pre-combustion (OPPC) plant could achieve a net efficiency over 45%, albeit with a somewhat lower CO_2 avoidance of around 80%. Another benefit is that the relatively low operating temperature of the GSOP reactors will circumvent possible technical challenges with downstream valves and filters after GSC reactors.

The results presented in the current report reveal the effects of these large efficiency gains from an economic point of view. For the GSC configuration with added natural gas firing, greater efficiency will decrease costs related to fuel and CO_2 transport and storage. Extracting more useful work from the produced syngas will also substantially reduce the levelized costs of the expensive gasification train (coal and ash handing, gasifier, air separation unit and gas clean-up). On the other hand, the use of natural gas for added firing will increase fuel costs and reduce CO_2 avoidance. For the OPPC configuration, cost decreases can also be expected due to the high efficiency, but the relatively diluted syngas produced by this configuration will substantially increase the cost of the gasifier and gas clean-up units.

To quantify these trade-offs, this report presents a bottom-up economic assessment of GSC-IGCC plants with and without added natural gas firing and the OPPC plant. These results are compared to several benchmarks, including IGCC plants with and without conventional pre-combustion CO_2 capture and a super-critical pulverized coal plant without CO_2 capture. Performance will be quantified in terms of levelized cost of electricity and CO_2 avoidance cost. In addition, the sensitivity of these performance measures to several important parameters will be identified. Finally, the economic performance of these advanced IGCC plants will be benchmarked against other clean energy technologies including nuclear, wind and solar PV in a future energy system with high CO_2 prices.

Based on the above discussions and the fact that variable renewable energy (VRE) will play a central role in the decarbonization of the global economy the report also presents another promising alternative: the gas switching reforming combined cycle (GSR-CC) plant. GSR-CC is a near-zero emission natural gas-fired CO_2 capture plant that maximizes capital utilization and delivers a steady-state CO_2 stream, even when producing intermittent power to balance VRE. In contrast to the calcium looping option, GSR-CC employs clean hydrogen as the energy storage mechanism. Hydrogen can be stored over much longer timescales and can also be employed to decarbonize sectors other than power production. The report also quantifies the economic advantages of the GSR-CC plant when operating at a reduced capacity factor to balance VRE. This novel solution will be benchmarked against conventional post-combustion CO_2 capture technology to objectively quantify its potential. This quantitative analysis will be complemented by qualitative discussions of the operational flexibility and risk profile of the GSR-CC plant, followed by recommendations for future work.

2 Methodology

In the GaSTech project, two Gas Switching Technologies were chosen for techno-economic assessments: Gas Switching Reforming and Gas Switching Combustion. The economic assessments for GSR/GSC plant were done base on mass and energy balance received from project's partners: NTNU, SINTEF and UPM.

Two primary GSR-based plants were designed and thoroughly assessed: the GSR-CC plant for power production and the GSR-H2 plant for hydrogen production. The GSR-CC power plant is compared to two benchmarks: an NGCC power plant with no CO_2 capture and the same NGCC plant with post-combustion MEA CO_2 capture.

Three high efficiency CCS concepts based on integrated gasification combined cycles (IGCC) was compared to standard IGCC power plants without and with CO_2 capture: 1) gas switching combustion (GSC), 2) GSC with added natural gas firing (GSC-AF) to increase the turbine inlet temperature, and 3) oxygen production pre-combustion (OPPC) that replaces the air separation unit (ASU) with more efficient gas switching oxygen production (GSOP) reactors. The results are also compared to a supercritical pulverized coal power plant [18] as this technology is widely deployed in the power sector today.

The economic assessment methodology applied for the gas switching technologies is presented in the following chapters: 2.1) the design and cost assessment of gas switching reactors and heat exchangers, 2.2) capital cost assumptions, 2.3) operating and maintenance cost assumptions.

2.1 Reactor and heat exchanger design and cost assessment

2.1.1 Gas switching reforming

In order to have the desired fluidization velocity of 0.5 m/s, a total cross-sectional area across all the reactors of 244 m^2 is required to process the total volume flow rate of gas that passes through the GSR unit. According to the correlations of Bi and Grace [19], this fluidization velocity is well within the bubbling fluidization regime when typical Geldart B particles with a diameter of 150 µm are used. Using the cost methodology described below, it was determined that a cluster of 64 reactors having a diameter of 2.2 m and a height of 4.4 m would be the option with the lowest cost for the reforming unit. The NiO oxygen carrier selected for this work is highly reactive and achieved equilibrium conversion even in a laboratory scale reactor [16]. It can therefore be reasonably assumed that the selected reactor height will result in good reactor performance.

The GSR reactors operate at a pressure of 18 bar and a maximum temperature of 1100 °C. To facilitate the high temperature and pressure, the reactor wall structure presented in Figure 1 was proposed. The layers are as follows (from left to right): a high temperature and corrosion-resistant Ni-alloy on the inside to withstand the abrasion of the fluidized bed, 0.73 m insulation in the middle to minimize the heat loss, and a steel shell on the outside to carry the pressure load. The thickness of the insulating material was calculated using Fourier's law assuming 1100 °C inner and 60 °C outer wall temperatures. The ambient temperature was assumed at 25 °C.

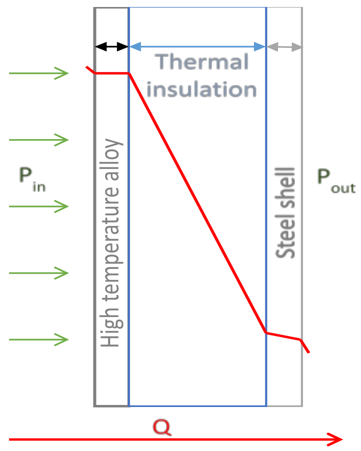


Figure 1: Reactor wall structure and temperature profile

The GSR reactor cost estimation was performed according to the cost functions presented in Turton et al. [20]. The reactor was assumed to be constructed of two process vessels: the inner reactor vessel was assumed to be constructed from a more expensive Ni-alloy material that does not carry any of the pressure load, while the outer pressure shell was constructed from standard carbon steel and carried the entire pressure load. The cost of the inner reactor vessel was doubled to account for fluidized bed elements like the gas distributor and inlet for oxygen carrier make-up.

Each GSR reactor has a high temperature valve both at the inlet and the outlet. The cost of these valves was estimated according to Hamers et al. [21]. In addition, the cost of the initial load of oxygen carrier material was added to the capital cost of the reactor. The NiO oxygen carrier cost was assumed to be 12.5€/kg [22]. Each component of the reactor cost was updated to the year 2018 using the CEPCI index and converted to Euros using a conversion factor of 1.2 $/€. The pressure shell and the reactor vessel are the two most important contributors to the total cost. As mentioned later, a process contingency of 30% is added to this reactor cost estimation in the economic assessment to account for the uncertainties arising from the low level of development of GSR technology.

2.1.2 Gas switching combustion

The methodology applied in the case of GSC process is similar to the calculations in the gas-switching reforming reactor design [23] when the reactor cost was estimated by the wall structure described by Turton [20] and by the fluidization velocity. The differences in this case are the following: the fluidization velocity in the reactor is 1 m/s and the total cross-sectional area of the reactors is 383 m^2. The reactors in the cluster are 2.2 m in diameter 4.4 m in height and the cost of the high temperature valves are estimated according to Hamers et al. [21] and are included at both inlet and outlet. The cost of the initial load of OC is added to capital cost of the reactor according to the reactor volume. Costs are updated for the year 2018 using the Chemical Engineering Plant Cost Index (CEPCI) [24].

2.1.3 Cost estimation methodology for the heat exchangers

The cost estimation methodology for the heat exchangers involved similar steps for both GSR and GSC technologies. Based on the literature and considering the particularities of the process, shell-and-tube heat exchangers were selected in order to ensure the best technical and economic performance. For the construction of the heat exchangers the selected material was stainless steel for both shell and tube part of the equipment, which involves a material factor of 2.9 and we also considered a pressure factor of 1.2. Energy and mass balance data are used to determine the heat flux transferred between different streams contacted in the heat exchangers. As it is well known, the calculation of film and overall heat transfer coefficients (U) is necessary in order to determine the heat transfer area which is used in the cost functions presented in Turton [20]. The overall heat transfer coefficient is calculated as a function of film coefficients of the cold and hot streams for different heat exchanger configurations. For the film coefficients Nusselt number correlations are used from the literature, which include the influence of pressure and temperature on U as well as on the heat transfer area considering their dependency on parameters like density, viscosity, specific heat and heat conductivity. In the final step of the design, the optimal configuration of heat exchangers is identified for which heat transfer area and implicitly the cost is the lowest and the obtained overall heat transfer coefficient value is comparable to the ones recommended by the literature considering the particularities of the process.

2.2 Capital cost estimation methodology

2.2.1 Gas switching reforming

The cost of other components was evaluated using capital cost correlations found in the literature according to Eq. 1. C_0 and Q_0 are the reference cost and capacity of the unit, and is an exponent that depends on the equipment type. These values are summarized in Table 1. Each value was adjusted to 2018 costs according to the CEPCI index. An install factor of 1.68 was applied to the costs from Franco et al. [18], as installation costs were not included in the cost correlations. However, costs from Spallina et al. [25] are erected costs that do not require an additional installation factor. The compressor reference cost from Smith [26] was calculated to the maximum allowable size of 10 MW using $C_0 = 0.082, Q_0 = 0.25$ and $M = 0.46$ and also multiplied by a material factor of 3.4 for high grade stainless steel construction [26], after which further scale-up is assumed to occur modularly ($M = 1$). The 1.68 install factor was also applied to this unit.

$$C = C_0 * \left(\frac{Q}{Q_0}\right)^M \qquad \textbf{Eq. 1}$$

Table 1: Reference costs, capacities and scaling exponents for different process units for use in Eq. 1, in case of GSR

Equipment	Scaling parameter	Reference cost (M€)	Reference capacity	Scaling exponent	Year	Reference
WGS	Thermal input (LHV) [MW]	9.54	1246.06	0.67	2007	[25]
PSA	Inlet flow rate [kmol/hr]	27.96	17069	0.6	2007	[25]
Gas Turbine	Net power output [MW]	49.4	272.12	1	2011	[18]
HRSG	ST gross power [MW]	45.7	292.8	0.67	2011	[18]
Steam Turbine	ST gross power [MW]	33.7	200	0.67	2011	[18]
Steam turbine condenser	ST gross power [MW]	49.8	292.8	0.67	2011	[18]
CO_2 compressor and condenser	Compressor power [MW]	9.95	13	0.67	2011	[18]
MEA CC system	CO_2 captured [kg/s]	28.95	38.4	0.8	2011	[18]
PSA off-gas compressor	Compressor power [MW]	1.52	10	1	2005	[26]
H_2 compressor	Compressor power [HP]	0.0012	1	0.82	1987	[25]

Adding all the process component installed costs together yields the bare erected cost (BEC). For the calculation of the total overnight cost, the EBTF guidelines [18] were applied as summarized in Table 2, with two modifications. Firstly, a process contingency was added to less mature units based on the guidelines of Rubin et al. [27]: 30% for the cluster of GSR reactors and the 2-phase flow heat exchangers and 10% for the MEA CO2 capture system. The rest of the system can be considered mature technologies with a 0% process contingency. Secondly, the owner's cost was increased from 5% used in Franco et al. [18] to 12%, which is an average of this value and three other values (7%, 15% and 22%) listed in Rubin et al. [27].

Table 2: Estimation methodology for the total overnight cost of the GSR plant

Component	Definition
Bare erected cost (BEC)	Install cost of each unit
Process contingency (PS)	0%, 10% or 30% of BEC
Engineering procurement and construction costs (EPCC)	14% of (BEC + PS)
Project contingency (PT)	10% of (BEC + PS + EPCC)
Total plant costs (TPC)	BEC + PS + EPCC + PT
Owners cost (12% of TPC)	12% of TPC
Total overnight costs (TOC)	TPC + Owners costs

2.2.2 Gas switching combustion

Capital costs are estimated using the costs from Franco et al. [18] and scaled to a major modeling parameter as presented in the general form of the cost (Eq. 1). The parameters for the cost calculation are presented in Table 3 and Table 4 for the cases without carbon capture and with carbon capture, respectively. The obtained capital cost is updated with CEPCI cost index [24] for the year 2018.

Table 3: Scaling parameters, reference costs, capacities and scaling exponents for the case without CC

Equipment	Scaling parameter	Reference cost (M€)	Reference capacity	Scaling exponent	Year	Ref.
ASU	Oxygen produced [kg/s]	64.48	26.54	0.7	2011	[18]
Coal handling	Coal input [kg/s]	49.5	32.90	0.67	2011	[18]
Ash handling	Ash flow rate [kg/s]	16	4.65	0.6	2011	[18]
HRSG	ST gross power [MW]	35.46	182.36	0.67	2011	[18]
Gas turbine	Net power output [MW]	88.6	254.42	1	2011	[18]
Steam turbine	ST gross power [MW]	55	182.36	0.67	2011	[18]
Condenser	ST gross power [MW]	40.56	182.36	0.67	2011	[18]
Gasifier	Thermal input [MW]	162	828.02	0.67	2011	[18]
Gas clean-up	Syngas flowrate [kg/s]	58.03	75.26	0.67	2011	[18]

The capital cost estimation for the base case IGCC power plant without CO_2 capture is performed using the reference data presented in Table 3 and applied in Eq. 1. Operating parameters and conditions are changing as a carbon capture unit is added to the plant and therefore separate cost correlations have to be used for the cases without and with carbon capture. The capital cost parameters used for the estimation of the pre-combustion CO_2 capture (Case 2), GSC and GSC with additional natural gas firing plant (Cases 3 and 4) is performed using the parameters presented in Table 4. Case 2 involves standard technologies for gas clean-up whereas the two cases applying the GSC technology uses hot gas clean-up as this offers significant efficiency improvements for IGCC systems[28]. The cost correlation parameters for the hot gas clean-up are obtained as 75 % of the standard gas clean-up unit presented by Franco et al. [18]. The WGS unit is only used for the pre-combustion capture option to concentrate the carbon containing components in the form of CO_2 and the cost correlation parameters are obtained from the work of Spallina et al. [25]. In Case 2 CO_2 is fed into the compression unit at 1 bar pressure whereas in the GSC plant the CO_2 feed stream has a pressure of 17 bar. This pressure difference requires a different compression train in the GSC cases from the reference case. This can also have a great effect on the capital cost of the plant; therefore a different cost correlation is applied, based on the work of Kolster [29].

Table 4: Reference costs, capacities and scaling exponents for the cases with CC

Equipment	Scaling parameter	Reference cost (M€)	Reference capacity	Scaling exponent	Year	Ref
ASU	Oxygen produced [kg/s]	72.8	31.45	0.7	2011	[18]
Coal handling	Coal input [kg/s]	53.89	38.72	0.67	2011	[18]
Ash handling	Ash flow rate [kg/s]	17.42	5.48	0.6	2011	[18]
HRSG	ST gross power [MW]	34.10	168.46	0.67	2011	[18]
Gas turbine	Net power output [MW]	92.32	282.87	1	2011	[18]
Steam turbine	ST gross power [MW]	52.00	168.46	0.67	2011	[18]
Condenser	ST gross power [MW]	39.00	168.46	0.67	2011	[18]
Gasifier	Thermal input [MW]	180	954.08	0.67	2011	[18]
Gas clean-up	Shifted syngas flow rate [kg/s]	86.66	111.04	0.67	2011	[18]
Hot gas clean-up	Syngas flow rate [kg/s]	46.97	89.21	0.67	2011	[18]
Selexol™ CO_2 capture unit	Shifted syngas flow rate [kg/s]	45.00	111.04	0.67	2011	[18]
WGS unit	Syngas flow rate [kg/s]	21.12	89.21	0.67	2011	[29]
CO_2 compression and condenser for Case 2	CO_2 flow rate [kg/s]	25.30	74.47	0.67	2015	[29]
CO_2 compression and condenser for Cases 3 and 4	CO_2 flow rate [kg/s]	26.18	71.30	0.67	2015	[29]

The total investment cost was calculated using the methodology presented by Rubin et al. [27] and presented in Table 5. A process contingency of 30% and a project contingency of 18% is applied for the results to stay relevant when compared to previous literature data [5].

Table 5: Estimation methodology for the TOC of the plant

Component	Definition
Total install cost (TIC)	Install cost of each unit
Process contingency (PS)	30% of TIC
Engineering procurement and construction costs (EPCC)	14% of (TIC + PS)
Project contingency (PT)	18% of (TIC + PS + EPCC)
Total plant costs (TPC)	BEC + PS + EPCC + PT
Owners cost	12% of TPC
Total overnight costs (TOC)	TPC + Owners costs

2.3 Operations and maintenance costs

2.3.1 Gas switching reforming

Table 6 presents the assumptions for the fixed and variable operating and maintenance (O&M) costs. The operating labour cost was scaled from the NGCC MEA plant in Franco et al. [18] proportionately to the output of the plant and was estimated at 12 M€/year. Maintenance and insurance costs were estimated as fraction of the TOC of the plant. The rest of the variable O&M costs were obtained from previous works as indicated in Table 6. A replacement period of 5 years was assumed for the catalyst, oxygen carrier and sorbent. In the case of the MEA replacement costs, both fresh MEA cost and MEA sludge disposal cost was included according to the IEAGHG report [30].

Table 6: Fixed and variable operating & maintenance cost assumptions for the GSR plant

Fixed O&M costs [18]		
Operating labour	12	M€
Maintenance, support and administrative labour	2.5	% of TOC
Property taxes	Included in insurance costs	
Insurance costs	2	% of TOC
Cost of NG	6.5	€/GJ LHV
Variable O&M costs [31]		
Process water costs	2.22	€/t
Cooling water make up costs	0.325	€/t
Catalyst and sorbent replacement		
Oxygen carrier	12500 [36]	€/t
WGS catalyst cost	12978 [23]	€/m^3
PSA sorbent replacement costs	907.82 [23]	€/t

MEA replacement cost	(1404.17+528.33) [41]	€/t
CO_2 costs [31]		
Transport and storage	10	€/t
Emissions tax	22.68	€/t
Chemicals [32]		
Cooling water chemical treatment	0.0025	€/m^3
Process water chemical treatment	45000	€/mo.

2.3.2 Gas switching combustion

Table 7 presents the assumptions for the fixed and variable operating and maintenance (O&M) costs used in every case. The operating labour cost is included in the maintenance cost according to Franco et al. [18] in both without and with carbon capture cases. Maintenance cost is estimated based on the gross power output of the plant. References are provided in the table for the estimations.

Table 7: Fixed and variable operating & maintenance cost assumptions for the GSC plant

Fixed O&M costs		
Operating labour	*Included in maintenance	
Maintenance and administrative	56 [33]	€/kW/year
Cost of coal	2.5	€/GJ LHV
Cost of ash disposal	9.73 [34]	€/t
Cost of NG	6.5	€/GJ LHV
Variable O&M costs		
Process water costs	6	€/t
Cooling water make up costs	0.325	€/t
Catalyst replacement		
Oxygen carrier	12500 [23]	€/t
Selexol™ replacement	5000 [18]	€/t
CO_2 costs		
Transport and storage	10	€/t
Chemicals		
Cooling water chemical treatment	0.0025	€/m^3
Process water chemical treatment	45000	€/mo.

For the OC NiO is selected as in the paper of Szima et al. [23] on the gas switching reforming process, the replacement period is selected as two years of operation. In Case 2 the Selexol™ absorbent loss in the system is calculated as 7 g lost/MWh gross power generated [18].

3 Economic Assessments of Gas Switching Reforming

3.1 Baseload economic assessment

The GSR-CC power plant is compared to two benchmarks: an NGCC power plant with no CO_2 capture and the same NGCC plant with post-combustion MEA CO_2 capture. Table 8 presents the cost breakdown of the three cases.

Table 1: Capital cost breakdown [M€] and performance indicators for the three power plants

Unit	NGCC	NGCC-MEA	GSR-CC
Heat exchangers			13.8
Gas reformer island			120.0
WGS unit			13.3
PSA			46.8
Gas turbine	159.3	159.3	187.5
HRSG	73.7	72.2	88.4
Steam turbine	69.7	56.6	85.1
Condenser	80.3	93.0	97.4
CO_2 compressor and condenser		23.2	21.8
H_2 compressor			5.2
PSA-off gas compressor			13.1
MEA CO_2 separation system		91.4	
Bare erected cost	382.9	495.8	692.3
Total overnight cost	532.6	702.25	1014.1
Specific total overnight cost [€/kWe]	641.7	989.2	1071.7
Net power production [MW]	829.9	709.9	946.3
Net electric efficiency [%-LHV]	58.3	49.9	51.1
CO_2 avoidance [%]	-	89.7	98.1

The Levelised cost of electricity (LCOE) was calculated for each case using the Net Present Value (NPV) method (cost of electricity which makes the NPV zero) and the results are presented in Table 9. The cost of CO_2 avoidance (COCA) is calculated using Eq.2 where E represents the specific CO_2 emissions of the plant. Subscript *CC* denotes the plant with CO_2 capture and *ref* the reference plant without CO_2 capture, respectively.

$$COCA\left(\frac{€}{tCO_2}\right) = \frac{LCOE_{cc} - LCOE_{ref}}{E_{ref} - E_{cc}} \qquad \text{Eq. 2}$$

The two CO_2 capture plants show similar results, with the LCOE in the case of the GSR plant being slightly higher. However, GSR achieved an identical COCA to the MEA plant because of its higher CO_2 avoidance rate.

Table 2: LCOE and COCA indicators for the three different power plants

	NGCC	NGCC-MEA	GSR-CC
LCOE [€/MWh]	53.95	73.18	74.95
COCA [€/ton]		60.86	60.86

Figure 2 shows the breakdown of LCOE for the three different plants. Clearly, fuel costs represent the dominant factor in the levelized costs of all three plants. Capital costs and fixed O&M costs (calculated as a percentage of capital costs) become more influential in the CO_2 capture plants due to their higher specific total overnight costs (Table 8). Relative to the MEA plant, the GSR plant has slightly higher capital costs, which are cancelled out by slightly lower fuel costs. However, GSR also has higher variable O&M costs due to replacement of oxygen carrier material and higher water consumption associated with H_2 production and syngas cooling. CO_2 T&S costs are also significant for the CO_2 capture plants and slightly higher for GSR due to its higher CO_2 capture rate.

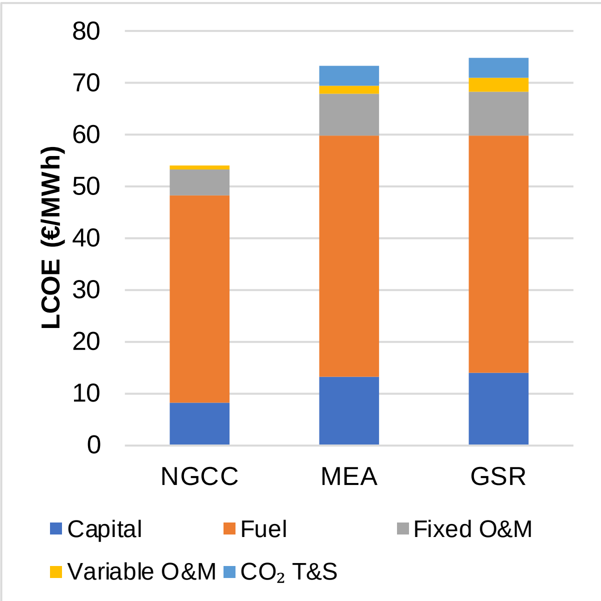
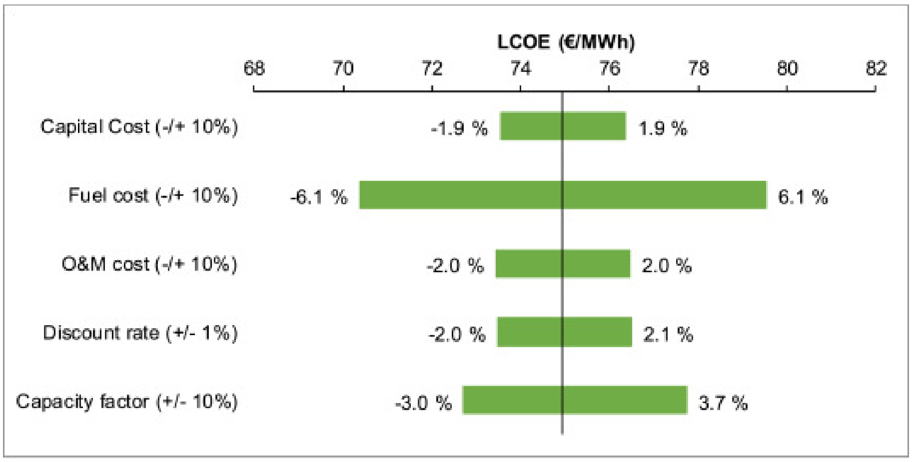


Figure 2: LCOE breakdown between different components for each plant

As the fuel cost is the dominant element in the plant economics, its variation has the greatest impact on the LCOE and COCA, as presented in Figure 3. Variation in the plant capacity factor has the second largest impact on the LCOE, with the other three variables having a similar impact.

Finally, Figure 4 shows the sensitivity of the LCOE of the three power plants to variations in the fuel cost. As expected, the gap between the LCOE of the CO_2 capture plants and that of the NGCC reference plant increases with increasing fuel cost due to the energy penalty imposed by these plants. The GSR energy penalty is slightly smaller than the MEA plant, so it experiences a slightly smaller sensitivity to increasing fuel prices.



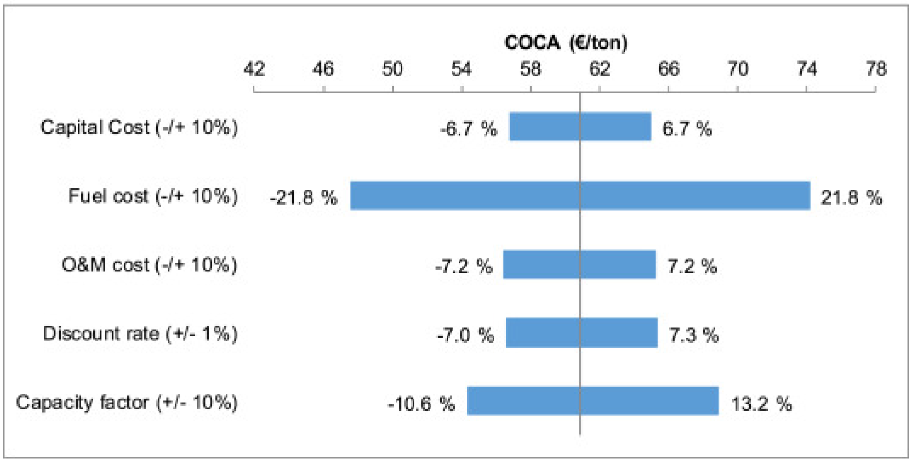


Figure 3: Sensitivity analysis for the GSR-CC plant. The percentage deviation from the base case is also indicated as data labels for each case.

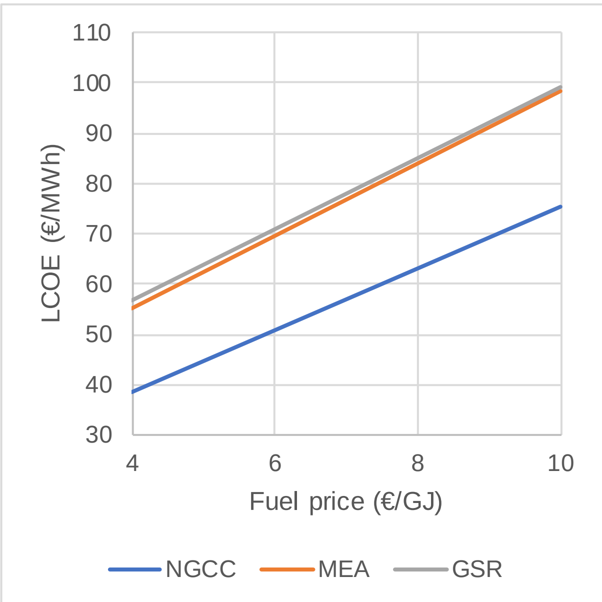


Figure 4: Sensitivity of the LCOE of the three different plants to variations in the natural gas price

3.2 Mid-load economic assessment

The baseload economic assessment presented in the previous section is common practice when assessing different CO_2 capture technologies. However, given the relatively high fuel cost, increasing CO_2 taxes and growth of VRE, it is unlikely that new natural gas-fired power plants will operate under base load conditions. This section will therefore evaluate the economic performance of the three plants under more realistic mid-load conditions, where most power is produced during times of high system load and/or low VRE power output.

German mid-load plants (based on hard coal and natural gas) already earn about 22% more than the system average electricity price for the average unit of electricity sold (and about 50% more than the average unit of wind electricity sold). This is the result of these plants generating most of the power during times of high residual demand, leading to high prices. As the growth of VRE continues, these price premiums enjoyed by mid-load plants will probably continue to grow.

For this reason, the results in this section will be expressed as a function of the price premium enjoyed by mid-load plants. In practice, this price premium will primarily depend on the electricity price volatility (influenced by VRE market share) and the plant capacity factor (lower plant utilization results in higher average price premiums as plant output is increasingly concentrated in times of high electricity prices). In this study, the capacity factor will be kept constant at 45% and the price premium will be varied over the range shown in Table 10 to investigate this uncertainty.

Table 3: Assumption in the economic assessment of mid-load plants differing from those in Table 8

System average wholesale price	60 €/MWh
Mid-load price premium	10-40 €/MWh
Hydrogen sales price	€1.35/kg
Electricity purchase discount	10-40 €/MWh
Capacity factor	45%
H_2 capacity factor	45%
First year capacity factor	30%
CO_2 price	20-100 €/ton
CO_2 T&S cost for MEA & GSR	15 & 10 €/ton
Flexible operation costs	Neglected
Ancillary services revenues	Neglected

Another important simplifying assumption in Table 10 is that the costs and revenues associated with load-following operation are ignored. Power plant efficiency reduces during part-load operation, while start-up and shut-down also imposes additional costs. On the other hand, power plants can earn additional revenues by providing ancillary services by adjusting their power output to balance the grid. In this study, it is assumed that these added costs and added revenues largely cancel out and can therefore be ignored.

It should also be mentioned that the average wholesale power price assumed is higher than the current price in Europe. As recently discussed in the IEA World Energy Outlook [35], current wholesale prices are insufficient to cover the full levelized costs of new power plants. This is primarily due to the subsidized deployment of VRE with near-zero marginal cost and stagnant electricity demand growth. In the future, further VRE expansion will exert downwards pressure on wholesale prices, while increased CO_2 taxes will exert upwards pressure. This study assumes a wholesale price level where moderate returns on investment are possible so that new dispatchable plants can be constructed when needed without additional revenue streams (such as capacity payments).

For GSR, it is assumed that the plant operates in H_2 production mode during times when no electricity is produced to result in a combined capacity factor of 90% over the whole operating year. The added costs of H_2 compressors for allowing H_2 export amounted to 47.2€/kWe, thus increasing the plant total overnight cost and fixed O&M cost by 4.5%.

The hydrogen price specified in Table 10 was selected so that it becomes economical for the GSR-CC plant to produce electricity rather than hydrogen when the wholesale electricity price rises above the average market price of 60€/MWh. The selected H_2 price is competitive even with current CO_2-intensive hydrogen production through thermochemical fossil fuel conversion and much lower than other clean hydrogen production technologies [36]. This can therefore be viewed as a conservative assumption with substantial upside potential for GSR economic performance.

In addition, it is assumed that the electricity consumption of the GSR plant in H_2 production mode enjoys a discount identical to the price premium during electricity production. This assumption is made because the plant will be producing electricity during times of high electricity prices and hydrogen during times of low electricity prices. As shown in Figure 5, electricity market data indicates that electricity prices adopt an almost perfect normal distribution, supporting the assumption of an identical discount during hydrogen production to the premium during electricity production.

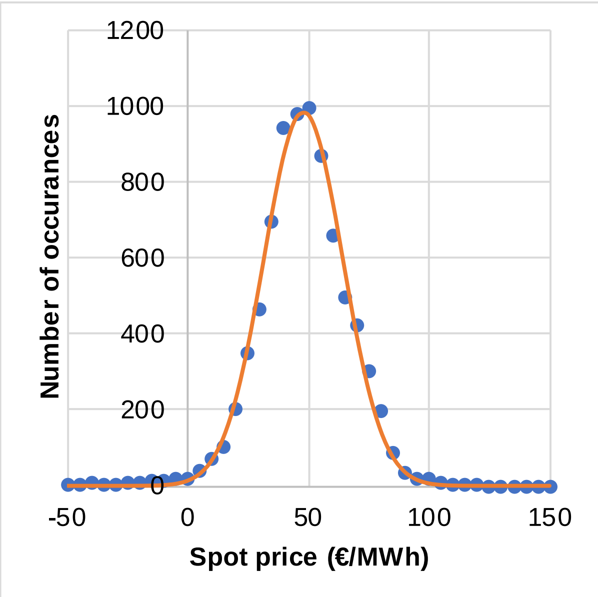


Figure 5: Distribution of electricity prices over the year 2018 January-November [37]. The data is represented by markers and the line indicates a normal distribution fit to the data

Finally, it was assumed that the CO_2 transport and storage (T&S) cost for the MEA mid-load plant increases from 10€/ton to 15€/ton because of the reduced utilization of the T&S infrastructure. This is done under the assumption that T&S costs are distributed evenly between fixed and variable costs. The GSR plant still uses the T&S infrastructure at maximum capacity, so T&S costs remain at 10€/ton.

Using the assumptions in Table 10, the cash flow analysis was repeated for all three plants to calculate the discount rate that returns zero net present value at the end of the plant's economic lifetime. This discount rate is a reasonable approximation of the return that can be expected from the plant capital investment. The expected investment return should be attractive relative to alternatives with similar risk profiles to enable investment in new power plant infrastructure.

Figure 6 shows the results from this discounted cash flow analysis. As expected, a larger price premium causes substantial increases in the expected investment returns from all three plants. Increasing electricity price volatility from further VRE growth is therefore positive for mid-load plants.

When the CO_2 tax is only €30/ton, the unabated NGCC plant still offers the best investment return. However, investment returns drop strongly when the CO_2 tax increases to 100€/ton, showing the risk posed by future CO_2 tax increases. It is noted that the points without any data in Figure 6 indicate that operating expenses rise above operating income, implying that the plant can no longer make money and must be temporarily shuttered or permanently decommissioned. In practice, the plant could also reduce its capacity factor to only produce during times of highest electricity prices, thus increasing the average price premium at the expense of lower electricity sales.

More importantly, the results show that the GSR plant now outperforms the MEA plant, counter to the economic outlook from the baseload economic assessment. Two reasons can be identified: 1) the hydrogen production section is being utilized at 90% capacity factor in GSR, whereas the absorption unit in the MEA plant is only utilized at 45% capacity factor and 2) the MEA plant pays 50% higher CO_2 T&S costs due to the intermittent CO_2 production from this plant.

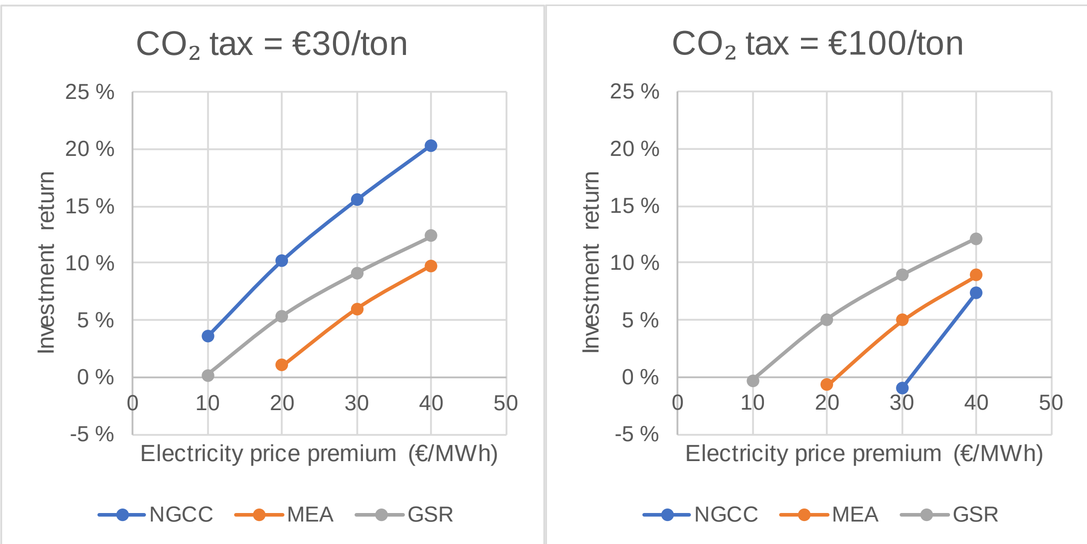


Figure 6: Annualized return on investment as a function of the electricity price premium received by the mid-load plant at two different CO_2 tax rates.

The economic advantage of the GSR plant over the MEA plant increases with increasing CO_2 price because of the very high CO_2 avoidance of the GSR plant. Figure 7 demonstrates this trend. It is also shown that the NGCC plant becomes less economically attractive than GSR at a CO_2 tax rate of 53€/ton, less economical than the MEA plant at a CO_2 tax rate of 69€/ton and must be shuttered at a CO_2 tax above 80€/ton.

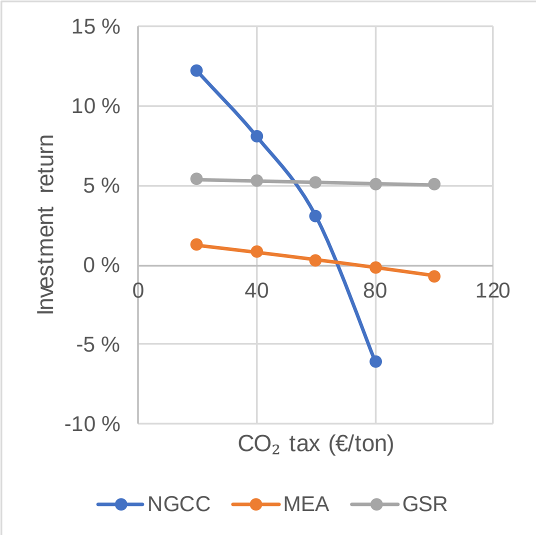


Figure 7: Annualized return on investment as a function of CO_2 tax at an electricity price premium of 20€/MWh

A breakdown of operating income and expenses for one operating year is shown for all three plants in Figure 8. The 100€/ton CO_2 tax strongly increases the expenses of the NGCC plant, almost to the level of the fuel costs, causing annual expenses to exceed annual income. The costs associated with CO_2 taxes and T&S costs for the MEA and GSR plants are much smaller. Figure 8 also shows that the cash flows for the GSR plant are much larger due to its high overall capacity factor. Income from electricity sales is substantially larger than hydrogen sales because of the price premium on electricity sales.

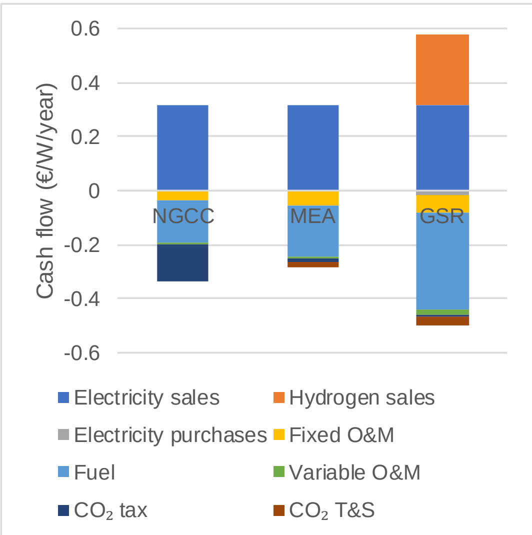


Figure 8: Breakdown of annual operating cash flow at a CO_2 tax of 100€/ton and a price premium of 20€/MWh

Finally, a few qualitative observations about the investment risk profiles of the different plants can be made. As mentioned earlier, the NGCC plant's economic performance is sensitive to large increases in the CO_2 tax. Such tax increases must happen if global temperatures are to be kept below 2 °C [35], but the timeframes within which this dynamic will play out remains highly uncertain.

If the NGCC plant is constructed to be CCS-ready, this risk reduces substantially because a CCS retrofit (potentially with MEA technology) can restore profitable operation after large CO_2 tax hikes. However, flexible operation of an NGCC plant with MEA CO_2 capture technology will pose some technical and economic challenges in the capture, transport and storage parts of the CCS value chain. As discussed in the introduction, MEA technology can aid in flexible operation, but the equipment oversizing required for this purpose is unlikely to be economical at CO_2 price levels required for market-driven CCS deployment [38]. In addition, intermittent CO_2 production can create problems for downstream CO_2 T&S [39].

The GSR plant should be just as flexible as an NGCC plant, with a potential to deploy the hot N_2-stream from GSR to further improve startup times and mitigate the minimum environmental load restriction of the gas turbine. In addition, the constant output of CO_2, even under flexible power output will simplify CO_2 T&S.

The primary risk related to GSR is the current lack of a large market for clean hydrogen. As mentioned earlier, the assumed hydrogen price in this study (1.35€/kg) is low compared to other options for clean hydrogen production. GSR will therefore perform well if the hydrogen economy is eventually realized. If CO_2 prices increase according to the requirements for 2 °C global warming and VRE expansion continues, hydrogen appears increasingly attractive as a carbon neutral energy carrier and storage mechanism. A rising sense of urgency about climate change therefore increases the likelihood that this primary requirement for investment in the GSR-CC plant will be fulfilled in the medium-term future.

If a large market for clean hydrogen is established, the ability of the GSR-CC plant to alternate between two valuable products will significantly reduce investment risk. The plant will be able to capitalize on profitable opportunities presented by price spikes in either electricity or hydrogen and will only be under economic pressure if prices for both commodities crash simultaneously. In addition, the very high CO_2 avoidance of the GSR plant makes it insensitive to CO_2 tax increases.

Given all these considerations, investment in the GSR-CC plant appears highly attractive if a large clean hydrogen market is established, which, in turn, appears likely upon a meaningful commitment to keeping global warming below 2 °C.

3.3 Conclusions

This study investigated the new gas switching reforming combined cycle (GSR-CC) plant that can flexibly convert natural gas to electricity (during low VRE output) or hydrogen (during high VRE output) with near-zero CO_2 emissions. In this way, this novel energy conversion plant overcomes the two most important techno-economic challenges facing flexible CCS: low capital utilization rates and the need for intermittent CO_2 transport and storage. In addition, clean hydrogen produced during times of high VRE output can aid in the decarbonization of sectors other than electricity.

A standard baseload economic assessment at a capacity factor of 85% revealed that the GSR combined cycle power plant has a slightly higher LCOE than the benchmark NGCC plant with MEA post-combustion CO_2 capture (74.95 €/MWh for GSR and 73.18 €/MWh for MEA). However, a more realistic mid-load scenario at a capacity factor of 45% reversed this outcome. When assuming an average electricity price of €60/MWh and a €1.35/kg hydrogen price, the GSR plant outperformed the MEA benchmark, showing an annualized investment return that is about 5 %-points higher. This advantage increased with higher CO_2 prices due to the very high CO_2 avoidance of the GSR plant.

The significant improvement in the GSR economic performance under mid-load operation is due to its high utilization of the CO_2 capture, compression, transport and storage equipment relative to the MEA benchmark. This feature of the GSR plant not only brings large economic benefits, but will also address the technical challenges related to intermittent influxes of CO_2 into a large future CO_2 transport and storage network. Given the rising importance of VRE in global decarbonization efforts, the development of CO_2 capture plants with these characteristics must be given high priority.

The primary requirement for the feasibility of the GSR plant is the establishment of a large market for clean hydrogen. Once such a market is established, the GSR plant will have an attractive risk profile relative to other CCS power plants, with reduced exposure to fluctuating electricity prices and the ability to avoid the techno-economic challenges related to intermittent CO_2 supply to downstream transport and storage infrastructure. This good economic performance and risk reduction merits further research into the GSR combined hydrogen and power plant.

Two key subjects are recommended for future work. First, the flexible operation of the GSR-CC plant must be studied in detail, including thermodynamic performance under part-load operation and detailed assessments of the load flexibility of the lean pre-mixed H_2 combustor. Second, power system simulations aiming to quantify the impact of the GSR-CC plant on total system costs in an environment with high VRE market share and CO_2 prices are strongly recommended.

4 Economic assessments of Gas Switching Combustion

4.1 Base case economic assessment

Capital costs generally represent the largest component of the LCOE of coal-fired plants with CCS. Figure 9 presents the capital cost breakdown in the GSC case. The gasifier and gas switching island have the highest share in the cost of the plant. The rest of the units' share is at 10 % or lower. It is also noteworthy that the power cycle represents only a third of the capital costs of the plant. All the units involved in transforming coal into a hot depleted air stream and a compressed CO_2 stream represent the other two thirds of the plant cost. This implies that any measures to get more useful electricity from the hot depleted air stream in the power cycle (such as the added firing with natural gas) can offer substantial reductions in the levelized capital cost of the plant.

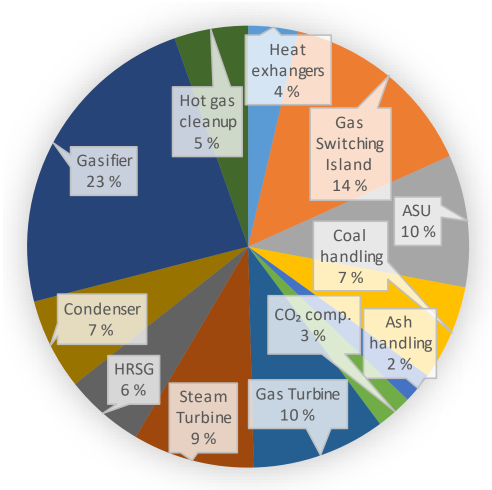


Figure 9: Total installed cost breakdown for GSC case.

As presented in Table 11, the gasifier has the highest cost in all cases followed by the gas turbine and the ASU or GSC unit in the GSC and GSC-AF cases. It is also interesting to note that the GSC plant relies more on the expensive steam cycle components (steam turbine, HRSG and condenser) rather than the cheaper gas turbine than the other plants because of the relatively low TIT of this case. The OPPC plant suffers from a very high gasifier cost due to the syngas flowrate that is more than double the size of the other plants. This high syngas flowrate also increases the gas clean-up cost.

Table 11: Installed costs for the four cases.

Unit	IGCC	IGCC-PCC	GSC	GSC-AF	OPPC
Heat exchangers			26.63	13.14	33.40
Gas Switching Island			106.52	106.52	51.08
ASU	70.07	70.60	70.60	70.60	
Coal handling	52.03	50.79	50.79	50.79	50.79
Ash handling	16.78	16.42	16.42	16.42	17.71
CO_2 compression		34.86	19.32	19.56	31.46
Gas Turbine	99.62	91.21	71.27	125.53	83.94
Steam Turbine	58.73	51.86	64.84	75.61	59.70
HRSG	37.87	34.01	42.52	49.58	39.15
Condenser	43.31	38.89	48.63	56.71	44.77
Gasifier	170.30	172.08	172.08	172.08	243.57
Hot gas clean up			39.33	39.35	65.59
WGS		19.47			20.18
Gas clean up	57.21	56.70			
Selexol^{TM} plant		42.71			39.25
Total Install cost (M€)	605.93	679.60	728.93	795.89	781.04
Total overnight cost (M€)	912.91	1058.77	1098.22	1218.67	1176.73
Net power output (MW)	406.69	322.19	367.95	582.80	380.56
Specific investment cost (€/kWe)	2244.71	3286.21	2984.69	2091.07	3092.14

The maintenance cost for the plant includes the labor cost and it is calculated as a function of the gross power output of the plant, this explains the substantial difference between the two GSC models, the GSC-AF plant having a significantly higher output, as presented in Table 11. Variable O&M costs depend on the capacity factor and this could change from year to year and can be expected to drop by the end of the economic lifetime. Table 12 presents O&M costs for the evaluated cases assuming a capacity factor of 85 %, as used in the economic model. For the GSC-AF case, the high cost of natural gas is clearly shown, given that it represents only about a quarter of the LHV fuel input to the plant. Beside fuel costs, the costs associated with CO_2 storage have the highest impact on the economics of the plant. In the GSC plants, oxygen carrier replacement costs are also considerable. These plants achieve a small saving in process water costs because of the water recovered from the high pressure CO_2-rich stream from the GSC reactors.

Table 12: O&M costs for the GSC cases.

Fixed O&M costs (M€/year)	**IGCC**	**IGCC-PCC**	**GSC**	**GSC-AF**	**OPPC**
Maintenance incl. labour	23.64	23.87	24.4	32.33	21.31
Variable O&M costs at 85% capacity factor (M€/year)					
Cost of coal	57.27	57.27	57.27	57.27	57.27
Cost of NG				56.28	
Cost of ash disposal	1.25	1.25	1.25	1.25	1.40
Process water	2.60	2.88	0.04	1.34	3.41
Cooling water consumption	1.10	1.22	1.26	1.58	1.45
Oxygen carrier replacement			10.75	10.75	2.10
WGS catalyst replacement		0.44			0.44
Selexol^{TM} make up		1.03			0.91
CO_2 transport and storage			19.79	20.63	18.01
Total cost (M€/year)	**85.86**	**87.96**	**115.18**	**183.8**	**106.3**

The main economic performance indicators are presented in Table 13 for all cases. The conventional pre-combustion capture plant has the highest LCOE, followed by the GSC and OPPC plants that return almost identical LCOE. Added NG firing strongly reduces the LCOE by 12.5 €/MWh relative to the standard GSC plant. As discussed earlier, the gasifier cost is an important uncertainty in the estimation of the OPPC cost. For perspective, the LCOE of this case reduces to 78.91 €/MWh if the gasifier costs are scaled only by the thermal input and increases to 87.09 €/MWh if scaled only by the raw syngas flowrate. Trends in the COCA indicators are similar to LCOE, although the COCA of the GSC-AF and OPPC plants are increased by their higher CO_2 emissions intensities.

Table 13: LCOE and COCA indicators for each case.

	IGCC	**IGCC-PCC**	**GSC**	**GSC-AF**	**OPPC**
LCOE [€/MWh]	60.15	94.23	83.40	70.93	83.00
$COCA_{IGCC}$ [€/ton]	-	51.62	32.69	16.53	35.75
$COCA_{SPPC}$ [€/ton]	-	56.95	38.66	24.26	42.76

Figure 10 shows the breakdown of the LCOE for all cases considered in this paper. Fuel cost and O&M costs have similar ratios in the cost breakdown of the LCOE for the four carbon capture cases, capital cost being the one that varies from technology to technology. In the IGCC-AF case, the capital cost share reduction obtained is counteracted to some extent by the higher cost of the NG. Even so, the overall cost is substantially reduced relative to the base GSC case and the OPPC case.

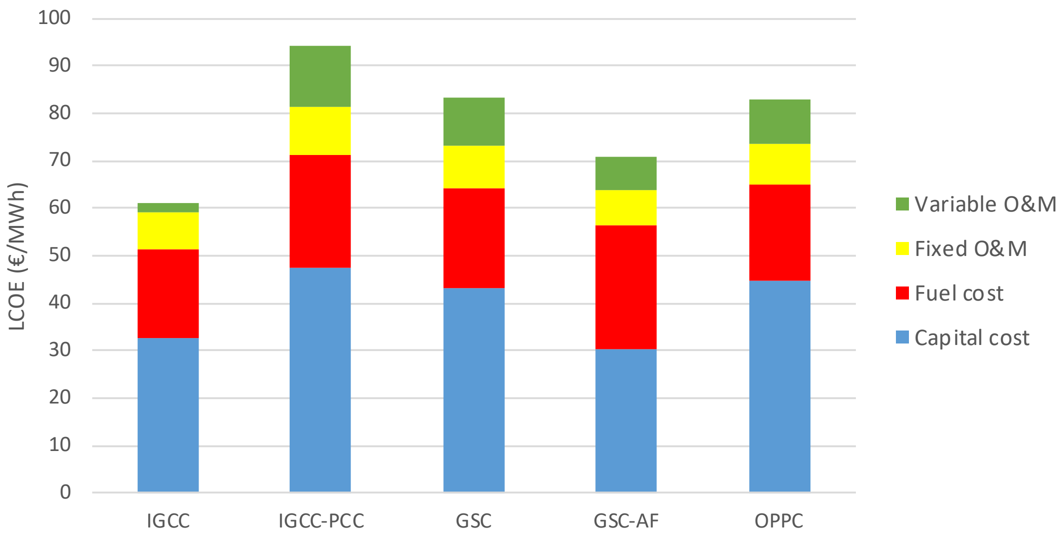


Figure 10: LCOE breakdown for the five IGCC configurations.

4.2 Sensitivity analysis

Uncertainty of the fuel price is a general issue regarding economic calculations of thermal power plants. The LCOE greatly depends on the cost of the fuel as presented in Figure 11a and Figure 11b, respectively. In all cases, aside from the GSC-AF case, the slopes of the lines in Figure 11a are inversely proportional to the plant efficiency. The GSC-AF plant has the lowest degree of dependency on the cost of coal because about a quarter of its fuel input is NG. When the natural gas price is varied a high degree of dependency is observed in the GSC-AF case, because of the high cost of NG when compared to coal.

According to the design of the reactor, the outer carbon steel shell is the one carrying the pressure load. This is the most sensitive component in the reactor design because an increase in the insulation layer thickness increases both the shell volume and its required thickness, thus strongly increasing its cost. Increasing the insulation thickness from 0.54 m to 0.88 m in the GSC case lowers the shell temperature by 20 ˚C, but increases the LCOE by 1.86 €/MWh (Figure 11c). Allowing the shell temperature to reach 100 ˚C reduces the insulation thickness to 0.38 m while the LCOE drops with 0.6 €/MWh. Thus, even though the total reactor cost increased by 43 % from the 100 °C wall temperature to the 60 ˚C wall temperature, the effect on the LCOE is relatively small. The effect is even smaller in the GSC-AF and OPPC cases where the gas switching reactors represent a smaller fraction of total plant costs. The calculated heat loss for the three temperatures on the total surface of the reactors in the case of the GSC plant are 893.8 kW, 1113.5 kW and 1365.9 kW, representing a bit more than 0.1 % of the heat input.

Oxygen carrier lifetime is another important uncertainty for all concepts based on chemical looping technology. For the base case, a two-year replacement period is assumed for both GSC and GSOP reactors. As presented in Figure 11d, the LCOE would increase in all cases if the OC lifetime reduces. The GSC case is the most sensitive to the OC lifetime, showing a 4.3 €/MWh increase in LCOE if the OC lifetime reduces from 2 years to 0.5 years.

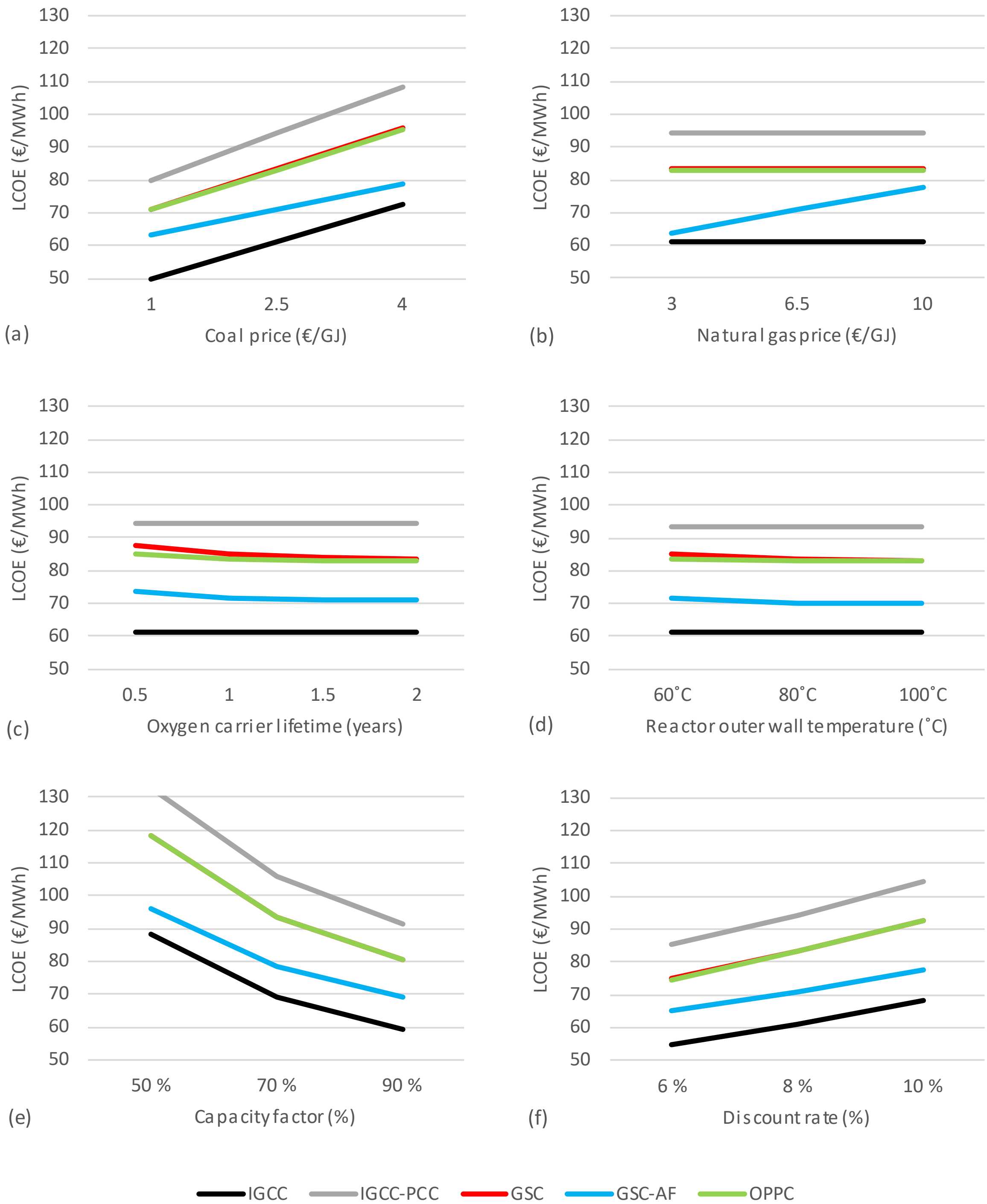


Figure 11: Coal and natural gas price dependency of the evaluated cases.

Given the capital-intensive nature of these plants, capacity factor and discount rate have the highest effect on the LCOE. A reduced capacity factor strongly increases the LCOE as presented in Figure 11e. With the rapid growth of wind and solar power, thermal power plants are increasingly expected to act as balancing capacity, operating at lower capacity factors. In this respect, the GSC-AF plant offers some additional benefits because it is the least capital intensive and, under part-load operation, it will reduce the fraction of fuel input required from more expensive natural gas. For example, when the F-class gas turbine output reduces by a little more than 50%, the turbine inlet temperature falls to the GSC outlet temperature [40], thus requiring no more natural gas firing. Under these conditions, the plant can operate with only a mild turndown of the relatively inflexible gasification train, but a larger turndown in overall plant output, saving the high natural gas fuel costs and associated CO_2 emissions. The variation of the discount rate also has a great effect on the LCOE for all three cases, with the GSC-AF case being the least sensitive due to its relatively low specific capital cost.

4.3 Benchmarking against other clean energy technologies

In today's energy market, the COCA relative to unabated fossil fuel plants is not the most important indicator of the competitiveness of CCS technologies. Alternative clean energy technologies represent a more relevant benchmark. For this reason, the power plants assessed in this paper will be benchmarked against nuclear, wind and solar technologies with cost data outlined in Table 14. Technology costs are taken from the IEA World Energy Outlook [35] for the year 2040 in the European Union. Wind and solar power integration costs, resulting from their large temporal and spatial variability, are taken from Hirth et al. [38] and are appropriate to the European Union for a wind and solar market share of 30-40%. Although nuclear and CCS plants would generally have longer operating lifetimes, all plants are assumed to have a 25-year economic lifetime. This assumption will give a conservative estimate of the competitiveness of the CCS plants evaluated in this study.

Table 4: Cost assumptions for nuclear, wind and solar benchmarks.

	Nuclear	Onshore wind	Solar PV
Capital cost (€/kW)	3750	1417	508
Construction period (years)	6	1	1
Capacity factor	85%	30%	14%
O&M costs (€/MWh)	20	15	10
Fuel costs (€/MWh)	15		
Integration costs (€/MWh)		25-35	25-35

Figure 12 shows the results of this benchmarking exercise. Clearly, the conventional CO_2 capture plant (IGCC-PCC) is not very well positioned in the competitive clean energy landscape. It is significantly more expensive than nuclear, only on par with wind and considerably more expensive than solar. Given the low air pollution and general green appeal of wind and solar energy, these clean technologies will be preferred over CCS if costs are similar. The GSC and OPPC plants achieve a better competitive position, being significantly cheaper than wind and nuclear and on par with solar with the higher integration costs bound. Only the GSC-AF plant clearly outperforms other clean energy benchmarks, although only slightly in the case of solar. However, solar in Europe is subject to strong seasonal variations and is misaligned with the seasonal electricity demand profile. Europe will therefore continue relying strongly on wind despite the lower future LCOE projected for solar.

This result suggests that highly efficient plants like the GSC-AF configuration will be required for CCS to be competitive in the clean energy landscape of the future. It should be noted, however, that the GSC-AF and OPPC configurations can benefit from using more advanced gas turbines with higher turbine inlet temperatures to further increase efficiency and reduce costs. Flexibility is also an important criterion for the attractiveness of new CCS plants as the expansion of variable renewables continues [41]. The higher degree of output flexibility offered by the GSC-AF case further increases its competitive position relative to the other CCS plants evaluated in this study.

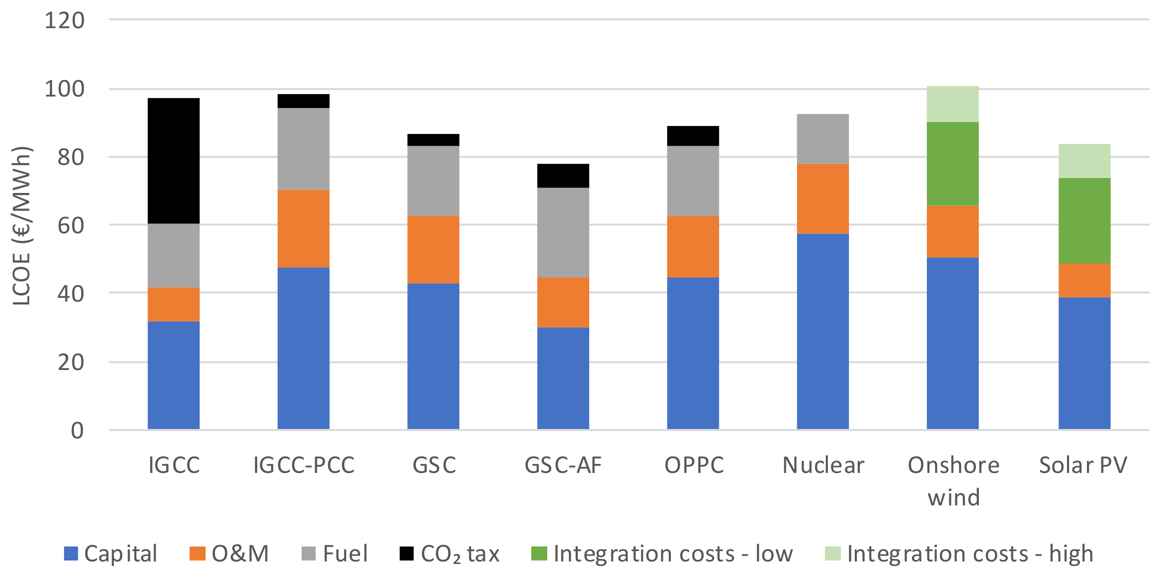


Figure 12: Benchmarking of the five IGCC-based power plants evaluated in this study against nuclear, wind and solar power using costs relevant to the year 2040 when the CO_2 price is set to €50/ton.

4.4 Conclusions

This study compared the economic performance of five different IGCC power plant configurations: a benchmark IGCC plant without CCS, conventional pre-combustion CCS, gas switching combustion (GSC), GSC with added firing with natural gas (GSC-AF) to increase the turbine inlet temperature, and a gas switching oxygen production pre-combustion (OPPC) configuration that replaces the air separation unit (ASU) with more efficient gas switching oxygen production (GSOP).

The GSC plant returned a LCOE that is 11.5% lower than the conventional pre-combustion benchmark (94.23 €/MWh vs 83.4 €/MWh) while maintaining a CO_2 capture rate of over 94%. Despite the higher cost of natural gas relative to coal, the large efficiency gain brought by added firing reduced the LCOE by another 15% to 70.93 €/MWh, reducing the cost of CO_2 avoidance as low as 24.26 €/ton when compared to a supercritical pulverised coal power plant. The large efficiency benefit of replacing the ASU with GSOP reactors in the OPPC configuration was partially counteracted by an increase in gasifier cost, resulting in a similar LCOE to GSC, but a 4.1 €/ton higher cost of CO_2 avoidance due to a lower CO_2 capture rate.

These results show that the GSC-AF configuration holds the most promise. In the sensitivity analysis, this case also showed reduced risk from several sources of uncertainty. Fuel costs are split evenly between coal and natural gas, limiting the sensitivity to price variations in either fuel. Uncertainties related to the GSC reactor cost and oxygen carrier lifetime are also limited since the added firing makes these components a smaller fraction of the LCOE. Added natural gas firing also makes the GSC-AF case less capital intensive (31% lower specific capital cost than GSC), limiting the cost increase related to lower capacity factors and higher discount rates. This plant could also hold benefits related to flexible operation for balancing wind and solar power since the expensive natural gas consumption can be ramped down first during part-load operation, requiring only a modest turndown of the relatively inflexible gasification train.

The good performance of the GSC-AF case was confirmed in comparisons to nuclear, wind and solar power, where it emerged as the only CCS technology consistently less expensive than other clean energy benchmarks. Among the advanced IGCC power plant configurations investigated in this study, the GSC-AF configuration therefore emerges as the preferred option for further development. Future work will investigate the possibility of further performance gains using more advanced gas turbine technology and the potential to do the added firing with hydrogen extracted from the syngas steam.

5 References

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