

# Low-Carbon Footprint Hydrogen Production from Natural Gas: a Techno-Economic Analysis of Carbon Capture and Storage from Steam-Methane Reforming

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Enabling cost-efficient low-carbon footprint hydrogen production is key to achieve the ambition of the Paris Agreement. This study aims to understand the techno-economic performances of hydrogen production from natural gas without and with carbon capture and storage. A hydrogen plant, based on steam-methane reforming and located in Northern Norway, producing 450 t H<sub>2</sub>/d is here modelled and evaluated. Hydrogen production costs without and with carbon emissions capture and storage of 12.2 and 18.1 c€/Nm<sup>3</sup> are obtained. This hydrogen cost increase results in a CO<sub>2</sub> avoidance of 67 €/t<sub>CO<sub>2</sub>,avoided</sub>. The main contributor to the CO<sub>2</sub> avoidance cost is the CO<sub>2</sub> capture and conditioning (57 %), while pipeline transport and the storage contribute to 17 % and 26 %. Equally important, a semi-detailed cost breakdown is presented to provide a deeper understanding of the key contributors to the cost of the whole chain and to identify points which if reduced could have the most impact.

## 1. Introduction

Hydrogen is now foreseen to be a key technological solution to reduce the CO<sub>2</sub> emissions associated with heat, power, industry, transportation, etc. Two main approaches can be used to produce hydrogen with low-carbon footprint at large-scale: electrolysis powered by renewable or fossil fuel reforming with carbon capture and storage (CCS). While hydrogen from electrolysis powered by renewable electricity is expected to be a key route for H<sub>2</sub> production in the future, it is important to realize that large-scale implementation also present several hurdles in practice. Massive amount of renewable capacity must be implemented to support it; competing with the already strong need for renewable investment to decarbonize power, as well as electrify industry and transport. Low electricity costs, stable throughout the year, are required for hydrogen from renewable electricity to be cost-competitive. Large short-term and long-term hydrogen storage capacities are required to cope with the transient nature of renewable power. These elements highlight that large-scale low-carbon footprint hydrogen will be based on the development of both hydrogen from natural gas with CCS and renewable electricity.

Currently, the vast majority of hydrogen being produced is based on reforming of natural gas or coal. In the case of natural gas, the main technology considered is steam methane reforming (SMR). In such a plant, the CO<sub>2</sub> can be captured at three different locations: (1) synthesis gas before the H<sub>2</sub> Pressure Swing Adsorption (PSA) (2) tail gas after H<sub>2</sub> PSA (3) flue gas of the SMR furnace (Collodi, 2010). While carbon capture and storage has been implemented in some SMR units, for example at Port Arthur (Texas, USA), it has mainly been implemented at the first and second locations. As a result, many studies have looked at CCS from these locations. Meerman et al. (2012), for example, evaluated commercially available solvent-based CO<sub>2</sub> capture from the synthesis gas before the H<sub>2</sub> PSA. Chou et al. (2013) investigated the potential of pressure swing adsorption for carbon dioxide capture and hydrogen purification from synthesis gas. Pichot et al. (2017) evaluated the potential of cryogenic capture for CO<sub>2</sub> capture from the syngas of an SMR. IEAGHG (2017a) evaluated solvent-based capture and a hybrid cryogenic and membrane capture concept.

A main drawback of CCS from these two locations is that only 60 %, maximum, of the plant CO<sub>2</sub> emissions can be captured. However, CCS from the SMR furnace can reduce the emissions of the hydrogen plant beyond

90 %, although it may be more expensive option as CO<sub>2</sub> is available at low partial pressure in the furnace flue gas.

To enable the production of low-carbon footprint H<sub>2</sub> based on the SMR technology, this study aims to present a complete evaluation of CCS from a SMR plant based on a post-combustion MEA-based process with a CO<sub>2</sub> capture ratio of 90 %. This study also seeks to provide a deep understanding of where effort should be focused in order to significantly reduce the energy penalty and costs of implementing CCS from such plants.

The study is structured as follow. The case study and the modelling approach is first presented, while the results are then summarized and analyzed.

## 2. Case study and modelling

### 2.1 Case study

Hydrogen production through natural gas reforming without and with CCS is designed and evaluated. The plant capacity is set at 450 t H<sub>2</sub>/d and is assumed to be produced from a single steam-methane reforming train. The natural gas is considered to have the reference characteristics established in the Decarbit project (Anantharaman, 2011). This plant, assumed to be located on Northern Norway shore, results in 1.37 MtCO<sub>2</sub>/y without CO<sub>2</sub> capture.

In the case of H<sub>2</sub> production with CCS, a CO<sub>2</sub> capture ratio of 90 % is targeted using a post-combustion MEA-based process on the reformer furnace flue gas. After CO<sub>2</sub> capture, the CO<sub>2</sub> is pressurized to 200 bar before being transported to an offshore saline aquifer located 140 km away. Considering the foreseen distance and volume of CO<sub>2</sub>, the transport takes place by a dedicated pipeline (Roussanaly et al., 2014).

A schematic block structure of the hydrogen plant with CCS capture is presented in Figure 1.

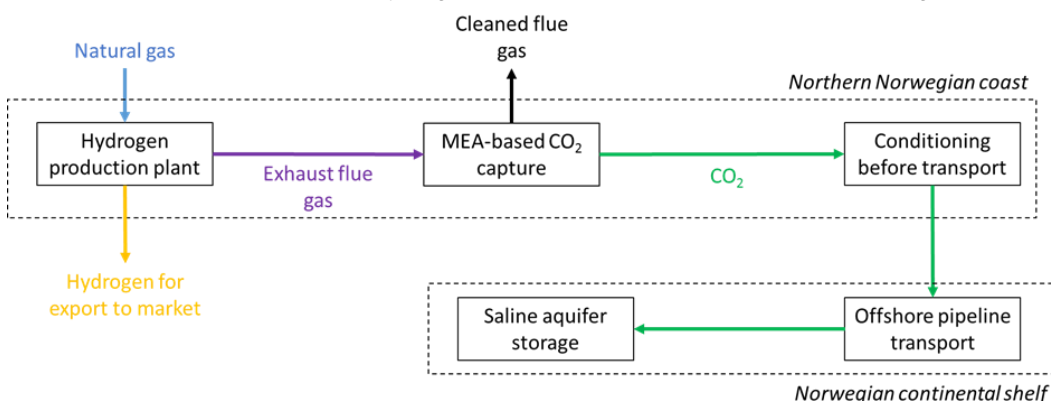


Figure 1: Schematic block diagram of the Hydrogen plant with CCS

### 2.2 Technical modelling

The hydrogen plant capacity is set 450 t H<sub>2</sub>/d and is assumed to be produced from a single steam-methane reforming train. In this process, the first step is a pre-reformer which operates at 29.9 bar with a steam-to-carbon (S/C) ratio of 2.5. The steam-methane reformer has an inlet pressure of 27.5 bar and an inlet temperature of 500 °C. The latter is result of the mixing of hot gas from the pre-reformer outlet and Intermediate Pressure (IP) steam. The reaction heat is assumed to be supplied by flue gas from the externally fired furnace. The S/C ratio is set to 2.5 and the outlet temperature of the steam-methane reformer is 950 °C. Water-gas shift is assumed to be carried out in two adiabatic stages. The CO-to-CO<sub>2</sub> conversion ratio in the High-Temperature (HT) and Low-Temperature (LT) stage is 65.4 % and 76.6 %.

The furnace supplies heat to the steam-methane reformer, and the additional waste heat is utilized for generation of IP steam, and and fuel pre-heating. In addition to natural gas, purge/tail gas from the pressure-swing adsorption unit for hydrogen purification makes a significant portion of the fuel consumption. The percentage of energy from the tail gas is around 40 % of the total fuel input on a lower heating value (LHV) basis.

Hydrogen purification is assumed to be carried out by pressure-swing adsorption. The hydrogen recovery rate is assumed to be 87 %. The tail gas contains the impurity components such as CO<sub>2</sub>, CO, unreacted methane and the unrecovered hydrogen fraction, and is assumed to be discharged at atmospheric pressure and subsequently sent to the furnace in the steam-methane reforming plant.

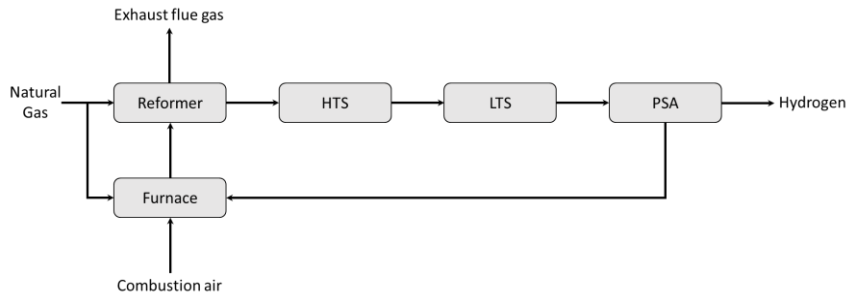


Figure 2: Process flow diagram of the hydrogen production plant without CCS

The "standard" option for CO<sub>2</sub> capture from an SMR process is usually capture from syngas prior to the PSA for H<sub>2</sub> purification due to the high partial pressure of CO<sub>2</sub> in the syngas. However, only approximately 60 % of the CO<sub>2</sub> emitted in the process can be captured when considering capture from the synthesis gas before the H<sub>2</sub> PSA or the tail gas after H<sub>2</sub> PSA, as the CO<sub>2</sub> emissions from the furnace are then not captured. As the aim of this study is to evaluate low-carbon footprint hydrogen, CO<sub>2</sub> capture from the furnace exhaust gas is considered in order to capture 90 % of the plant emissions. This is a typical post-combustion process with a relatively high CO<sub>2</sub> concentration of around 16.3 %. The process, illustrated in Figure 2, has been modelled and simulated in steady state using HYSYS v9.0 by AspenTech (2019) using the Soave-Redlich-Kwong (SRK) and acid gas fluid packages. The steam and power required by the CO<sub>2</sub> capture process are assumed to be extracted from the hydrogen plant.

The assessment of the CO<sub>2</sub> pipeline transport and storage from the hydrogen production plant are performed using the iCCS CO<sub>2</sub> value chain tool developed by SINTEF Energy Research (Roussanaly et al., 2014). As part of this evaluation, the optimal pipeline diameter was identified to be 10.75 in (0.27305 m). For the CO<sub>2</sub> storage in a saline aquifer, a well injection rate of 0.8 MtCO<sub>2</sub>/y/well is assumed (Roussanaly and Grimstad, 2014).

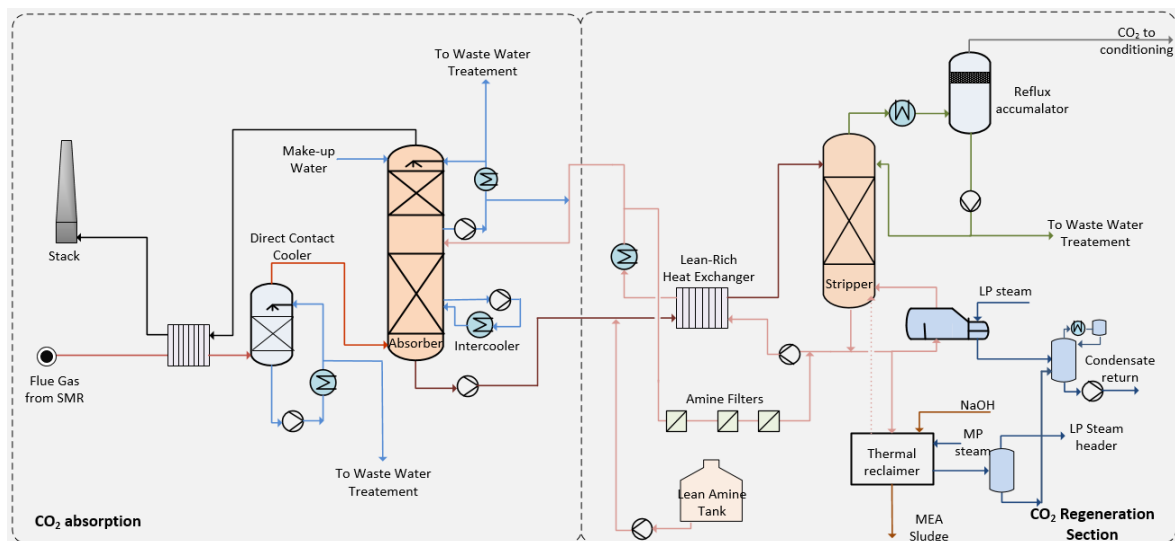


Figure 3: Detailed Process Flow Diagram of the CO<sub>2</sub> capture process for the hydrogen production plant with CO<sub>2</sub> capture (IEAGHG, 2017)

### 2.3 Cost modelling

The costs estimated here are based on a Nth Of A Kind (NOAK) estimates, for a Northern Norway location, and are representative of 2016 price levels.

The CAPEX of the hydrogen plant with and without CO<sub>2</sub> capture and conditioning are estimated using a Bottom-Up approach (BUA). In this approach, the equipment and direct cost for each basic equipment of the different processes are estimated. The direct costs of the hydrogen production plant equipment are scaled from cost published by the IEAGHG (2017a), while the direct costs of the CO<sub>2</sub> capture equipment evaluated in Aspen Process Economic Analyzer. The Total Plant Cost (TPC) are obtained by multiplying direct cost by a factor of

1.39 to account for Engineering, Procurement and Construction Costs (EPC), contingencies and owner cost (IEAGHG, 2017b).

The CAPEX of the transport and storage are assessed using the iCCS tool developed by SINTEF Energy Research (Jakobsen, 2017) and previous documented. The transport cost model relies on the pipeline cost model developed by Knoope et al. (2014) and the storage cost model relies on the Zero Emission Platform for Zero Emission Fossil Fuel Power Plants (2011).

The fixed operating cost of the hydrogen without and with CO<sub>2</sub> Capture and conditioning are scaled based on workforce evaluation and the maintenance cost methodology from IEAGHG (IEAGHG, 2017a). The variable operating costs are evaluated considering the estimated utilities and waste disposal and corresponding cost (Table 1).

*Table 1: Considered utilities and waste disposal costs*

Utility or waste	Cost
Natural Gas (€/GJ)	6 (IEAGHG, 2017a)
Raw process water (€/t)	0.2
Pure MEA solvent (€/t)	1,830 (IEAGHG, 2017b)
MEA sludge disposal (€/t)	205 (IEAGHG, 2017b)
Electricity in Norway (€/MWh)	57.4

The levelised cost of hydrogen with and without CCS, and the CO<sub>2</sub> avoidance cost are calculated following the methodology of IEAGHG (2017a) and assuming the following project characteristics: operating 7446 h/y, 25 y project duration and a discount rate of 8 %.

### 3. Results and discussions

#### 3.1 Technical performances

Based on the process simulation, the obtained performances of the hydrogen production plant without and with CCS are presented in Table 2. The natural gas consumption and hydrogen production remain the same between both cases, however the net power output of the hydrogen plant decreases due to 1) the steam consumption associated with CO<sub>2</sub> regeneration which decreases the gross power 2) the power consumption associated with CCS.

*Table 2: Key performances of hydrogen production plant without and with CCS*

Parameter	Without CCS	With CCS
Natural Gas to feedstock (t/h)	51.66	51.66
Natural Gas to fuel (t/h)	26.59	26.59
Natural Gas LHV (MJ/kg)	46.49	46.49
Total Energy Input (MW)	1,010	1,010
H <sub>2</sub> to battery limit (t/h)	18.77	18.77
H <sub>2</sub> to battery limit (Nm <sup>3</sup> H <sub>2</sub> /h)	208,700	208,700
Total energy in H <sub>2</sub> product (MW)	626	626
Gross power output from Steam cycle (MWe)	123.8	91.6
H <sub>2</sub> plant and co-generation power consumption (MWe)	-3.5	-3.5
CO <sub>2</sub> capture plant (MWe)	-	-6.7
CO <sub>2</sub> conditioning plant (MWe)	-	-18.3
Net Power output (MWe)	120.3	63.1
Total energy in H <sub>2</sub> product compared Total Energy Input (%)	61.9	61.9
Total energy in H <sub>2</sub> and electricity produced compared Total Energy Input (%)	73.8	68.2
Emissions (kg <sub>CO2</sub> /Nm <sup>3</sup> H <sub>2</sub> )	0.994	0.100

#### 3.2 Cost performances

The techno-economic performances resulting of the chain assessment are presented in Table 3 in a "semi-detailed" way.

The results show that the hydrogen production costs without and with CCS of 12.2 and 18.1 c€/Nm<sup>3</sup> are obtained. The hydrogen production cost with and without CCS are slightly higher than in the IEAGHG study

(IEAGHG, 2017a). This makes sense due to the location factor considered, however the results are hard to compare in detail as the electricity output and cost are significantly different between the two studies.

This cost increase results in a CO<sub>2</sub> avoidance of 67 €/t<sub>CO<sub>2</sub>,avoided</sub>. As expected, the main contributor to this cost is the CO<sub>2</sub> capture and conditioning which represent 57% of the CO<sub>2</sub> avoidance cost. The pipeline transport and the storage represent 17 % and 26 % of the CO<sub>2</sub> avoided cost. This emphasizes that to reduce the cost of CCS of this case, the focus should be mainly on options which can reduce the capture cost but also, to a lower extent, transport and storage. When looking more in detailed in the cost item contribution to the CCS cost, the main individual contributors are the energy penalty linked to capture (15.3 %), the storage Pre-Final Investment Decision (Pre-FID) cost (13.7 %), the absorber section CAPEX (11.7 %), energy penalty linked to conditioning (7.2 %), the capture fixed OPEX (7.2 %), the regeneration section CAPEX (7 %).

Table 3: "Semi-detailed" breakdowns of H<sub>2</sub> production cost and CO<sub>2</sub> avoidance cost of the H<sub>2</sub> production plant with and without CCS

	H <sub>2</sub> production without CCS		H <sub>2</sub> production with CCS			
	H <sub>2</sub> production cost		H <sub>2</sub> production cost		CO <sub>2</sub> avoidance cost	
	c€/Nm <sup>3</sup>	%	c€/Nm <sup>3</sup>	%	€/t <sub>CO<sub>2</sub>,avoided</sub>	%
<b>H<sub>2</sub> plant</b>	<b>12.20</b>	<b>100</b>	<b>11.94</b>	<b>66.1</b>		
CAPEX	3.49	28.6	3.31	18.3		
Fixed OPEX	1.43	11.7	1.38	7.6		
Fuel cost	10.46	85.7	10.46	57.9		
Electricity sale	-3.31	-27.1	-3.31	-18.3		
Make-up water	0.07	0.6	0.05	0.3		
Chemical and catalyst	0.06	0.5	0.06	0.3		
<b>CO<sub>2</sub> capture and conditioning</b>			<b>3.59</b>	<b>19.9</b>	<b>37.8</b>	<b>56.8</b>
CAPEX Absorber section			0.69	3.8	7.8	11.7
CAPEX Regeneration section			0.41	2.3	4.6	7.0
CAPEX conditioning section			0.26	1.4	2.9	4.4
Fixed OPEX			0.42	2.3	4.8	7.2
Energy penalty linked to capture			1.07	5.9	10.2	15.3
Energy penalty linked to conditioning			0.50	2.8	4.8	7.2
Make-up water			0.03	0.2	0.4	0.5
MEA make-up			0.16	0.9	1.8	2.8
MEA sludge disposal			0.05	0.3	0.5	0.8
<b>CO<sub>2</sub> pipeline</b>			<b>1.00</b>	<b>5.5</b>	<b>11.3</b>	<b>17.0</b>
CAPEX Material cost			0.15	0.8	1.7	2.6
CAPEX Labour cost			0.38	2.1	4.3	6.5
CAPEX Right Of Way			0.00	0.0	0.0	0.0
CAPEX Onshore-Offshore landfall			0.16	0.9	1.9	2.8
CAPEX Miscellaneous			0.17	1.0	2.0	3.0
Annual Fixed OPEX			0.13	0.7	1.5	2.2
<b>CO<sub>2</sub> storage</b>			<b>1.54</b>	<b>8.5</b>	<b>17.5</b>	<b>26.2</b>
Pre-FID			0.80	4.4	9.1	13.7
Injection wells			0.40	2.2	4.6	6.9
Operation and Maintenance			0.17	0.9	1.9	2.9
Monitoring Measurement Verification (MMV) CAPEX (annualised)			0.00	0.0	0.0	0.0
MMV OPEX (annualised)			0.07	0.4	0.7	1.1
Liabilities			0.09	0.5	1.0	1.5
Decommissioning			0.01	0.0	0.1	0.1
<b>Sum</b>		<b>100.0</b>	<b>18.07</b>	<b>100.0</b>	<b>66.6</b>	<b>100.0</b>

#### 4. Conclusions

While enabling low-carbon footprint hydrogen is key to decarbonise heat and power, industry, and transportation, developing solutions which can cost-efficiently deliver it is key. The present study develops an understanding of the techno-economic performances of hydrogen production from natural gas with CCS and where the cost lies.

Hydrogen production costs without and with CCS of 12.2 and 18.1 c€/Nm<sup>3</sup> are obtained, resulting in a CO<sub>2</sub> avoidance of 67 €/t<sub>CO<sub>2</sub>,avoided</sub>. CO<sub>2</sub> capture and conditioning is the main contributor to the CO<sub>2</sub> avoidance cost (57 %) while pipeline transport and the storage represent 17 % and 26 % of the CO<sub>2</sub> avoided cost. This emphasizes that to reduce the cost of CCS of this case, the focus should be mainly on options which can reduce the capture cost. In particular, for post-combustion solvent system, reducing the energy penalty associated with CO<sub>2</sub> capture and the cost of the absorber section is key. However, emerging post-combustion CO<sub>2</sub> capture technologies such as membrane, adsorption, or hybrid concepts also present significant potential to reducing cost and should be further investigated.

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