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Economic perspectives of Power-to-Gas technologies in bio-methane production

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Abstract

A study on integration of Power-to-Gas technology with bio-methane production from bio-syngas produced by biomass gasification shows that a significant amount of excess electricity can be accommodated in bio-SNG production. By adding hydrogen produced from intermittent renewable sources to a CO_2 methanation section, production capacity of methane can be doubled. The business case for Power-to-Gas for bio-methane has been evaluated using three future cumulative electricity prices curves. Results show that a positive business case exists only for price curves based on large amounts of intermittent electricity installed. The room for investment for the electrolyser will mainly and highly depend on future commodity prices and price curves, and will benefit significantly from a decrease in the cost price of the electrolyser. The projected room for investment available for a PEM electrolyser is lower than for a Solid Oxide Electrolyzer (SOE) , because of its lower efficiency and resulting higher operating costs. In the case of large capacity of intermittent electricity, the projected room for investment of an SOE electrolyser is 650 €/kW and for a PEM electrolyser 350 €/kW, which corresponds to the projections of future electrolyser costs.

Keywords: Power-to-Gas, bio-SNG, producer gas, biomass gasification, techno-economic evaluation

Nomenclature and Abbreviations

α	Slope of the line profit line in the price duration curve [€/MW]
η_{system}	overall efficiency of the system based on lower heating value [-]
ρ_{cat}	bulk density of the methanation catalyst [kg/m^3]
APEA	Aspen Process Economic Analyzer (software)
CRF	Capital Return Factor
EFF	Cold gas efficiency
Flow	Volumetric flow [m^3_n/h]
GHSV	Gas Hourly Space Velocity [h^{-1}]
HEX	Heat exchangers
IG band	Industrial consumers of electricity >150,000 MWh/year
In	Inlet
MEA	Mono-ethanol amine scrubbing
m_{cat}	Mass of catalyst in the methanation reactor [kg]
OP	operating profit [M€/yr]
P	electric power [MW]
PEM	Proton Exchange Membrane
P2G	Power-to-Gas

RFI	Room for investment
SNG	Substitute natural gas
SOE-EL	Solid Oxide Electrolyser, electrolysis mode
SOE-FA	Solid Oxide Electrolyser, fuel assisted mode
t	Cumulative operating hours [h/yr]
TCI	Total Capital Investment
LHV	Lower Heating Value [MJ/m^3_n]
Out	Outlet
$V_{g,in}$	Volumetric gas inlet flow to the reactor [m^3_n/h]

Introduction

Power-to-Gas (P2G) is a concept that allows for connecting and balancing the gas-grid with the power-grid and can be used to balance supply and demand for both commodities. Electricity from renewable sources is expected to significantly increase in the future as a result of the current European policies, as well as in other parts of the world. Conventional measures such as grid expansion and increasing the capacity of flexible power plant can only balance supply and demand in the electricity grid up to a certain level and in the long term new technologies are needed that enable efficient transmission and storage of energy supplied by highly fluctuating and non-controllable, natural, power sources[1]. The Power-to-Gas conversion chain uses the excess renewable electricity from fluctuating renewable sources for the production of hydrogen via water electrolysis and converts hydrogen with CO_2 to methane via the Sabatier reaction, which is fed into the natural gas distribution system as SNG (Substitute Natural Gas):

$$CO_2 + 4H_2 \leftrightarrow CH_4 + 2H_2O \qquad \Delta H=-164.9 \text{ kJ/mol}$$

Hence the advantage of Power-to-Gas concept is 2-fold: make use of peak electricity production typically induced by renewable sources in times of favourable weather conditions and mitigate the use of fossil fuel by using SNG. Furthermore the SNG can make use of the very large capacity of that is available in the Natural Gas transmission and storage infrastructure. Conversion to SNG rather than direct feed-in of electrolyser hydrogen in the natural gas grid avoids limitations to feed-in capacity set by the maximum amount of hydrogen allowed by the natural gas grid quality specifications. CO_2 is available in raw biogas from biomass fermentation processes for SNG production. Similarly, CO_2 is found in producer gas or bio-syngas from biomass gasification for SNG production that is currently in an advanced stage of development. Other sources for CO_2, but not further discussed here, are concentrated streams from industrial processes or from CO_2 from capture at fossil or biomass fuelled power plant.

Both the biogas from biomass fermentation and producer gas or bio-syngas from biomass gasification contain significant amounts of CO_2 (about 50%) that need to be removed to bring the SNG up to pipeline specification, which is normally done with mainly scrubbing technologies that involve a substantial efficiency penalty. Conversion of this CO_2 by the Sabatier reaction into methane avoids the energy required for the removal and increases the SNG production volume.

The economic feasibility of Power-to-Gas concepts has some very specific aspects that need special consideration. Electricity has in most occasions a higher market value than natural gas, but in times of favourable conditions for generation of renewable power, the large supply of electricity makes that market electricity prices are expected to be low. It can be expected that a larger spread in electricity prices depending on the demand-supply balance will emerge in future markets, which will be an incentive for a more flexible use of power. A special characteristic of renewable power from like solar and wind is that the marginal costs (the costs for power production without taking into account the investments) are close to zero. This is expected to result in in very low market prices of power during periods with a large supply of (renewable) power.

During favourable weather conditions for production of electricity from solar and wind, excess electricity could be available, implying that the production could exceed the demand, leading to curtailment of renewable sources. Under such market circumstances, technologies that allow for flexible operation could benefit by using low-value electricity in periods of excess renewable power. Since the future electricity and gas prices will be different from the current ones an analysis is needed to assess under which circumstances which P2G technologies are economically viable. In such analysis one needs to take into account the distribution of electricity prices over the year, which is done by making use of cost duration curves[2]. In this analysis, also the financial incentives which are present to cover the difference between fossil natural gas and SNG from renewable sources need to be taken into account.

This paper aims at evaluating the potential of Power-to-Gas technology in the production of bio-methane (SNG) from biomass gasification from a thermodynamic and economic perspective. In this system hydrogen is combined with CO_2 in the producer gas from the gasifier to produce additional methane through the Sabatier reaction. The first the lay-out of systems based on hydrogen from both Proton-Exchange-Membrane (PEM) based electrolysis and Solid Oxide Electrolysis (SOE) are defined as presented in Figure 1, and operating strategies are devised. System sizing and the energy balance of the selected processes are discussed. Based on cost duration curves the economics of the systems are derived, and the evolution of the profit throughout the cost duration curve is discussed.

The investment costs of future electrolysis are very uncertain. Rather than taking fixed value or ranges of electrolyser cost, an approach was taken quantifying the room for investment (RFI) for the electrolyser which can then be compared to cost projections discussed later in this paper. The room for investment is here the allowed electrolyser costs, i.e. those costs for which the P2G energy conversion route with electrolyser will have the same profitability as the CO_2 removal route without electrolyser.

A sensitivity study finally gives insight in the relative impact of changes in the assumptions and uncertainties in the analysis.

1 Methodology

1.1 Sizing and energy balance

In this work use of Power-to Gas concept to produce SNG or the second generation bio-methane is evaluated where the SNG is produced by gasification from ligno-cellulosic biomass (wood or straw). This process is carried out in two stages. First, the biomass is converted into producer gas or bio-syngas (mixture of methane, CO_2, CO, H_2, higher hydrocarbons, sulphur compounds, dust and tars). After gas cleaning, this producer gas is then transformed into bio-methane by catalytic synthesis.

For biomass gasification indirect gasification technology is considered [3]. This makes use of an indirect circulating fluidized bed gasifier (Milena). The gasifier consists of a gasification fluidized bed in which the biomass is converted into producer gas in the presence of steam and hot sand. In this step, also a significant amount of char is formed which flows with the cooled sand to a combustion fluidized bed zone in which the char is combusted thereby heating the sand. Downstream the gasifier, tar components present in the producer gas are removed by an oil gas absorber. This is then followed by subsequent gas cleaning steps: water scrubbing, hydrodesulphurization for removal of organic sulphurs, and a pre-reforming reactor in order to convert aromatic hydrocarbons [4]. Resulting product gas has following molar composition 21% CH_4, 17% CO_2, 35% CO and 21% H_2[4]. The gas enters the methanation section, which is conventional technology and consists of a synthesis loop of multiple adiabatic reactors with intercooling[5]. Next to the Sabatier reaction here, also CO is converted into methane the main constituent of SNG via:

$$CO + 3H_2 \leftrightarrow CH_4 + H_2O \quad \Delta H = -206.4\ kJ/mol \qquad [e.1]$$

For the hydrogen production from electricity several technologies for water electrolysis can be identified: alkaline water electrolysis, PEM and SOE [6,7]. Currently alkaline electrolysers are considered as state-of the art[7-9] and PEM cells are entering the market at small scale. However, because of better stop/start behaviour, a wider operating range and expected higher hydrogen purity of PEM cells, it is expected that shortly PEM technology will overtake the market. The Solid Oxide Electrolyser (SOE) is in a much lower development phase, but has the potential to be designed to operate in two different modes (electricity mode and fuel assisted mode) with a significantly different power demand. This opens up the opportunity to adapt the operation of the electrolyser depending on electricity market conditions. In periods of large excess electricity from renewable sources, electricity prices are expected to be low and the SOE will be operated in electric mode. In periods of high electricity prices either raw biogas or SNG product is introduced to the SOE to assist the electrolysis, leading to a significant reduction in electricity demand. This increases the number of operating hours of the electrolyser substantially and thereby the depreciation period. Moreover the SOE is operating at higher temperatures, resulting in a higher efficiency for the electrolysis and better opportunities for heat integration with the gasifier and methanation section. For PEM electrolysers such a fuel assisted mode is not feasible, here the option is either to maintain operation of the electrolyser in spite of a high electricity price, or to switch off the entire plant. Introduction of a CO_2 scrubbing unit parallel to the PEM electrolyser is not considered because of the associated large investments of the CO_2 scrubbing unit in cost and energy consumption.

The study was done for 5 cases varying the use and type of electrolysis and also varying the operating strategy with respect to high vs. low electricity prices. In the reference case, since H_2 is already present in the producer gas, the required stoichiometric ratio between CO, CO_2 and H_2 in the methanation reactor is achieved by means of an amine scrubbing (MEA), for CO_2 removal from the producer gas. In the P2G cases the CO_2 as well as CO in the stream will be converted into SNG by adding H_2 from an electrolyser unit. The hydrogen requirement has been set to match stoichiometric $H_2/(CO+CO_2)$ in the methanation reactor. In the case of electricity demand, two cases are evaluated: either the PEM cell will continue to operate or to total SNG production facility will be switched off when there is no low price electricity. For the SOE, this will mean operating in electric mode at periods of low electricity prices. When the electricity price is high, part of a fuel stream (produced SNG or producer gas) is used for fuelling the electrolyser and assists in producing hydrogen from water electrolysis by oxidation at the anode of the SOE, thereby significantly lowering the power demand. Two configurations have been evaluated for which fuel is used; in the first, producer gas downstream the tar and contaminants removal and in the second, using part of the SNG product. This adds up to the following cases, which are graphically presented in Figure 1.

(i) REF: a reference case SNG plant with amine scrubbing for CO_2 removal down to the required stoichiometric ratio of the methanation reactor.

(ii) PEM-CONST: an SNG plant with additional power-to-gas CO_2 conversion using PEM electrolysis for hydrogen production and using constant operation throughout the year irrespective of electricity price

(iii) PEM-SWITCH: an SNG plant with additional power-to-gas CO_2 conversion using PEM electrolysis for hydrogen production and an operating strategy which switches off the total plant during periods of high electricity prices.

(iv) SOE-SNG: an SNG plant with additional power-to-gas CO_2 conversion using SOE electrolysis for hydrogen production and an operating strategy which switches between electric mode for low electricity prices and using feed-in of part of the SNG product as feed for the fuel assisted mode during high electricity prices.

(v) SOE-PG: an SNG plant with additional power-to-gas CO_2 conversion using SOE electrolysis for hydrogen production and an operating strategy which switches between electric mode for low electricity prices and using feed-in of part of feed producer gas as feed for the fuel assisted mode during high electricity prices.

This study has focused only on those sections relevant for the analysis of the P2G concept. Therefore the complex gasification and gas cleaning section has been excluded. The feed stream is gas from the biomass gasifier after tar and contaminant removal. The molar composition 21% CH_4, 17% CO_2, 35% CO and 21% H_2 is taken from literature[4]. The impurities are removed before the Sabatier reaction to levels required for the catalysts, SOE as well as natural gas grid specifications.

When process conditions and feed composition are kept constant, the systems can be analysed without the need for complex flow sheeting calculations but can be simplified to calculations using lower heating value efficiencies, especially when aiming at a high-level comparison of concepts. The cold gas efficiency EFF of a unit operation is defined based on the product of volumetric feed flow Flow [m^3_n/s] and lower heating value LHV [MJ/m^3_n] also accounting for electric power P [MW] according to:

$$EFF = (Flow_{,out} \cdot LHV_{out})/(Flow_{,in} \cdot LHV_{in} + P_{in})\ 100\ [\%] \qquad [e.2]$$

In the calculations it was assumed that the efficiency of a PEM electrolyser was 80%, which is on the high side of reported ranges in literature[7] (range is from 67-82%). In the case of SOE, because of operation at higher temperatures, and the possibility to integrate heat available from the methanation reactors with the electrolyser, a higher electrolyser efficiency of 87% was taken[4]. All calculations were performed for 200 MW equivalent of producer gas from low temperature indirect gasification. This corresponds to a large-scale gasification plant for SNG production[10].

Cold gas efficiency in the methanation section is assumed to be 80%. The ratio of fuel to electricity in SOE in fuel assisted mode calculated from the mass and heat balance of the electrolyser was 11.63 MJ_{LHV}/MJ_e for either SNG or producer gas feed.

The steam required for the amine scrubber regeneration is supplied by the hot off-gases available from the biomass gasifier[3]. More details on the producer gas upgrade system are given in references[4,11]. The cold gas efficiency of the Sabatier reaction, the methanation reaction with CO_2, in all calculations was 86%[11,12].

The technology readiness level and an indication of studied technologies flexibility are given in Table 1. Table shows that only PEM electrolysers and a methanation technology are currently available at the commercial scale. Biomass gasifier is currently at the pilot scale and SOE electrolysers are at the research and development. In terms of flexibility of P2G concepts, it can be seen in Table 1 that if switched-off , all studied systems will need hours to start-up. This is due to the slow start-up required for the gasification unit, methanation section or, in the case when SOE is used, SOE unit. However, frequent shut down of the plant, in the case of the high electricity price (B in Figure 1) may permanently damage the chemical catalyst used, and a turndown of the plant in this case will be preferable. In that case studied P2G systems can reach the full production capacity in several minutes. However, additional hydrogen storage units will be required to provide the hydrogen in the period of the high electricity price.

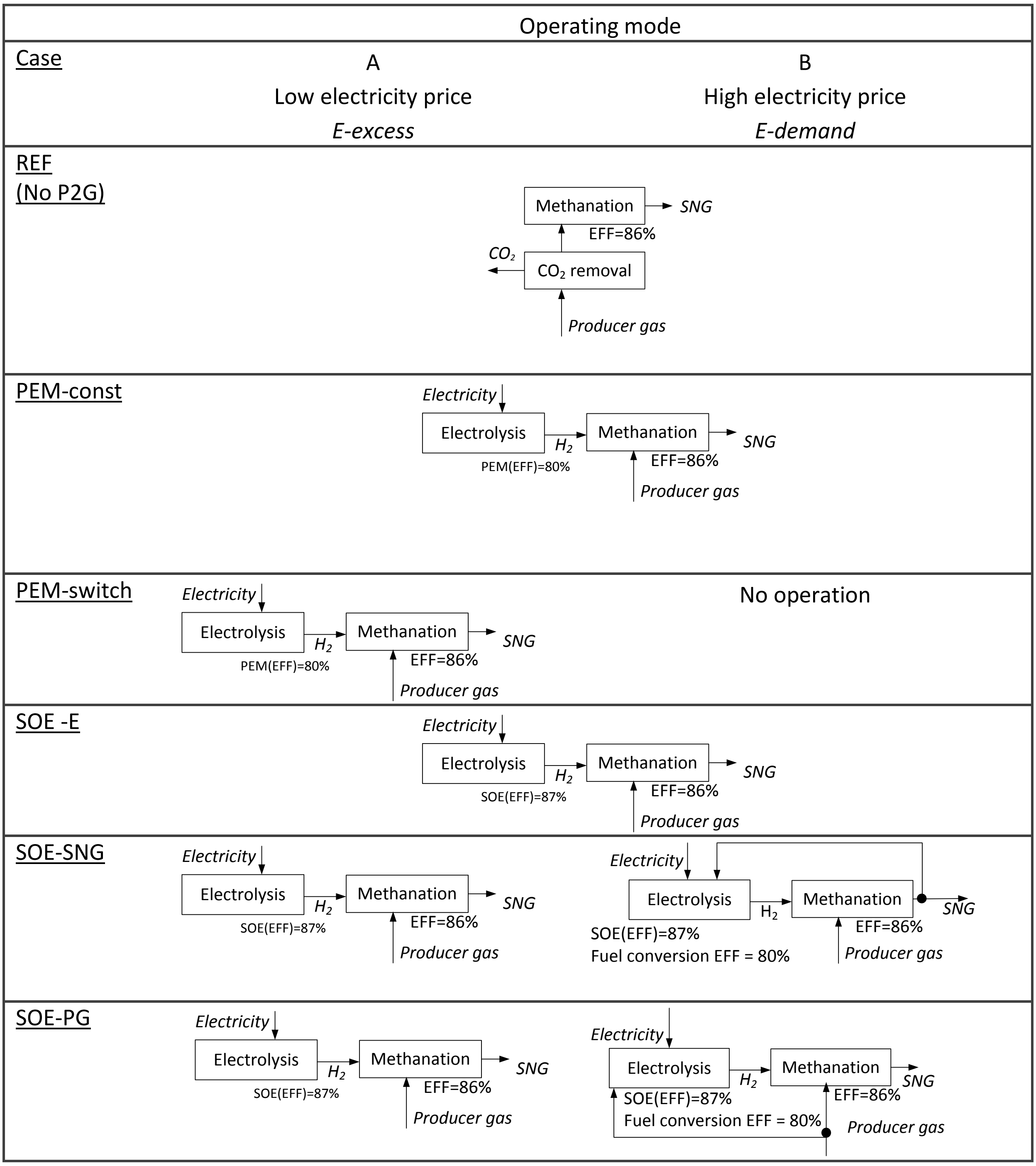

Figure 1 Overview of concepts evaluated

Table 1 Characteristics of different technologies studied

	Technology readiness level[13]	Start-up from cold	Deployment from stand-by modus
Biomass gasification and gas cleaning)[14]	TRL 4-6	hours	minutes
PEM [7,15]	TRL 9	10 min	10 sec
SOE[7,15]	TRL 2-5	hours	15 min
Methanation [7]	TRL 9	hours	15 min

Different concepts are evaluated thermodynamically, based on the following criteria: the SNG production capacity, electricity demand, overall efficiency and the contribution to the overall natural gas share.

The overall efficiency is defined on a lower heating value basis by:

$$\eta_{system} = (Flow_{SNG} \cdot LHV_{SNG}) / (Flow_{in} \cdot LHV_{in} + P_{in})\ 100\ \ [\%] \qquad [e.3]$$

The overall impact on the natural gas balance in the Netherlands was calculated based on the literature [16,17] in which the potential production of SNG from biomass gasification in The Netherlands has been estimated at 3.5 10^9 $m^3_n \cdot y^{-1}$ which represents between 5-7% of the yearly natural gas consumption.

1.2 Economic evaluation

An overview of all the relevant starting points used in the capital cost estimation is listed in Table 2. The values are commonly accepted general values taken from literature. In the economic calculations the CAPEX considered is for the gasifier, gas cleaning and methanation section. The investment costs for the plant are calculated based on the estimated volumetric flows from the system evaluations in earlier work [4], in which the system analysis for producer gas to SNG energy conversion chain was presented. For the estimation of purchase costs of a methanation section the APEA® (Aspen Process Economic Analyzer) program was used [18]. The catalyst costs were based on a nickel-based methanation catalyst using a typical gas hourly space velocity (GHSV) and a correction for deactivation by coking.

The installation costs of the equipment were calculated using standard installation factors from literature[19]. The analysis has been done for the n^{th} plant not taking into account increased risk surcharges for novel equipment. The installation costs of the MEA absorption unit was calculated from the literature[20] and scaled down to the required size using a six-tenths rule[21]. The installation costs of the gasifier and a producer gas cleaning section was estimated from literature[22]. Finally overall plant cost including indirect costs was estimated using the guidelines by the American Association for Cost Engineering[23]. In the calculations, the depreciation period has been assumed the project lifetime, including the technical and economic lifetime of the electrolyser being 10 years. With an assumed 6% interest rate, the capital return factor (CRF) is 0.136. The yearly capital costs are calculated by multiplication of the capital return factor with the total capital investment of the plant (TCI).

Table 2 Starting points for capital costs calculation

Parameter	Value
Methanation reactor GHSV [h-1]	10,000
Methanation catalyst lifetime[7] [yr]	3
Design factor for coking/deactivation	30%
Catalyst costs [k€/t][24]	19
$\rho_{cat,}$ bulk density methanation catalyst [kg/m^3][25]	930
Heat exchanger purchased costs	50% of methanation unit costs
MEA solvent exchange [yr]	2
Exchange rate	0.72 $/€
Plant Location	Western Europe
Material and Labour factors	Standard values from ACCE[23]
Installation factors for process equipment	
Compressors	2
Vessels	4.1
Heat exchangers	4.8
Capital costs	
Indirect costs	1.15 of Total Field Labour costs
General Facilities Factor	15% of Total Process Capital
Home office overhead and fee	15% of Total Process Capital
Prepaid royalties	0.5% of Total Process Capital

Spare parts	0.5% of Total Process Capital
Working capital	2 months of annual operating costs
Contingency	13%
Start-up	
Operator training, extra maintenance	2 months of annual operating costs at full capacity
Fuel consumption	25% additional of total fuel at full capacity for 1 month
Expected changes, modification equipment	2% of total plant costs
Operating costs	
Supervisory labour	15% direct labour
Maintenance labour	3% of total Plant Costs
Payroll Overhead	35% of total Annual Labour
Maintenance Material	3% of total plant costs
Indirect Material	25% of total direct labour
Property Taxes and Insurance	2% of total plant costs
Administration and Corporate	60%of total labour

In the analysis, a renewable gas incentive (subsidy) is included for SNG from biomass, as is current practice in the Netherlands. This incentive is a financial incentive paid to operators on top of the market prices for natural gas. The current natural gas price used is 7.5 €/GJ and a green gas subsidy can vary from 3.6 €/GJ for a large scale unit (1000 MWth) to 32.4 €/GJ for a small scale unit (10 MWth)[26,27]. The assumed base case subsidised SNG price used in this work was 21 €/GJ[8,28-30], which is at the high end of the spectrum. Therefore, a sensitivity study on the SNG price is performed.

The electricity price used in this study is expressed in cumulative electricity price duration curves, given the electricity price as a function of the number of operating hours per year, in order of increasing electricity price. The level of the electricity price and especially the shape results from many factors in future electricity markets. In scenarios with a very large increase in the supply of renewable electricity, significant changes in these markets will occur. The two different price duration curves evaluated in this study are depicted in Figure 2:

1. Curve 1, a curve based on the current electricity spot market in Germany [2]. Germany was selected as an example of a country with high intermittent electricity introduction.

2. Curve 2, a hypothetical two-level electricity market curve based on contract pricing in which the electricity price of P2G competes with alternative applications. Assuming competition of Power-to-Gas with electrification for heating purposes (Power-to-Heat) at large electricity excess the electricty price will then compete with the heat price. The low price plateau is based on a natural gas price of 7.5 €/GJ[26], and efficiencies of 0.93 for primary energy to heat and 0.95 for electricity to heat, resulting in an electricity price of 27.5 €/MWh. The amount of hours per year for these low prices is equal to the amount of hours of excess electricity and is estimated at 3950 hrs per year. This is based on literature[31] using a scenario with a 50% higher capacity of renewable intermittend electricity production capacity than the current 2020 target in the Netherlands. For the rest of the operating hours, a high plateau electricity price is assuming competition with an electricity mix from the fossil fueled plants and renewables. The value used is 70 €/MWh, which is based on the market expectations for large demand customers in 2012 (IG band, average of the range 50-70 €/MWh, escalated with a 6% increase to 2025[32]) and estimated wind electricity price of 63 €/MWh[33] for 2030.

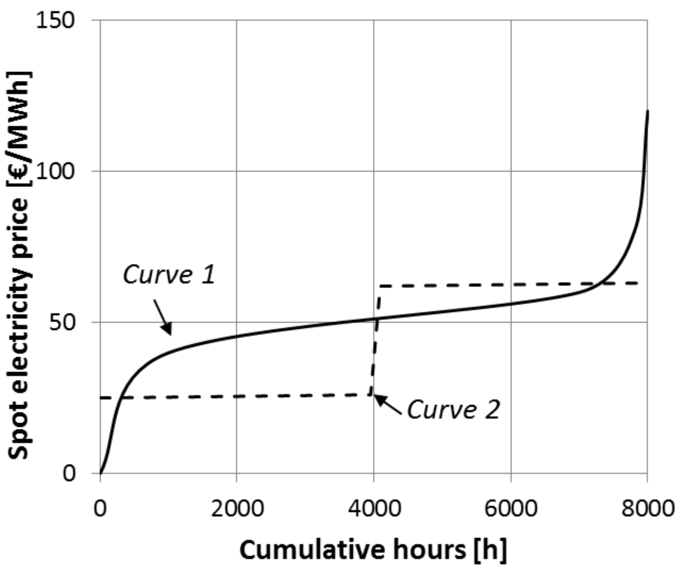

Figure 2 Electricity price duration curves

For both curves, the situation of excess electricity will be found at the left hand side of the price duration curve. Here supply exceeds demand leading to very low market price. Using the electricity price curves combined with other operating costs, SNG benefits and capital costs, the profit evolution over the cumulative operating hours can be calculated and plotted in a cumulative operating profit (Figure 3 and Figure 4), using on the x-axis the same cumulative operating hours as in the cumulative price curve. For this, the operating profit (OP) is calculated for each finite time element dt using:

$$OP(t+dt) = OP(t) + SNG\ benefits(dt) - Operating\ costs(dt) - Capital\ costs(dt) \qquad [e.5]$$

The overall operating profit at the end of one year of operation is then found at the right side of the graph (operating hours=8000 [h]).

The SOE can operate in electrolysis or fuel assisted mode, following an operating strategy to maximize the profit based on the slope of the profit curve defined in e.6.

Since SOE can operate in electrolysis or fuel assisted mode, a switching point between the SOE electrolysis and fuel assisted mode will be defined using the slope α of the curve of the profit as function of the cumulative operating hours defined by:

$$\alpha(t) = \frac{d\,OP}{dt} \qquad [e.6]$$

The SOE is operated in SOE-FA mode if:

$$\frac{\alpha_{soe-el}}{\alpha_{soe-FA}} < 1 \qquad [e.7]$$

Else the SOE-EL mode is more profitable and the system is operated in this mode.

Finally, the room for investment for the electrolyser is calculated from an equal profit between the P2G case and the reference case using:

$$RFI\left[\frac{€}{KWh}\right] = \frac{(Profit\ E\text{−}excess\ [\frac{K€}{year}] - Profit\ E\text{−}demand\ [\frac{K€}{year}])}{Electrolyzer\ power\ \ [KWh]\cdot CRF} \qquad [e.8]$$

More important than the absolute answer, which is subject to significant uncertainties, is the impact of input parameters. Hence, a sensitivity study on the room for investment curve 2 was performed determining the impact of the main variables over an estimated uncertainty interval:

- PEM cell efficiency. Currently, PEM electrolysis is used in applications where the overall efficiency is not critical. It is expected that efficiency of PEM electrolysers will increase in the future from 67-82% to 87-93% [7]. The efficiency of the PEM electrolysers was varied from 80% to 93%. However, there will be trade –off between the improvement of efficiency and decrease of the electrolyser costs by increase of the current density. In fact reported long term targets lay in optimising efficiency in lower-cost systems, e.g., those with high current densities[15].
- A relative contribution of the heat exchangers costs to the overall costs. The contribution was varied ±50%.
- Compressor costs. Taking into account that Aspen APEA® is used to estimate the costs for the large scale installations, it is expected that the cost of few hundred kW[34] compressor is at the higher range. Therefore the sensitivity study was done for compressor costs reduced by 90%.
- MEA absorber capital costs. The contribution of these costs was varied ±20%.
- Capital charge factor. The value was varied between 0.10-0.15.
- SNG price. The subsidy for the SNG plant will decrease with the plant capacity. In our calculations rather high subsidy was assumed. The SNG price was varied ±20%.
- The number of curtailment hours. The number of curtailment hours was varied from the base case value (3950 h) down to 1000 h.
- The natural gas price. This will determine the electricity price at curtailment hours when it competes with Power to Heat. The range 5 – 9 €/GJ[26] was used.

- Electricity price. The high electricity price (price for electricity above >4000 h) in curve 2 is increased from 70 to 112 €/MWh, which is a current estimated price of intermittent electricity[33].

2 Results and discussion

2.1 Sizing and energy balance

Table 3 gives an overview of the results of the sizing and energy balance evaluation. The envisaged system size is based on the size of the biomass gasifier, for which a capacity equivalent to that of a commercial coal gasification unit is taken. The resulting total electricity feed-in is approximately 250 MW per plant, which corresponds to the installed electricity generating capacity of 2 to 3 large off-shore wind farms[35,36] and corresponds to the hydrogen production of approximately 6 t/h. The input energy are presented for all cases both for periods of electricity surplus (system running in mode A, Figure 1, Low electricity price, *E-excess* mode) as in times of electricity demand (system running in mode B, Figure 1, High electricity price, *E-demand* mode). The main finding is that for the large electricity surplus mode the SNG production capacity can almost be doubled in the P2G cases compared to the base case, from 166 MW to 319 MW of SNG produced. This holds both for PEM as well as for SOE based systems, but for PEM the electricity input is larger.

For the electricity demand mode, the system will produce less SNG than the reference case, since part of the producer gas feed, SNG, is used in the electrolyser. Amongst these two options, the system with recycling of the SNG (SOE-SNG) is not an attractive option, since in **mode B (*E-demand* mode**), the amount of SNG required for the SOE is so large that the resulting SNG produced is insignificant (45 MW) and has a very low efficiency of 20%. A much more attractive option is to use cleaned producer gas in the SOE-PG system, which avoids the energy loss involved in conversion of producer gas into SNG, resulting in the production of 127 MW of SNG.

Table 3 SNG production, electricity demand and overall system efficiency, cases refer to Figure 1

Case/mode	Electricity input [MW]	SNG product [Nm^3/h]	SNG product [MW]	η_{system} [%LHV] Calculated from (eq.3)
REF (no P2G)	0	33,357	166	83%
PEM-CONST A PEM-CONST B	264 264	64,008 64,008	319 319	69% 69%
PEM-SWITCH A PEM-SWITCH B	264 0	64,008 0	319 0	69% -
SOE-E A SOE-E B	243 243	64,008 64,008	319 319	72% 72%
SOE-SNG A SOE-SNG-B	243 24	64,008 9,023	319 45	72% 20%
SOE-PG A SOE-PG-B	243 10	64,008 25,591	319 127	72% 61%

Based on the energy balance analysis it was decided not to consider the SOE-SNG option and to focus on the remaining options.

2.2 Economic evaluation

A breakdown of the installed equipment costs for reference and P2G case is given in Table 4 and Table 5.

The breakdown of the capital expenditure (CAPEX) for P2G case is given in Table A.1. For the reference case, the highest contributions to the capital costs are the MEA absorber and the heat exchangers. For the P2G cases, both for PEM and SOE the highest contribution is from the heat exchangers (HEX). It must be noted that the electrolyser costs for PEM or SOE are not included and are accounted for in the room for investment. If included they will be dominant in the overall investments. The estimated capital costs of the methanation section of the 286 €/kW SNG are in agreement with the literature[7]. Table 4 shows a quite high contribution of the heat exchanger cost to the overall costs. This is because rather high heat exchanger area is required for the utilization of the heat from the methanation section [37,38]. In these references, heat integration was obtained in such a way that the heat export was maximized. The heat exchange area can likely be decreased by using a larger temperature difference, at the cost of efficiency. Since a detailed heat exchanger network was not developed, the contribution of the heat exchanger costs to the overall costs will be subjected to a sensitivity study.

Table 4 Breakdown of the installed equipment costs for the reference case (no P2G)

Item	**Purchased equipment costs [M€]**	**Installed equipment Costs [M€]**	**% of total costs**
Producer gas compressor	2.28 [18]	4.56	11
Reactor vessel 1	0.38 [18]	1.56	4
Reactor vessel 2	0.13[18]	0.55	1
Reactor vessel 3	0.09 [18]	0.368	1
Recycle compressor	0.77 [18]	1.54	4
SNG compressor	1.47 [18]	2.94	7
KO drum	0.008 [18]	0.03	0
Heat exchangers	2.57	12.33	30
MEA adsorber	8.86 [20]	17.82	43
Total costs	**17.10**	**41.71**	**100**

Table 5 Breakdown of the installed equipment costs for the P2G case

Item	Purchased equipment costs [M€]	Installed equipment Costs [M€]	% of total costs
Producer gas compressor	3.24 [18]	6.49	19
Reactor vessel 1	0.89 [18]	3.65	11
Reactor vessel 2	0.31 [18]	1.27	4
Reactor vessel 3	0.15 [18]	0.63	2
Recycle compressor	0.94 [18]	1.87	5
SNG compressor	1.6 [18]	3.21	9
KO drum	0.04 [18]	0.17	1
Heat exchangers	3.59	17.24	50
Total costs	**10.77**	**34.54**	**100**

The results of the economic assessment are presented in 1-year cumulative operating profit diagrams, depicting the operating profit (OP) evolution over 1 year on the y-axis and on the x-axis there is the cumulative hours from the price duration curves 1 and 2.

The cumulative operating profit curve starts at a negative value which is the yearly depreciation. The OP then increases as a result of the operational margin, but some curves show a decline as a result of a negative operation margin, caused by high peak electricity prices. The final yearly profit [M€/year] is found at the right hand side of the diagram at the 8000 h of total operation.

Figure 3 present the results for electricity price curve 1 with current market prices. The yearly deprecations excluding those for the electrolyser (intercept at left-hand side of the curve) is only slightly lower for the P2G cases considered compared to the reference case. The reference case is a straight line, and has an operating margin of 17.4 M€/year. All P2G lines show some curvature as a result of variation of operating margin over the year. The SOE based systems have a higher efficiency than the PEM based systems, resulting in a steeper line.

In the case of the PEM electrolyser, the plant will be switched off in the period of high spot electricity prices between 7500 to 8000 cumulative hours. This will mean that for PEM- SWITCH capital will be depreciated over a shorter time. Comparting PEM-SWITCH and PEM-CONST profit can be increased from 16.3 M€/year to 16.7 M€/year by switching off the PEM electrolyser. However, the calculated savings are not significant, taking into account operability issues connected to shutting down of the plant.

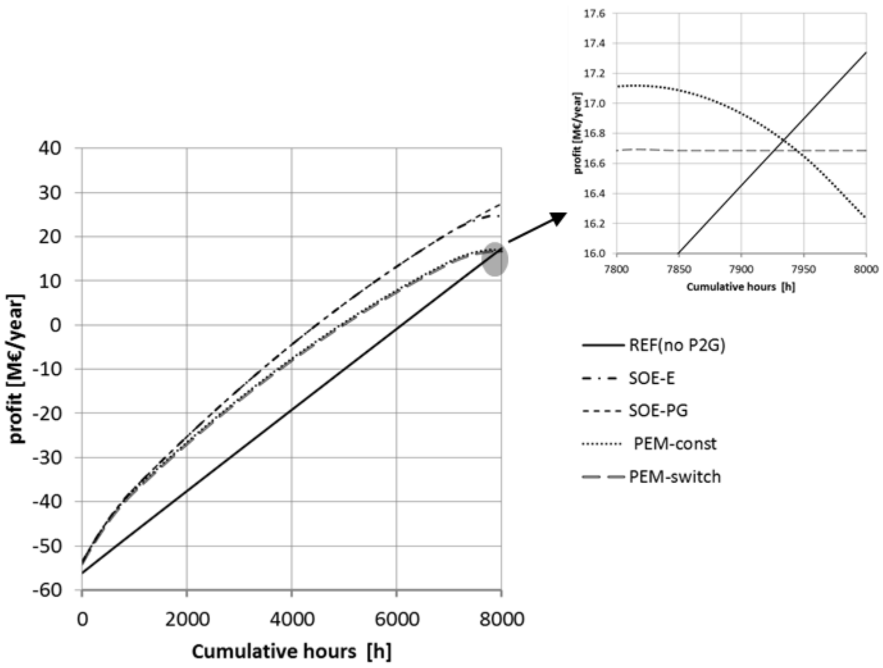

Figure 3 Operating profit curve 1, evolution of profit as function of hours on the cumulative electricity price curve 1. The electrolysis cell costs excluded.

Figure 4 depicts the evolution of the operating profit over the year for a future scenario, curve 2, with a large amount of installed renewable power. At 4000 h most of the systems switch in mode due to the change in electricity price. The option to switch off the PEM system during high-electricity prices (PEM-SWITCH) is very unattractive compared to continuous operation (PEM-CONST). Comparing the SOE options it can be seen that the difference between the SOE-E and SOE-PG options is negligible, meaning that there is no additional benefit for switching to fuel assisted mode. This is however very much dependent on the assumed electricity prices as will be discussed later. For this scenario, P2G technologies clearly generate a higher yearly operating profit compared to curve 1.

Again, because of the higher efficiency, SOE is preferred over PEM electrolysis with respect to operating profit without taking into account the electrolyser investments.

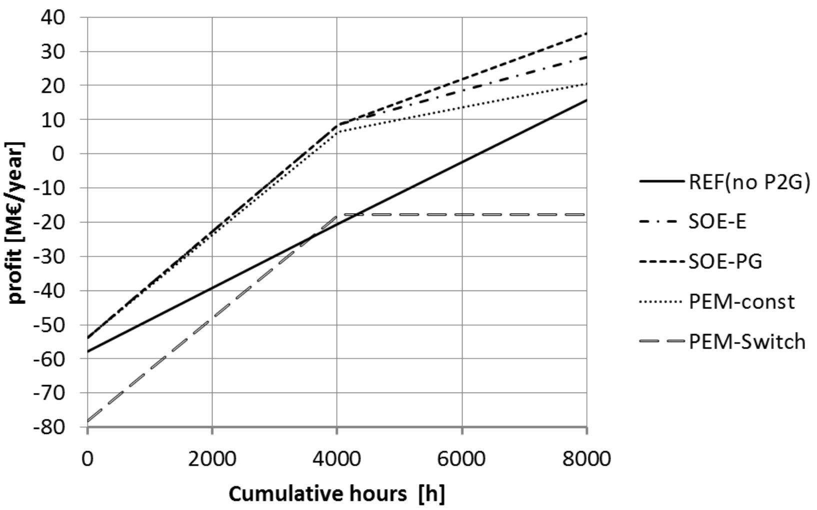

Figure 4 Profit curve 2, evolution of profit as function of hours on the cumulative electricity price curve 2. The electrolysis cell costs excluded.

The estimated room for investment (RFI) for the installation of electrolyser system for different operation modes is calculated from the yearly profit obtained at t-8000 h of continuous operation and is presented in Table 6. At current market prices as used in curve 1, the RFI is much lower than that for the future price scenario of curve 2. For curve 2, the RFI for the SOE electrolyser is about 650 €/kW and for the PEM electrolyser 350 €/kW. So clearly a higher room for investment is found for the SOE system.

Comparison to projected electrolyser cost is subject to significant uncertainties. Currently there is no commercial SOE electrolyser available. Estimates in literature[7] indicate that in the future SOE cells might be brought on the market for 280-440 €/kW. Current costs of the PEM electrolysers are in the range of 2000-10,000 €/kW [39]. However, it is expected that in the near future these costs can decrease to 500 €/kW[8]. From this it cannot be said, however, that PEM investments will be higher than SOE, since both these cost projections rely on yet unfinished successful technology development and large market volumes. It can be concluded though, that the room for investment found for both options is in the range of price projections for electrolyser investments. All electrolyser costs indicated are purchased costs of a package unit electrolyser system including power supply, system control, gas drying but exclude grid connection [15]. Grid connections are assumed to be included in general facilities for the total plant and not listed separately for the electrolyser in order to simplify the analysis.

From the results it can be seen that the end-of-year operating profit is small compared to the overall operational and capital costs, so it is also very interesting to see how a change in the underlying assumptions would impact the RFI for the electrolyser. The results of a sensitivity study for the parameters defined above are presented in tornado diagrams, both for the PEM system and for SOE system.

The most important cost factors for the PEM-CONST system (Figure 5) are the electricity price during electricity demand, and the hours per year of excess electricity, which is also known from literature[1,31]. The scenario of curve 2 with 4000 hours of low-price electricity corresponds to very large amounts of installed intermittent electricity supply e.g (wind, solar or tidal energy**)** suggesting that P2G for PEM systems become feasible for post 2020 scenarios with a very high share of renewable energy implementation. Most important in the sensitivity assessment are factors affecting the operating margin, rather than the investments. Further technology development could help PEM electrolysis here, it can be seen that increasing the efficiency to the upper value of the range taken (from 80 to 90%) would bring the RFI in range with the projected PEM electrolyser investment target.

The SOE-PG (Figure 6) system has a clear advantage being able to switch to fuel assisted mode at high electricity prices. This makes that the sensitivity towards especially the value of the high electricity price, but also that towards the hours of low price electricity, is reduced compared to the PEM system. For a high electricity price of 112 €/ MWh the available room for investment for the electrolyser is approximately 300 €/ kW, while PEM system is running at a significant loss for such high electricity prices. For this system the number of hours of low cost electricity and the SNG price are the two most important factors in the economics. The profit curve for this system is shown in the Figure 7. Comparing the SOE-E and SOE-PG lines it is concluded that the significant decline of the operating profit evolution at high spot electricity prices (between 4000 and 8000 cumulative h) observed for the SOE-E can effectively be reduced with the fuel assisted mode. In fact, for this case SOE-PG is the only configuration that can generate profit higher than the reference case.

Table 6 Operating profit and room for investment for different modes of operation

Mode	Curve 1 Yearly operating profit (excl. electrolyser) [M€/year]	Curve 1 RFI electrolyser [€/kW]	Curve 2 Yearly operating profit (excl. electrolyser) [M€/year]	Curve 2 RFI electrolyser [€/kW]
SOE -E	24.3	236	34.8	640
SOE-PG	27	339	36	680
PEM-SWITCH	16.7	<0	28	350
PEM-CONST	16.3	<0	<0	<0
REF (no P2G)	17.3	n.a	16	n.a.

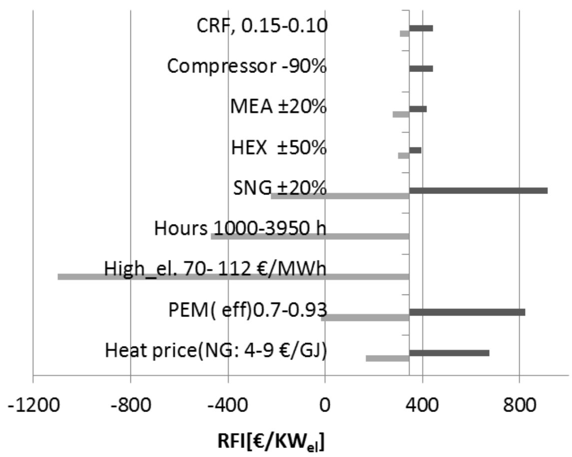

Figure 5; Sensitivity study for the PEM- Const

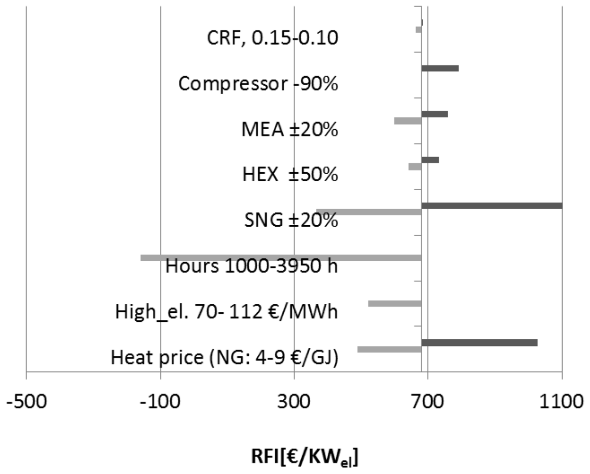

Figure 6 Sensitivity study for the SOE-PG system

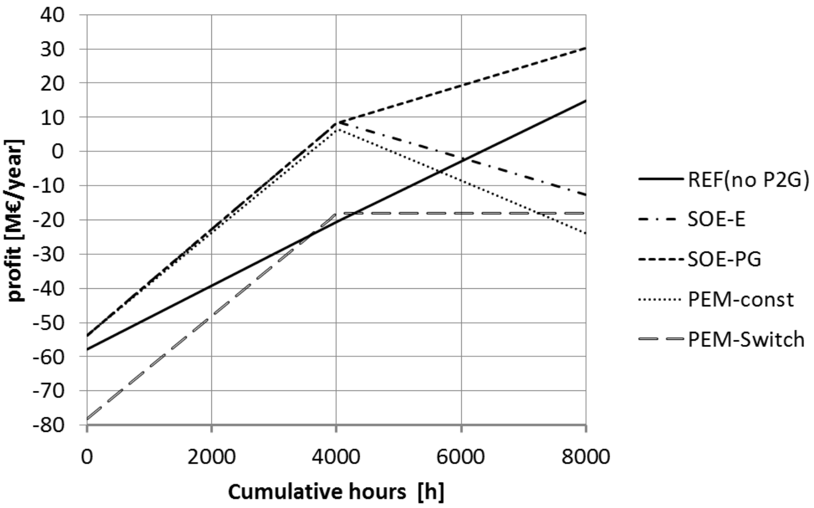

Figure 7 Profit curve 2, evolution of profit as function of hours on the cumulative electricity price curve 2, high electricity price 112 €/MWh

3 Conclusions

The value of the producer gas in the Power-to-Gas concept assessed by the present study has revealed to be an attractive option for the production of renewable methane and further transport and storage in the existing gas infrastructure from a technical perspective. Beyond allowing for large scale storage of fluctuating renewable power, it enables the introduction of renewable energy in the whole energy system, from power production for industry to households. The results show that renewable hydrogen addition to a producer gas originating from the gasification of biomass allows for doubling the SNG production compared to using the producer gas alone for SNG production.

An economic analysis has been made, determining the room for investment for the electrolyser for several configurations. As shown in Figure 5 and Figure 6, in order to have a positive business case for P2G for bio-methane a large amount of the intermittent electricity installed, where lot hours at the low electricity price are available, is essential. As presented in Figure 7, if 8000 hours of plant operation is required, operating the SOE by switching between electricity mode to fuel assisted mode, for high electricity prices, has clear economic advantage. It was shown in

Table 3 that only the use of producer gas is a feasible option and that using SNG product for the fuel assisted mode should be avoided.

For the PEM cells systems, this fuel assisted mode is not an option and as a result electricity prices higher than 70 €/MWh (Figure 5) do not give an economic perspective. Room for investment for the PEM electrolyser is smaller than that of the SOE case, because of its lower efficiency and resulting higher operating costs. The sensitivity study showed that available room for investment for the electrolyser primarily depends on the future commodity prices and the number of operational hours. Increase in electrolyser efficiency will always improve the business cases. For the SOE electrolysers estimated room for investment is within the range of predicted future costs. For PEM electrolysers, this can also be envisaged, but under more optimistic assumptions on efficiency and/or SNG selling price. Given the challenges of accommodating large amounts of renewable electricity, both systems, but especially the SOE based one, are concluded to be options that deserve further attention. Current research into increasing the PEM power density by a factor of 3-5 will decrease the cost by similar factors, thus holding the promise for a larger profitable window of operation[15].

4 Acknowledgment

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A. Appendix

Table A.1 Breakdown of total capital investments based on Table 2 and installed equipment costs from Table 5, for P2G case, installed equipment costs do not include electrolyser

	M€
Installed equipment costs	**34.54**
Indirect Field costs	5.96
Total process capital (excl. process contingencies)	**40.50**
General Facilities	6.07
Home office, Overhead and Fee	6.07
Process Contingenties	5.26
Project Contingenties	12.96
Total plant costs	**70.87**
Pre-paid royalties	0.20
Start-up Costs	
a) X month of total annual operating costs at full capacity	4.23
c) expected changes and modifications of equipment	1.42
Total Start-up	5.65
Working Capital	13.75
Spare Parts	0.35
Initial catalyst and chemicals	1.06
Total Capital Investment	**91.88**
Of which depreciable investments	**72.48**

Table A.2 Breakdown of total capital investments based on Table 2 and installed equipment costs from Table 4, for reference case, installed equipment costs do not include electrolyser

	M€
Installed equipment costs	41.71
Indirect Field costs	7.20
Total process capital (excl. process contingencies)	**48.91**
General Facilities	7.34
Home office, Overhead and Fee	7.34
Process Contingenties	6.36
Project Contingenties	15.65

Total plant costs	85.59
Pre-paid royalties	0.24
Start-up Costs	
a) X month of total annual operating costs at full capacity	1.12
c) expected changes and modifications of equipment	1.71
Total Start-up	2.83
Working Capital	15.77
Spare Parts	0.43
Initial catalyst and chemicals	0.53
Total Capital Investment	**105.38**
Of which depreciable investments	**86.78**