청정에너지기술

Techno-economic Analysis of Power to Gas (P2G) Process for the Development of Optimum Business Model: Part 1 Methane Production

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Abstract

This study provides an overview of the production costs of methane and hydrogen via water electrolysis-based hydrogen production followed by a methanation based methane production technology utilizing CO_2 from external sources. The study shows a comparative way for economic optimization of green methane generation using excess free electricity from renewable sources. The study initially developed the overall process on the Aspen Plus simulation tool. Aspen Plus estimated the capital expenditure for most of the equipment except for the methanation reactor and electrolyzer. The capital expenditure, the operating expenditure and the feed cost were used in a discounted cash flow based economic model for the methane production cost estimation. The study compared different reactor configurations as well. The same model was also used for a hydrogen production cost estimation. The optimized economic model estimated a methane production cost of $11.22/mcf when the plant is operating for 4000 hr/year and electricity is available for zero cost. Furthermore, a hydrogen production cost of $2.45/GJ was obtained. A sensitivity analysis was performed for the methane production cost as the electrolyzer cost varies across different electrolyzer types. A sensitivity study was also performed for the changing electricity cost, the number of operation hours per year and the plant capacity. The estimated levelized cost of methane (LCOM) in this study was less than or comparable with the existing studies available in the literature.

Keywords : Hydrogen, Renewable methane, Excess renewable electricity, Power to gas, Economics

1. Introduction

Solar power is more affordable, accessible, and prevalent worldwide as well as in the United States in the most recent years [1]. Due to the high affordability and volatile nature renewable energy sources like solar, wind the renewable energy share in the electricity grid is increasing. This increased share of solar power results the grid is imbalance at certain time of the day. Power curtailment is a common scenario for such case when grid stability is important. Power curtailment is the way of cutting the power delivery from a generator to the electrical grid. In this article, the focus is power curtailment when power supply exceeds the power demand due to volatile renewable energy generation. An example is shown in Figure 1 and Figure 2: power is curtailed in California for grid stability at certain time of the day. In 2020, the total amount power curtailed in California was about 1.6 TWH [2]. In 2015, 4.7 TWH of electricity being curtailed in Germany for grid stability [3]. While the solar power curtailment is common, from 2010 to 2016, in China, 150.4 TWH wind power was curtailed which is about 16 percent of overall wind generation [4]. This loss is estimated to exceed $1.2 billion.

The power loss is huge in California or China as well as worldwide where the volatile energy source is present even after the battery storage. This electric power is available for storage in battery or in any other form. The battery storage is technologies help utilities to provide the power quality and reliability required, and transition to intermittent renewable energy sources [5]. Energy storage advantages the system responsiveness, reliability, and flexibility. Energy storage improves the power grid stability and manage the utilization of volatile energy sources including the high-power demand during certain time of the day. Battery technologies are the widely used energy storage system around

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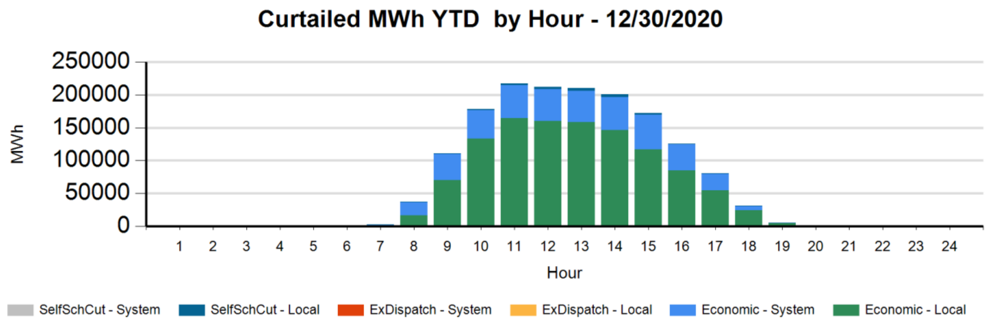

Figure 1. Power curtailed in California in 2020 [2].

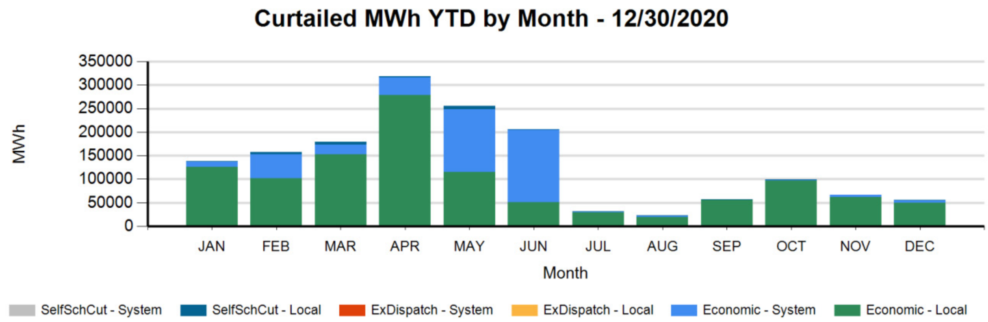

Figure 2. Power curtailed in California in 2020 by month [2].

the globe. However, the battery technologies are not the resolution for long term energy storage (years after year) and cannot address the seasonal volatile energy production variation as shown in Figure 2. The summer production is larger than the winter production as shown in the figure and a key challenge for the countries with strong seasonal energy demand patterns is way to tie the gap between summer and winter. The battery technologies are also facing different environmental issues like chemical disposal or toxicity [6].

Power-to-gas (P2G or PtG) is an alternative to the battery storage refers the process of converting electric power to chemical energy carriers (mostly gaseous form) such as hydrogen or methane via water electrolysis [3,7,8]. Energy storage in gaseous form in the gas network is a way to face the seasonal variation challenges [9]. Water electrolysis splits water into hydrogen and oxygen. Currently, utility operators in California are led to believed that hydrogen gas produced in large quantity from renewable resources are to be stored and carried out by existing natural gas infrastructure. Initially, electric power is used to produce hydrogen by water electrolysis using an electrolyzer. The hydrogen storage is complicated when produced in large quantity. Putting hydrogen can damage the pipeline structure earlier than the existing lifeline. Hydrogen storage and transportation is complex due to issues like hydrogen attack, hydrogen induced blistering, hydrogen embrittlement etc. of the storage system [10,11]. One potential option is producing CO_2-neutral methane, the major constituent of natural gas by methanation of CO_2 and H_2.

The major component of natural gas is methane and natural gas is mostly produced from fossil sources. Synthetic hydrogen is also produced from methane are from fossil fuels. 80% to 90% of the natural gas consumption is the United States is produced domestically [12] and almost all the natural gas is produced from fossil sources [13]. 250 anerobic digester system site is using biogas from livestock operations to produce electricity [12]. In US, the potential natural gas production from wastewater treatment plant is huge and can meet 12% of the national electricity demand [12]. However, P2G is the pipeline quality renewable methane production technology and consume CO_2 from any sources.

Excess electricity generated from volatile renewable sources produce hydrogen and conversion of hydrogen and CO_2 to methane via methanation reaction could solve long-term large-scale storage issues and benefit the transportation sector with green energy. Heat generated from concentrated solar power can produce chemical for energy storage [14]. The methanation process is the reverse of combustion and is comparable with photosynthesis: CO_2 is electrochemically (water electrolysis and reduction via methanation) reduced to methane using the excess renewable electricity [15,16]. The overall process is an energy efficient process and energy efficiency can be as high as 80% [16,17].

Methanation from syngas (a mixture of CO and H_2) is an industrially established technology [18,19]. Studies on CO and CO_2 methanation focus on the process optimization in the 1970s and 1980s. Recent focuses are on the reactor technologies (micro reactor manufacturing [20-22]) and material properties for meeting the

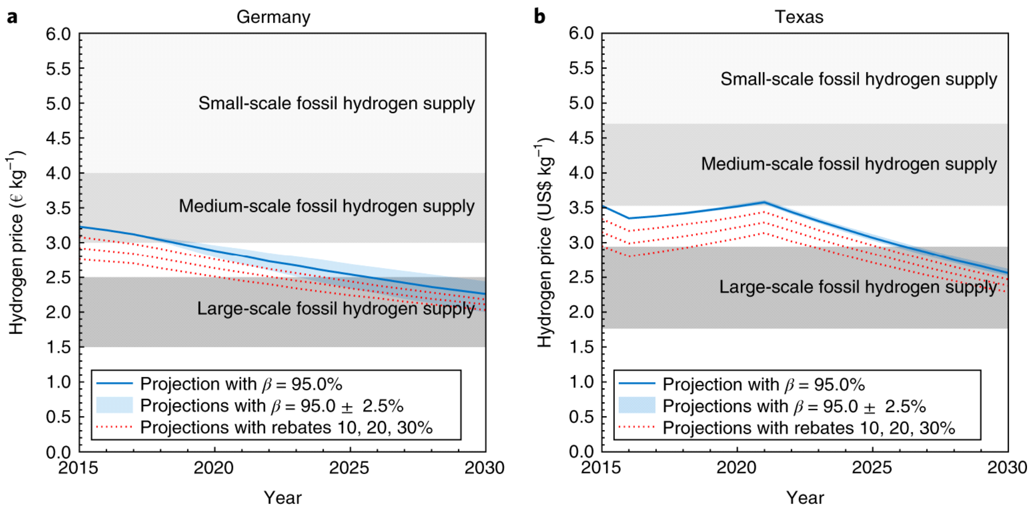

Figure 3. Hydrogen production cost from current fossil fuel technologies [23].

requirements of energy storage system [19].

Power-to-gas technology is studied in Europe and there are at least 128 research and demonstration projects are ongoing in Europe [8]. The power to gas technology received some attention from the economic evaluation point of view for hydrogen production but not from the methane production [23-28]. The electricity cost from renewable sources is low even compared to natural gas-based power generation leads to the idea of low-cost hydrogen production or storage [23]. The current level of hydrogen production cost from fossil fuel technologies is presented in Figure 3 [23]. As it is not very convenient to produce hydrogen as the final product for excess renewable energy storage but methane an economic assessment is necessary for the pipeline quality green methane production.

This study performs the economic assessment of the hydrogen and methane production from excess renewable resources. The study provides the comprehensive analysis with techno-economic evaluation of the high viability P2G business models in the potential project location. The study estimates the capital cost requirement for the methanation processing plant and change in the methane production cost with different factor modification. The study also focuses process exhaust utilization impact on the methane economics.

2. Material and Methods

2.1. Assumptions and Boundaries

The electricity available in excess quantity during the certain time of the day due to increased solar power share in the grid. The excess electricity is curtailed, for infrastructure for battery storage is limited and chemical storage of electricity can be expensive. Therefore, this excess electricity might be available without any cost or with little cost. The plant requires an electrolyzer section and a methanation section. The final product is methane and cost of methane production is calculated by using the discounted cash flow method. The capital cost for few components is estimated by Aspen Plus simulation except the cost of multistage reactor electrolyzer. The electrolyzer and reactor system cost is obtained from the other source as explained in the following sections.

The modeling part of this study is performed using Aspen Plus, Chemical Process Simulator, widely used for the simulation studies [29]. The modeling combines the electrolysis and methantion in a multistage reactor system. The model developed for the simulation is shown in Figure 4. Aspen Plus does not have an option for electrolyzer. A simple conversion reactor is used for replicating the eletrolyzer that converts the water into hydrogen and oxygen. The energy efficiency value for electrolyzer is taken from a reputed European industrial electrolyzer manufacturer. The electrolyzer produces two separate streams for hydrogen and oxygen. Hence in Aspen Plus simulator a separator is used for separating the hydrogen and oxygen. The separated hydrogen mixed with the CO_2 gas before compressing to the desired reaction pressure. The compressed gas is enter's the multistage reactor for the desired reactant conversion level. The product contains methane, CO, CO_2, steam, and hydrogen. The product is cooled and expanded (decompressed), and separated for pure methane production, exhaust liquid, and exhaust gas. The separated pure methane pressurized to the transmission/distribution pipeline requirement before supplying to the natural gas pipeline.

Figure 5 shows the baseline system boundary and scope of this economic evaluation. As shown in Figure 5, the electricity and demi water is supplied to an electrolyzer which is produced hydrogen and oxygen. The electrolyzer is equipped with the facility that can separate and produce oxygen and hydrogen stream. The hydrogen is produced at 35 bar pressure. The produced hydrogen is mixed with CO_2 and supplied to a compressor to compress the mixed

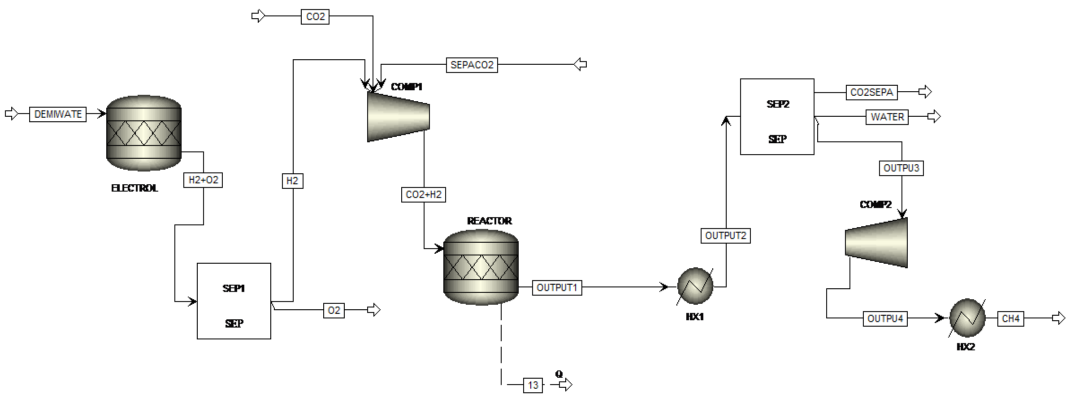

Figure 4. Aspen plus process diagram for the baseline case.

gas at 40 atm pressure before supplying to the reactor. The multistage reactor along with the recycling converts all the H_2 and CO_2 to methane. The reactor product is cooled down 50 ℃ before supplying to the separation unit. The separation unit separates pure methane, pure water and remaining mixed gas is recycled to the reactor. The recycling process helps to achieve 100% H_2 and CO_2 conversion. The water is supplied to the electrolyzer as demi water. The product methane is pressurized to the natural gas pipeline condition of 25 psi (about 1.7 atm) before sending to the pipeline.

Case-1; Baseline Case;

The baseline case is described above without any recycling of exhaust gases and demi water or utilization of the high temperature gases for steam generation.

Case-2: The separated water from the product gas is supplied to the electrolyzer and therefore, the electrolyzer requires less demi water supply from the external source. For the 1500 m^3/hr methane production capacity plants, the electrolyzer requires 4.855 m^3 of water per hour. This water utilization reduces the demi water requirement to 1855 m^3/hr. The Process boundary for Case-2 is shown in Figure 6.

Case-3: this reduces the cooling water supply requirement from 100% to 1% by circulating the cooling water. This circulation process losses about 1% water and utilize 99% of the cooling water. The Process boundary for Case-3 is shown in

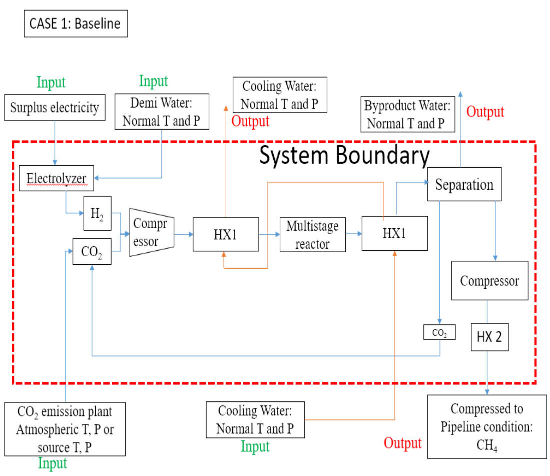

Figure 5. Baseline system boundary.

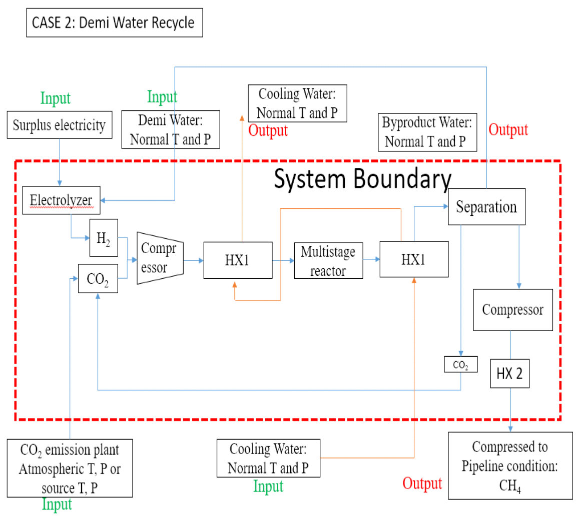

Figure 6. Case 2 system boundary.

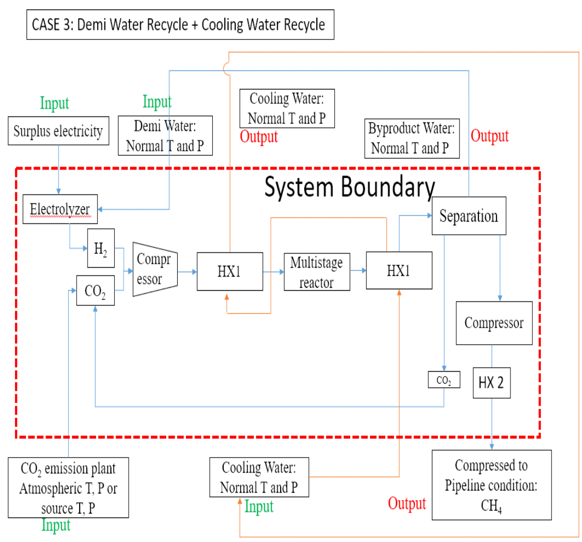

Figure 7. Case 3, recycles the cooling water.

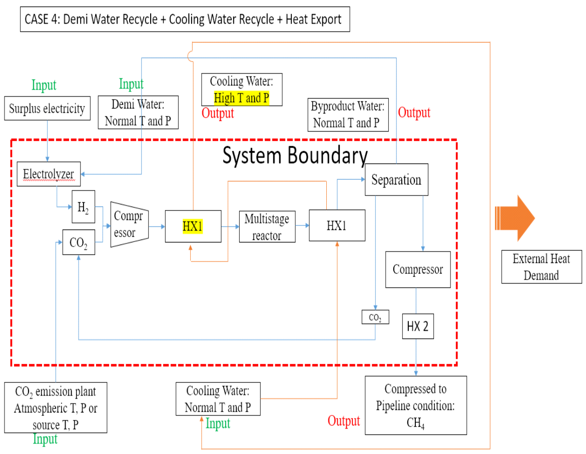

Figure 8. Case 4, Heat Sale to External Case.

Figure 7.

Case-4: Further study was conducted to add the scenario where heat is exported to external service areas. CAPEX for this case is increased by adding steam generator for the external service [30]. However, in this study, the generated heat is assumed to be sold for $0.25/therm. This revenue stream is credited to the plant operation cost. Therefore, the operation cost is reduced as well as the methane production cost. The Process boundary for Case-4 is shown in Figure 8.

2.2. CAPEX Assumptions and Estimation

The major assumptions for economic assessment are:

The CAPEX cost is predicted by Aspen Plus simulation as listed in the following tables for each scenario. Two plant sizes are studied. They are;

Capacity-1: 1,500 NM^3/hr of CH_4 production capacity (nominal), Plant operates 50% of capacity (4,000 hr/year), with GHSV of 1,500/hr

Capacity-2: 750 NM^3/hr of CH_4 production capacity (nominal), Plant operates 15% /30% of the nominal capacity (1,314 or 2,686 hr/year), with GHSV of 3,000/hr

In addition, two types of methanation process were studied. They are;

Reactor Type-1: 3 stage adiabatic reactor

Reactor Type-2: 2 stage isothermal and 1 adiabatic reactor

Equipment cost assumptions

Electrolyzer Cost is based on 4.63 kW/Nm^3 (using the data from a reputed manufacturer in Europe) of H_2 and $380/kW [31].

Hydrogen is produced by electricity consumption in an electrolyzer and power consumption in the electrolyzer is an important parameter for the hydrogen production efficiency. The average power consumption is 4.63 kW/Nm^3 hydrogen produced. This value is obtained from a quotation from Green Hydrogen Systems (https://greenhydrogen.dk/) a Denmark based electrolyzer manufacturer company. The quotation also provides the price of a small capacity electrolyzer which is not used for the economic evaluation as the small-scale equipment's are expensive. US Department of Energy estimated the capital costs of electrolyzer as $380/kW [31] and this value is used for the electrolyzer capital cost estimation. USDOE also projected the electrolyzer cells capital replacement is required every 7 years which is 25% of total purchased capital.

The compressor, heat exchanger and separator costs are directly obtained from Aspen Plus process simulation and used as obtained. The standard compressor was selected that can compress the gas to the desired pressure. The capex for compressor system and heat exchanging system is directly obtained from the Aspen Economic Analyzer. The system separation cost is directly obtained from Aspen Economic Analyzer as well.

The methanation reactor is one of the most important parts of the whole process. The reactor sizing is complex and depends on the resident time of the feed gases. Also, the high-pressure system makes the reactor materials expensive compared to the regular flow reactor. For the baseline 1,500 m^3/hr or 25 m^3/min product gas flow rate three 0.5 m^3 flow reactor are placed in series before converting all the feed gases into the desired product (methane). The residence time for this assumption is 1.2 second. The unconverted gases are recycled for complete conversion. A separator is used for separating the methane and water from the recycle gas. The separated water can be used as demi water required for electrolyzer for cost savings. Separated water is not supplied in the baseline case. The cost of each reactor is calculated based on the reactor volume and materials required. Based on the values published by 1989_Bookmatter_ChemicalEngineeringEconomics, the 0.5 m^3 reactor cost falls in the range of $30,000 in 1980. Therefore, the inflation rate and production cost changed the value significantly in 2020 and estimated as $700,000 (each reactor of 0.5 m^3) based on the most recent data (https://www.matche.com/equipcost/Reactor. html)[32]. The estimated values also support the reactor cost published by NREL [33]. The NREL study estimated the installation cost is about 1.7 times of the fixed bed reactor cost. The higher installation cost is specifically for the uncertainty in the new technology and higher safety rating related to the hydrogen rich gas handling. The installation cost factor is taken from the NREL study as the study represents new technology, similar temperature, and pressure range in this study.

ASPEN Parameters: (for both reactor type and capacity)

Temperature: 400 ℃ and Pressure: 40 atm.

Other assumptions are:

Project economic life: 30 years.

Plant is operating 4000 hr every year.

Salvage value: 0%.

Table 1. Capital cost and LCOM for Capacity-1, Reactor Type-1.

	Case 1, Case 2, Case 3		Case 4	
Unit	Equipment cost (USD)	Installation cost (USD)	Equipment cost (USD)	Installation cost (USD)
Electrolyzer	$15,531,289		$15,531,289	
Compressor 1	$1,788,700	$1,944,100	$1,788,700	$1,944,100
Compressor 2	$669,000	$818,600	$669,000	$818,600
CH_4 separator	$165,000	$1,177,000	$165,000	$1,177,000
HX1	$20,600	$155,600	$20,600	$155,600
HX2	$13,100	$83,700	$13,100	$83,700
Reactor (estimated based on materials, volume, pressure)	$2,100,000	$3,570,000	$2,100,000	$3,570,000
Piping and Instrumentation (assumed)	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Steam generation unit (including installation)			$3,009,422	
Total	$22,287,689	$9,749,000	$25,297,110	$9,749,000
Total Capital Expenditure	$32,036,689		$35,046,110	
LCOM ($/mcf)	Case 1: 13.16 Case 2: 13.14 Case 3: 11.83		11.22	

Discount rate: 10%

Engineering Procurement and Construction Cost is 30% of the total capital expenditure.

Variable operating and maintenance are 4% of Engineering Procurement and Construction Cost.

Fixed operating and maintenance are 3% of Engineering Procurement and Construction Cost.

Electrolyzer cells capital replacement = 25% of total purchased capital every 7 years.

The byproduct oxygen sale for $1/mcf is considered in the all the cases.

3. Results and Discussion

3.1. Methane Production Cost

Table 1 thru 4 summarizes the CAPEX for each case, scenario and corresponding LCOM (Levelized Cost Of Methane production).

The LCOM is calculated using the discounted cash flow method. This cost calculation involves the CAPEX, OPEX, equipment replacement over the project life, feedstock cost etc.

The Case 2 reduces the methane production cost from $13.16 (baseline case with reactor type-1 and capacity-1) to $13.14 (small change due to the small amount of demi water requirement reduction, about 3 m^3/hr).

Table 2. Capital cost and LCOM for Capacity-1, Reactor Type-2.

	Case 1, Case 2, Case 3		Case 4	
Unit	Equipment cost (USD)	Installation cost (USD)	Equipment cost (USD)	Installation cost (USD)
Electrolyzer	$15,531,289		$15,531,289	
Compressor 1	$1,788,700	$1,944,100	$1,788,700	$1,944,100
Compressor 2	$669,000	$818,600	$669,000	$818,600
CH_4 separator	$165,000	$1,177,000	$165,000	$1,177,000
HX1	$20,600	$155,600	$20,600	$155,600
HX2	$13,100	$83,700	$13,100	$83,700
Reactor (estimated based on materials, volume, pressure)	$1,400,000	$2,380,000	$1,400,000	$2,380,000
Piping and Instrumentation (assumed)	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Steam generation unit (including installation)			$3,009,422	
Total	$21,587,689	$8,859,000	$25,297,110	$8,859,000
Total Capital Expenditure	$30,146,689		$33,156,110	
LCOM ($/mcf)	Case 1: 12.73 Case 2: 12.76 Case 3: 11.47		10.85	

Table 3. Capital cost and LCOM for Capacity-2, Reactor Type-1.

Unit	Case 3		Case 4	
	Equipment cost (USD)	Installation cost (USD)	Equipment cost (USD)	Installation cost (USD)
Electrolyzer	\$7,765,644		\$7,765,644	
Compressor 1	\$1,180,102	\$1,282,628	\$1,180,102	\$1,282,628
Compressor 2	\$441,375	\$540,075	\$441,375	\$540,075
CH_4 separator	\$108,859	\$776,530	\$108,859	\$776,530
HX1	\$13,591	\$102,658	\$13,591	\$102,658
HX2	\$8,643	\$55,221	\$8,643	\$55,221
Reactor (estimated based on materials, volume, pressure)	\$869,473	\$1,478,104	\$869,473	\$1,478,104
Piping and Instrumentation (assumed)	\$1,319,508	\$1,319,508	\$1,319,508	\$1,319,508
Steam generation unit (including installation)			\$1,504,711	
Total	\$11,707,195	\$5,554,723	\$13,211,906	\$5,554,723
Total Capital Expenditure	\$17,261,919		\$18,766,630	
LCOM	\$33.88 (15% yearly operation 1314 hr) \$20.38 (30% yearly operation 2628 hr)		\$33.26 (15% yearly operation 1314 hr) \$18.87 (30% yearly operation 2628 hr)	

Case-3 reduces the methane synthesis cost to \$11.83. The cooling system uses about 200 m^3/hr of water and recycling most of this water reduces the water demand as well as the production cost. This case is used for the future cases for sensitivity analysis.

Case 4 reduces the cost further to \$11.22 due to the profit from heat selling. However, the steam generation from plant heat is not continuous as the plant is not operating 24 hr a day due to the availability of excess electricity at certain time of the day.

At 10% discount rate and zero electricity cost, LCOM (Levelized Cost of Methane production) is \$13.16/mcf for the baseline case. (case-1, capacity-1, reactor type-1).

LCOM is defined as the cost for the during the project lifetime, calculated by proprietary process economic spread sheet developed for this study. Among the major variables, Electricity cost is mostly influencing variable for the LCOM.. For free curtailment case, \$12/mcf production cost is expected.

The methane production obtained in this study closely compares the limited study performed earlier in the literature. Gorre et al., proposed the synthetic methane production cost of \$11.65/mcf by 2030 when the electricity is available for free [34]. The methane production cost estimated by Böhm et al., shows a significantly high value of \$52/mcf of methane with the regular electricity cost much higher than this study [35]. In another study, performed by Szima et. al., the levelized cost of methane production is estimated as \$23.24/mcf methane [36].

3.2. Sensitivity Analysis

Feedstock prices is the most important parameter for the excess power electrolysis coupled methanation as electricity the major feedstock for the whole process. Other feedstock includes CO_2 and demi water. The excess electricity is assumed to be available at no cost, but electricity cost can vary depending on the location and time of the year. The assumed costs of the feedstocks are shown in Table 5.

Plant capacity and electricity cost are the major influencing

Table 4. Capital cost and LCOM for Capacity-2, Reactor Type-2.

Unit	Case 3		Case 4	
	Equipment cost (USD)	Installation cost (USD)	Equipment cost (USD)	Installation cost (USD)
Electrolyzer	\$7,765,644		\$7,765,644	
Compressor 1	\$1,180,102	\$1,282,628	\$1,180,102	\$1,282,628
Compressor 2	\$441,375	\$540,075	\$441,375	\$540,075
CH_4 separator	\$108,859	\$776,530	\$108,859	\$776,530
HX1	\$13,591	\$102,658	\$13,591	\$102,658
HX2	\$8,643	\$55,221	\$8,643	\$55,221
Reactor (estimated based on materials, volume, pressure)	\$579,649	\$985,402	\$579,649	\$985,402
Piping and Instrumentation (assumed)	\$1,319,508	\$1,319,508	\$1,319,508	\$1,319,508
Steam generation unit (including installation)			\$1,504,711	
Total	\$11,317,371	\$5,062,022	\$12,922,082	\$5,062,022
Total Capital Expenditure	\$16,479,393		\$17,984,104	
LCOM	\$32.96 (15% yearly operation 1314 hr) \$19.92 (30% yearly operation 2628 hr)		\$32.34 (15% yearly operation 1314 hr) \$18.41 (30% yearly operation 2628 hr)	

Table 5. Feedstock Prices (For the Base Year, then escalated by the levelized factor) for the baseline case.

Electricity	**0.0**	(¢/kWh)
Water	**30**	(¢/m^3)
CO_2	**10**	(¢/m^3)

variable for the LCOM.

The electricity cost is the major factor for the methane production cost. The most likely and suitable operating point is when the electricity is available for free. The impact of cost of electricity is presented in Figure 9. If the electricity prices go up to ₵8/kWh, the methane cost will be more than $60/mcf.

The plant size significantly changes the methane production cost. Figure 10 shows variation of methane production cost with plant size. Production cost is significantly low when the plant production capacity is over 1500 m^3/hr.

As described earlier, the number of operating hours can vary sufficiently as the availability of the excess electricity is location dependent and unknown. The operation hour can change the methane production cost as shown in Figure 11. An operating hour below 4000 hr/year can adversely impact the project economics. Considering the different nature of various renewable electricity generation scenario, this value can fluctuate.

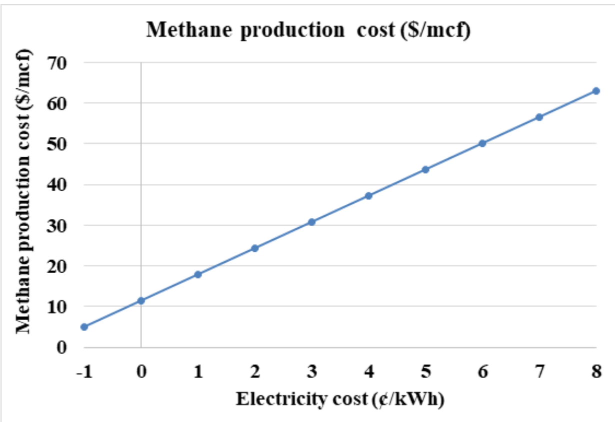

Figure 9. Methane production cost variation (power to gas) due to change is electricity cost variation.

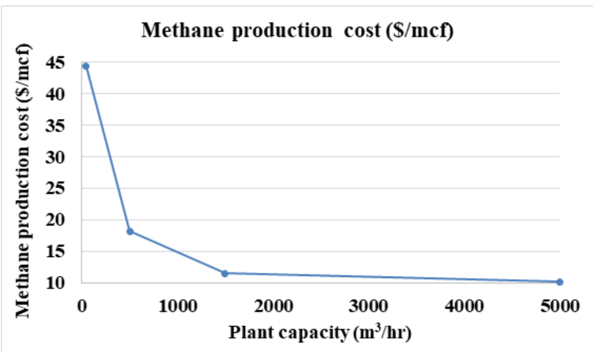

Figure 10. Methane production cost variation (power to gas) with plant capacity (zero electricity cost).

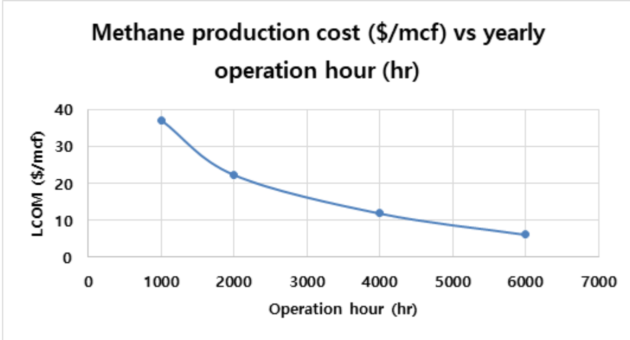

Figure 11. Methane Production cost ($/mcf) variation by yearly operation hour

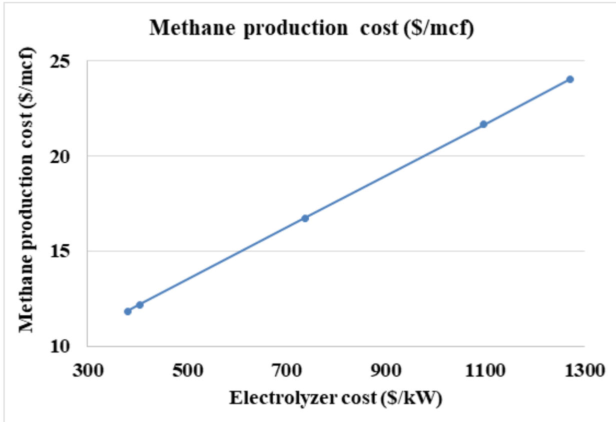

Figure 12. Variation of methane production cost with change in electrolyzer cost.

3.3. Uncertainty on the Electrolyzer Cost

The electrolyzer is most important part of the plant and a custom-built utility scale electrolyzer price can vary a lot compared to the DOE estimated value of $380/kW. Studies have shown wide variation of the electrolyzer price: a typical electrolyzer cost is listed below for different types of electrolyzer.

Here are several values predicted by other users/manufacturers:

Solid oxide electrolysis: 405 $/kW [37]

Solid oxide electrolysis: 737 $/kW [38]

Proton Exchange Membrane: 1097 $/kW [39]

Alkaline electrolysis: 1271 $/kW [40]

A sensitivity test is performed using various electrolyzer cost as shown in Figure 12. The technology is improving continuously, and the methane production will be economically comparable with the fossil natural gas if the electrolyzer cost goes down.

As there are limited studies for green methane economical evaluation, further study was performed for the hydrogen production cost. Hydrogen production cost involves just the electrolysis cost, demi water cost and cost of electricity.

Sensitivity study is conducted for the hydrogen production cost variation with the variation of electrolyzer cost as shown in Figure 13. The proposed hydrogen production cost by UCI is

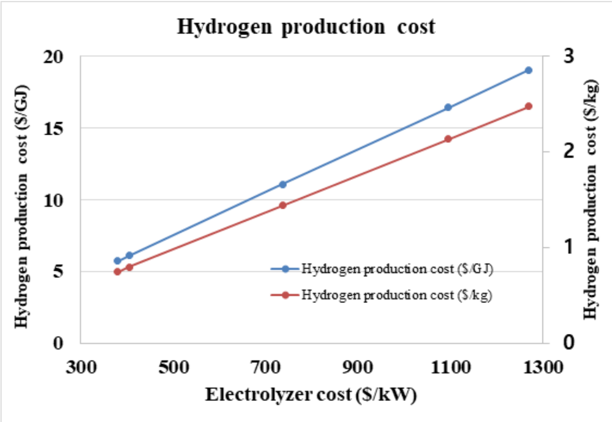

Figure 13. Variation of hydrogen production cost with change in electrolyzer cost.

\$5.6~10.36/GJ and the cost is in this study is on the lowest range if a low cost electrolyzer is available [41]. The hydrogen production cost in the future is estimated as by European Commission [42]. Böhm et al., also reported the hydrogen production cost as \$1.92/kg comparable to the results in this study [35]. The hydrogen production cost estimated by Rozzi et al., is also at the very higher end of \$11/kg much higher than this study estimates [43]. Figure 3 presents the hydrogen production cost from the fossil sources. The cost is comparable and currently hydrogen from renewable sources can be cheaper than the fossil sources if the targeted low cost electrolyzer is available. The study performed by Nicodemus estimates the cost for hydrogen production is to be below \$3/kg by 2030 [44].

4. Conclusions

Four different configurations were studied for estimation of levelized cost of methane production using the power to gas power to gas technology. These configurations vary among themselves for the process optimization with recycling demi water and waste heat utilization as well as byproduct oxygen sale. The study shows the significant cost reduction of methane production while water produced from methanation process is utilized as demi water and cooling water is recycled. The mixed gas compression and electrolyzer, other aux power using electricity is considered in this study is taken from excess renewable sources. After several case analysis, the methane production cost is estimated as \$11.83/mcf (when operating for 4000 hr/year) with an operating capacity of 1500 m^3/hr CH_4 production. The production cost increases when the plant is operating for less time due to availability of excess renewable electricity depending on the time of the day or season of the year. The plant capacity significantly impacts the methane production cost as desired that the large-scale facility reduces the production cost. Along with the sensitivity studies, the study compares the methane production cost is less or comparable with the existing studies as no industrial data is available for the power to gas-based methane production process. The study also compares the hydrogen production cost is less or comparable with the existing studies. The study indicates an economic viability of green methane production when free excess electricity is available for more than 50% of the time daily.

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Nomenclature

P2G/PtG : power to gas
LCOM : levelized cost of methane

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