Allocation of Hydrogen Produced via Power-to-Gas Technology to Various Power-to-Gas Pathways

by
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AUTHOR'S DECLARATION

I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

I understand that my thesis may be made electronically available to the public.

Abstract

Demand for renewable energy systems is accelerating and will account for a significant share of future power systems aimed to enhance and decarbonize the world's energy system. Unlike conventional power plants, electricity output from renewable sources cannot be adjusted easily to match consumer power demand because renewable resources are intermittent short-term seasonal power sources. Accordingly, a rapid increase in surplus power is expected in the future. The Canadian Province of Ontario, in line with global efforts, has targeted 80 % reduction of greenhouse gas emission levels by 2050 compared to 1990 levels. One key step to accomplish this goal is to harness more renewable energies for power generation. Instead of losing the surplus power or exporting it for low returns, storage and utilization in other sectors urgently need to be explored.

Power-to-Gas technology offers a possible solution for optimal use of energy surplus. It is efficient at the huge — national— consumption scale and global acceptance of Power-to-Gas as energy storage and transportation technology is growing noticeably. In short, Power-to-Gas is a potential means to manage intermittent and weather-dependent renewable energies like wind, solar, or hydro in a storable chemical energy form. The main concept behind Power-to-Gas technology is to make use of surplus electricity to decompose water molecules into their primary components: hydrogen and oxygen. Power-to-Gas is not only a storage technology; its role can be extended to other energy streams including transportation, industrial use, injection into the natural gas grid as pure hydrogen, and renewable natural gas.

The current study investigated four specific Power-to-Gas pathways: Power-to-Gas to mobility fuel, Power-to-Gas to industry, Power-to-Gas to natural gas pipeline for use as hydrogen-enriched natural gas, and Power-to-Gas to Renewable Natural Gas (i.e., Methanation).
This study quantifies the hydrogen volumes at three production capacity factors (67%, 80%, and 96%) upon utilizing Ontario's surplus electricity baseload. Five allocation scenarios (A-E) of the hydrogen produced to the four Power-to-Gas pathways are investigated and their economic and environmental aspects considered. Allocation scenario A in which hydrogen assigned to each pathway is constrained by a specific demand, is based on Ontario's energy plans for pollution

management in line with international efforts to reduce global warming impacts. Scenarios B-E are about utilization of the produced hydrogen entirely for one of mobility fuel, industrial feedstock, injection into the natural gas grid, or renewable natural gas synthesis, respectively. The study also examines the economic feasibility and carbon offset of the PtG pathways in each scenario.

The research sets the assumption that hydrogen is produced at three capacity production factors: 67% (16 h/day), 80% (19 h/day), and 96% (23 h/day). The amount of surplus baseload electricity for 2017 of each capacity factor is converted to hydrogen via water electrolysis. Accordingly, the total hydrogen produced is approximately 170 kilo-tonnes (kt), 193 kt, and 227 kt, respectively. Results indicate that the Power-to-Gas to mobility fuel pathway in scenarios A and B has the potential to be implemented. Utilization of hydrogen produced via Power-to-Gas technology for refueling light-duty vehicles is a profitable business case with an average positive net present value of $4.5 billions, five years payback time, and 20% internal rate of return. Moreover, this PtG pathway promises a potential 2,215,916 tonnes of CO_2 reduction from road travel. In the scenario to utilize Ontario's surplus electricity to produce hydrogen via the PtG technology for industrial demand, results indicate that supply could achieve 82%, 93%, and 110% of the industrial demand for hydrogen at the three capacity factors, respectively. Nevertheless, hydrogen production through PtG is still costly compared to other available cheaper alternatives, namely hydrogen produced via steam methane reforming. Power-to-Gas for industry projects should, however, be part of government incentives to encourage clean energy utilization. In addition, although using hydrogen-enriched natural gas or renewable natural gas instead of the conventional natural gas could offset huge amounts of carbon, their capital and operational costs are extremely high, resulting in negative net present values and very long payback time.

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Dedication

To my dear husband, Khalid for his support and patience

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List of Acronyms

AEM	Anion Exchange Membrane
CAPEX	Capital Expenditure
e^3m^3	Thousand cubic meter
FCV	Fuel-cell vehicles
GHG	Greenhouse gases
HENG	Hydrogen-enriched natural gas
IESO	Independent Electricity System Operator
IRR	Internal rate of return
kt	kilo-tonne ($1x10^6$ kg)
MWh	Megawatt hour
NPV	Net present value
OPEX	Operating Expense
PBP	Payback time
PEM	Proton Exchange Membrane
PtG	Power-to-Gas
RNG	Renewable natural gas
SBG	Surplus baseload generation
TWh	Terawatt hour

Chapter1: Introduction

1.1 Background and Literature Review

In 2015, the highlighted recommendation of the Conference of the Parties (COP 21) was to "… holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C above pre-industrial levels" [1]. This universal climate agreement restricts all countries of the international community (developed and developing countries) that are responsible for CO_2 concentration in the atmosphere to take prompt action against the emissions of Greenhouse Gases (GHGs). It also requires economies around the globe to enhance and decarbonize large parts of the world's energy system. Some leading countries have already considered strategic plans for emission reduction. These include lowering coal consumption by switching to low or free carbon fuels and increasing renewable power generation, such as wind, solar, and water energy. Subsequently, the total global GHG emissions slowed in 2016, the lowest since the early 1990s, reaching 49.3 giga-tonnes CO_2 equivalent [2].

The main origins of GHGs are the use of fossil fuels (coal, oil, natural gas, lignite) in electricity generation, transportation, manufacturing, etc. Therefore, achieving sustainable energy requires substituting fossil fuels with equally efficient ones. In the energy sector, renewable energy is seen as the most promising approach to generating green energy. However, the intermittent nature of renewables is still an obstacle, in which a storage system is required to secure the supply and demand.

In line with the global efforts, Ontario's Climate Change Action Plan [3] targets 80 % reduction of GHG emission levels by 2050 compared to 1990 emissions levels. The Province is aiming to accomplish this goal through serious consideration of environmentally friendly energy generation procedures. One clear action was closing the five coal-fired generating stations by 2014 [4], which were the largest GHG emitters. Furthermore, Ontario is looking to initiate a low emission power system that relies mainly on renewable and non-GHGs emitting sources [5]. For example, one of 2013-Ontario's Long-Term Energy Plan (LTEP) recommendations is to increase power generation from solar and wind up to 10,000 MW by 2021[6]. In 2017, Ontario energy output was "clean and diverse" as the Independent Electricity System Operator (IESO) described it, in which 95% of power was generated from near-zero GHG resources such as nuclear, hydro, wind and solar [7] (Figure 1). Nuclear energy is the dominant electricity recourse representing 63 percent of the total energy produced in 2017.

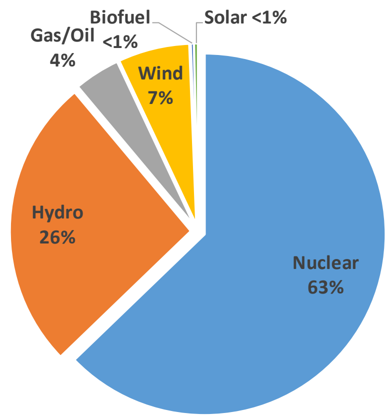

Figure 1 Ontario's Energy output-2017 [7]

However, Ontario's ambitious plan to increase the green and renewable energy content of the electrical grid requires short and long-term energy storage technologies to balance power supply and demand inside the Province. Network stability relies on the supply and demand equilibrium. However, increasing the contribution share of intermittent renewable energy will result in increasing the baseload generation, exceeding the normal energy needs.

As per IESO, the surplus baseload generation (SBG) is defined as the baseload difference between the baseload generation (nuclear, hydroelectric, wind and solar) and the electricity demand [8]. This baseload power variance is of interest in this study and is what is subsequently referred to as surplus baseload generation or excess electricity. Since Ontario does not have an electricity market for utilizing the surplus electricity inside Ontario, most surplus electricity is managed through electricity curtailment and exportation [8].

In fact, energy generation curtailment is a typical practice of power reduction from variable resources such as wind and solar generators during excess baseload generation in low demand periods. Solar and wind power generation are easily curtailed since they are operated by free and accessible resources; in other words, they require no fuel cost [9]. As it is not easy to shut down the nuclear operators during periods of surplus generation, IESO curtails the variable generation sources (wind and solar) to maintain the system balance instead. The downsized amount of electricity from wind and solar in 2017 was 3.3 tera-watt hour (TWh) [7].

Also, Ontario continuously imports and exports electricity to its five neighbors, Quebec, Manitoba, Minnesota, Michigan and New York, as the interconnected grid is important to enhance system reliability and cost-effectiveness. The problem is that the Province becomes a net exporter by exporting zero greenhouse gas emissions at very lower prices; the exported amount is enough to power two million homes for an entire year according to Ontario Society of Professional Engineers (OSPE). In 2017 alone, around 19 TWh of clean electricity was exported, costing Ontario more than one million dollars in profits [8], [10], [11]. If the Province were to have a surplus electricity utilization plan, surplus electricity could be used for GHG reduction in other sectors inside Ontario instead. Therefore, there is an increasing need to overcome the problem of surplus electricity and the fluctuation nature of renewable energy by installing electrical energy storage (EES) systems.

The process of storing energy means capturing energy by converting it into accessible and economically storable forms. EES technologies are categorized into electrical, electrochemical, mechanical, chemical, and thermal energy storage systems [12]. The various types of EES have their advantages and disadvantages [12]. Ibrahim et al. [13] confirme the need for energy storage and compare different types of energy storage technologies available and applicable. Their comparison is based on different technical and economic characteristics such as storage capacity, portability, storage time, and economic aspects. These characteristics determine the most appropriate technique for each type of application. In addition, an analytical hierarchy analysis (AHP) was done by Walker et al. [14] to compare most well-established EES considering certain applications. These include residential load shifting, bulk energy storage, and utility-scale frequency support. Further, a sophisticated dynamical model of 100% renewable electricity baseload scenario using a demand profile of 160 countries was done by Pleßmann et al. (2014) [15]. The study investigates the achievability of three energy storage alternatives: batteries, thermal energy storage, and bio-methane through Power-to-Gas (PtG) concept. As the study showed, thermal energy storage is a favorable storage option for short-term electricity storage, and the role of batteries are minor compared to the thermal storage. However, PtG is not only a storage technology; its role can be extended to many other applications like energy distribution, transportation, and heating. Similarly, Jentsch et al. (2014) [16] simulated a Power-to-Gas system for a case of 85% renewable energy for Germany. The study aims to quantify the optimum cost and optimize the optimal location for the plant to utilize the optimal renewable energy. However, Balibar et al. (2017) [17] claimed that the only method that is known and efficient at the huge–national energy–consumption scale that might contribute to tracking this issue is Power-to-Gas. Overall, these studies highlight the fact that the demand for energy storage technologies will be a necessity in line with the exponential increase of electricity generation from renewable sources.

1.2 Thesis Objective and Approach

The main objective of this thesis is to introduce a Power-to-Gas technology as a solution to utilize Ontario's excess baseload electricity that otherwise is being curtailed or exported at very low prices. A recent series of publications has studied the implementation of different Power-to-Gas pathways separately in the Canadian province of Ontario. The current study investigates the feasibility of hydrogen allocation, produced via PtG concept, to different power to gas pathways.

The overall goal is achieved via multiple steps as follows:

1. Estimating the amount of surplus baseload generation in Ontario in 2017 by subtracting the hourly electricity demand from the hourly electricity supply.
2. Reviewing Ontario's plans and polices regarding the climate change impact and greenhouse gas emission reduction. Based on that, the demand of hydrogen for each PtG pathway is assigned.
3. Defining the most applicable PtG pathways and their required technologies.
4. Calculating the amount of hydrogen that could be produced through PtG technology based on the amount of surplus baseload electricity available considering three different capacity productions.
5. Exploring different scenarios for allocating the generated hydrogen to four PtG energy streams: power-to-gas to mobility fuel, power-to-gas to industry, power-to-gas to pipeline to use as HENG, and power-to-gas to renewable natural gas.

6. Estimating the amount of CO_2 offset as well as some economic aspects such as capital and operational costs, and the economic validity of each PtG pathway.
7. Performing a sensitivity analysis to assess the impact of changing the number of electrolysers, final-product selling prices, and carbon price on the costs and profits of each PtG pathway.

1.3 Thesis Outline

The current study consists of five chapters:

- Chapter 2: Power-to-Gas Technology

A literature review and introductory background of energy storage concept and its importance, as the share of intermittent renewable energies in the power grid is continuously growing. This chapter introduces the concept of Power-to-Gas and its approach of storing energy as well as its advantages and disadvantages. Next is a general overview of the technology components and steps. The chapter ends by detailing the Power-to-Gas potential pathways.

- Chapter 3: Power-to-Gas Pathways economy

This Chapter highlights the methodology used to evaluate PtG pathways economy. This includes overall capital expenses (OPEX), annual operational expenses (OPEX), potential revenue streams, and some economic validity indicators.

- Chapter 4: Hydrogen Allocation Scenarios

This chapter is the heart of this study, where five scenarios are suggested to allocate the hydrogen produced via the Power-to-Gas technology. The chapter also investigates the environmental and economic aspects of each Power-to-Gas pathway within each allocation scenario.

- Chapter 5: Sensitivity Analysis

This chapter discusses how sensitive the PtG pathways’ economy is to changes in: 1) number of electrolysers; 2) final products selling prices; and 3) carbon prices.

Chapter 2: Power-to-Gas Technology

2.1 Power-to-Gas Technology

Power-to-Gas (PtG) is an energy storage technology that utilizes the surplus electricity to produce hydrogen via electrolysis, and this hydrogen is either used directly for multiple applications or combined with carbon dioxide to produce renewable natural gas (RNG). Figure 2 demonstrates the PtG concept [18]. PtG is a potential means of managing intermittent and weather-dependent renewable energies such as wind, solar, hydro, etc. into a storable chemical energy form. In fact, hydrogen, defined as an energy carrier for various further applications, is the actual usable product from PtG technology. Hydrogen as pure gas can be used as fuel for transportation, for industrial purposes as a green option, and also blended with the natural gas grid and stored in the existing natural gas infrastructure. Also, hydrogen could be stored as pure gas for short and long terms in appropriate facilities or underground storage caverns. Combining hydrogen with captured carbon dioxide is a further process in PtG to produce bio-methane or what is called renewable natural gas. The green fuel is then injected into the natural gas grid to increase its renewable content. PtG technology is discussed in sufficient detail elsewhere [19]–[24].

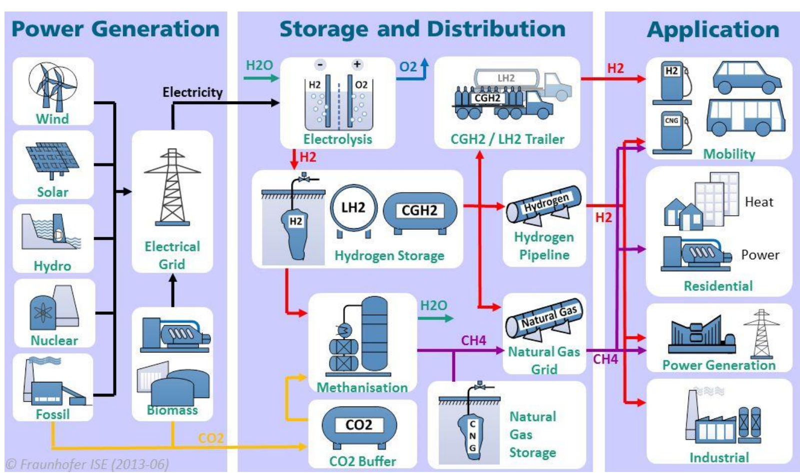

Figure 2 Power-to-Gas Concept [18]

PtG's main advantages are as follows:

- Produces green hydrogen that can be injected into existing natural gas infrastructure for distribution and storage purposes, thus there is no extra cost [22], [23], [25];
- Permits regional energy market to improve system operability and efficiency [25];

- Provides a means for energy storage, encouraging more renewable energy generation; and
- Plays a noticeable role in decreasing GHG emissions by substituting regular natural gas with RNG and utilization of captured CO_2 in methanation [22].

The low performance and excessive prices are the principle drawbacks of PtG systems that need to be overcome on the road to market place launch. Moreover, system components (electrolysis, compression, storage, and methanation reactor) need to be optimized to accomplish higher efficiency and economical operation [26].

The growing reliability and maturity of wind and solar technologies and their increasing share in the baseload supply, in the early 1990s, motivated the appearance of power-to-gas theory [27]. Then, the actual application of PtG as storage means has started in the 2000s [23]. Figure 3 [23] illustrates the timeline of PtG concept development from theoretical idea to actual demonstrations in Europe.

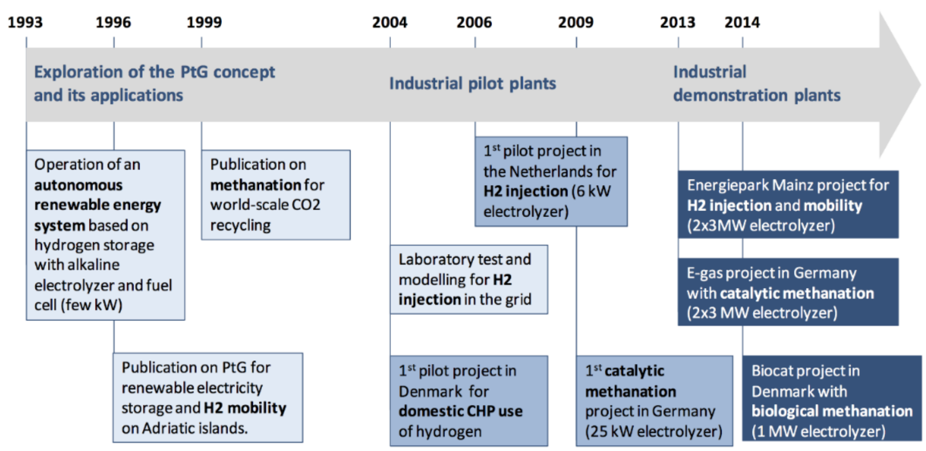

Figure 3 Power-to-Gas development timeline [23]

Canada has started to adopt green-hydrogen energy, led by Hydrogenics, which is a global company for industrial and commercial hydrogen systems [28]. Currently, there are two PtG facilities in Canada: 1) In Ontario, a 2-MW Power-to-Gas plant in the Greater Toronto Area built and operated by Ontario's Independent Electricity System Operator (IESO) with a collaborative with Hydrogenics and Enbridge in 2017; and 2) In Quebec, a 350-kW storage capacity built by TUGLIQ Energy Co particularly as Power-to-Power facility in 2015 [29] .

2.2 Power-to-Gas process steps and key components

This section provides the main process steps and technologies in PtG process chains: water electrolysis for hydrogen production, methanation process for renewable natural gas synthesis, and fuel cell for re-electrification.

2.2.1 Hydrogen Production via Electrolysis

The first and central brick of PtG systems is the electrolyzer, which converts the electrical energy into chemical energy as hydrogen gas. Production of green hydrogen via electrolysis is not a new technology; it has been used for more than a century for small productions. Other lower-cost hydrogen production technologies are used for global production, namely, steam reforming of natural gas and coal gasification. Interest in electrolytic hydrogen has increased again recently, influenced by its potential to provide pure hydrogen with a very low associated carbon footprint as well as providing ancillary services, such as load response management, in changing electricity grids. However, the possible production of green hydrogen from water electrolysis with renewable electricity is an opportunity for the process to address new and large markets [23], [30].
The electrochemical decomposition of water molecules is an endothermic reaction (Equation 1) and hence requires energy which can be a flow of an electric current through an appropriate electrochemical cell. Hydrogen production systems consist of multiple electrolysis cells connected in parallel or in series to form the overall electrolysis unit.

$$H_2O + \text{electrical energy} \rightarrow H_2 + \tfrac{1}{2}\, O_2 \qquad \textit{Equation 1}$$

Conventional alkaline electrolyzers (liquid electrolyte), Proton Exchange Membrane (PEM) electrolyzers and, most recently, anion exchange membrane (AEM) are three different types of electrolyzer technology currently available as commercial products [30]. Table 1 illustrates the characteristics of the three technologies.

2.2.1.1 Alkaline Water Electrolysis

Alkaline water electrolysis is a mature, reliable and safe technology; it has been used for industrial applications since 1920 [31]. Alkaline electrolyzers constitute the most extended technology at the global commercial level, exhibiting up to 15 years lifetime [32]. In alkaline electrolysis, water decomposition occurs between two electrodes in an alkaline solution, composed of 30% KOH or NaOH. By applying sufficient voltage between the two electrodes, H_2 molecules evolve from the cathode according to Equation 2, where water molecules take electrons to make H_2 and OH^- ions. Then, OH^- ions circulate through the electrolytic media toward the anode, where they recombine, giving their extra electrons to produce water and O_2 molecules (Equation 3) [33]. Alkaline electrolysers have a significant efficient operation within the range of 47%–82% and relatively low investment cost in the range of 1000– 5000 $/kW [34], [35], due to mature stack components and the avoidance of noble metals [36].

$$\text{Electrolyte: } 4H_2O \rightarrow 4H^+ + 4OH^- \qquad \text{Equation 2}$$

$$\text{Cathode reaction: } 4H_2O + 4e^- \rightarrow 4OH^- + 2H_2\uparrow \qquad \text{Equation 3}$$

$$\text{Anode reaction: } 4OH^- \rightarrow 2H_2O + 4e\text{-} + O_2\uparrow \qquad \text{Equation 4}$$

$$\text{Overall reaction: } 2H_2O \rightarrow 2H_2\uparrow + O_2\uparrow \qquad \text{Equation 5}$$

2.2.1.2 Proton Exchange Membrane (PEM) Electrolysis

Proton exchange membrane (PEM) electrolyzers is a hydrogen production equipment based on a solid proton electrolyte instead of alkaline electrolyte. PEM electrolyzers consist of cathode and anode separated by a polymer electrolyte membrane. By applying a DC voltage higher than a thermoneutral voltage, water molecules are split apart into their two components: hydrogen and oxygen. Then, protons produced (H^+) pass through the membrane driven by the electroosmotic drag to form hydrogen molecules (H_2) on the cathode by combining with electrons [7]. Equations 6-8 demonstrate the half-cell reactions and the overall reaction [8].

$$\text{Cathode reaction: } 4H^+ + 4e^- \rightarrow 4H_2\uparrow \qquad \text{Equation 6}$$

$$\text{Anode reaction: } 2H_2O \rightarrow 4H^+ + 4e^- + O_2\uparrow \qquad \text{Equation 7}$$

$$\text{Overall reaction: } 2H_2O \rightarrow 4H_2\uparrow + O_2\uparrow \qquad \text{Equation 8}$$

PEM electrolyser efficiency ranges between 67% to 82% [37] and component cost is high, in the 2400– 2900 $/kW range due to short durability of the membrane and noble metals utilization [30].

2.2.1.3 Anion exchange membrane (AEM) Electrolysis

Anion exchange membrane (AEM)–known as alkaline-PEM–combines the benefits of both alkaline and PEM electrolysers and overcomes their weaknesses. AEM contains a thin anion exchange membrane as an electrolyte, reducing the cost of using the expensive proton exchange membrane as in PEM electrolysers [38]. Generally, AEM technology is considered as a highly stable hydrogen production method and relatively less expensive compared to alkaline and PEM electrolysers [39]. Equations 9 and 10 demonstrate hydrogen and oxygen production in the cathode and anode, respectively.

$$\textit{Cathode reaction: } 4H2O + 4e^{-} \rightarrow 2H_2\uparrow + 4OH^{-} \qquad \textit{Equation 9}$$

$$\textit{Anode reaction: } 4OH^{-} \rightarrow 2H_2O + 4e^{-} + O_2\uparrow \qquad \textit{Equation 10}$$

$$\textit{Overall reaction: } 2H_2O \rightarrow 2H_2\uparrow + O_2\uparrow \qquad \textit{Equation 11}$$

Table 1 Characteristics of available electrolyzer: alkaline, PEM, and AEM [30]

		Alkaline	PEM	AEM
Development status		Commercial	Commercial medium and small-scale applications (≤ 300 kW)	Commercial in limited applications
System size range	kW	1.8 – 5,300	0.2 - 1,150	0.7 – 4.5
Hydrogen purity		99.5% – 99.9998%	99.9% – 99.9999%	99.4%
Indicative system cost	$/kW	1,200-1,500	2,400 – 2,900	N/A

To date, the cheapest and the most highly developed electrolyzer technology is alkaline, especially for continuous operation; they show high performance and provide high production capacities [40]. However, alkaline electrolyzers are not designed for dynamic operations because they are composed of high thermal capacity parts limiting the flexibility of the device and show slow start-up behavior (may take hours). On the other hand, PEM electrolyzers have a simpler design and exhibit faster start-up (few minutes or seconds) compared to alkaline electrolyzers, making them a convenient option for dynamic operations [41]. Moreover, PEM electrolysers have more pros over alkaline electrolysers, such as lower energy consumption, higher hydrogen purity, high-pressure operation, and a higher safety operation [42]. The significant drawbacks of PEM electrolyzers are the high cost because they contain noble metals like platinum (Pt), short lifetime (6-15 years) because of the limited membrane lifetime, and small hydrogen production capacity [43].

2.2.2 Renewable Natural Gas Synthesis

Synthesis of hydrogen and carbon dioxide into methane, using methanation, is the second and optional step within the PtG process chain. The RNG produced by methanation can serve as a substitute for natural gas, a fossil resource, and thus it can reduce greenhouse gas emissions, especially in the energy sector.

CO_2 methanation is an exothermic reaction, in which H_2 and CO_2 react to form CH_4 and H_2O. Equation 12 illustrate reaction stoichiometry [44].

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \qquad \Delta H = -165 \text{ kJ/mol} \qquad \textit{Equation 12}$$

In renewable natural gas (RNG) manufacturing, hydrogen via PtG system and captured carbon oxides from different potential sources are combined. There are two approaches for methanation reaction, summarized by Götz et al. (2014) [45] as thermochemical methanation and biochemical conversion. In the first approach–thermochemical methanation–H_2 and CO_2 are combined at about 300 - 550 °C, usually with nickel-based catalysts. However, in the biochemical reaction, microorganisms are utilized as the biocatalyst, within a temperature range of 40 - 70 °C in aqueous solutions [45].

There are several sources from which CO_2 can be captured and utilized in methanation. Reiter and Lindorfer (2015a) [46] evaluated viable CO_2 sources for PtG applications. In this present study, the exhaust gases captured from biogas digesters is considered as potential CO_2 source for methanation. Figure 4 shows GHG emissions by sector in Ontario, Canada, for 2013, according to Ministry of the Environment and Climate Change, Ontario [47]. The transportation sector is the largest GHG emitter by 35%, followed by industry by 28%. CO_2 sources from the agriculture and industry sectors are easier to be captured since they are CO_2-rich sources. The Transportation and Building sectors emit CO_2 into the air, making the CO_2 capture more energy-intensive and costly than separating CO_2 from more concentrated sources [48].

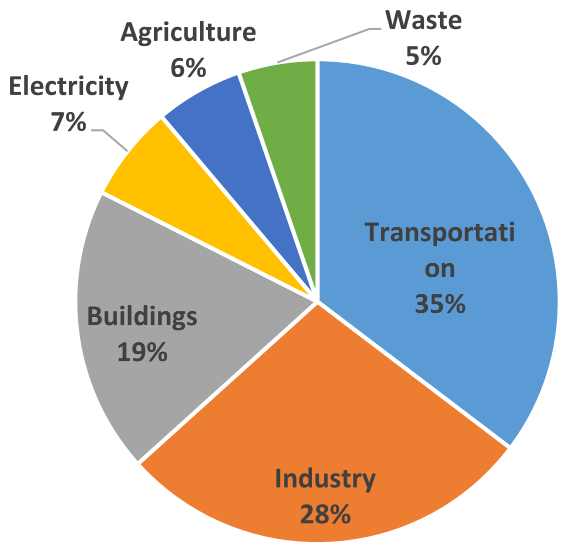

Figure 4 GHGs by Sector in Ontario, Canada (2016) [47]

2.2.2.1 Carbon Dioxide Sources for Methanation

The growing emission rates and globally rising temperatures due to fuel combustion have raised pressures to reduce global CO_2 emissions. However, none of today's solution alone can address this matter, but that carbon capture and storage could be a potential approach [49].

Carbon Capturing and Utilization technology (CCU) is one of the key options for reducing CO_2 emissions growing levels. It is an essential step for methanation reaction since pure carbon dioxide sources are rarely available [50]. The Transportation of CO_2 from its sources to a PtG plant is not considered in this study, due to its high variability in real operation. CO_2 separation units depend on the source and concentration of CO_2 [51]. The efficiency of the separation process is directly influenced by the concentration and purity of CO_2 in the exhaust gas. As a rule of thumb, the higher the CO_2 concentration in the exhaust stream, the higher the CO_2 capture efficiency and more cost-effective the process [52].

- **CO_2 from Biogas**

Typically, biogas refers to a mixture of gases, produced by the breakdown of organic matter in the absence of oxygen. It is primarily composed of 60% CH_4, 38%CO_2 and traces of other gases such as H_2S (1984 ppm), NH_3, SO_2, and H_2. The typical sources are raw materials such as agricultural waste, manure, municipal waste, plant material, sewage, green waste or food waste. Anaerobic digestion with anaerobic organisms is the process set up for biogas production, in which the organic material is digested inside a closed system [53].

Since the main component of biogas is methane, it can substitute for natural gas in all applications. For effective use of biogas in various applications, e.g., vehicle fuel, biogas needs to be purified into methane only. This is primarily achieved by carbon dioxide removal, which enhances the energy value of the gas so that it gives longer driving distances with a fixed gas storage volume [54]. The concentration of captured carbon dioxide out of a biogas exhaust stream is high enough (38-40 vol.%) [46] to be a feedstock for another process, methanation in this case, instead of it being discharged into the atmosphere.

The methanogenic bacteria in organic waste, manure, kept at an optimal 37 °C, cause the manure to decompose in warm slurry. The CO_2 produced from fermentation processes is a saturated gas, at low to atmospheric pressure. It can be nearly a pure stream of CO_2. The few impurities are in the forms of organic compounds, such as ethanol, methanol and sulfur compounds, including H_2S and dimethyl sulfide (DMS) [55]. Before digester biogas can be used for methanation, it must be scrubbed, and the remaining methane gas can be injected into the natural gas network. Figure 5 illustrates the inputs and outputs of methanation process steps, starting from the organic wastes to the natural gas grid.

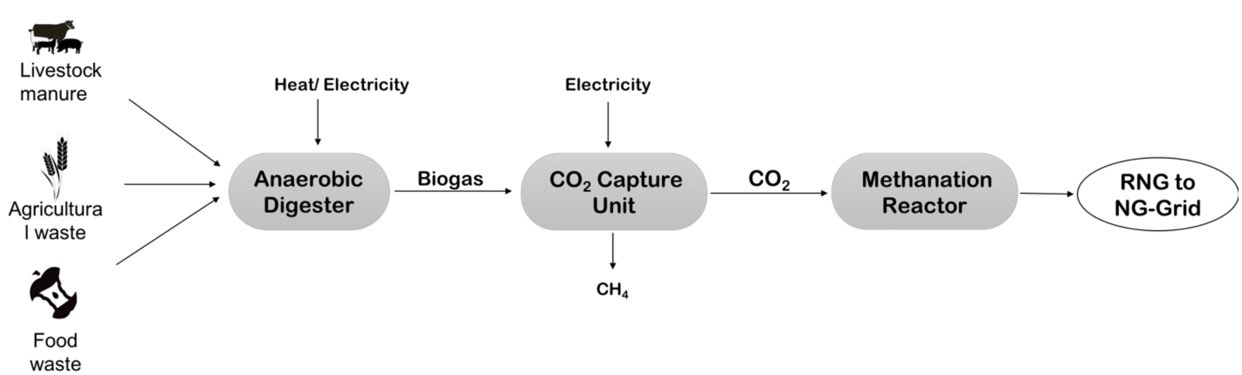

Figure 5 CO_2 captured from biogas digester for Methanation

In Canada, handling dairy-farms' organic-waste is unregulated yet, in which 62% of manure is used directly as fertilizer without treatment [56]. Such organic wastes are a rich source of methane and carbon dioxide which can be upgraded for power generation or renewable natural gas synthesis [57].

- **CO_2 from cement industry**

Considerable amounts of CO_2 arise during cement manufacturing, which is the third-largest source of anthropogenic emissions of carbon dioxide after fossil fuels and land-use change accounting for global emission of 1.45 Gt CO_2 in 2016, and contributing 8% of global CO_2 emissions [58]. Andrew (2017) [58] categorized CO_2 emissions from cement plants into two aspects, Figure 6. The first is the chemical reaction involved in the production of clinker, which is the main component of cement. Clinker, which consists mostly of limestone ($CaCO_3$) is decomposed into oxides (CaO) and CO_2 by the addition of heat. The second source of emissions is the combustion of fossil fuels to generate the significant energy required to heat the raw ingredients to well over 1000°C, and these 'energy' emissions, including those from purchased electricity, could add a further 60% on top of the process emissions [60]. Additionally, cement production is an energy-intensive process, consuming thermal energy of the order of 3.3 GJ/tonne of clinker produced. Electrical energy consumption is about 90-120 kWh/tonne of cement [61].

The levels of carbon dioxide in the flue gases from cement kilns vary depending on the production process, type of cement produced, and the type of fuel used for heat generation. [62]. A wide range of fossil fuels such as coal, natural gas, oil, liquid waste materials, solid waste materials and petroleum coke are used as sources of energy for firing cement-making kilns [63]. CO_2 volumes produced from the cement industry are usually large, and the plants can be equipped with a capture plant to produce a source of high-purity CO_2 for subsequent storage.

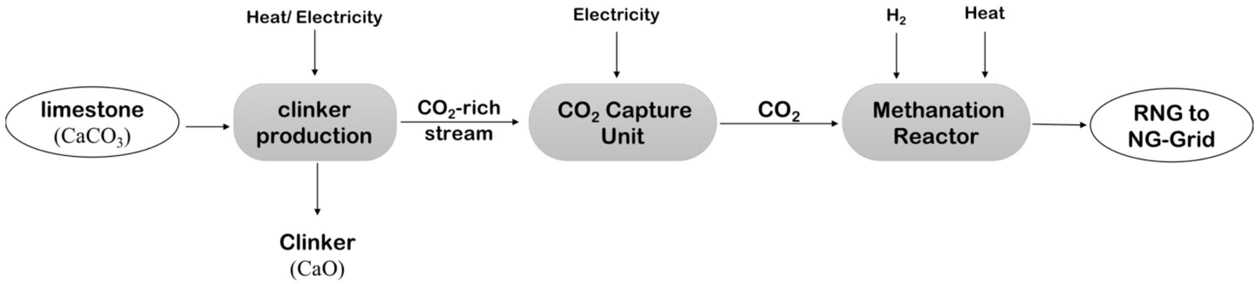

Figure 6 CO_2 captured from a cement plant for Methanation

2.2.3 Re-Electrification in the Fuel Cell

A fuel cell is a device that contains a galvanic cell which transforms the chemical energy into electrical energy continuously as long as oxidant and fuel are supplied [53]. Fuel cells are modular, therefore can be used for various applications including mobility sector and electricity generation [54]. Some of fuel cell systems advantages are: 1) it could produce electricity without pollution mainly when it is run on hydrogen, the only by-products are water and heat; 2) it requires no re-charging rather, fuel cell system need to be refueled, which is much faster than charging; 3) it can be used as electricity generation devices and compared to conventional engines, it requires fewer energy conversions [54]. However, the fuel cell technology needs enormous capital investment, talking about fuel cell vehicles the cost may exceed 2 million per mile [64].

2.3 Power-to-Gas Pathways

Global acceptance of Power-to-Gas as energy storage and transportation technology is growing noticeably. Power-to-Gas technology is one of the promising alternatives to end the fossil fuels reliance. The main concept behind power to gas technology is simply making use of surplus electricity to decompose water molecules into their primary components: hydrogen and oxygen. Hydrogen gas holds promise as an alternative carbon-free fuel that can be used for homes heating and lighting, electricity generating, motor vehicles fueling, and other related applications. Therefore, Power-to-Gas offers valuable energy pathways that can be applied to residential and industrial purposes. These applications have been discussed widely in literature. The majority of prior reports [21][22] has categorized the hydrogen streams as follows: 1) green fuel for mobility applications; 2) residential applications; 3) replacing fossil-based hydrogen in industry; and 4) long-term energy storage and distribution through the natural gas grid by injecting pure hydrogen or renewable natural gas into the natural gas system.

Tractebel Engineering (2017) [21] describes these pathways as “value streams” and categorized them into primary and secondary value streams based on the volume of hydrogen dedicated and revenues captured. The streams that generate the highest potential revenues are called the primary value streams, which represent hydrogen for industry and mobility applications. The potential revenues from primary applications are higher than those of the secondary streams. The secondary value streams are those which create opportunities to stack additional layers of revenues next to the primary applications, namely hydrogen for injection into gas grid and grid services [21].

In almost all the pathways, the “surplus” electricity is converted to hydrogen via electrolysis as the first step. Then, the electrolyte hydrogen is either used directly for multiple applications, such as: end-user’s applications (heating or generating electricity) and sold for industrial purposes, or further compressed to be used as zero emissions transportation fuel. As an alternative pathway, the energy carrier can be also stored or utilized to generate power again through gas turbines or fuel cells, known as Power-to-Power. Additionally, combining the green hydrogen with capture carbon dioxide to produce renewable natural gas (RNG)–in a process called ‘methanation’– is a promising means for utilizing carbon dioxide and increasing renewable content of natural gas. The importance of Power-to-Gas system is based on its final “high value” hydrogen streams that are starting to be competitive in different sectors because of its economy and environmentally benefits.

Moreover, in the Hydrogen Scaling up report by Hydrogen Council (2017) [22], the pathways are defined to supply seven different applications: power generation, transpiration, industry energy, hydrogen for building heating and power and hydrogen as industry feedstock. On the other hand, Maroufmashat (2017) [65] extends the definition of the hydrogen energy pathways to ten different pathways, including: Power to Gas-to Mobility Fuel, Power to Gas to Natural Gas Pipeline for use as hydrogen enriched natural gas (HENG), Power to Gas to Seasonal Storage to HENG, Power to Gas to Industry, Power to Gas to Power, and Power to Gas to Renewable Gas (Methanation).Theses pathways are to be implemented gradually in Ontario, Canada, making the most efficient use of the power generation mix.

Some Power-to-Gas pathways are profitable and acceptable already today [21], [23]. For most power to gas applications, the technology has been proven and is ready for use. Commercialization could start before 2020 for some applications, hydrogen for transportation is an example. Based on today's electricity prices, a total (baseload) electricity price of 50-60 $/MWh or lower is needed to build a rewarding PtG business case, as reported by Hydrogen Council (2017) [22].
Electricity is the main input to the PtG electricity, which is converted to hydrogen via electrolysis. In addition, captured carbon dioxide from different sources is utilized in the methanation process to produce renewable natural gas. Figure 7 demonstrates the PtG process-chains inputs, outputs and the final value streams.

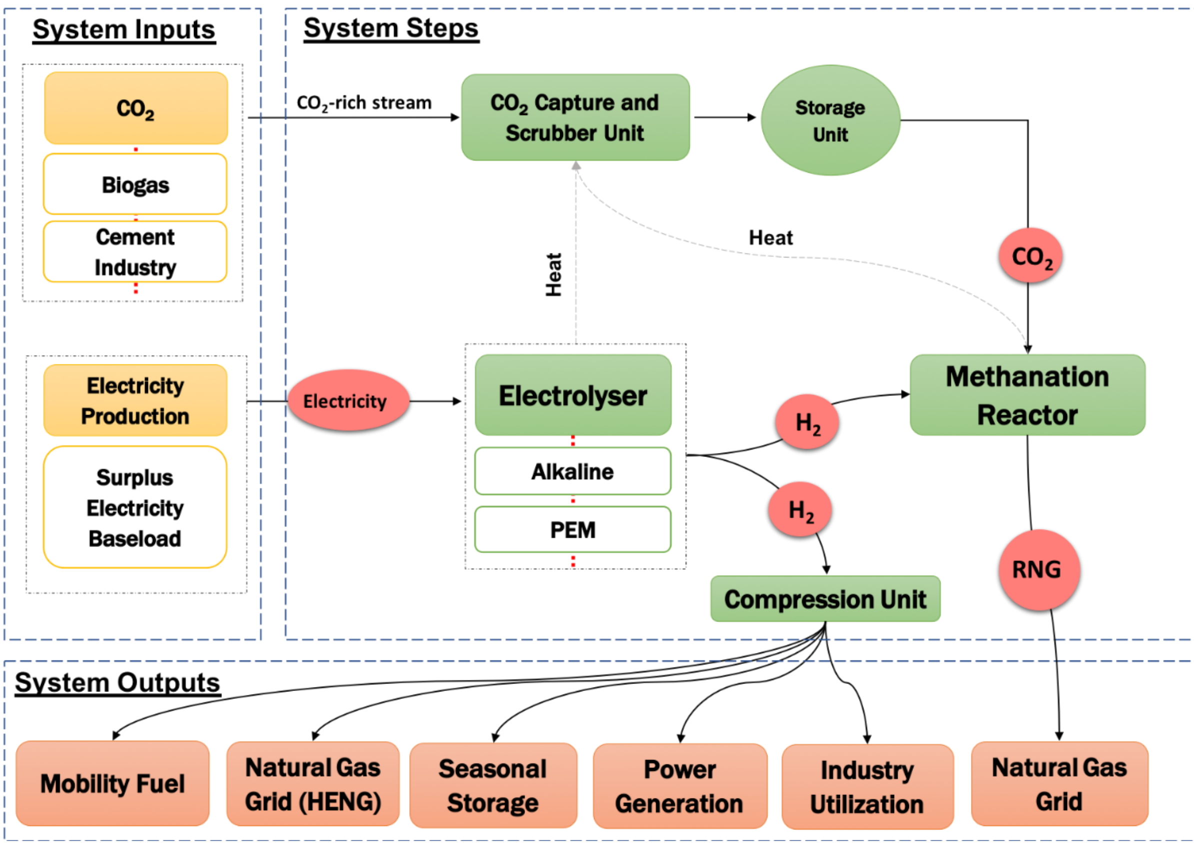

Figure 7 Power-to-Gas pathways

In the current study, the following PtG pathways are investigated: Power-to-Gas to Mobility Fuel, Power-to-Gas to Industry, Power-to-Gas to Natural Gas Pipeline for use as HENG, and Power-to-Gas to Renewable Natural Gas (i.e., Methanation).

A large body of literature has explored the suitability of various PtG pathways for applications. Schiebahn et al. (2015) [66] assessed the achievability of three PtG process chains including 1) hydrogen injection into the natural gas grid; 2) RNG–from methanation–blending with conventional natural gas; and 3) renewable hydrogen utilization for transportation. The study confirmed that the PtG process chains need to be economically competitive to be attainable and applicable. Indeed, large-scale projects of the first two pathways are not economical yet, since the production costs of hydrogen or methane to be injected into the gas network is still high compared to the conventional natural gas production. However, utilization of renewable hydrogen as a fuel in the transportation sector is a promising and profitable business [66].

2.3.1 Power-to-Gas to Mobility Fuel

The implementation of electrolytic hydrogen in the mobility market is still in its early stages. Moreover, its development depends on national strategies and policies that aim to achieve high-efficiency automobiles and zero-emissions transportation [23]. In some leading countries like Japan, South Korea, California, and Germany the deployment of hydrogen application as transport solutions has already begun. Furthermore, activities in other European countries, Northeast America, and East Asia are also under way. There are two good examples to demonstrate this progress, China and Japan have already invested in large-capacities green hydrogen manufacturing to achieve their target plan of having around one million fuel-cell vehicles (FCV) on their road by 2030 [22].

To accomplish the most benefits of FCVs, hydrogen should be produced from renewable resources. Hydrogen Council (2017) [22] confirmed the maturity of hydrogen-powered vehicles, as they are commercially available currently or will be available in the next five years. Chiefly, by 2030, one out of twelve cars sold in United States, Japan, and Germany could be powered by hydrogen, almost 350,000 hydrogen trucks could be transporting goods, and thousands of trains and passenger ships could be transporting people without carbon and local pollution. Beyond 2030, hydrogen will be used for renewable fuels production increasingly to decarbonize commercial aviation and freight shipping, which are harder to decarbonize using pure hydrogen and fuel cells [22].

The technology is proven, as reported by Hydrogen Council (2017) [22], that three models of hydrogen-fueled vehicles are already offered commercially in Japan, South Korea, California, and Germany (Honda Clarity, Hyundai ix35/Tucson, Toyota Mirai), and one model is available as a retrofit (Renault Kangoo, retrofitted by Symbio FCell).
In addition, vehicles powered by hydrogen are matured and reliable; they are able to satisfy all safety certifications and regulations under real-world conditions, that they have already driven more than 20 million kilometres. Moreover, hundreds of refueling stations have been operational for years [22].

There is zero carbon air contamination for FCVs since no combustion takes place in the vehicle; nevertheless, the emission should cover the whole hydrogen production lifecycle, starting from emissions during upstream electricity generation ending to the tailpipe. In fact, considering the entire lifecycle, the carbon emissions of FCVs are very low. Even if hydrogen were produced entirely from natural gas through steam methane reforming (SMR) without the use of carbon capture, FCV emissions are 20 to 30% lower than those of internal combustion engine vehicles. In total, an FCV powered by green or clean hydrogen could achieve combined CO_2 emissions of 60 to 70 g/km [22]. To sum up, this hydrogen energy stream (Power-to-Gas to mobility fuel) is a significant technology, which passed the laboratory-testing phase and it is ready for large-scale deployment. Hydrogen is already competitive with other green fuel options; competitiveness with fossil fuels will likely remain out of reach without financial incentives, however.

Figure 8 illustrates the Power-to-Gas to mobility fuel energy stream, where the fundamental technologies are the electrolysers, compression system, and storage facilities. Actually, on-site hydrogen production is economically favorable to reduce the transportation costs and a storage capacity is needed as a backup in case of demand increase [21].

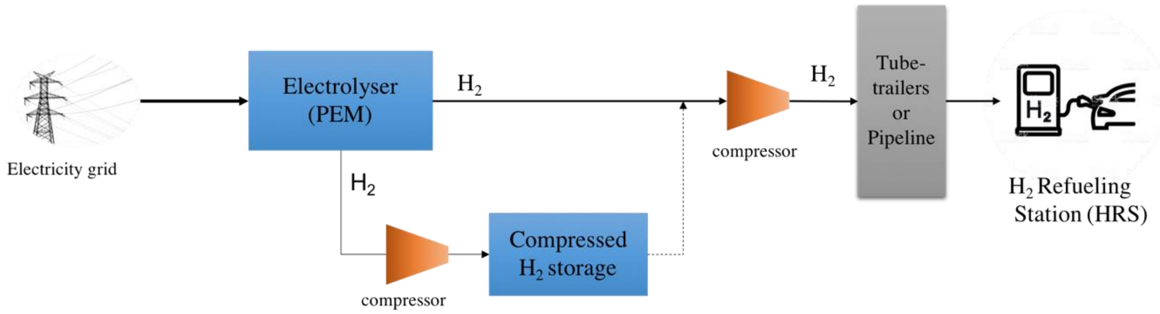

Figure 8 Power-to-Gas-to Mobility Fuel [21], [67]

The process chain of converting the surplus electricity into hydrogen as mobility fuel within PtG system is associated with energy losses. Lehner et al. (2014) [68] evaluated this pathway's efficiency to be within the range 57-73%, whereas Maroufmashat and Michael Fowler (2017) [65] considered slightly wider efficiency range 50-79%.

Several studies have investigated the reliability of hydrogen from PtG technology to meet the hydrogen-mobility market. For example, Mukherjee et al.(2016) [69] develop a simulation model for a 2-MW PtG plant which aims to meet the transportation sector hydrogen demand as well as offer electrical grid ancillary services in Ontario, Canada. The model has evaluated the economic variables that are capable of making the PtG to mobility fuel pathway financially competitive by adjusting potential revenue streams, i.e., hydrogen selling price and carbon pricing. The suggested hydrogen price and carbon credit are 5.5 $/kg and 27 $ per tonne of CO_2, respectively.

2.3.2 Power-to-Gas to Industry

Globally, industrial and power sectors combined dominate 60 % of the total CO_2 emissions. The harmful carbon contamination in these sectors are generated by boilers and furnaces burning fossil fuels and are typically emitted from large exhaust stacks [4]. Governments and policymakers aim to reduce the CO_2 emissions by reducing the use of fossil fuels in the industrial sector. Hydrogen, the most appendant compound, is the promising solution, in which hydrogen can create high temperatures while producing little or no CO_2 emissions. Equipment can be modified to run on hydrogen or a combination of hydrogen and other combustible fuels. In fact, CO_2 emissions could be reduced annually by as much as 440 million tonnes by 2050, if hydrogen production is largely decarbonized through water electrolysis or carbon capture [22] .

Hydrogen in the industrial sector is typically consumed in two ways: as feedstock and as heat and power source. To make progress toward national and global CO_2 reduction targets, large industries, such as methanol and iron production, can replace fossil feedstock with green hydrogen and utilize the captured carbon to produce zero-emission fuels [21], [67].

In the Potential of Power-To-Gas report by ENEA Consulting (2016) [23], it is stated that large amounts of green hydrogen are already used in refining, ammonia, and methanol production. In addition, refineries and ammonia plants could start producing their hydrogen from clean sources, reducing upstream emissions in the petrochemicals, and chemicals industries, by the middle of the next decade [23]. An example of a business that uses hydrogen produced via electrolysis is Toyota Motor Corporation in Japan. It launched a challenge termed the "Plant Zero CO_2 Emissions Challenge" To be achieved by 2050. Hydrogen energy is a central pillar of this strategy, along with the use of renewable electricity and improvements in energy efficiency [22].
Furthermore, according to Hydrogen Council [22], some industrial plants in Europe are already pioneering the use of clean or green hydrogen for existing feedstock applications. In the refining industry, Shell and ITM Power recently announced a plan to install a 10-MW electrolyser at a Shell site in the Rheinland Refinery Complex in Germany. In the iron and steel industry, a newly formed Swedish joint venture by SSAB, LKAB, and Vattenfall is demonstrating zero-carbon steelmaking using DRI with green hydrogen from electrolysis (the HYBRIT project) [22].
Hydrogen to supply the industrial sector demand is either produced on-site–for large industries–or produced elsewhere and delivered by tube-trailers or H_2-pipelines for light industries [21] (Figure 9).

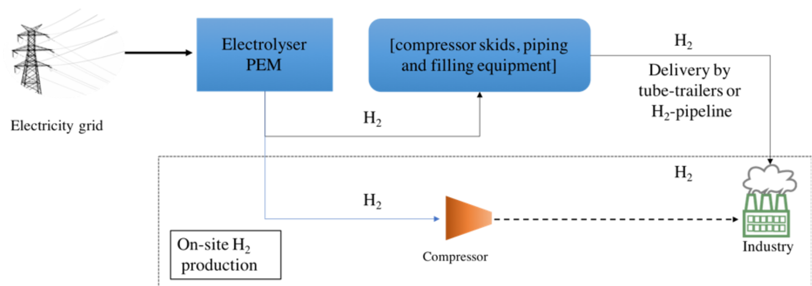

Figure 9 Power-to-Gas to Industry [21], [67]

The process chain of converting the surplus electricity into hydrogen for the industry sector utilization within PtG system is associated with energy losses. Lehner et al. (2014) [68] evaluated this pathway's efficiency within the range 67-77% for non-compressed hydrogen and 57-73% otherwise, where Maroufmashat and Fowler (2017) [65] considered slightly wider efficiency range 55-83%.

To date, several studies have investigated replacing fossil-based hydrogen production (i.e., steam methane reforming (SMR) and coal gasification) with green hydrogen deployment for the manufacturing sector. A seminal study in this field is the work of Al-Subaie et al. (2017) [70] on the utilization of electrolytic hydrogen produced via PtG concept for the petroleum-industry. The PtG plant is able to supply 25 MMscfd of clean hydrogen to the refinery; offsetting CO_2 release what is equivalent to emissions produced from 34,893 conventional gasoline light-duty vehicles.

2.3.3 Power to Gas to Natural Gas Pipeline for use as HENG

Combining electrolytic hydrogen with natural gas is a cost-effective option for providing heat and power for residential and business sectors while decarburizing natural gas networks [23]. The blend, which is called hydrogen enriched natural gas (HENG), contains hydrogen within the concentration range 5-20% by volume [21], [22], [65], [71]. Combining the advantages of both hydrogen and methane, HENG has much higher volumetric energy storage density than pure hydrogen. By adding green hydrogen to the gas grid, the grid provides huge and long-term energy storage capacity and increases the renewable content of the natural gas grid at the same time [72]. There are three ways of using hydrogen to decarbonize the natural gas grid: 1) by direct blending with natural gas within a specified volumetric range (HENG); 2) by combining hydrogen with carbon dioxide (methanation), which does not require any volumetric limitation; and 3) by using hydrogen in its pure form [21], [65] .

The Hydrogen Council (2017) [22] expects that this pathway would reduce CO_2 emissions by more than 700 mega-tonne (Mt) annually by 2050 . Blending hydrogen is a well-established, safe, and proven technology since the mid-1800s in the United States and the 1970s in the United Kingdom and Australia. It was known as 'manufactured gas' and contained 30 to 60% hydrogen, generally produced from coal or oil. Hydrogen blends are still common in areas with limited natural gas resources such as Hawaii and Singapore [22].

The cost of producing hydrogen via this energy stream is still high compared to steam methane reforming. However, pioneering projects are under way now in Europe to demonstrate the value of hydrogen in generating heat and power [23]. Hydrogen injection represents a smaller and hard-to-quantify market due to technical limits on the maximum allowable content of hydrogen in the grid [5]. In fact, Power-to-Gas for grid injection needs strong financial support in order to be viable and bankable [21], [23], [71].

Although the market of hydrogen for residential heating is still not completely mature, some projects around Europe have already been started and could start scaling up around 2030 [22]. In France, for instance, a project called "Network Management by Injecting Hydrogen to Reduce Energy Carbon Content" is preparing to blend up to 20% hydrogen into the local natural gas grid [22]. Globally, hydrogen could provide 10% of building heat and 8% of building energy by 2050 [22].

According to current standards and policies, the maximum allowable hydrogen concentration should not exceed 20% by volume. High hydrogen concentration may pose some risks in the distribution pipelines and end-user instruments [29]. Mostly, natural gas systems can tolerate low hydrogen concentration within the range 0-10% [29]; otherwise, extensive modification would be required on the level of the natural gas pipelines and end-users' appliances.

Figure 10 illustrates the process-conversion chain of this PtG pathway, where the key technologies are water electrolysis, compression skids and the injection station [21], [67]. The process chain of converting surplus electricity into hydrogen to be injected into the natural gas grid by PtG concept is associated with energy losses. Lehner et al. (2014) [68] evaluated this pathway's efficiency to be within the range 57-73%. Maroufmashat and Fowler (2017) [65] considered different scenarios for efficiency based on end-use applications, including hydrogen injection into the natural gas grid (59-83 %), heat for residential applications (52-76%), and to large scale gas-turbine use (18-26%).

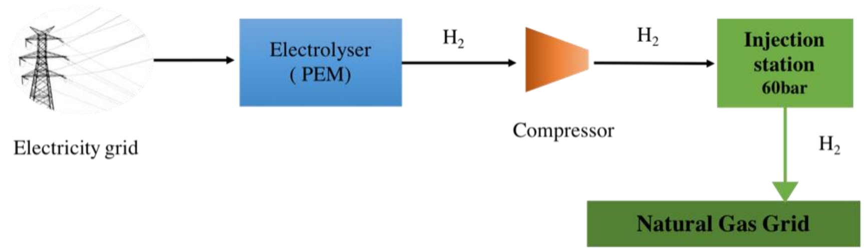

Figure 10 Power-to-Gas to Natural Gas Pipeline for use as HENG [21], [67]

2.3.4 Power-to-Gas to Renewable Natural Gas, "Methanation"

Methanation is a further step in Power-to-Gas systems, involves combining electrolytic hydrogen with carbon dioxide (CO_2) by a thermo-catalytic or biologic process, producing what is called "renewable natural gas" (RNG) [73].

Converting electrical energy to RNG has lower efficiency, about 20% compared to direct blending because it requires a CO_2 source and energy for the methanation reaction and consequently additional costs are added [21], [22], [73] . The renewable gas resulting from the methanation process is pure and therefore matches existing natural gas networks and storage infrastructure [22]. This production pathway has now moved beyond the design modeling stage to working projects on site. For instance, the "STORE&GO" project has built large-scale electrolysis and methanation pilot plants using a mix of renewable energies, and different CO_2 sources to produce RNG in Germany, Italy, and Switzerland [22].

In renewable natural gas (RNG) manufacturing, hydrogen via PtG system and captured carbon oxides from different potential sources are combined. There are two approaches for methanation reaction, summarized by Götz et al. (2014) [45] as thermochemical methanation and biochemical conversion. In the first approach–thermochemical methanation–H_2 and CO_2 are combined at about 300 - 550 °C, usually with nickel-based catalysts. However, in the biochemical reaction, microorganisms are utilized as the biocatalyst, within a temperature range of 40 - 70 °C in aqueous solutions. The pathway conversion efficiency is reported by Grond et al. (2013) [19] to be 70–85 % for the chemical methanation, and 95 % or even more for the biological methanation. Maroufmashat and Michael Fowler (2017) [65] expected this pathway efficiency the chemical methanation for to be 40-63% because it involves multiple energy conversion steps, which boosts the energy loses. Figure 11 demonstrates the RNG-production for CO_2 from biogas digesters [21], [74], [75].

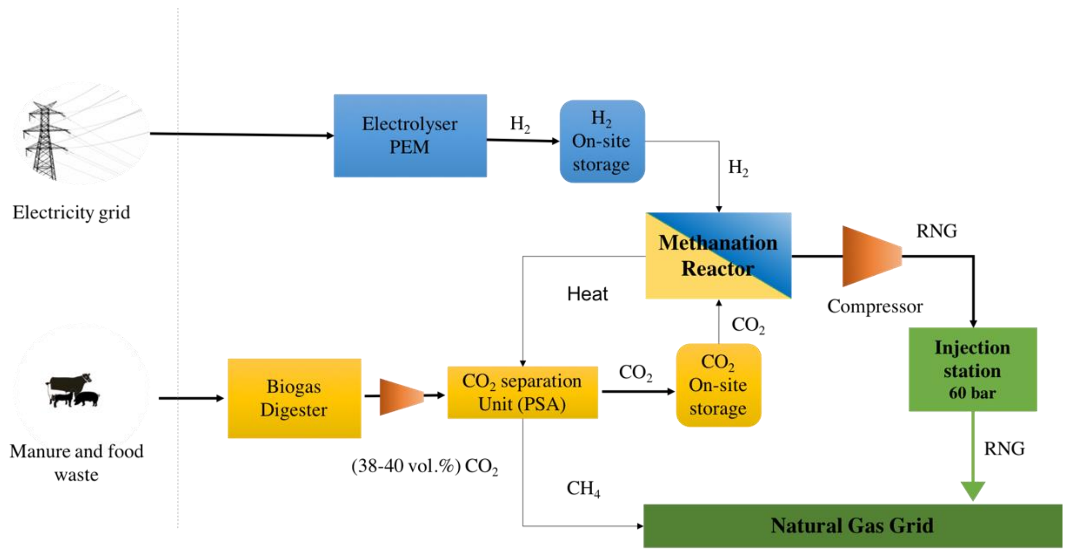

Figure 11 Power-to-Gas-to-RNG (Methanation) [21] [74] [75]

2.3.5 Other Power-to-Gas pathways

Various other PtG process chains not considered in this study because of their low potential suitability and high production cost are mentioned here in brief.

2.3.5.1 Power-to-Gas to Seasonal Storage for Use as HENG

Hydrogen could play a growing role in the integration and storage of renewable energies and production of clean power in the transition toward greener global energy. By 2030, 250 to 300 TWh of surplus renewable electricity could be stored in the form of hydrogen for use in other end-use segments [22].

Hydrogen can be stored easily for long periods to fulfill seasonal heating demand. A large share of electrical heating would create a strong seasonal variation in demand for power, which would require an extensive additional renewable capacity for use only in winter [65]. Figure 12 illustrates the key components and process steps of this PtG pathway.

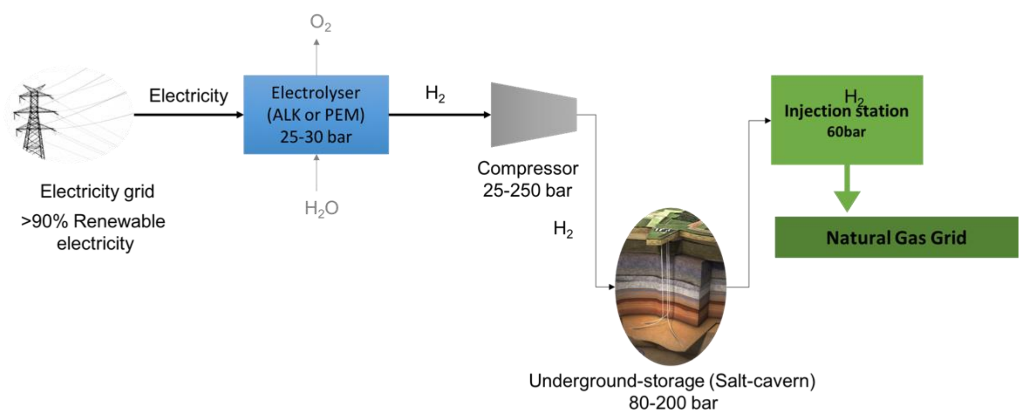

Figure 12 Power to Gas to Seasonal Storage to HENG [21], [67], [76]

2.3.5.2 Power-to-Gas to Power

Re-transformation of hydrogen generated during periods of peak renewable generation into electrical energy again–when needed–by means of gas turbines and fuel cells, is called Power-to-Power. This pathway is sufficient for on-site hydrogen production so that hydrogen is produced and stored as per requirements. Furthermore, hydrogen produced during sufficient renewable capacities could be a source of clean energy during peak demand.

Large quantities of hydrogen can be stored for long periods of time. For example, more than 200 TWh could be generated from hydrogen in large power plants to accompany the transition to more renewable electricity [22]. Figure 13 illustrates the key components and process steps of this PtG pathway.

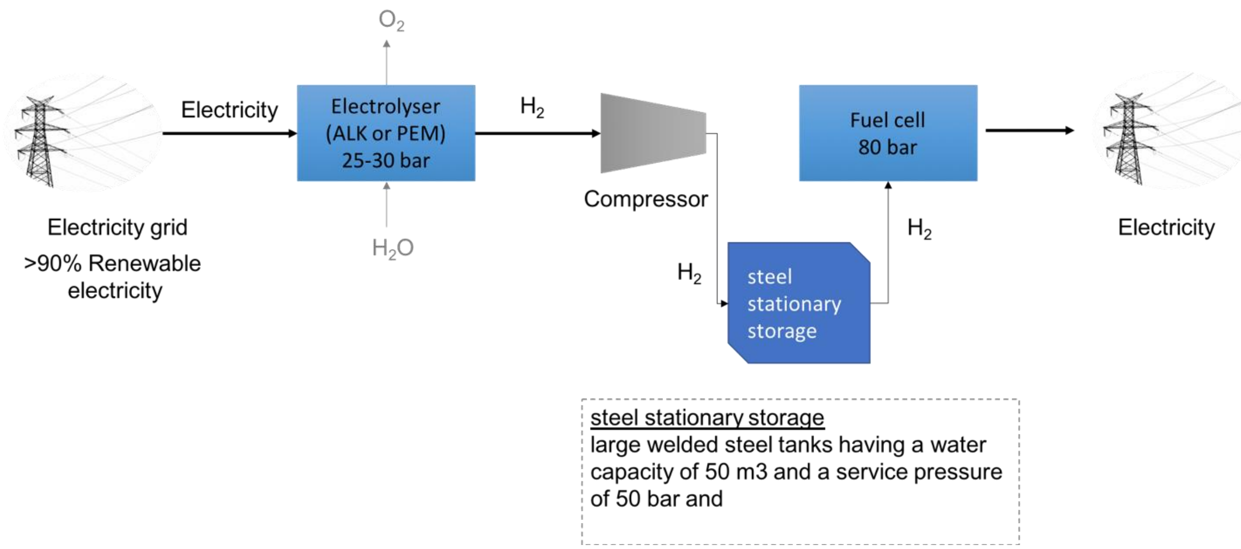

Figure 13 Power to Gas to Industry adapted from [21], [67]

Chapter 3: Power-to-Gas Pathways' Economy

This chapter highlights the methodology used to evaluate PtG pathways economy. This includes: overall capital expenses (OPEX), annual operational expenses (OPEX), potential revenue streams, and some economic validity indicators.

3.1 Overall Capital Expenses (CAPEX)

The overall capital expenses is the fixed costs necessary to acquire the PtG pathways. It is the summation of pathway's equipment cost; civil works costs; engineering costs; distributed control system (DCS) and energy management unit (EMU); and Interconnection, commissioning, and start-up costs [21]. A brief description of overall capital costs is illustrated in Figure 15.

Overall Capital Expenses (CAPEX)	**1. Civil work costs** - Costs associated with plant construction, including foundation, industrial buildings, lighting, water supply, fencing, security. - this cost is estimated by Equation 13.
	2. Engineering costs Expenses related to engineering practice for project management. That covers architectural, engineering, studies, permitting, legal fees, and other pre and post construction expenses. Engineering costs depend on production capacity, complexity, and storage size. - These expenses stand for 20% of total equipment costs.
	3. Distributed Control System (DCS) and Energy Management Unit (EMU) -Costs of plant control system components. - DCS and EMU represent 13% of the total equipment costs.
	4. Interconnection, commissioning, and start-up costs - Payments corresponding to piping, interconnection, inspection, test, commissioning, and start-up. - Estimated to be about 25% of equipment costs.
	5. Related costs - Costs other than equipment and civil costs acount for 60% of equipment costs.

Figure 14 Capital cost–CAPEX components [21]

Equation 13 is the cost function to estimate the civil work expenses, in which Equation 13 parameters are described in Table 2.

$$CAPEX_{Civil\,works} = (A + B)\left(S_{adjust} \times area_{total}\right) + C \times \, area_{building} \quad \textit{Equation 13}$$

Table 2 Parameter values of Overall Capital Expenses (CAPEX) [21]

	Description
$\boldsymbol{CAPEX_{Civil\,works}}$	Capital expenditure of plant civil work [$]
A	Base cost [$/m^2]
B	Additional cost for greenfield [$/m^2]
$\boldsymbol{S_{adjust}}$	Considered surface adjustment
C	Building additional cost [$/m^2]
$\boldsymbol{area_{building}}$	The electrolyser system surface area (m^2) fitted inside the building.

3.2 Overall Operating Expenses (OPEX)

PtG plant overall operating costs involves: 1) cost of electricity to be utilized for hydrogen production and other technologies operation, in which the hourly Ontario energy price (HOEP) in $/MWh offered by Independent Electricity System Operator (IESO) [77], Figure 16 shows HOEP for 2017; 2) the equipment annual operating costs (OPEX), which is the cost related to the maintenance, spare parts and replacement associated with the equipment. It is always a percentage of the equipment CAPEX as described in section 3.3; 3) the cost of water purchasing for electrolysis [78].

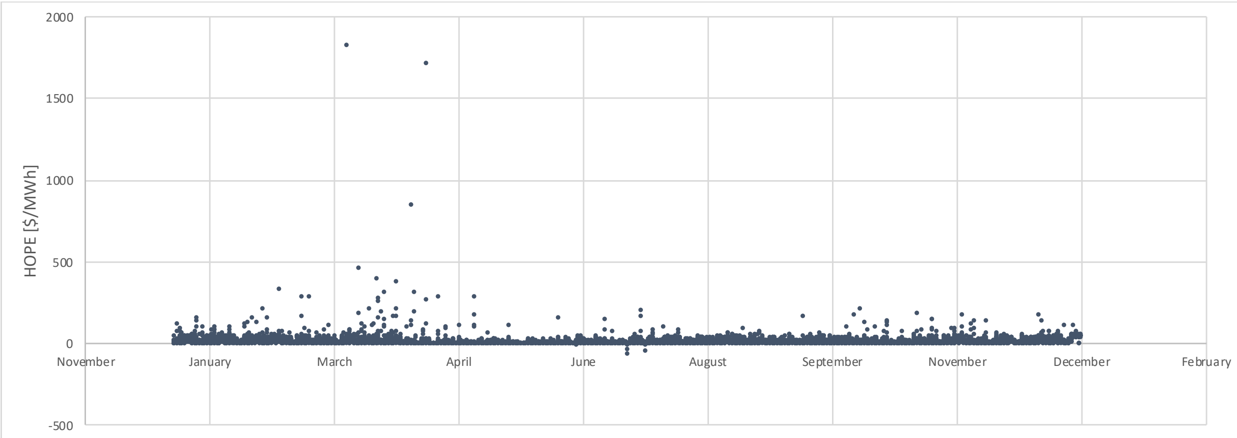

Figure 15 The hourly Ontario energy price (HOEP) in $/MWh[77]

3.3 PtG Pathways Technologies CAPEX and OPEX

3.3.1 Electrolyser System

The current study considers PEM electrolysis system from Hydrogenics [21], [79]. Table 3 summarized the selected cost and performance values.

Table 3 PEM electrolyser selected cost and performance data [21], [79]

Technology Data	Unit	Value
Nominal Power	MW	1
Output Pressure	bar	30
Power consumption	kWh_{el}/kg	63
Water consumption	L/kg H_2	15
Electrolyser-CAPEX	$/kW	1324
Electrolyser-OPEX	% CAPEX	4%
Stack replacement	$/kW	464

3.3.2 Hydrogen Compression

Compressor skids are necessary for on-site hydrogen or RNG production and compression. this system is consists of compressor, cooling, and control system [21]. Moreover, compression ratio (P_{out}/P_{in}) determines the number of compression stages required for hydrogen compression. the compression ratio 1-3 implies one compression stage, while 3-5 two stages are required [80]. The power consumption for hydrogen compression is calculated by adiabatic compression equation, Equations 14 and 15 [80] [81].

$$for\ 1\ stage - compressor:\ \ W = \left[\frac{n}{n-1}\right] P_i V \left[\left(\frac{P_f}{P_i}\right)^{\frac{n-1}{n}} - 1\right] \qquad \textit{Equation 14}$$

$$for\ 2\ stages - compressor:\ W = \left[\frac{2n}{n-1}\right] P_i V \left[\left(\frac{P_f}{P_i}\right)^{\frac{n-1}{2n}} - 1\right] \qquad \textit{Equation 15}$$

where:

W is energy required for compression [J/kg H_2]

n: the adiabatic coefficient (ratio of specific heats) which is n= 1.41 for H_2

P_i and P_f: are initial and final pressures, respectively

V: Volumetric flow rate, m^3/min

The compression efficiency is calculated to be 86% and 77% for single stage and two-stages respectively from equations 16 and 17 [80].

$$for\ 1\ stage - compressor:\ \eta = 93 - \left(\frac{P_f}{P_i}\right) - 8\left(\left(\frac{P_f}{P_i}\right)^{\frac{1}{n}} - 1\right) \qquad \textit{Equation 16}$$

$$for\ 2\ stages - compressor:\ \eta = 89 - \left(\frac{P_f}{P_i}\right) - 7.8\left(\left(\frac{P_f}{P_i}\right)^{\frac{1}{2n}} - 1\right) \textit{ Equation 17}$$

Table 4 shows the calculated number of stages and energy consumption for the current study.

Table 4 Hydrogen compression power consumption

Pressure [bar]		Number of stages	Power consumption [kWh_{el}/kg H_2]
Input	Output		
30	200	2	1.7
30	60	1	0.58
30	100	1	1.09

Table 5 shows the technical and economic data for H_2 compression.

Table 5 the technical and economic data for H_2 compression [82]

	booster compressor	**pre-storage compressor**
capacity [Kg/h]	42	87
CAPEX [$]	$37,368	$25,442
OPEX [% CAPEX]	6%	6%

3.3.3 Hydrogen Storage

Hydrogen can be stored in its three physical-states (gas, liquid, and solid) using different storage methods that include above and underground technologies. Current technology and economic statues of hydrogen storage methods are described in detail elsewhere [75], [76], [83]–[85]. Overall, storing hydrogen as compressed gas is the most common, simplest and efficient method [86]. In this study, steel stationary storage is considered for on-board storage. Steel tank storage facility is sufficient for low-pressure (20-70 bar), short time and small quantity gas storage [21], (Table 6).

Table 6 Storage methods technological and economic data

Storage method	Pressure [bar]	CAPEX [$]	OPEX	Life time [year]	Reference
Steel tanks	20-70	577,404	2% CAPEX	30-40	[21]

The storage of electrical energy in the form of compressed hydrogen via PtG technology is correlated to a significant cost. Although a large investment is required, they are reasonably cheap with respect to the capacity installed, however [87].

3.3.4 Injection station

The injection of hydrogen gas or renewable natural gas into the natural gas grid is a promising energy stream for large scale and long-time storage of surplus electricity produced from renewable energy. The main advantage of this pathway is that the natural gas grid is used as storage and transport intermediate facility and hence no need for a new investment. For this study, the following cost data will be used [21].

Table 7 Injection station cost data [21]

	Unit	Value
Pressure	bar	60
Lifetime	years	35
Injection station-CAPEX	[$]	860,083
OPEX	% CAPEX	8%
H2-connecting piping	[$/km]	368,607
H2-connecting piping equipment	[$]	245,738
OPEX	% CAPEX	2%

3.3.5 Methanation Process

The methanation process performance and cost data is illustrated in Table 8. In this study, CO_2 source for methane synthesis is acquired from a nearby biogas digester and authors assume that CO_2 are being upgraded and 99.99% pure.

Table 8 Methanation process performance and economic data

	Unit	Value	Reference
Methanation production capacity	Nm^3/h	2000	[68][88]
CAPEX	[$/kW$_{CH4}$]	496	
OPEX	[% CAPEX]	10%	
Storage tanks (for hydrogen and CO_2 on-site storage)–CAPEX	[$]	577,404	[21]
Storage tank–OPEX	% CAPEX	2%	

3.4 Potential Revenue Streams

Generally, two revenue streams are proposed for the PtG pathways, specifically: 1) direct revenue from hydrogen, HENG, or RNG selling; 2) monetary paybacks from CO_2 emission reduction earned credits. Table 10 illustrates the selling prices for each PtG pathway's final product.

Table 9 Final product selling price for each PtG pathway [89]–[91]

PtG Pathway	Final product selling price	Reference
PtG to mobility fuel	10 $/kg H_2	[89]
PtG to industry	Price of H_2 produced via steam methane reforming 2.69 $/kg H_2	[90]
PtG to pipeline to be used as HENG	Natural gas price 3 $/MMBtu	[91]
PtG to renewable natural gas		

Additionally, part of the Climate Change Action Plan, the Province initiated the cap-and-trade program, which aims to support businesses and industry stakeholders to invest in more efficient and clean technologies and pollution reduction consequently [88]. The market-based program, which has been in action since January 1st, 2017, sets a hard emission-boundary or (cap) to the industrial organizations to lower emissions gradually starting by the major emitters of GHGs. Furthermore, the price is put on carbon reduction, encouraging the companies to reduce more; said otherwise, the less the companies emit, the less money they pay [103]. On the other hand, companies who emit less can make a profit from selling emission-permits or allowances to other companies that exceed their emission-cap [88]. Therefore, the carbon credit for Ontario is 18 $/tonne CO_2 [92].

Furthermore, to estimate the carbon offset, CO_2 emissions calculated for each pathway are compared against the carbon emissions produced by the conventional methods. For PtG to mobility fuel, CO_2-offset is estimated by assuming that FCVs emit zero CO_2, since they are certified as zero emission vehicles [93]. The same amount of hydrogen produced via this pathway is compared against gasoline conventionally used to fuel light-duty vehicles. To illustrate, according to the United States Environmental Protection Agency (EPA) the annual emission of a typical light-duty gasoline vehicle is about 4.6 tonnes of carbon dioxide. This is based on an average fuel economy of about 22 miles per gallon (9.35 km/L) and average annual mileage of a vehicle around 11,500 miles per year (18507 km/y) [94]. Additionally, CO_2-offset of the second PtG pathway, PtG to industry, is the difference between CO_2 emitted from hydrogen production via this PtG pathway (based on Ontraio's electricity emission factors, Table 10) and the same amount of hydrogen produced by the established method SMR. In fact, producing 1 kg of hydrogen via SMR emits about 15 kg-CO_2e per kgH_2 [95]. Moreover, the emission factor of conventional natural gas production is 56 kg CO_2 per GJ, according to Natural Resources Canada [96]. Therefore, for the third PtG pathway, PtG to pipeline to be used as HENG, the emission associated from hydrogen production via this pathway is compared to emission from natural gas production. Such compression seeks to answer the question, what if the amount of hydrogen injected into the natural gas grid is natural gas instead of hydrogen? Lastly, the production of renewable natural gas by methanation is compared against the conventional natural gas production.

- **Greenhouse gas (GHG) emission**

Estimating carbon emissions is essential to identifying and prioritizing greenhouse gases reduction strategies. In Ontario, approximately 90 percent of electricity is generated from carbon-free sources (nuclear, hydro, and renewables); nevertheless, the other 10 percent comes from fossil-based sources. Greenhouse gas releases amounts depends strongly on the type and source of energy used for electricity generation. In the current study, emission factors of different power sources for Ontario's electricity generation for 2017 are illustrated in Table 10, according to Independent Electricity System Operator (IESO). Further, Figure 14 shows hourly emission factor of Ontario's electricity mix for 2017 [7].

Table 10 Greenhouse gas emission factors from power generation sources [7]

Power source	GHG emission factor (kg CO_2/MWh)
Nuclear	17
Hydro	18
Solar	39
Gas	622
Biofuel	177
Wind	14

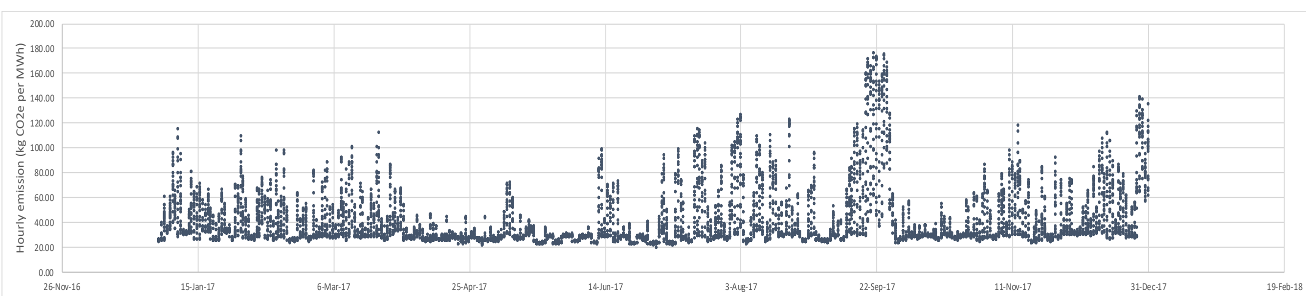

Figure 16 hourly emission factor of Ontario's electricity mix for 2017 [7]

3.5 PtG pathways economic viability

The PtG pathways' profitability is examined by considering three profitability indicators: net present value (NPV), payback time (PBP), and internal rate of return (IRR). These three indicators are the most common methods used to assess the financial viability of a project.

3.5.1 Net Present Value

The net present value (NPV) is a key indicator to assess the financial viability of a project. NPV is the value of the difference between the present value (PV) of cash inflow and outflow, where PV is the current value of a future sum of money given a specified rate of return, as Equation 18 illustrates.

$$PV = \frac{CF}{(1+r)^n} \qquad \textit{Equation 18}$$

CF is the money cash flow, r is the interest rate, and n is the time. In this study, PV is calculated at 8 % interest rate and a project lifetime of 20 years. NPV is used as an indicator in investment decisions, in which a positive value means that a project's revenue is greater than its costs and exceeds the initial capital investment required to fund it [97].

3.5.2 Payback Period

Payback time method is a way to estimate the time required to regain a project's initial investment. In fact, PBP is a key determinant of how cost-effective the project is, in which the shorter the PBP, the more likely the project will be undertake [80]. To demonstrate, PBP is expressed in years and is equal to the ratio of initial investment to the net annual cash flow. One of drawbacks of PBP method is that it does not give a clear conclusion of a project's profitability; that is, the shorter period does not necessarily mean that the project is profitable [97].

3.5.3 Internal Rate of Return (IRR)

One typical method to evaluate a project and come up with a decision whether to accept it or not is the internal rate of return (IRR). In brief, IRR is defined as the interest rate at which the net present value (NPV) of the cash flow and the initial investment become equal amount [80]. Assuming F(n) is the project's cash flow and n is the time (years), then:

$$NPV = F(0) + F(1)/(1+r) + F(2)/(1+r)^2 + \ldots + F(n)/(1+r)^n \qquad \text{Equation 19}$$

IRR is calculated by setting NPV equals zero and solving for r. Indeed, a positive IRR ratio indicates that a business gains money at the rate of IRR and vice versa [81]. In cases where all cash flow values are all negative or positive, IRR is undefined value because there is no interest rate small enough to make NPV equals zero [98].

Chapter 4: Hydrogen Allocation Scenarios

A recent series of publications has studied the implementation of different Power-to-Gas pathways in the Canadian province of Ontario. Mukherjee et al. (2017) [69], Hajimiragha et al. (2009) [99], and Walker et al. (2015) [100] examine the utilization of hydrogen via power-to-gas in the transportation sector. Also, Walker et al. (2016) [101] and Al-Subaie et al. (2017) [70] study the implementation of electrolytic hydrogen into the petroleum-industry, aiming to optimize GHG reduction and system costs. Further, the feasibility of hydrogen injection into the natural gas grid and its environmental and economic consequences is examined by Mukherjee et al. (2015)[102]. Ozbilen et al. (2012) [103], and Walker (2016) [104] investigate Power-to-Gas system as seasonal storage technology in Ontario. However, the current study is a snapshot of the time to optimize the allocation of hydrogen–produced from Ontario's surplus baseload electricity–to various PtG pathways in terms of environmental and economic aspects for the year 2017. Therefore, this chapter first determines the amount of hydrogen that could be produced from Ontario's surplus baseload electricity at three different capacity factors through PtG technology. Then, it explores different scenarios for allocating the generated hydrogen to four PtG energy streams: power-to-gas to mobility fuel, power-to-gas to industry, power-to-gas to pipeline to use as HENG, and power-to-gas to renewable natural gas. Furthermore, the work estimates the amount of CO_2 offset as well as some economic aspects such as capital and operational costs, and the economic validity of each PtG pathways.

In Ontario, most surplus electricity is managed through exportation to nearby jurisdictions and electricity curtailment [8]. In both cases, the clean and insignificant fuel cost electricity goes unused. In 2017, about 19 TWh of energy was exported, and 3.3 TWh was curtailed, costing the province more than one million dollar in profits [10], [11].

Typically, the surplus baseload generation (SBG) takes place during periods of low demand, when the baseload generation is higher than Ontario's demand. To calculate the SBG, the Ontario demand forecast is compared against the baseload generation in 2017, which includes nuclear, hydroelectric, and intermittent sources [7].

Figure 17 illustrates hourly Ontario's baseload production, demand, and surplus baseload electricity for 2017 [7].

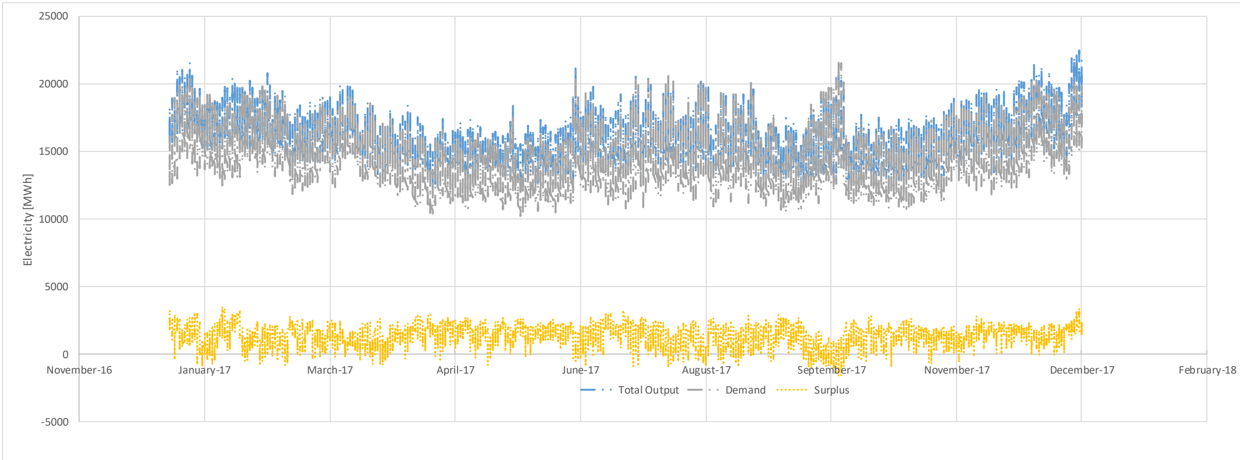

Figure 17 Hourly Ontario baseload production, demand and surplus electricity for 2017 [7]

The PtG system is assumed to operate for 350 days, at three capacity factors, which are 67 percent (16 h/day), 80 percent (19 h/day), and 96 percent (23 h/day), with an electrolysis efficiency of 80 percent. Table 11 shows the ranges of hourly emission factors and hourly Ontario energy price for the three capacity factors. In this study, a 1-MW polymer electrolyte membrane (PEM) electrolyzer with an electricity consumption of 51.5 kWh per kg hydrogen is assumed for hydrogen production [105]. Some general assumptions need to be mentioned here: the production of hydrogen is assumed to be close to the demand, therefore piping and distribution costs are not considered in this study. Also, for each pathway, an amount equal to the demand for a week is assumed as backup in case of demand increase.

Table 11 Ranges of hourly emission factors and hourly Ontario energy price for the three capacity factors [7]

Capacity factor	67%	80%	96%
Emission range [kg CO_2/MWh]	20-142	20 - 169	20-176
HOEP [¢/kWh]	-6.7 – 4.0	-6.7 – 31.4	-6.7 – 182.3

Figure 18 illustrates the monthly trends of Ontario’s surplus baseload electricity in gigawatts hour (GWh) along with the electrolytic hydrogen production at the three different capacity factors in tonne, for 2017. The figure shows the inconstancy of surplus baseload generation over the whole year, with peak power-generation occurring in April 2017. The decrease in SBG during February and March, and from July to September could be due to stronger demand during winter and summer, respectively.

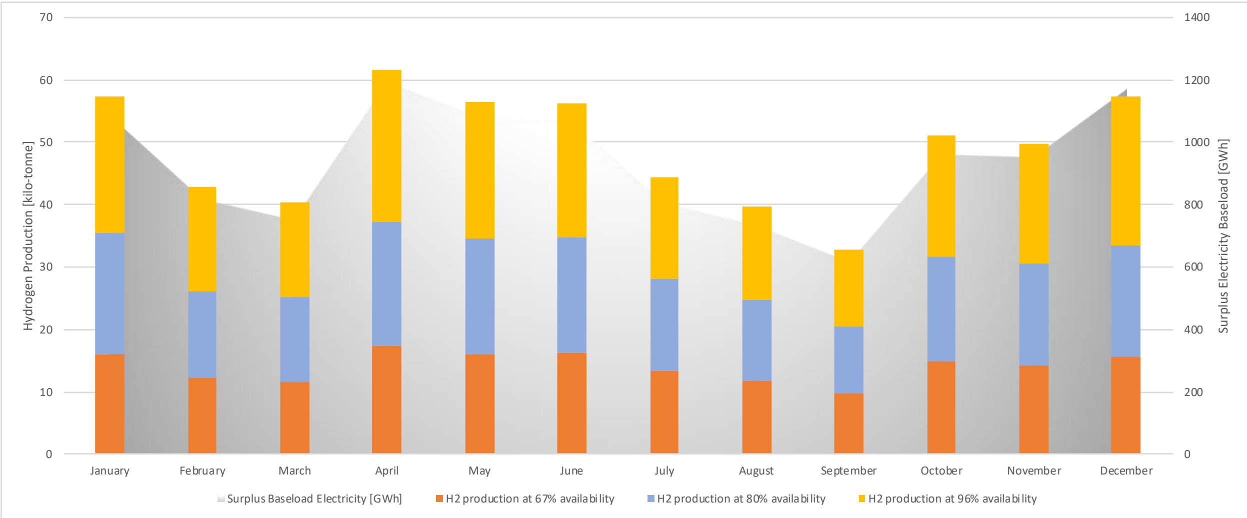

Figure 18 The monthly trends of Ontario's surplus baseload electricity and the electrolytic hydrogen production at the three different capacity factors

Hydrogen allocation will be based on five scenarios as follows:

- Scenario A: hydrogen allocation based on each pathway's demand and constraints, set by Ontario's Climate Change Action Plan and Long-Term Energy Plans;
- Scenario B: utilization of produced hydrogen entirely as a mobility fuel
- Scenario C: utilization of produced hydrogen entirely for industry
- Scenario D: utilization of produced hydrogen entirely as hydrogen enrich natural gas
- Scenario E: utilization of produced hydrogen entirely for methanation.

4.1 Scenario A

In this scenario, the total hydrogen produced via PtG concept is allocated based on each pathway's demand as set by Ontario's energy plans and policies to eliminate greenhouse gases by 2050, Table 12. Figure 19 illustrate Ontario's monthly hydrogen demand for 2017 for each PtG pathway, which will be described in the following subsections.

Table 12 Hydrogen, HENG, and RNG demand to be met by PtG pathways

Power-to-Gas pathway	Demand to be met
Power-to-Gas to Mobility fuel	1.2% penetration of FCV on Ontario's road in 2017
Power-to-Gas to Industry	Supply 5% of Ontario's industrial hydrogen demand
Power-to-Gas to Natural Gas Pipeline for use as HENG	5% by volume hydrogen concentration in Ontario's natural gas grid (2017)
Power-to-Gas to Renewable Gas	Up to 10% by volume RNG content in Ontario's natural gas grid

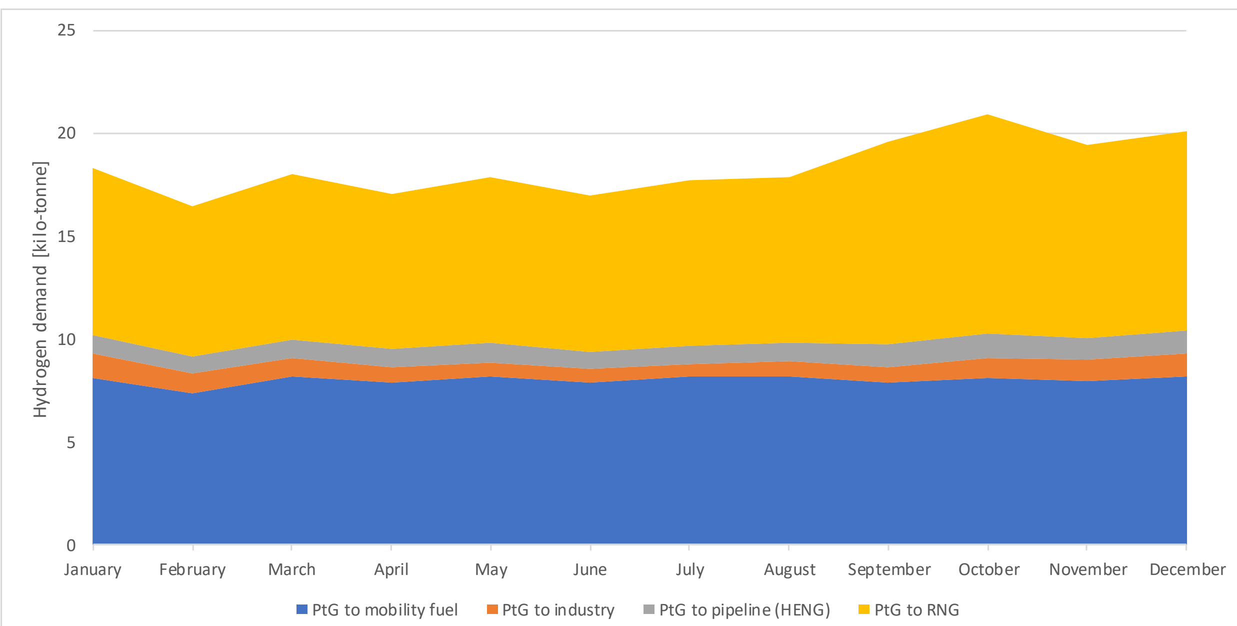

Figure 19 Hydrogen demand to be met for each PtG pathway

4.1.1 Hydrogen Demand in the Transportation Sector

According to Ontario's Climate Change Action Plan, the transportation sector is considered as a significant challenge in the road toward emission reduction, as one third (70%) of the total GHG pollution comes from the mobility sector [3]. Generally, in the transportation sector, hydrogen demand depends on the needs of the light-duty vehicles that represent 75% of total vehicles on the roads [6], The hydrogen production and electrolyser sizing depend mainly on the hydrogen demand, which can be estimated based on the number of FCVs in 2017 in Ontario's roads. Hajimiragha at al. (2009) [99] developed an optimization model to find the optimal electric hydrogen production rate to supply the transportation sector demand from 2008 to 2025, as well as the optimal penetration percentage of hydrogen-FCVs on Ontario's roads. Their study, based on the total baseload electricity generation from all Ontario zones, validated the feasibility of current and projected hydrogen production by Ontario's grid system, using PtG technology. The hydrogen production capacity is capable of supporting 1.2-2.8% penetration of FCVs in Ontario's road by 2025. In the current study, the demand of the PtG to mobility fuel pathway is set to supply 1.2% penetration of FCVs into the Province's total vehicles based on Hajimiragha at el.'s optimization model [99]. In 2016, the number of light-duty vehicles registered was 8,037,343, according to Statistics Canada [106]. Assuming 2% annual increase in the number of cars [106], the number would have been 8,198,090 light-duty vehicles in 2017, making the number of FCVs about 100,000.

4.1.2 Industrial Demand for Hydrogen

As One-quarter of Ontario's GHG emissions come from industry, Ontario's government has set some policies to achieve its vision of a low-carbon economy and related the reduction of emissions with the economic competitiveness. A part of its Climate Change Action Plan (CCAP), Ontario initiated a cap-and-trade program, which aims to support businesses and industry stakeholders to invest in more efficient and clean technologies and pollution reduction consequently [88]. The market-based program, which has been in effect since January 1st, 2017, sets a hard emission-boundary or (cap) for the industrial organizations to lower emissions gradually starting by the major emitters of GHGs. Furthermore, a carbon reduction is rewarded, encouraging companies to reduce more; said otherwise, the less companies emit, the less money they pay [107]. On the other hand, companies who emit less can make a profit from selling emission-permits or allowances to other companies that exceed their emission-cap [107]. In Ontario, hydrogen for industrial purposes is currently produced via the process of steam methane reforming (SMR). Table 13 shows H_2-production capacities for the primary industries in Ontario [108]. This study covers up to 5% of the total hydrogen demand for industry.

Table 13 Hydrogen Production Capacities by Sector in Ontario[108]

	Production Capacity (MSm³/d)
Oil Refining	~ 3.5
Chemical	~ 2.37
Others	~ 0.4
Total	~ 6.3

4.1.3 Hydrogen to be Injected into the Natural Gas Grid

The natural gas market in Ontario accounts for 40% of Canada's total natural gas consumption, with an average daily provincial demand of 218 thousands of cubic meters per day (e^3m^3/d) [109]. Injecting hydrogen into the natural gas grid is a proposed approach toward scalable and long-term energy storage and grid decarburization. Hydrogen blending is a way to increase the renewable content of the natural gas system. According to current standards and policies, the maximum allowable hydrogen concentration should not exceed 20% by volume. High blend concentrations may pose some risks in the distribution pipelines and end-user instruments. Mostly, natural gas systems can tolerate low hydrogen concentration (0-10%) [72]; otherwise great enhancement would be required for higher hydrogen concentrations. For this study, 5% H_2 by volume will be considered as a demand for this pathway.

4.1.4 Hydrogen for Renewable Natural Gas Synthesis

Under the Climate Change Action Plan, Ontario is seeking to displace the fossil natural gas in the long-term by increasing the natural gas renewable content by encouraging renewable natural gas (RNG) projects [3], [110]. RNG, also known as bio-methane, is a biogas of high methane content (90% or more), produced by biomass digestion [111]. The current RNG sources in Ontario are wastewater, landfill, and animal manure. Power-to-gas to renewable gas (methanation) is a potential source for RNG production which utilizes captured carbon dioxide and converts it along with hydrogen to RNG. RNG can be blended with regular natural gas without any concentration boundary as the two have almost the same chemical composition [21], [23]. According to the Canadian Gas Association (CGA), up to 10 % RNG -content for Canada's natural gas network has been set as a long-term goal to be reached by 2050[112]; which will be the target of this study as well.

- **Scenario A Results and Discussion**

In this study, hydrogen is assumed to be produced at three capacity production factors: 67%, 80%, and 96%. The amount of surplus baseload electricity for 2017 of each capacity factor is converted to hydrogen and then allocated according to the pre-defined demand for each pathway (Table 14). Accordingly, the total hydrogen produced is approximately 170 kilo-tonnes (kt), 193 kt, and 227 kt, respectively. For each capacity factor, the hydrogen amount is allocated to four pathways: hydrogen as mobility fuel, hydrogen for industry, hydrogen to be injected into the natural gas grid to be used as HENG, and hydrogen to be blended with CO_2 for RNG synthesis. Figure 20 illustrates hydrogen allocation percentage for each PtG pathway for each capacity factor.

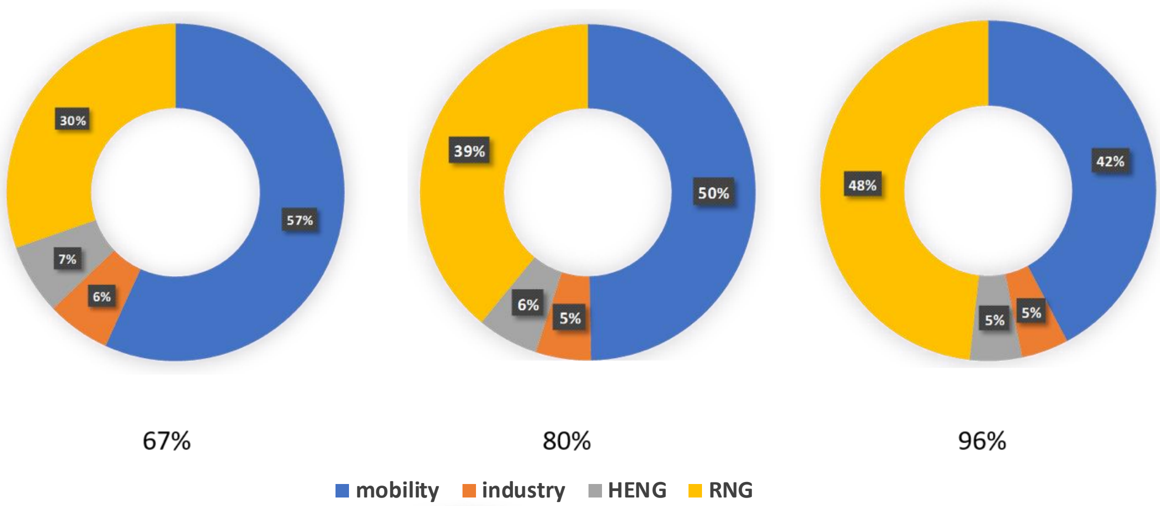

Figure 20 H_2 allocation at three different capacity factors

Furthermore, Table 14 shows the amount of carbon offset by producing hydrogen via the PtG technology instead of the conventional methods. The highest carbon reduction occurs in the case of utilizing hydrogen as mobility fuel instead of gasoline, about 2,215,916 tonnes of CO_2 might be reduced.

Table 14 also shows PtG pathways economy considering scenario A allocation for each pathway for the three capacity factors. Wherein the pathways' costs are represented by the overall capital exposures (CAPEX) and the overall annual operational expenses (OPEX); and the pathways' profitability are expressed by NPV, PBP, and IRR. In fact, CAPEX value is strongly dependent on the type and the number of technologies for each pathway, electrolyzers in particular, because the capital cost of the electrolysis equipment is high.

For scenario A, hydrogen allocation is constrained by each PtG pathway demand illustrated by Figure 19 and Table 12. Therefore, hydrogen amount for each pathway will be constant at three capacity factors except for the PtG pathway Power-to-Gas to Renewable Gas which has relatively flexible demand.

The pathway PtG to mobility fuel has the highest CAPEX, about 4.6 billion dollars, since it requires 1610 electrolyzers–considering the maximum surplus electricity generation–compared to other pathways. Further, OPEX is changing since the HOEP range (refer to Table 11) is different for each capacity factor. For the three capacity factors, the pathway shows an acceptable economic validity, in which NPV is positive, the average payback period is 5 years, and an IRR of 19%.
PtG to industry, the second pathway, has the lowest overall CAPEX andOPEX among the other pathways. However, with a PBP of more than 10 years the project investment costs will not be recovered sooner although the IRR indicates a positive possibility of money gain up to 4%. Moreover, the negative NPV indicates that the total income is less than the costs and the reason might be because of the hydrogen is sold at the same price as hydrogen produced through steam methane reforming (2.69 \$/kg H_2 [90]), which is low compared to hydrogen as mobility fuel (10 \$/kg H_2 [89]) . For this particular case, selling hydrogen at least at 4 \$/kg makes the project profitable with a positive NPV of \$45,456,997, payback time of 9 years, and 10% IRR. Such projects should be part of government incentives to encourage clean energy utilization.

The third and fourth pathways, PtG to pipeline for use as HENG and PtG to RNG, show un-acceptable economic validity with highely negative NPVs and PBPs reache more than 100 years. This is might be because HENG and RNG are sold at very low price (3 \$ per million Btu [91]) compared to their extremely high production costs. For this current study, the prices that make PtG to pipeline for use as HENG and PtG to RNG profitable business cases start from 105 $/MMBtu and 56 $/MMBtu, respectively. Which are high prices compared to the current natural gas price range.

Generally, this result ties with a previous German case study by Schiebahn et al. (2015) [66], wherein the production costs of injecting hydrogen or renewable natural gas into the natural gas grid are several times higher than conventional natural gas production cost. Hence, large-scale implementation of such projects is currently uneconomic [66]. Although injecting RNG would not pose any risks to distribution pipelines or end-user appliances compared to hydrogen injection, this technology has some main drawbacks that need to be overcome. First is low overall process efficiency (40-63%) because it involves multiple energy conversion steps, which boosts the energy loses [65]. The second problem is that the CO_2 methanation requires an enormous amount of carbon dioxide. For example, in this study, CO_2 source is assumed to be from Ontario's biogas farms in which the total annual biogas production is 118.98 million cubic meter [113], accordingly 55 kilo-tonne of CO_2 (40% concentration of CO_2 in the biogas). What is required, however, in the case of 67% availability, equals around 281 kilo-tonnes of CO_2; that is, requirements exceed CO_2 availability. Albeit, CO_2 could be captured from other sources like the cement industry, but that is an expensive option.

In addition, the realization of hydrogen injection into the natural gas grid to be used as HENG requires re-specifying composition and gas quality standers along with transmission and distribution pipeline tolerances for high hydrogen concentration. Further, some other concerns need to be addressed regarding HENG blend, namely those related to process control, safety, and public acceptance [72].It is neither possible nor legal to blend hydrogen in high concentration with natural gas (more than 2 vol% H_2) because that will result in natural gas composition change, which affects consumer devices [114].

Conversely, the high-efficiency of fuel cell vehicles tolerates hydrogen cost competitiveness compared to gasoline, making the use of hydrogen as a green fuel for automobiles an economically sound, commercial case. Though for this pathway to be implemented, hydrogen infrastructure would need to be built from scratch, and a collaboration among industry, governments, and the public would be required for cost-effective conversion to renewable energy [66].

Producing hydrogen via electrolysis has always been seen as an ideal means in industry, especially if it is generated from renewable sources. Even though the electrolytic hydrogen is an excellent solution for industrial greenhouse gases reduction, it is still inherently expensive and not continually efficient. Therefore, adoption of a large-scale plant that produces hydrogen via PtG technology is currently not bankable because cost matters, especially if there are cheaper alternatives available [115] .

Table 14 allocation of hydrogen produced via PtG concept at three capacity factors (67%, 80%, and 96%) for the four PtG pathways

	PtG-Mobility	PtG-to Industry	PtG-HENG	PtG-RNG	PtG-Mobility	PtG-to Industry	PtG-HENG	PtG-RNG	PtG-Mobility	PtG-to Industry	PtG-HENG	PtG-RNG
Capacity Factor	67%				80%				96%			
surplus electricity [GWh/y]	8,327				9,512				11,210			
Total Hydrogen befor allocation[kg/y]	169,275,028				193,131,431				227,615,472			
Amount of H_2 [kg/y]	96,344,160	10,334,413	11,461,057	51,444,504	96,344,160	10,334,413	11,461,057	75,737,743	96,344,160	10,334,413	11,461,057	110,034,079
Demand to be met	1.2% FCVs penetration	5% of industrial demand	5% vol.	3.6% vol. RNG	1.2% FCVs penetration	5% of industrial demand	5% vol.	5.3% vol. RNG	1.2% FCVs penetration	5% of industrial demand	5% vol.	7.7% vol. RNG
Equipment												
Electrolysers	1160	81	131	635	1160	81	131	866	1160	81	131	1258
pre-storage compressors	536	38	61	272	536	32	61	618	536	38	61	898
booster compressors	259	18	29	847	259	18	29	298	259	18	29	433
Storage tanks	124	17	14	68	124	17	14	308	124	17	14	145
CO_2 for methanation [kg/y]	-	-	-	280,762,976	-	-	-	413,345,492	-	-	-	600,520,809
CO_2-offset [tCO_2/y]	2,215,916	86,913	7,262	119,250	2,215,916	102,971	8,336	210,251	2,215,916	133,097	10,033	399,173
Overall CAPEX [$]	$4,579,650,865	$322,108,291	$519,249,027	$2,571,826,242	$4,579,650,865	$322,108,291	$519,249,027	$3,479,708,304	$4,579,650,865	$322,442,321	$519,249,027	$5,014,074,169
Overall OPEX [$]	$59,820,472	$4,916,527	$6,346,866	$36,491,490	$72,622,147	$4,916,527	$7,777,982	$59,071,009	$106,974,741	$9,336,053	$11,397,484	$119,367,287
NPV [$]	$4,624,487,221	-$86,995,939	-$562,726,957	-$2,759,830,087	$4,558,157,203	-$92,850,132	-$577,430,247	-$3,802,863,216	$43,594,908,932	-$117,642,852	-$612,667,125	-$5,796,372,412
PBP [years]	4.85	13.38	115	134	4.92	13.79	87	106	5.11	15.46	55	63
IRR [%]	20.07%	4.18%	-	-	19.77%	3.84%	-	-	18.97%	2.59%	-	-

4.2 Scenario B

In this scenario, hydrogen produced via PtG technology is utilized entirely for the pathway PtG to mobility fuel, at three production capacities, 67%, 80%, and 96% (Table 15). The hydrogen amount, which is generated from the surplus electricity, could refuel up to 1,147,732 FCVs, which represents 14% of the total light-duty vehicles in Ontario in 2017. Accordingly, a huge amount of carbon would be eliminated from Ontario's roads, 5,235,156 tonnes of CO_2, if hydrogen were produced at a capacity of 96%. Moreover, this pathway still shows good economic validity, in which the PBP is less than or equal to 9 years considering a discount rate of 8%. Despite the high CAPEX and OPEX, the NPV and IRR are greater than zero, indicating a positive gain and profitable business case.

Table 15 hydrogen allocation, Scenario B

PtG Pathway		100% PtG to mobility Fuel		
Capacity Factor		67%	80%	96%
surplus electricity [GWh/y]		8,327	9,512	11,210
Amount of H_2 [kg/y]		169,287,434	193,131,431	227,615,472
FCVs penetration		10%	12%	14%
Equipment	Electrolysers		3665	
	pre-storage compressors		1693	
	booster compressors		817	
	Storage tanks	273	312	373
CO_2-offset [tCO_2/y]		3,893,611	4,442,023	5,235,156
Overall CAPEX [$]		$14,373,891,507	$15,602,340,046	$14,474,400,375
Overall OPEX [$]		$142,604,532	$172,809,234	$218,677,367
NPV [$]		$1,392,386,339	$2,447,945,894	$6,651,407,145
PBP [years]		8.96	8.49	6.73
IRR [%]		9.26%	10.05%	13.73%

4.3 Scenario C

In this scenario, hydrogen produced via PtG technology is utilized entirely to the pathway PtG to industry, at three production capacities 67%, 80%, and 96% (Table 16). Utilizing Ontario's surplus electricity to produce hydrogen via the PtG technology could supply 82%, 93%, and 110% at the three capacity factors, respectively. By implementing this PtG energy stream, up to 3,131 kilo-tonne of CO_2 could be offset, as Table 16 illustrates. Nevertheless, hydrogen production through PtG is still costly compared to other available cheaper alternatives, namely hydrogen produced via steam methane reforming. The economic validity indicators (NPV, PBP and IRR) show some improvement by increasing hydrogen production capacity, but they are not indicating any positive gain feedback. To increase this pathway's profitability, hydrogen could be sold at a higher price; however, in this case, hydrogen would not be a favorable option for stockholders. For this particular case, selling hydrogen at least at 10 $/kg makes the project profitable with a positive NPV of $1,259,846,895, payback time of 9 years, and 9% IRR. Such projects should be part of government incentives to encourage clean energy utilization.

Table 16 Hydrogen allocation, Scenario C

	PtG Pathway	100% PtG to industry		
	Capacity Factor	67%	80%	96%
	surplus electricity [GWh/y]	8,327	9,512	11,210
	Amount of H_2 [kg/y]	169,275,028	193,131,431	227,615,472
	Industrial demand [kg/y]		206,725,050	
	Percentage of industrial demand	82%	93%	110%
Equipment	electrolyzers		3665	
	pre-storage compressors		1693	
	booster compressors		817	
	storage tanks	273	312	373
	CO_2-offset [tCO_2/y]	2,255,516	2,617,574	3,130,678
	Overall CAPEX [$]	$14,373,891,507	$14,470,328,519	$14,474,400,375
	Overall OPEX [$]	$141,018,779	$162,717,784	$164,981,145
	NPV [$]	-$10,889,133,191	-$10,504,561,783	-$9,529,424,829
	PBP [years]	40.50	35.82	28.74
	IRR [%]	-5.95%	-5.01%	-3.23%

4.4 Scenario D

In scenario D, hydrogen produced from the surplus electricity is allocated totally to the third PtG pathway, PtG to pipeline to be used as HENG, at the three different capacity factors (Table 17). As illustrated in Table 17, increasing the capacity factor results in increasing the hydrogen concentration in the natural gas grid, exceeding the constraint (less than 5 %). Although using HENG instead of the conventional natural gas could offset up to 268,970 tonnes of carbon, its capital and operational costs are extremely high, resulting in extremely negative NPV and very long payback time. In this case, IRR is undefined because there is no interest rate small enough to make NPV equals zero (refer to Equation 19). Therefore, the probability of implementing a large-scale project is not yet feasible. For this current study, the selling price that makes this PtG pathway a profitable business case starts from 190 $/MMBtu, which is relatively a high price compared to the current natural gas price range.

Table 17 Hydrogen allocation, Scenario D

PtG Pathway		100% PtG to pipeline to be used as HENG		
Capacity Factor		67%	80%	96%
surplus electricity [GWh/y]		8,327	9,512	11,210
Amount of H_2 [kt/y]		169,275,028	193,131,431	227,615,472
Natural gas production [e^3m^3/y]			2,422,248	
H_2 concentration in the natural gas grid [vol.%]		87%	89%	106%
Equipment	electrolyzers		3665	
	pre-storage compressors		1693	
	booster compressors		817	
	Storage tanks	273	312	373
CO_2-offset [tCO_2/y]		215,117	238,082	268,970
Overall CAPEX		$14,291,161,242	$14,472,203,500	$14,476,275,356
Overall OPEX		$138,818,879	$162,457,467	$213,268,925
NPV [$]		-$15,321,431,824	-$15,685,815,833	-$15,911,513,729
PBP [years]		136	117	99
IRR [%]		-	-	-

4.5 Scenario E

In this scenario, the amount of hydrogen produced via PtG technology is entirely combined with CO_2 from biogas digestion plant for RNG synthesis. Table 18 shows the selected three capacity factors for hydrogen production, the amount of CO_2 offset, the economic cost, as well as the profitability indicators. The product of combining hydrogen with carbon dioxide could add 12%, 14%, and 16% by volume of renewable content into the natural gas grid at three capacity factors, respectively. Regarding the methanation reaction an enormous amount of carbon dioxide is required; Ontario's biogas digesters are unlikely to be able to supply this carbon dioxide because of resource limitations. Therefore, other more expensive options may be considered, for instance, utilizing CO_2 captured from the cement industry. On one hand, methanation could eliminate up to 997,080 tonnes of carbon dioxide from the atmosphere in the case of 96% electrolysis availability. On the other hand, the cost of RNG production is exceedingly high because it demands multiple processes, namely water electrolysis, CO_2 separation, and CO_2 synthesis. This PtG pathway shows low profitability potential as Table 18 illustrates, with a negative NPV and a payback period exceeding 100 years. In this case, IRR is undefined because there is no interest rate small enough to make NPV equals zero (refer to Equation 19). For this current study, the selling price that makes this PtG pathway a profitable business case starts from 100 \$/MMBtu, which is relatively a high price compared to the current natural gas price range.

Table 18 Hydrogen allocation, Scenario E

PtG Pathway		100% PtG to RNG		
Capacity Factor		67%	80%	96%
surplus electricity [GWh/y]		8,327	9,512	11,210
Amount of H2 [kg/y]		169,275,028	193,131,431	227,615,472
Natural gas production [e^3m^3/y]			2,422,248	
RNG produced [kg/y]		336,702,809	384,155,278	452,747,045
RNG content in the natural gas grid [vol.%]		12%	14%	16%
amount CO_2 required for methanation [tCO_2/y]		923,833	1,054,032	1,242,231
Equipment	electrolyzers		3665	
	pre-storage compressors		10933	
	booster compressors		5278	
	Storage tanks	1763	2015	2412
CO_2-offset [tCO_2/y]		756,604	855,882	997,080
Overall CAPEX		\$15,198,918,416	\$15,595,760,530	\$15,648,349,282
Overall OPEX		\$181,554,848	\$213,999,898	\$269,720,226
NPV [\$]		-\$16,330,965,392	-\$16,628,120,335	-\$17,425,413,126
PBP [years]		132	148	86

Chapter 5: Sensitivity Analysis

This chapter discusses how sensitive the PtG pathways' economy is to changes in: 1) number of electrolysers; 2) final products selling prices; and 3) carbon prices.

5.1 Changing Number of Electrolysers

The current study is a general estimation of Ontario's surplus electricity utilization if the surplus is converted into storable chemical energy via Power-to-Gas technology. To illustrate, the surplus electricity is transformed into hydrogen, which can be harnessed for different applications. Hydrogen is assumed to be produced hourly through the hourly conversion of surplus baseload generation via water electrolysers that have a production capacity of 200 Nm^3/h. Therefore, based on the maximum hourly surplus baseload generation, a maximum number of electrolysers were assumed. This assumption is not economically accurate since SBG changes hourly and hence not all electrolysers are used if SBG is less than the maximum baseload. Hence, an optimal number of electrolysers need to be optimized to obtain the maximum economic benefits, which is beyond the scope of this study. This section assesses the impact of varying number of electrolysers on the PtG pathways economy for the hydrogen allocation scenarios. Results are illustrated in Tables 19-23. Changing the number of electrolysers directly affects the overall capital costs, since electrolysers represents a significant share of the total equipment costs. On the other hand, the number of electrolysers reflects the utilization of surplus electricity and the amount of hydrogen produced. Idle electrolysers–are those unused during periods without excess electricity in the grid –are calculated based on the difference between the maximum and the minimum SBG.

5.1.1 Scenario A

Table 19 The impact of changing the number of electrolysers on H_2 production and overall capital cost, scenario A

	PtG to mobility fuel					PtG to industry					PtG to pipeline to be used as HENG					PtG to renewable natural gas				
	max	80%	60%	40%	20%	max	80%	60%	40%	20%	max	80%	60%	40%	20%	max	80%	60%	40%	20%
Number of electrolysers	1160	928	696	464	232	81	65	49	33	16	131	105	79	52	44	588	470	353	235	195
Idle electrolysers	1108					40					87									
max-hourly SBG [GWh]	1108	886	665	443	222	78	62	47	31	16	125	100	75	50	42	562	449	337	225	187
SBG utilized [GWh]	4,744	3,795	2,846	1,897	948	509	407	305	203	101	564	451	339	226	188	2,534	853	639	426	354
H_2-produced [tonne/y]	96,344	77,075	57,806	38,538	19,269	10,334	8,267	6,200	4,133	2,066	11,461	9,168	6,876	4,584	3,810	51,444	17,311	12,983	8,655	7,193
Total SBG-unutilized [GWh]	0	949	1,897	2,847	3,796	0	102	204	305	407	0	2,452	2,565	2,678	2,716	0	1,681	1,894	2,107	2,179
Overall capital costs [M$]	$4,579	$3,665	$2,751	$1,836	$922	$322	$258	$193	$129	$65	$519	$415	$312	$209	$176	$2,433	$1,969	$1,505	$1,041	$883
Capital costs saved [M$]	0	$914	$1,829	$2,743	$3,657	0	$64	$128	$193	$257	0	$103	$206	$309	$342	0	$463,	$927	$1,391	$1,550

5.1.2 Scenario B

Table 20 The impact of changing the number of electrolysers on H_2 production and overall capital cost, scenario B

	max	**80%**	**60%**	**40%**	**20%**
Number of electrolysers	3665	2932	2199	1466	733
Idle electrolysers	3659				
max-hourly SBG [GWh]	3502	2802	2101	1401	700
SBG utilized [GWh]	8,327	3,796	2,847	1,898	949
H_2-produced [tonne/y]	169,077	77,075	57,807	38,538	19,269
Total SBG-unutilized [GWh]	0	4,531	5,480	6,429	7,378
Overall capital costs [M$]	$14,373	$11,502	$8,631	$5,760	$2,889
Capital costs saved [M$]	0	$2,871	$5,742	$8,613	$11,484

5.1.3 Scenario C

Table 21 The impact of changing the number of electrolysers on H_2 production and overall capital cost, scenario C

	max	80%	60%	40%	20%
Number of electrolysers	3665	2932	2199	1466	733
Idle electrolysers	3659				
max-hourly SBG [GWh]	3502	2802	2101	1401	700
SBG utilized [GWh]	8,326	407	305	203	101
H_2-produced [tonne/y]	169,064	8,267,530	6,200	4,133	2,066
Total SBG-unutilized [GWh]	0	7,919	8,021	8,122	8,224
Overall capital costs [M$]	$14,373	$11,502	$8,631	$5,760	$2,889
Capital costs saved [M$]	0	$2,871	$5,742	$8,613	$11,484

5.1.4 Scenario D

Table 22 The impact of changing the number of electrolysers on H2 production and overall capital cost, scenario D

	max	80%	60%	40%	20%
Number of electrolysers	3665	2932	2199	1466	733
Idle electrolysers	3659				
max-hourly SBG [GWh]	3502	2802	2101	1401	700
SBG utilized [GWh]	8,326	6,661	4,995	3,330	1,665
H_2-produced [tonne/y]	169,064	135,251	101,438	67,625	33,812
Total SBG-unutilized [GWh]	0	1,665	3,330	4,995	6,661
Overall capital costs [M$]	$14,291	$11,433	$8,575,518,984	$5,717	$2,859
Capital costs saved [M$]	0	$2,857	$5,715	$8,573	$11,431

5.1.5 Scenario E

Table 23 The impact of changing the number of electrolysers on H_2 production and overall capital cost, scenario E

	max	80%	60%	40%	20%
Number of electrolysers	3665	2932	2199	1466	733
Idle electrolysers	3659				
max-hourly SBG [GWh]	3502	2802	2101	1401	700
SBG utilized [GWh]	8,326	852	639	426	213
H_2-produced [tonne/y]	169,064	135,251	101,438	67,625	33,812
Total SBG-unutilized [GWh]	0	7,473	7,686	7,900	8,113
Overall capital costs [M$]	$15,198	$12,309	$9,419	$6,529	$3,639
Capital costs saved [M$]	0	$2,889	$5,779	$8,669	$11,559

5.2 Changing H_2-Selling Price

Hydrogen prices are subject to change in the future depending on developments in the hydrogen market, production methods, and technology. Therefore, the impact of different H_2 selling prices on the net present value, payback period, and internal rate of return is examined in this section for the five hydrogen-allocation scenarios mentioned in Chapters 4. As discussed, the four PtG pathways that considered are Power-to-Gas to mobility fuel, Power-to-Gas to industry, Power-to-Gas to natural gas pipelines for use as hydrogen-enriched natural gas, and Power-to-Gas to renewable natural gas (i.e., Methanation). Previously, PtG pathway overall costs and profitability indicators (NPV, PBP and IRR) were estimated based on a fixed selling price, as Table 10 demonstrates. The following sub-sections describe the sensitivity analysis under the ranges of PtG final-product selling prices. These prices are summarized in Table 24.

Table 24 Final product selling price for each PtG pathway [89]–[91]

PtG Pathway	Final product selling price	Reference
PtG to mobility fuel	8-16 \$/kg H_2	[89]
PtG to industry	Price of H_2 produced via steam methane reforming 2.48–3.17 \$/kg H_2	[90]
PtG to pipeline to be used as HENG	Natural gas price 2.82-3.3 \$/MMBtu	[91]
PtG to renewable natural gas		

5.2.1 Scenario A

In scenario A, hydrogen produced from Ontario's surplus electricity via PtG concept is allocated to the four PtG pathways. The allocation process is based on each PtG pathway's demand (Table 12 and Figure 19). Only one hydrogen capacity factor is considered for this scenario , 67%, since the demand is kept constant and therefore no difference or variation is expected in the three examined factors (NPV, PBP, and IRR).

For the PtG to mobility fuel, Figure 21 illustrates the effect of selling H_2 at different prices, ranging from 8 \$/kg to 16 \$/kg, according to the California Fuel Cell Partnership [89]. Increasing the selling price of hydrogen results in an increased NPV.

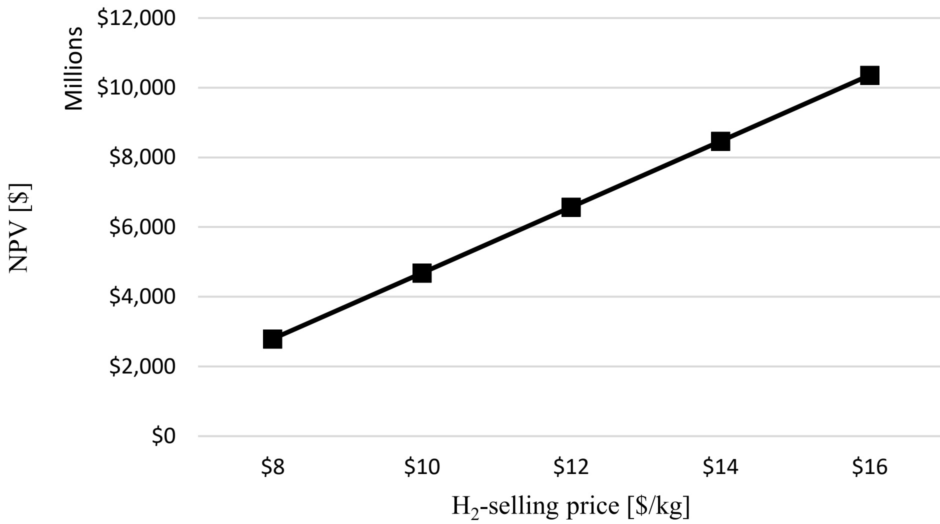

Figure 21 The effect of changing H_2-selling price on the NPV for the PtG to mobility fuel pathway

Figure 22 illustrates the impact of changing H_2-selling price–of the first PtG pathway– on the values of PBP and IRR. As is clear, the time required for PtG to mobility fuel pathway to recover its initial investment decreases by increasing the selling price from 6 years to around 3 years. Moreover, IRR shows also a positive percentage as selling price increases.

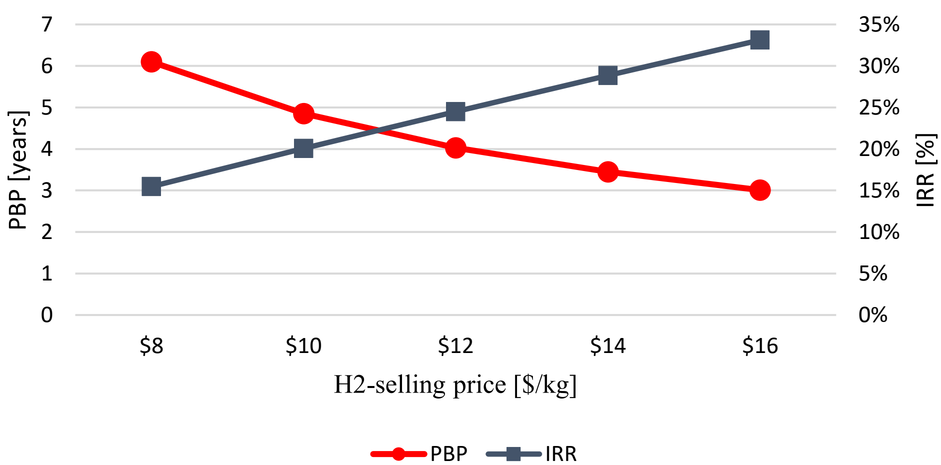

Figure 22 The impact of changing H_2-selling price on the values of PBP and IRR for PtG to mobility fuel

The NPV of the second PtG pathway, PtG to industry, shows an increasing tendency of NPV by increasing H_2-selling price. Nonetheless, NPVs are less than zero, indicating non-profitable business case, as Figure 23 illustrates.

Figure 23 The effect of changing H2-selling price on NPV for the PtG to industry

Figure 24 shows how PBP and IRR are changing by increasing the selling price of H_2 from 2.4 to 3.17 $/kg H_2. PBP is decreasing from 15 to almost 11 years, while IRR percentage is growing from 3% to more than 6%.

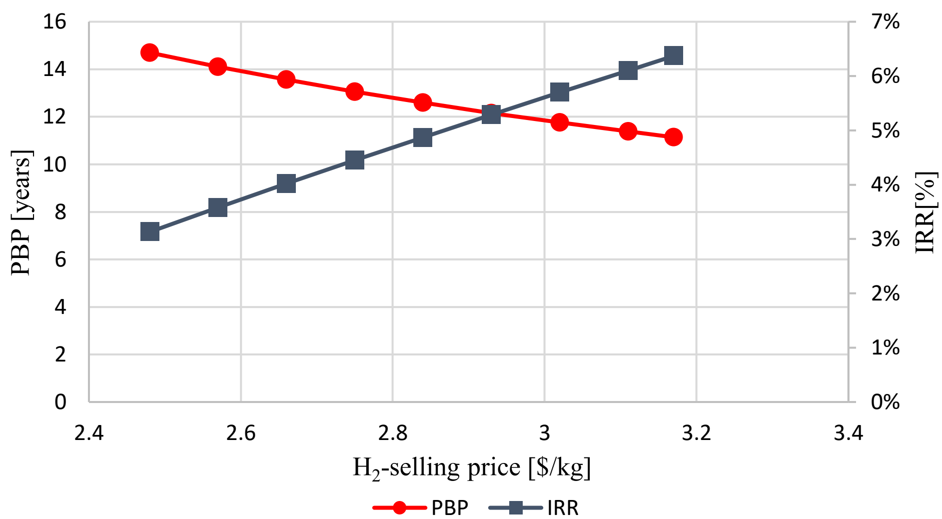

Figure 24 The impact of changing H2-selling price on the values of PBP and IRR for PtG to industry

The third PtG pathway, PtG to pipeline to be used as HENG, NPVs of this pathway shows an increasing trend by increasing the selling price of HENG, though NPVs are all negative values since the total annual revenue is less than the annual costs. Also, PBP exceeds 100 years and IRR function is not defined.

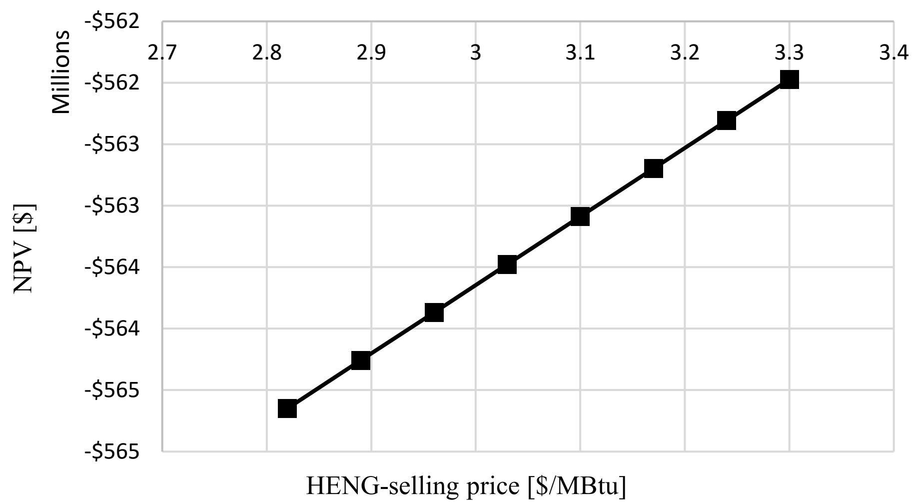

Figure 25 The effect of changing HENG-selling price on NPV for the PtG to pipelines to be used as HENG

Increasing the selling price of RNG for the fourth PtG pathway, PtG to renewable natural gas, is not making it a profitable business case, since NPVs are negative for all RNG selling prices (Figure 26). In addition, PBP exceeds 100 years and IRR function is undefined.

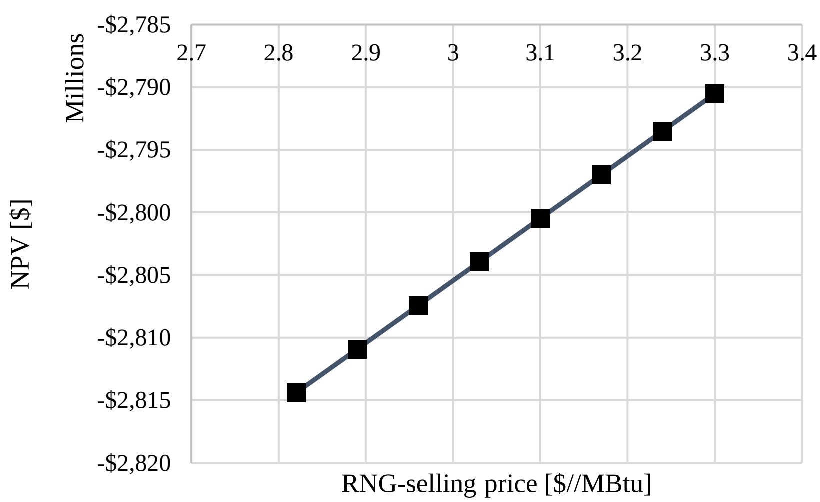

Figure 26 The effect of changing RNG-selling price on NPV for the PtG to RNG

5.2.2 Scenario B

In this scenario, the hydrogen produced by the conversion of Ontario's surplus electricity via PtG technology is utilized entirely as mobility fuel. Figures 27, 28, and 29 show the relative snseties of NPV, PBP, and IRR, to changes in the H_2-selling price of the pathway PtG to mobility fuel. The sensitivity analysis is done considering the three capacity factors for hydrogen production, namely 67%, 80%, and 96%. NPV exhibits an overall increasing trend as a result of increasing H_2-selling price, with all NPVs being positive for the three capacity factors (Figure 27). The number of years required to recover for the initial investment of this pathway is declining, reaching a minimum of 4 years in the case of 96%, indicating a profitable business case (Figure 28). In addition, the profitability of this PtG pathway is confirmed by the increasing rate of gaining money, since the IRR percentage grows significantly along with the increasing H_2-selling price, (Figure 29).

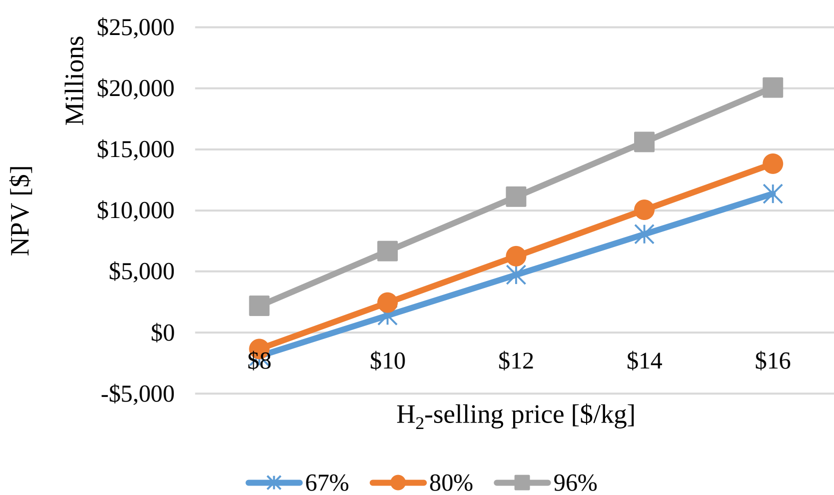

Figure 27 The effect of changing H2-selling price on the NPV for scenario B at three capacity factors

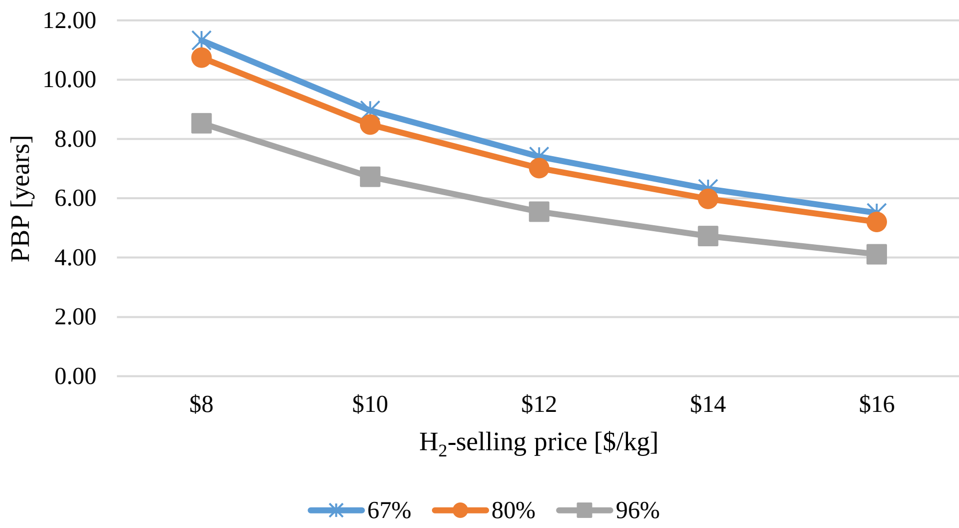

Figure 28 The effect of changing H2-selling price on PBP for scenario B at three capacity factors

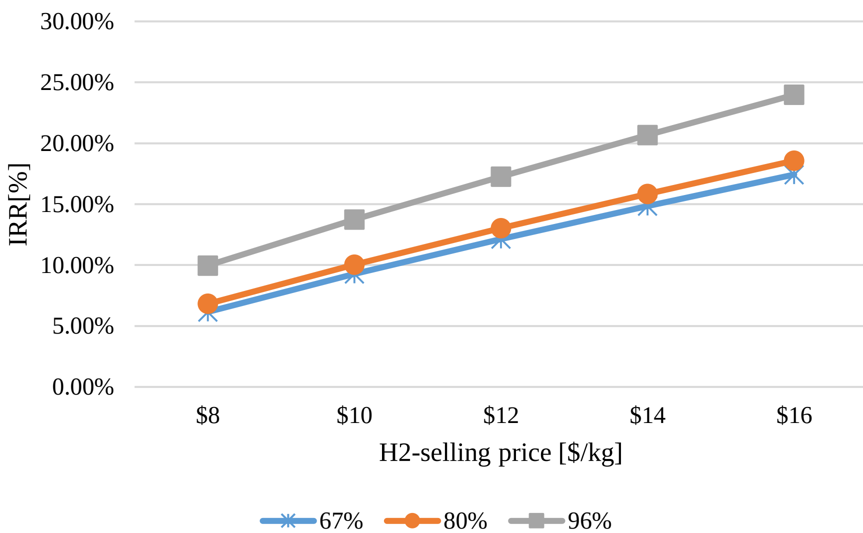

Figure 29 The effect of changing H2-selling price on IRR for scenario B at three capacity factors

5.2.3 Scenario C

Scenario C describes using H_2 entirely for industry as a green and clean option instead of hydrogen produced from natural gas (SMR). Figures 30, 31, and 32 show how varing the H_2-selling price of the pathway PtG to industry can affect the profitability indicators: net present value, payback period, and internal rate of return, respectively. H_2 for industry is sold at the same price as H_2 produced via SMR, within the range 2.48-3.17 $ per kg H_2 [90]. As a consequence of increasing H_2-selling price, NPV shows an increasing trend but it is still in negative values, PBP is greater than 20 years, and IRR is a negative percentage. Hence, H_2 needs to be sold at a higher price because H_2 production costs via PtG technology are high.

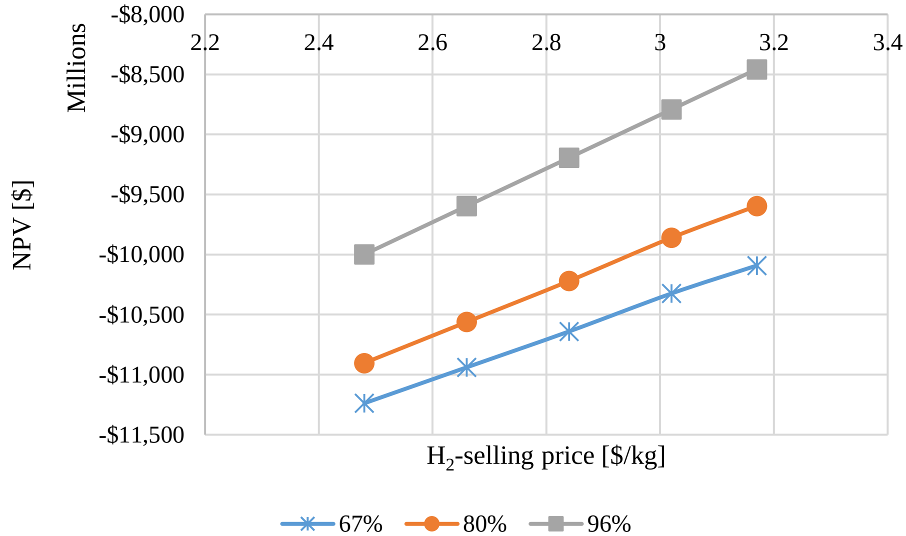

Figure 30 The effect of changing H_2-selling price on NPV for scenario C, at the three capacity factors

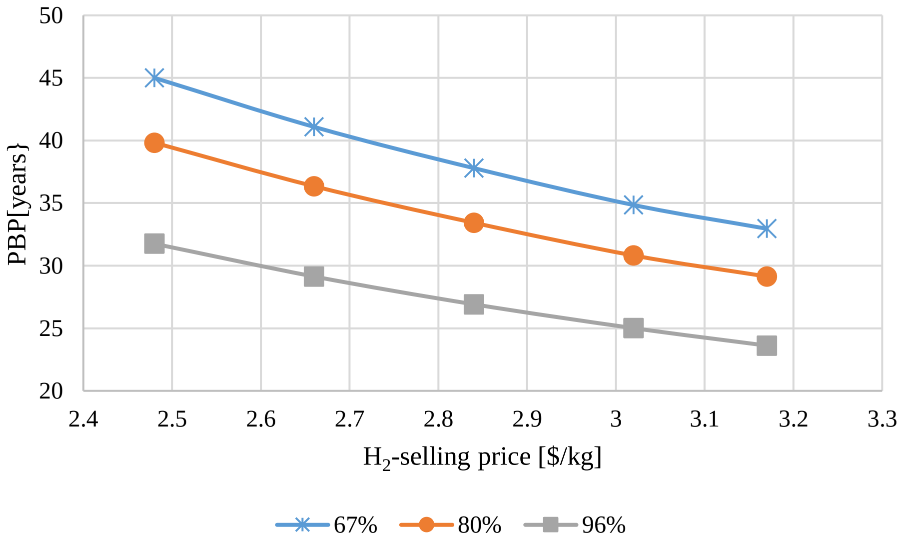

Figure 31 The effect of changing H_2-selling price on PBP for scenario C, at the three capacity factors

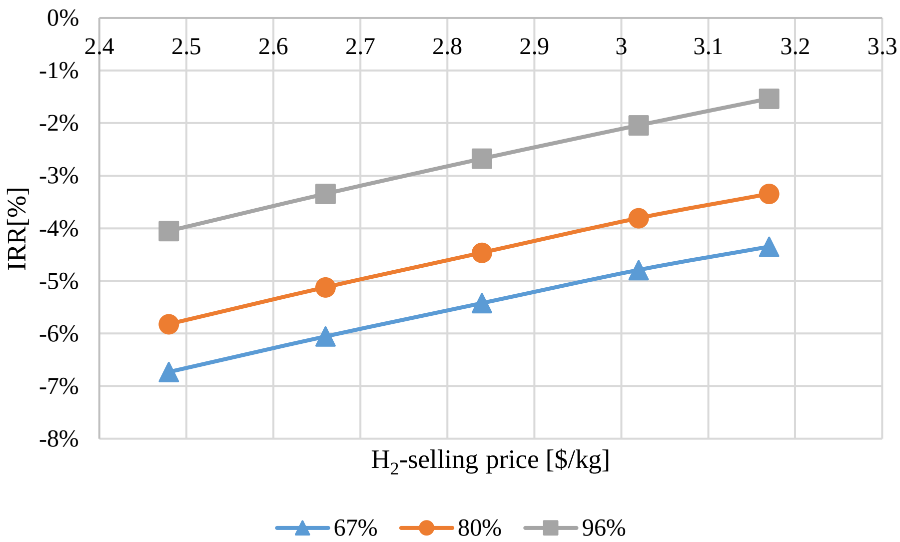

Figure 32 The effect of changing H_2-selling price on IRR for scenario C, at the three capacity factors

5.2.4 Scenario D

In this scenario, all H_2 which produced via PtG concept by utilizing Ontario's surplus electricity is injected into the natural gas grid to be used as HENG. Thus, HENG is sold at the same price as natural gas. The range of natural gas prices for 2017 is 2.82-3.30 $ per million Btu based on Henry Hub spot price [91]. Figure 33 shows how the variation in the HENG-selling price of this pathway can affect the net present value. This allocation scenario indicates un-acceptable economic validity with highely negative NPVs. This negativity might be because HENG is sold at very low price (3 $ per million Btu [91]) compared to its extremely high production cost. In addition, PBP for this scenario exceeds 100 years and IRR is undefined because there is no interest rate small enough to make NPV equals zero (refer to Equation 19).

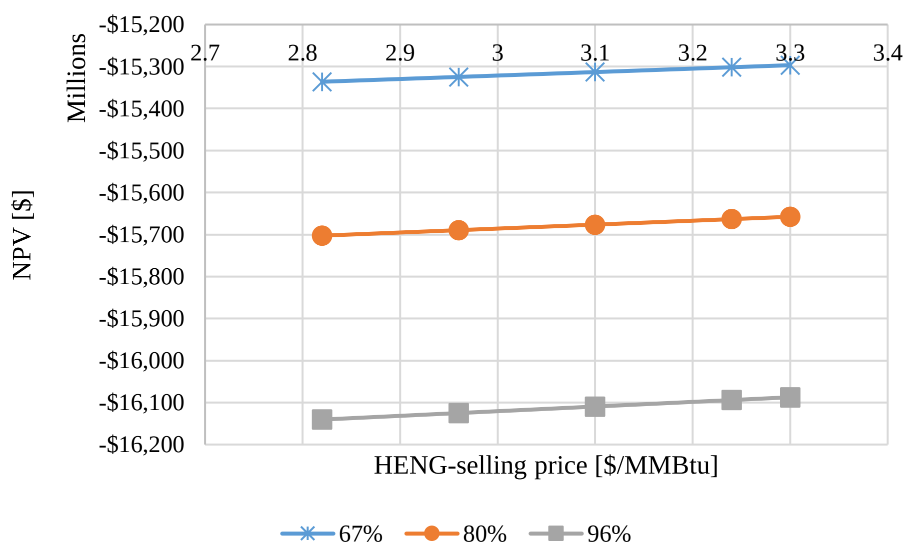

Figure 33 The effect of changing HENG-selling price on NPV for scenario D, at the three capacity factors

5.2.5 Scenario E

Scenario E describes combining H_2 produced entirely with carbon dioxide from biogas digester (or other possible sources) for RNG synthesis. RNG is then injected into the natural gas grid to boost its renewable percentage. Thus, RNG is sold at the same price as natural gas. The range of natural gas prices for 2017 is 2.82-3.30 $ per million Btu based on Henry Hub spot price [91]. Figure 34 shows that this allocation scenario indicates unprofitable business case with highely negative NPVs. This is might be because RNG is sold at very low price (3 $ per million Btu [91]) compared to its extremely high production cost. In addition, PBPs for this scenario exceeds 100 years and IRR is undefined because there is no interest rate small enough to make NPV equals zero (refer to Equation 19).

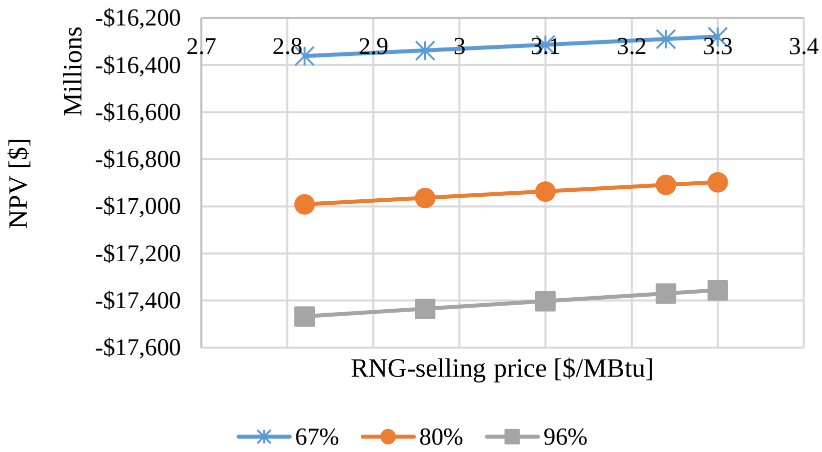

Figure 34 The effect of changing RNG-selling price on NPV for scenario E, at three capacity factors

5.3 Changing Carbon Prices

Ontario has had adopted a cap-and-trade system for carbon credits sale since the beginning of 2017. This program encourages incentivizing technologies and adds economic value to GHG-emission reduction. The basic idea behind this step is that individuals and firms are expected to produce less GHG as the price of emissions increases [107]. Therefore, PtG pathways can gain revenues by selling carbon credits. Potential carbon credit values vary worldwide. For example, the EU emission allowance fluctuats significantly and ranges as high as €96 ($112) per tonne of CO_2 in Sweden and low as less than €1 ($1.17) per tonne of CO_2 in Poland, according to the Institute for Climate Economics, 2017 [116]. In California, the average price was $15.22 per tonne of CO_2 in 2017, and previously reached a maximum of $30 per tonne CO_2 [117]. A number of Canadian jurisdictions have already adopted systems of carbon pricing including British Columbia ($24.59/ tCO_2); Alberta and Manitoba ($20/$tCO_2$); Ontario and Quebec ($18/tCO_2) [116], [118]. Carbon prices in Canada started at a minimum of $10/ tCO_2 and are expected to rise to $50/$tCO_2$ by 2022 [119]. Hence, in this section, a sensitivity analysis is conducted to examine how varying carbon prices will affect the net present value, payback period, and internal rate of return for PtG pathways considered in this study. The range of carbon prices to be used is 10 – 50 $/$tCO_2$.

5.3.1 Scenario A

It is clear from Figure 35 that a high carbon price will result in higher NPVs for all PtG pathways. The amount of increase in the NPV for each pathway is different because that is associated with other factors, including the amount of hydrogen allocated to a pathway, final product selling price, and technologies used. The highest increase occurs in the PtG to mobility fuel, where NPV increases from 4.5 billion dollars to more than 5.4 billion dollars, for $10/$tCO_2$ and $50/$tCO_2$, respectively. This increase may be because the share of hydrogen that is allocated to this pathway (about 57% in the case of 67% availability) and its selling price are relatively high compared to other pathways. On the other hand, the other three PtG pathway show almost the same progression, with negative NPVs.

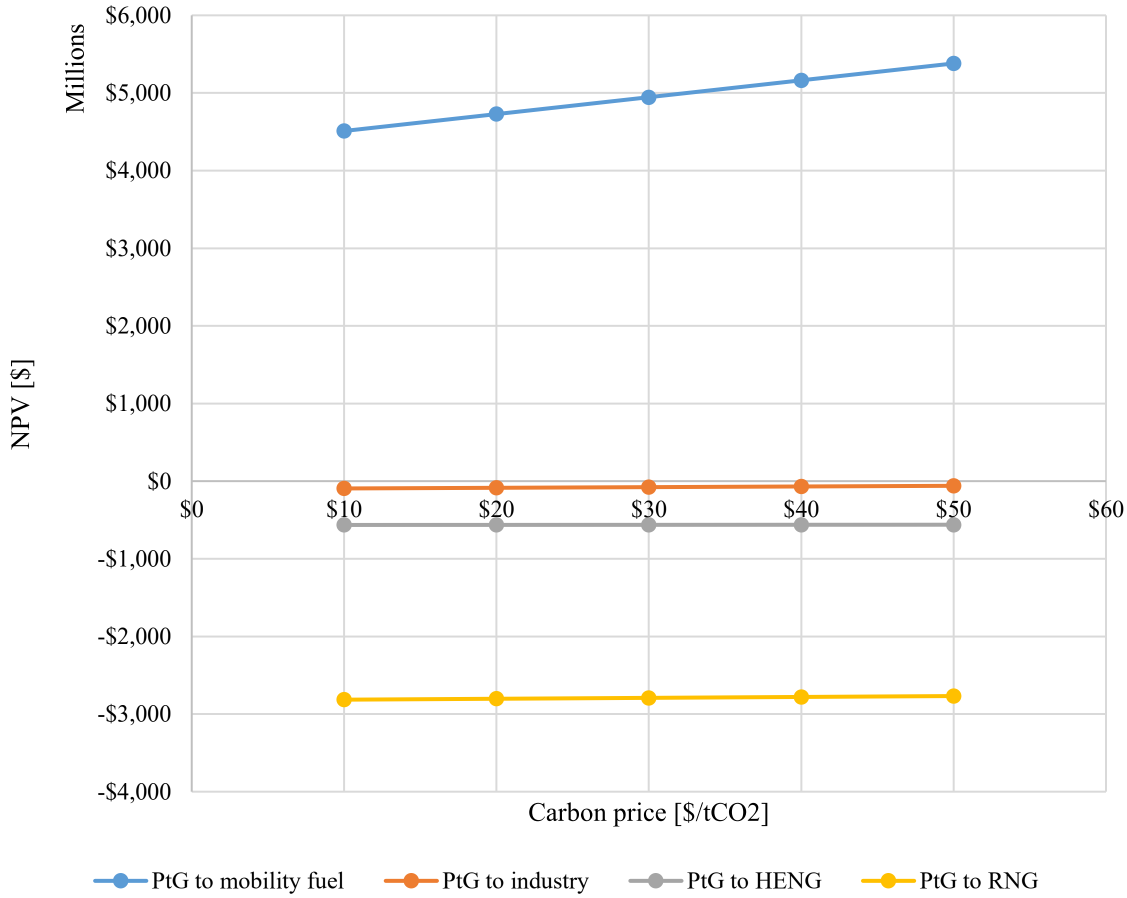

Figure 35 The effect of changing carbon price on the NPV for scenario A

Figures 36 illustrates how PBP varies as a result of changing carbon selling price for scenario A. the PBP of PtG to mobility fuel and PtG to industry show some decline as the annual net revenue increases. However, the length of time required to recover the investment cost of the other two pathways, PtG to pipeline to be used as HENG and PtG to RNG more than 100 years because their net cash flow is always negative.

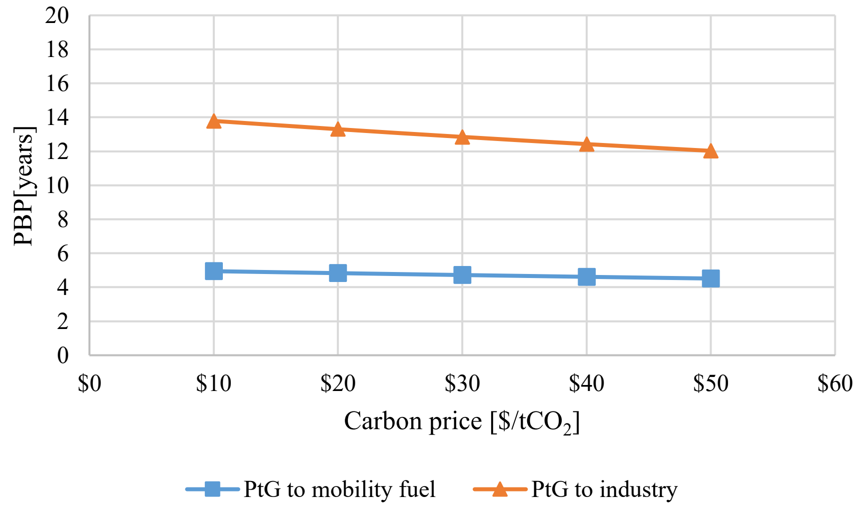

Figure 36 The effect of changing carbon price on PBP, for scenario A

The IRR of the PtG pathways PtG to mobility fuel and PtG to industry are illustrated in Figure 37. For both pathways, IRR is increasing by increasing the carbon price as the net annual revenue increases. For the other PtG pathways, PtG to pipeline to be used as HENG and PtG to RNG, IRR percentage is not defined because there is no interest rate small enough to make NPV equals zero (refer to Equation 19).

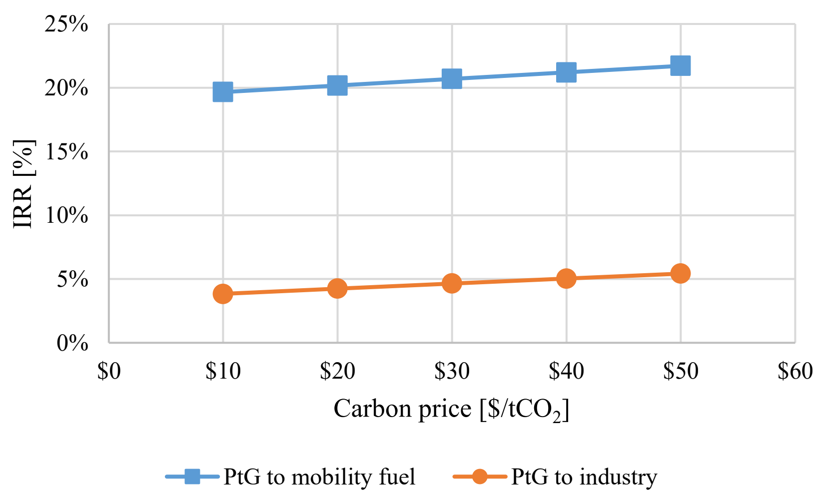

Figure 37 The effect of changing carbon price on IRR, for scenario A

5.3.2 Scenario B

In this scenario, the hydrogen produced from the conversion of Ontario's surplus electricity via PtG technology is utilized entirely as mobility fuel. Figures 38, 39, and 40 show how the variation in the carbon price of the pathway PtG to mobility fuel can affect the values of the net present value, payback period, and internal rate of return, respectively. The sensitivity analysis is done considering the three capacity factors for hydrogen production, namely 67%, 80%, and 96%. NPV exhibits an overall increasing tendency as a result of increased carbon price, keeping NPVs greater than zero (Figure 39). The number of years required to recover the initial investment of this pathway is declining, reaching a minimum of 6 years in the case of 96% (Figure 39). In addition, the profitability of this PtG pathway is confirmed by the increasing rate of gaining money, since the IRR percentage grows significantly along with the increasing CO_2 price, as indicated by Figure 40.

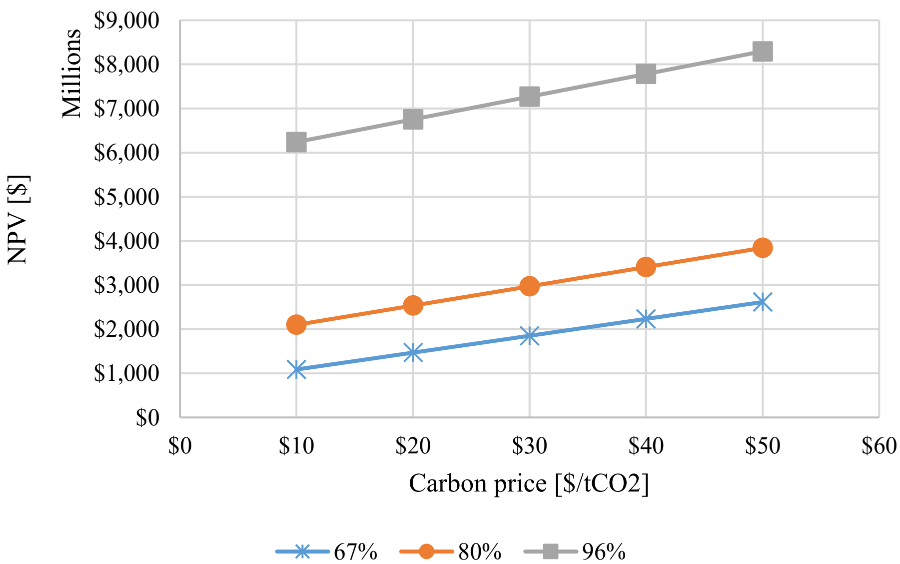

Figure 38 The effect of changing carbon price on NPV for scenario B

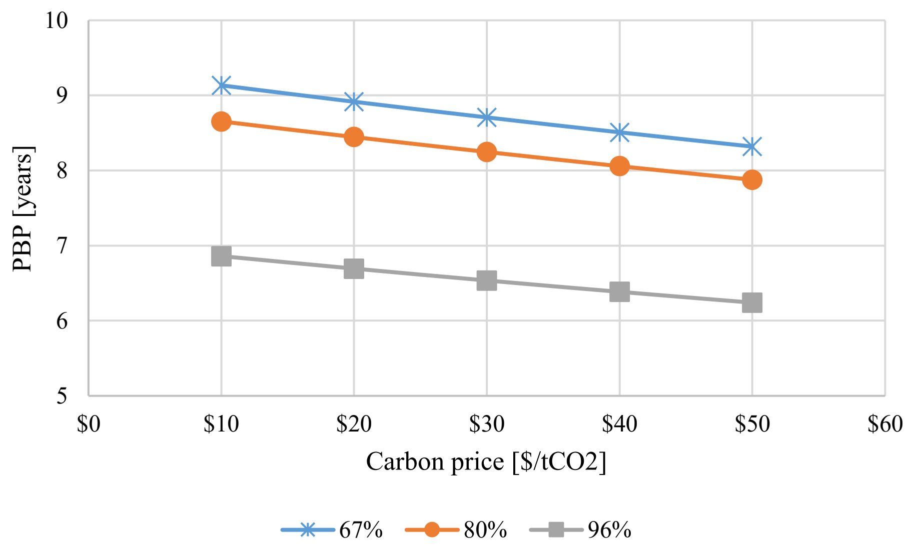

Figure 39 The effect of changing carbon price on PBP, for scenario B

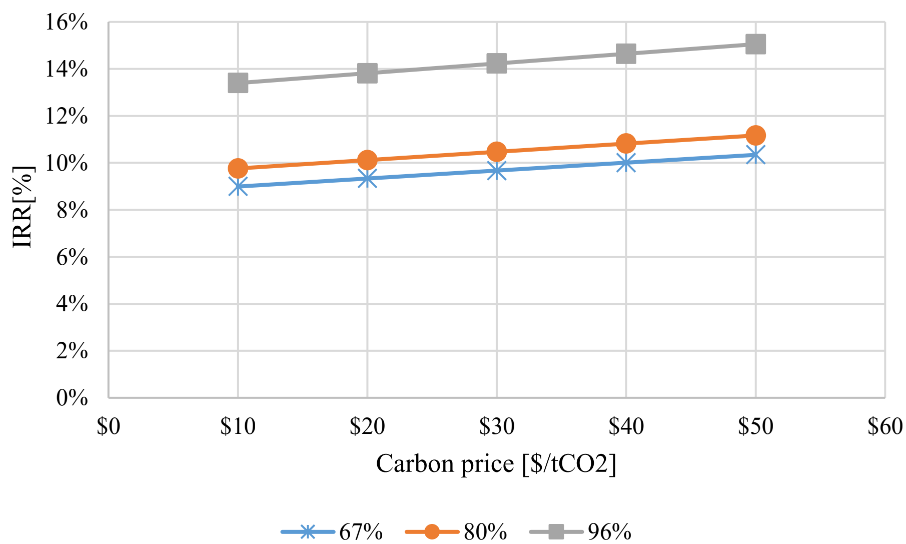

Figure 40 The effect of changing carbon price on IRR, for scenario B

5.3.3 Scenario C

Scenario describes utilizing H_2 entirely for industry as a green and clean option instead of hydrogen produced from natural gas. Figures 41,42, and 43 show how varying the carbon price of the pathway PtG to industry can influence net present value, payback period, and internal rate of return, respectively. Figure 41 clearly illustrates a poor profitability indication for this scenario, in which NPV shows an increasing trend on the negative side, PBP is greater than project lifetime (20 years), and IRR is a negative percentage.

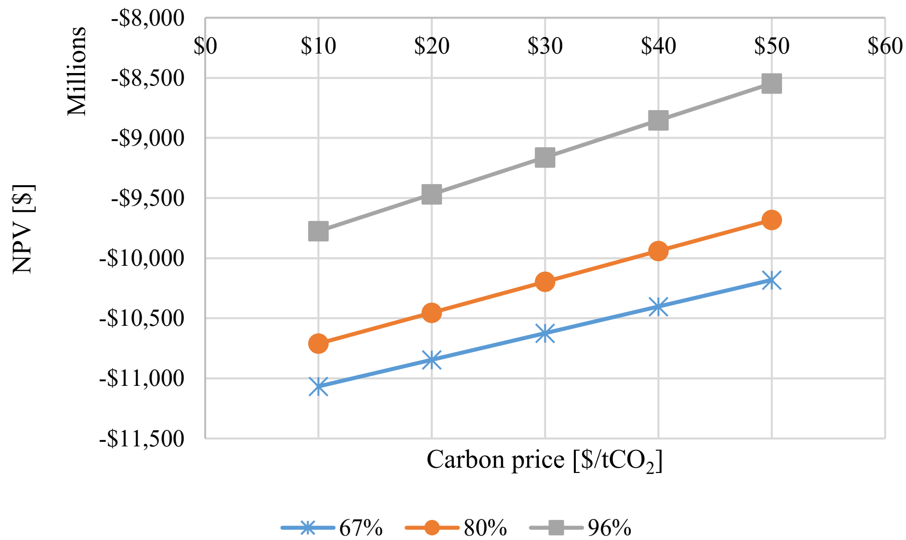

Figure 41 The effect of changing carbon price on the NPV for scenario C

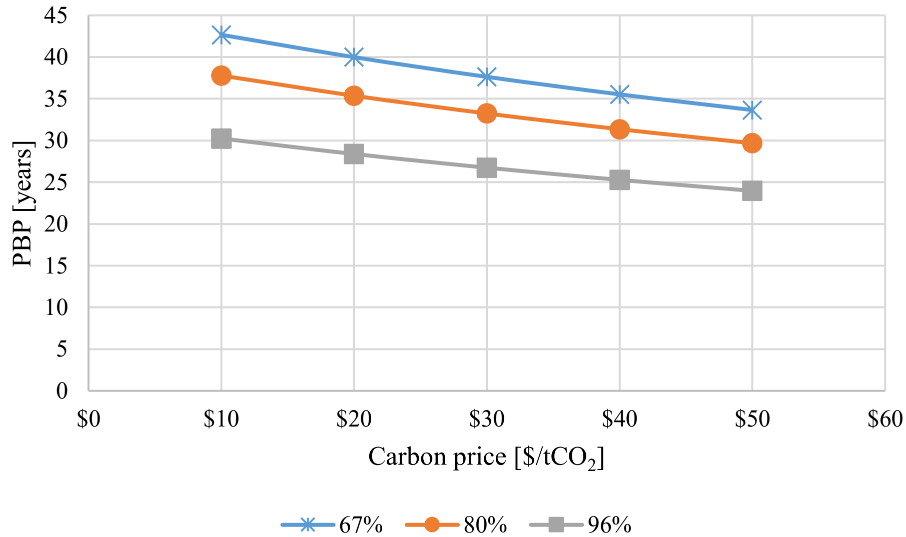

Figure 42 Figure 23 The effect of changing carbon price on PBP, for scenario C

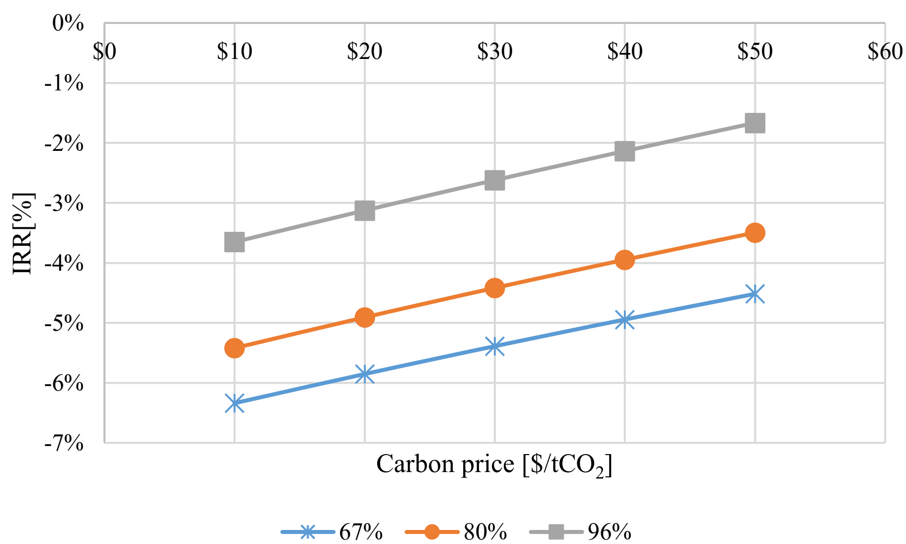

Figure 43 The effect of changing carbon price on IRR, for scenario C

5.3.4 Scenario D

In this scenario, H_2 which is produced via PtG concept by utilizing Ontario's surplus electricity is injected entirely into the natural gas grid to be used as HENG. Figures 44 shows how the variation in the carbon price can affect NPV. NPV is less than zero, the time required for the initial investment to be recovered exceeds 100 years, and IRR is undefined. This is a clear indication that increasing carbon price does not have a great impact on the pathway's profitability, since HENG production cost is higher than the production cost of the conventional natural gas.

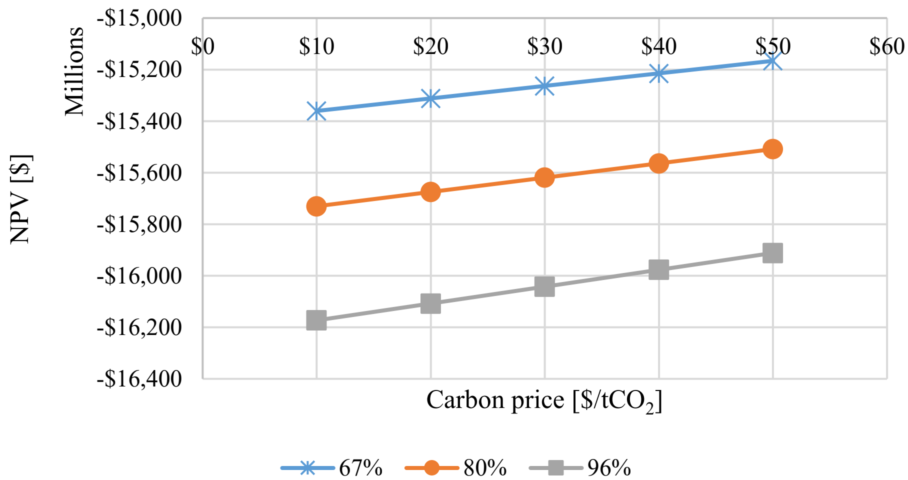

Figure 44 The effect of changing carbon price on NPV for scenario D

5.3.5 Scenario E

Scenario E describes combining H_2 produced entirely with carbon dioxide from biogas digester (or other possible CO_2 sources) for RNG synthesis. RNG is then injected into the natural gas grid to boost its renewable portion. Although increasing carbon price results in increasing NPV, but it is still in negative values. Moreover, PBP are greater than 80 years and IRR is undefined for this case, because there is no interest rate small enough to make NPV equal zero (refer to Equation 19), Figure 45.

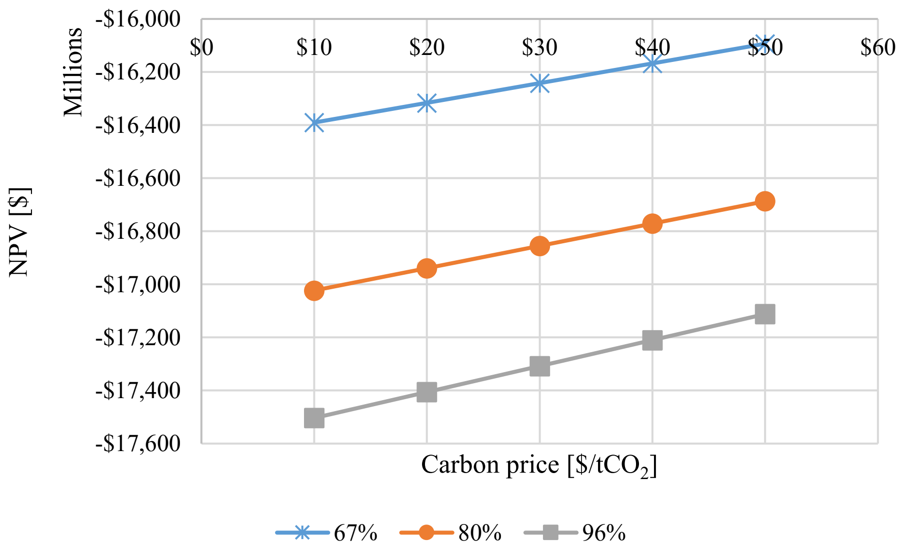

Figure 45 The effect of changing carbon price on the NPV for scenario E

Chapter 6: Conclusion and Future Work

Power-to-Gas is a novel energy storage concept that could be used to manage Ontario's surplus baseload electricity in various applications. This study has focused on four Power-to-Gas pathways: Power-to-Gas to mobility fuel, Power-to-Gas to industry, Power-to-Gas to natural gas pipelines for use as hydrogen-enriched natural gas, and Power-to-Gas to renewable natural gas (i.e., Methanation). The surplus power in Ontario has been quantified at three capacity factors (67%, 80%, and 96%) for 2017, and then allocated to the four Power-to-Gas pathways, analyzing the economic and environmental benefits. The purpose was to investigate the use of Ontario's surplus electricity–that would otherwise exported or curtailed–to reduce the emissions as well as supply the demand of other sectors within the province, including transportation, industry, and energy storage and distribution.

The study shows that the hydrogen produced via the Power-to-Gas technology could have been allocated to supply four different energy demands of four sectors in Ontario in 2017. In fact, the realization of Power-to-Gas pathways will demand substantial financial support and collaboration among governments, stockholders, and the public. Utilization of hydrogen produced via Power-to-Gas technology for refueling light-duty vehicles is a profitable business case with an average positive net present value of $4.5 billions, five years payback time, and 20% internal rate of return. Moreover, this PtG pathway promises a potential 2,215,916 tonnes of CO_2 reduction from road travel. In the scenario to utilize Ontario's surplus electricity to produce hydrogen via the PtG technology for industrial demand, results indicate that supply could achieve 82%, 93%, and 110% of the industrial demand for hydrogen at the three capacity factors, respectively. Nevertheless, hydrogen production through PtG is still costly compared to other available cheaper alternatives, namely hydrogen produced via steam methane reforming. Power-to-Gas for industry projects should, however, be part of government incentives to encourage clean energy utilization. In addition, although using hydrogen-enriched natural gas or renewable natural gas instead of the conventional natural gas could offset huge amounts of carbon, their capital and operational costs are extremely high, resulting in negative net present values and very long payback time. Taken together, these outcomes do not support strong recommendations, and continued effort is needed to investigate the environmental and economic feasibility of large implementations of Power-to-Gas pathways in Ontario.

Some recommendations for future analysis are:

- Projecting hydrogen production in Ontario for the next 15 years based on the SBG forecasts and considering other hydrogen allocation scenarios, according to Ontario's long-term strategic plans;
- Optimizing the optimal number of electrolysers required for each PtG pathway as well as other technologies;
- Performing additional life cycle assessment models to demonstrate the environmental benefits and negative effects of implementing PtG pathways in Ontario;
- Including other PtG pathways, particularly Power-to-Power and Power-to-Gas to seasonal storage; and,
- Considering other revenue streams like selling oxygen in the overall economic estimation of PtG pathways.

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