Hydrogen Integrated Greenhouse Horticultural (HIGH) Energy | Part 1: H_2 Greenhouse Case Study

University of Windsor

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1. Executive Summary

This study investigates the feasibility of using green hydrogen produced via PEM electrolysis powered by a 200MW wind farm at a commercial Greenhouse in Ontario, Canada. Nine different scenarios are analyzed, exploring various approaches to hydrogen production, transportation, and utilization for electricity generation. The aim is to transition from using 100% natural gas to using varying blends of hydrogen and natural gas that include 10%, 20%, and 100% of H_2 with 90%, 80%, and 0% of natural gas respectively, to generate 13.3 MW from grid connected greenhouse CHP engines. The techno-economic parameters considered for the study are levelized cost of hydrogen (LCOH), payback period (PBT), internal rate of return (IRR), and discounted payback period (DPB). The study found that a 10% H_2-Natural Gas blend (W-10H_2) with 5 days storage capacity and 2,190 hours of CHP operation per year had the lowest LCOH at CAD 7.1/kg at CAD 83.06/MWh of electricity purchase price and CAD 45/MWh of electricity selling price. At the purchase rate of CAD 33.07/MWh with same case scenario, the lowest LCOH was found to be CAD 4.6/kg. Alternatively, based on PBT, IRR, and DPB, the W-100H_2 variant performed best with values of 6.2 years, 15.16% and 7.99 years respectively for the same storage and operation hours. It was found that it is not practical to build a new pipeline or transport H_2 via tube trailer from wind farm site to greenhouse. A sensitivity analysis was also conducted to understand what factors affect the LCOH value.

2. Introduction and Goal

This study provides a detailed techno-economic assessment of nine distinct scenarios, where a wind farm is used to power a commercial greenhouse operation located 26 kilometers away. The wind farm has capacity to generate 200 MW of electrical power, which is integrated into the existing transmission grid. The commercial greenhouse is equipped with four natural gas-fired Combined Heat and Power (CHP) engines, each with a generation potential of 3.3 MW, and five natural gas fired hot water boilers, each offering a substantial thermal output of 8,830 kW. These installations not only fulfill the greenhouse's energy demands, ensuring an optimal growth environment for the plants, but also facilitate the contracted delivery of surplus electricity.

The core objective of this study is to transition the greenhouse's energy generation from natural gas-fired CHP engines to a more sustainable solution employing hydrogen, either in its pure form or as part of a hydrogen-natural gas blend. The study explores three different levels of demand which are classified as low (10% hydrogen, 90% natural gas = 10H_2), medium (20% hydrogen, 80% natural gas = 20H_2), and high (100% hydrogen = 100H_2) and integrates them into three overarching delivery scenarios. **Table 1** delineates these nine case scenarios.

The delivery scenarios are as follows: the 'Wired/Existing Grid' scenario, where hydrogen production, storage, and blending facilities are installed directly at the greenhouse premises (identified as W-10H_2, W-20H_2, and W-100H_2); the 'Trucking' scenario, where hydrogen is produced and compressed at the wind farm, then transported to the greenhouse via truck or tube trailer for storage and blending (referred to as T-10H_2, T-20H_2, and T-100H_2).

And the 'Pipeline' scenario, where hydrogen is also produced at the wind farm but conveyed through a pipeline to the greenhouse for subsequent storage and blending (denoted as P-10H_2, P-20H_2, and P-100H_2).

Table 1 | Case Scenarios

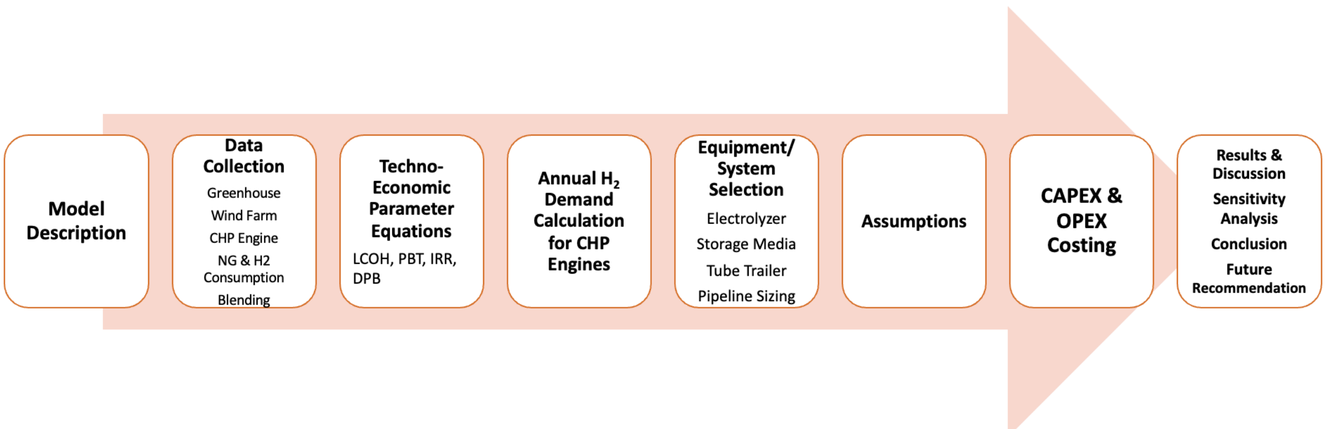
Case Scenarios								
Wired/Existing Grid			**Trucking**			**Pipeline**		
1	2	3	4	5	6	7	8	9
W-10H_2	W-20H_2	W-100H_2	T-10H_2	T-20H_2	T-100H_2	P-10H_2	P-20H_2	P-100H_2

The research is built on extensive data collection from both the wind farm and greenhouse, covering electricity generation, thermal and electrical needs of the greenhouse, auxiliary power consumption of the CHP engines, and fuel usage for boilers and engines. Utilizing this data, a comprehensive model has been developed to ascertain the requirements for hydrogen, power, and demineralized water for each scenario, aiming to achieve a 13.3 MW electricity output from the CHP engines. These engines provide heat to the greenhouse when operating and fulfill the greenhouse owner's electricity delivery contract obligations with Ontario's Independent Electricity System Operator (IESO).

The study considers engine model and capacity, production systems i.e. electrolyzer, compressor and storage media and capacities, tube trailer capabilities, and pipeline sizing for each individual case. The analysis also requires market prices for equipment and systems, power purchase and selling rates, and other economic factors such as the duration of analysis and discount rate. The study's ultimate goal is to examine the techno-economic viability of the nine cases through financial metrics including the levelized cost of hydrogen (LCOH), payback period (PBT), internal rate of return (IRR), and discounted payback period (DPB).

Figure 1 shows the methodology used in this study.

Figure 1 | Methodology of the Study



3. Jurisdictional Scan

This study includes green hydrogen production, storage, compression, transportation through pipeline and tube trailer (trucking), blending with natural gas (NG), producing electricity and heat from CHP engines to provide necessary heat and power in greenhouse while exporting the surplus energy to grid. To evaluate techno-economic feasibility LCOH, PBT, DPB, and IRR metrics are considered. A jurisdictional scan of relevant literature that helped inform this study yielded the following.

In 2020, Ozturk et al. [1] introduced a new integrated system that blends hydrogen and natural gas for residential heating and cooking with combi boiler and gas stove. Franco et al. [2] conducted a techno-economic assessment on the different pathways that includes onshore and/or offshore H_2 production, conversion to different H_2 carriers and transportation by pipeline or ship to the import terminal. Among the studied pathways, the use of pipelines to transport hydrogen was identified as the best solution having LCOH of €5.35/kgH_2. Tebibel et al. [3] presents a multi-objective optimization approach for a wind-hydrogen production system (WHPS) by integrating wind turbines, a water electrolyzer, battery bank, power converters, and a hydrogen tank to optimize total hydrogen deficit, levelized cost of hydrogen, CO_2 emissions, and natural gas required to produce an LCOH of $33.70/kg. Dinh et al. [4] introduced a new model that includes calculations for wind power output, electrolyzer plant size, and hydrogen production based on varying wind speeds. By applying Discounted Payback and Net Present Value analyses, the study evaluated the economic feasibility of a hypothetical offshore wind farm, demonstrating profitability at a hydrogen price of €5/kg with different storage capacities.

Various investigations with techno-economic analysis of green hydrogen production technology, transportation and application were conducted in 2022. Sorgulu et al. [5] set up an experimental lab-scale system to supply a mixture of hydrogen and natural gas, as well as electricity, for a community of 100 houses for its heating, cooking and power consumption to find the net present costs, energy and exergy. Lucas et al. [6] explored the feasibility of using excess wind energy for green hydrogen production, focusing on the WindFloat Atlantic offshore wind farm. The study emphasizes the importance of optimizing the hydrogen plant power-to-wind farm capacity ratio for cost-effective hydrogen production. Jang et al. [7] examined the most cost-effective method for connecting offshore wind power plants to hydrogen production facilities, through a techno-economic analysis using net present value calculation, sensitivity analysis, and Monte Carlo simulation. The calculated H_2 production costs were $13.81/kg$H_2$ for distributed production, $13.85/kg$H_2$ for centralized production, and $14.58/kg$H_2$ for onshore production.

Lamagna et al. [8] investigated the integration of a reversible Solid Oxide Cell (rSOC) with an offshore wind turbine for local energy management benefits. With the dynamic model simulation, controlled by an algorithm, the system can produce up to 15 tons of hydrogen with an export-based strategy. Benalcazar and Komorowska [9] focused on assessing the economic and technical factors affecting the success of Poland's green hydrogen strategy through the development of a Monte Carlo-based model. The study analyzed the economics of renewable hydrogen at different stages of technological development and market adoption by comparing the LCOH in some regions in 2020, 2030, and 2050.

Groenemans et al. [10] compared two scenarios: producing hydrogen offshore and transporting it to shore via a gas pipeline and producing hydrogen onshore using electricity from an offshore wind farm. The analysis revealed that the offshore production method resulted in a lower LCOH of $2.09/kg, and $3.86/kg H_2 for offshore. Luo et al. [11] discussed converting wind-generated electricity into hydrogen through water electrolysis for long-term storage to address increasing costs of offshore wind projects. They explored different methods of hydrogen production, highlighted economic analyses, and concluded that hydrogen production from offshore wind could become more cost-effective and feasible in the future. Nasser et al. [12] evaluated a hybrid renewable energy system in terms of energy storage, efficiency, and cost that uses wind turbines and PV panels for hydrogen production and storage across different climates in five Egyptian cities. Results show production costs varied from $4.54/kg to $7.48/kg.

Several relevant studies were conducted in 2023. Costa et al. [13] evaluated a setup for producing green hydrogen through electrolysis using renewable energy sources and capturing CO_2 from cogenerator exhaust gases. They then used the captured CO_2 in a methanation reaction with hydrogen to produce synthetic methane. Economic analysis showed payback times below ten years, especially with hydromethane, indicating potential residential applications with small photovoltaic sizes. This study was among a group of even more recent works on green H_2 production and integration like Egeland-Eriksen et al. [14] that presented a model to simulate an energy system where electricity from an offshore wind turbine is considered over a 31-day period having a maximum of 17,242 kg of production, with the lowest production cost of $4.53/kg.

Superchi et al. [15] explored the feasibility of integrating wind farm electricity with alkaline electrolyzers to produce green hydrogen. By coupling the model with historical wind farm data and using a sizing algorithm, they found the best combination between the actual wind farm power output and the electrolyzer capacity to reach the lowest LCOH possible. Superchi et al. [16] focused on using green hydrogen to decarbonize the steelmaking industry. By coupling an onshore wind farm with lithium-ion batteries and alkaline electrolyzers, the research conducts techno-economic analyses on various configurations to optimize the LCOH and Green Index (GI) with LCOH of around €6.5/kg. Idriss et al. [17] focused on producing hydrogen from wind energy in rural area using renewable energy and energy storage systems through an ecological analysis. They found the mass and the LCOH were 29.68 tons and $11.48/kg for Region1, and 18.68 tons and $18.25/kg for Region2 respectively.

Akdag et al. [18] presented a comprehensive model examining hydrogen production, storage, and transportation, with a detailed techno-economic analysis projecting a decreasing cost of green hydrogen production over time. The estimated cost of producing green hydrogen is expected to decrease from €6.26/kg in 2023 to €1.13/kg by 2050, with overall hydrogen costs decreasing from €10.7/kg in 2023 to €2.42/kg in 2050. In their study, Cheng and Hughes [19] investigated the prospective contribution of offshore wind power to renewable hydrogen production in Australia by 2030. Utilizing wind and solar data along with wind turbine power curve inputs, they simulated hydrogen production through PEM electrolysis, yielding an estimated LCOH range of AU$4.4-5.5/kg H2 for 2030. Li et al. [20] examined the techno-economic feasibility of a wind-photovoltaic-electrolysis-battery (WPEB) power system. The study indicates that the WPEB system outperforms the wind-photovoltaic-battery (WPB) system economically when hydrogen production exceeds 12,000 kg/day, where metrics such as NPV, IRR, LCOH, and PBT came in at ¥1781.22 million, 13.19%, ¥13.1665/kg, 9 years respectively.

Kim et al. [21] highlights the potential of green H_2 production from a wind farm through optimization. The production costs ranged from $1.64 to $4.46 per kg of H2. The analysis indicates that systems using alkaline electrolyzers can achieve feasible prices in certain regions compared to current green H_2 production costs. Komorowska et al. [9] developed a Monte Carlo-based framework to assess the competitiveness of offshore wind-to-hydrogen production, focusing on the variability of the LCOH and uncertainties in long-term planning in 2030 and 2050. Results indicate that offshore wind-based hydrogen could cost between €3.60 to €3.71/kg H2 in 2030 and €2.05 to €2.15/kg H2 in 2050. Nasser et al. [12] in 2023 evaluated hydrogen production systems using PEM and SOEC electrolyzers powered by various sources, including PV panels, wind turbines, waste heat recovery Rankine cycles, and grid electricity. The highest efficiency is achieved with waste heat systems (22.91%), with LCOH ranges from $1.19 to $12.16/kg.

In 2024, Reyes-Bozo et al. [22] investigated the feasibility of using green hydrogen as a substitute for natural gas in aluminum recycling processes to reduce carbon emissions. The evaluation indicates that on-site green hydrogen generation offers a positive NPV of €57,370, an IRR of 9.83%, and a payback period of 19.63 years with a significant reduction of CO_2 emissions. Makepeace et al. [23] introduced a techno-economic model to demonstrate the feasibility of transporting green hydrogen globally along major regional routes using various mediums such as ammonia, liquid organic hydrocarbons (LOHC), hydrogen slush, compressed or liquefied hydrogen, and different transportation modes like shipping, truck, train, and pipeline. A Monte Carlo-based technique is employed to evaluate the LCOH over the next 30 years, indicating that by 2050, around 85% of the projected 300Mt of green H_2 demand will need to be transported between regions for the most economically optimal distribution.

Giampieri et al. [24] evaluated technical requirements and costs for green hydrogen production and transport via data analysis, technology selection, system design, and simulation models. The most cost-effective scenario for projects starting in 2025 involves compressed hydrogen production, but economic feasibility depends on storage period and distance to shore. Liquefied hydrogen and methylcyclohexane could become more cost-effective by 2050, potentially reducing the LCOH to around £2 per kilogram or lower.

4. Approach/Methodology and Assumptions

4.1 Model Description

The study delineates nine distinct scenarios, which are grouped into three principal modalities: integration with the existing electrical grid, hydrogen transportation via trucking, and pipeline delivery. Illustrated in **Figure 2** are scenarios W-10H_2, W-20H_2, and W-100H_2, which involve hydrogen production utilizing power from the central grid, with the hydrogen being generated at 30 bar. This hydrogen is then stored and blended within the vicinity of the greenhouse at varying ratios: 10%, 20%, and 100% hydrogen to 90%, 80%, and 0% natural gas, respectively. **Figure 3** presents the T-10H_2, T-20H_2, and T-100H_2 scenarios, where hydrogen is produced at wind farm sites, compressed to 500 bar, and conveyed to the greenhouse area by tube trailers for storage and blending operations.

The P-10H_2, P-20H_2, and P-100H_2 scenarios are depicted in **Figure 4,** showcasing the transportation of hydrogen produced at wind farm sites at 30 bar through pipelines directly to the greenhouse.

In all the scenarios, the produced hydrogen is utilized in combined heat and power (CHP) engines—either solely hydrogen-fired or using a hydrogen-natural gas blend—to generate 13.3MW of electricity. Baseline data from conventional natural gas-fired CHP engines were used to ascertain fuel consumption, total heat and power output. A market-available hydrogen-fueled CHP engine model was then selected to determine the heat input and fuel consumption necessary for the same power output. From this, the individual hydrogen demand for each blending ratio was calculated.

For the nine scenarios, the design parameters for the electrolyzer, compressor, tube trailer, and pipeline were computed based on an assumption of 5 and 10 days of hydrogen storage capacity respectively, an operational duration of 1010 hours per year, and the greenhouse operating as a peaking power plant for 6 hours daily, equivalent to 2190 hours per year respectively. These power plant operational figures are taken directly from the participating greenhouse partner. Equipment costs, as well as operation and maintenance expenses, were sourced from various recently published literatures and adjusted to current US dollars, factoring in inflation and exchange rates. A 20-year analysis period and a 6% discount rate were employed to calculate the levelized cost of hydrogen (LCOH), the payback period (PBT), Internal Rate of Return (IRR), and Discounted Payback Period (DPB).

Figure 2 | Case Scenarios W-10H_2, W-20H_2, W-100H_2

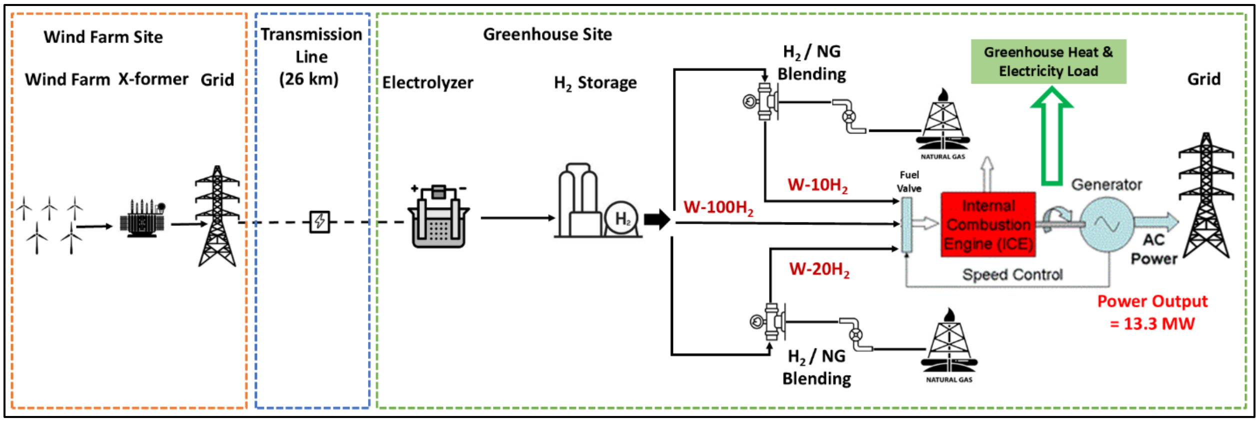


Figure 3 | Case Scenarios T-10H_2, T-20H_2, T-100H_2

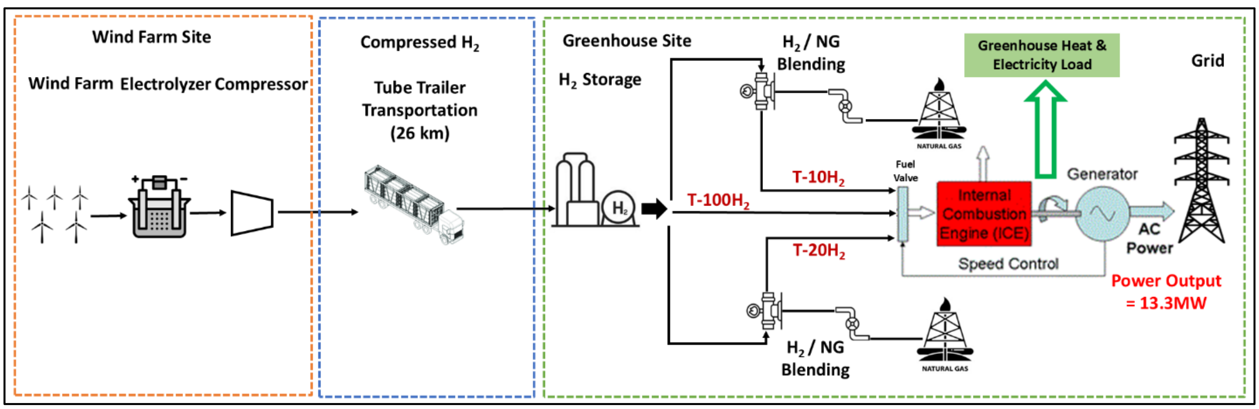
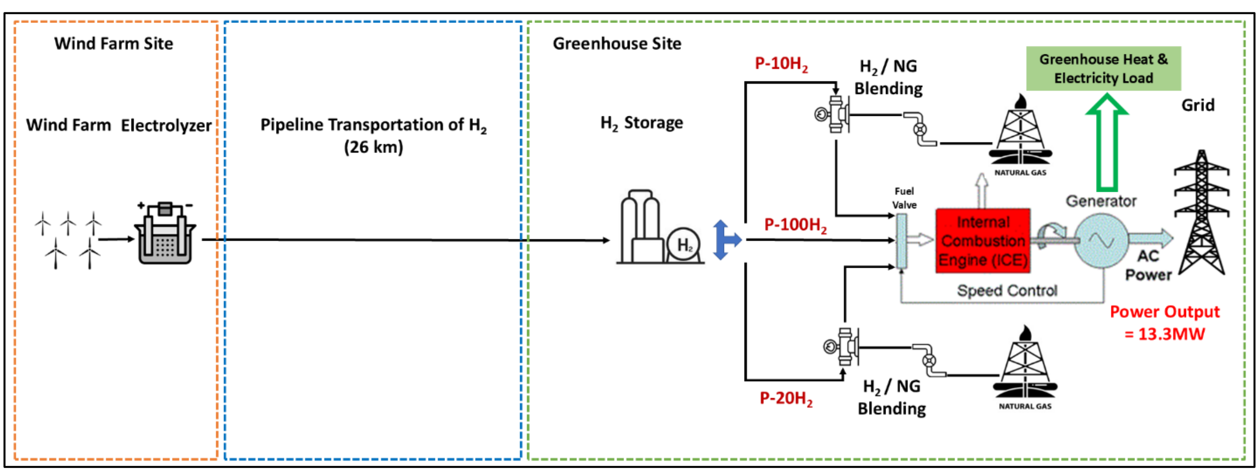


Figure 4 | Case Scenarios P-10H_2, P-20H_2, P-100H_2



4.2 Data Collection

4.2.1 Greenhouse Data

In this case study the data are collected from Under Sun Acres Greenhouse, Ontario, Canada. It is 25 acre Bell Pepper Greenhouse having average yield of 34 kg of peppers per m^2 [25]. The farming operation also includes 13.3 MW of grid connected generation capacity using four 3.3 MW natural gas fired CHP engines and five 8,830 kW of hot water boilers, and a 6,000 m^3 hot water tank to maintain an ideal temperature in the greenhouse.

Figure 5 illustrates the thermal circuit of the greenhouse where the hot water is taken from the CHP economizer, plate heat exchanger; hot water boiler which contributes to the hot water tank to maintain a certain temperature in the tank. The hot water from the header is supplied to the greenhouse to maintain an ideal temperature with blowers and after releasing heat the cold or warm water will be reverted to the feed water tank. On the power side, the electricity is produced at 4,000 V by the CHP engine and stepped up at 28,000 V to export it to grid. When the engines are running, the auxiliary usage and plant usage electricity taken from engine itself, but when the engines are not running, power is taken from grid using a step-down transformer at 600 V.

Figure 5 **|** Heat Balance of Greenhouse

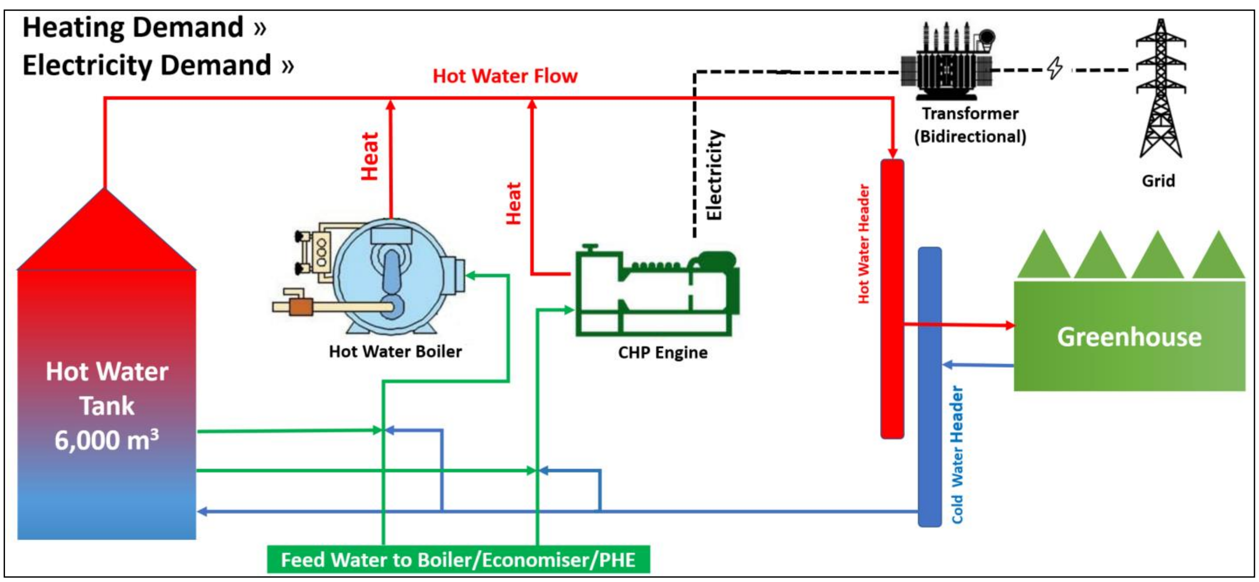


Figure 6 shows the hourly electricity generation from the CHP engines in 2022 where the total generation was 10,336 MWh with a maximum production of 14.06 MW on 21st December. From this data the operating hour (OH) was found to be 1010 hr/yr.

Figure 6 | Hourly Electricity Generation from CHP Engine

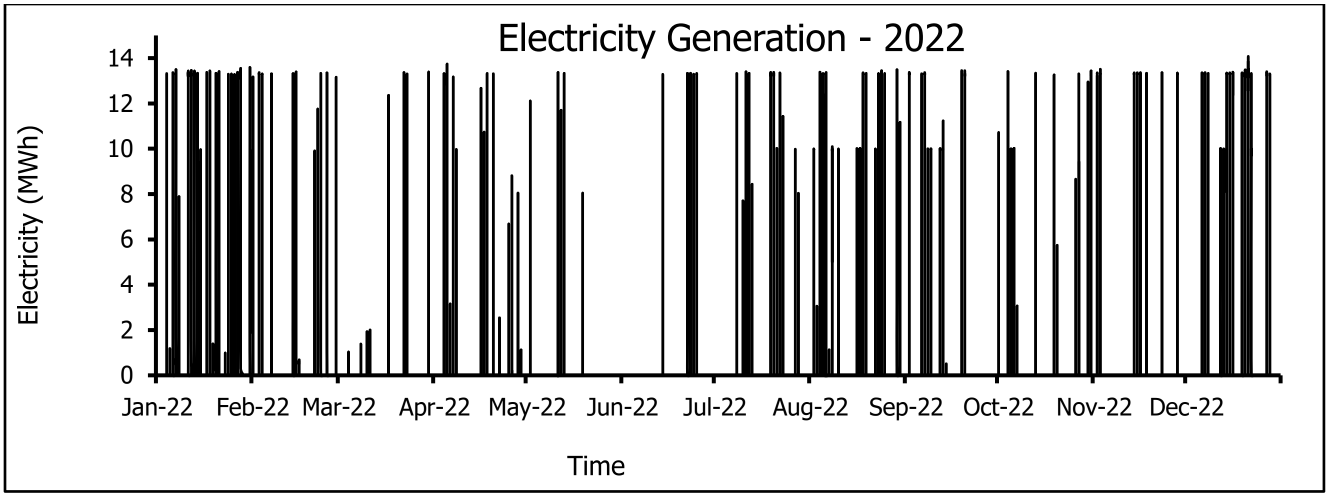


Figure 7 shows the hourly heat production from CHP engine having the total production of 11,172 MWh with a maximum production of 15.82 MWh on 20th September 2022.

Figure 7 | Hourly Heat Production from CHP Engine

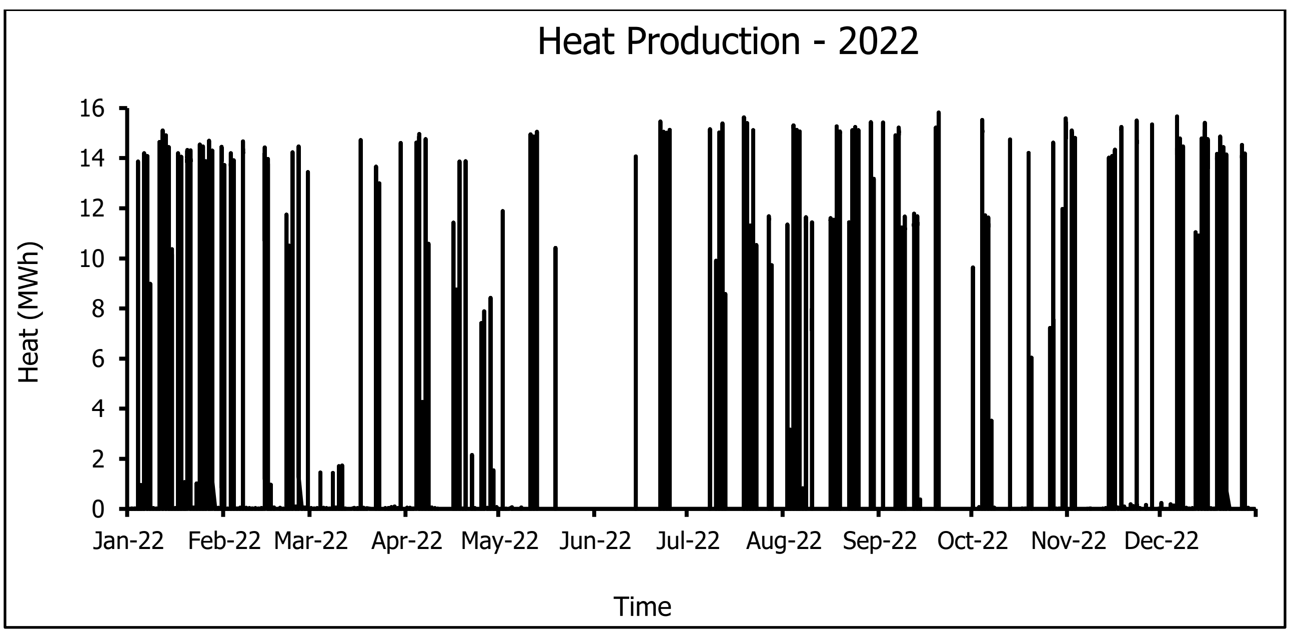


Figure 8 and Figure 9 show the annual CHP auxiliary consumption and hourly electricity usage in greenhouse. Total auxiliary consumption in 2022 was 187.26 MWh and total electricity usage was 2,094 MWh in 2022.

Figure 8 | CHP Auxiliary Consumption

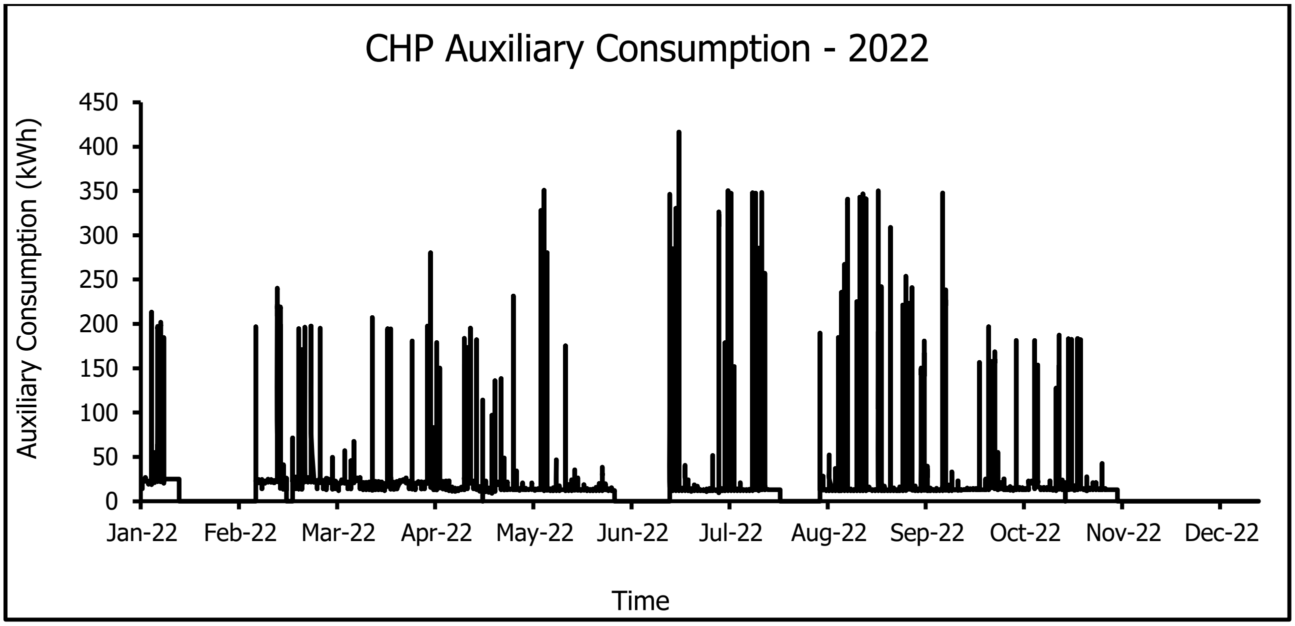


Figure 9 | Hourly Electricity Usage for Greenhouse

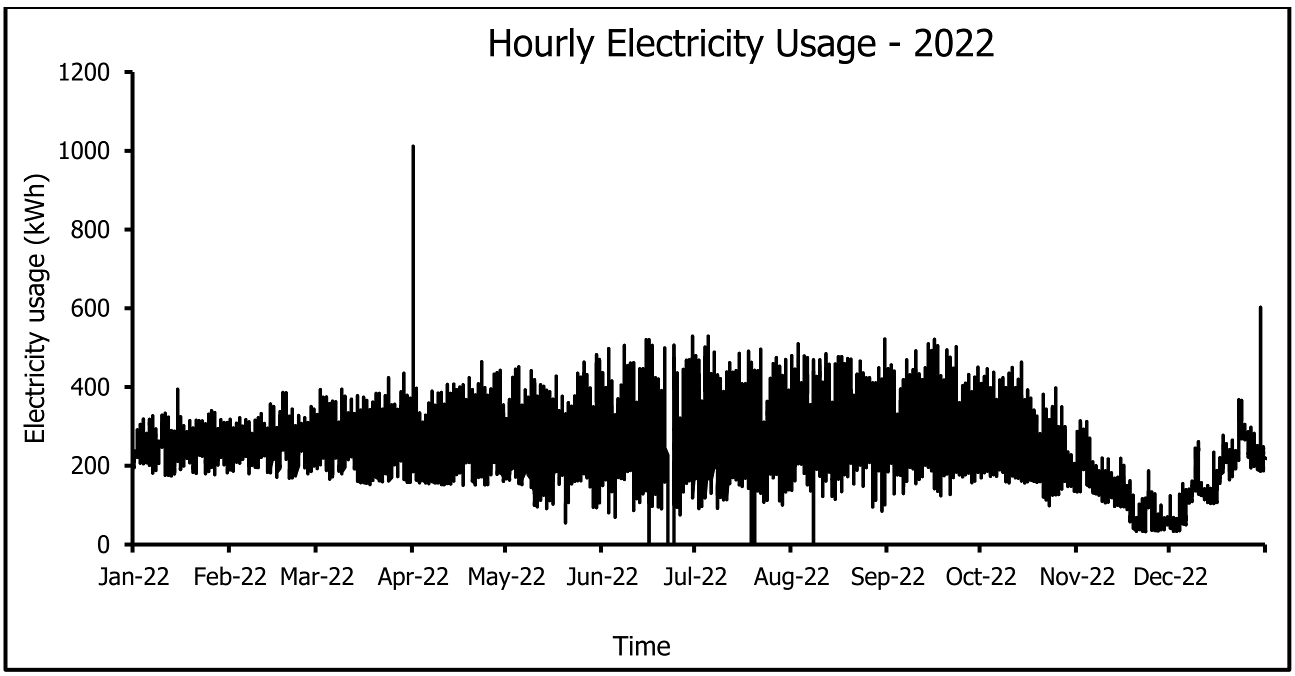


Figure 10 shows the hourly natural gas consumption by CHP engines and hot water boilers combined. The total gas consumption was 8.96 million cubic meters having an average of 1,023 m^3 in 2022. But this data shows the total natural gas consumption for both CHP engines and hot water boilers. The individual gas consumption for CHP engines and hot water boilers have been calculated from overall efficiency of CHP engine and lower calorific value of natural gas [25].

Table 2 shows the natural gas consumption in 2022 and 2023 where the consumption from CHP was 2.58 Mm^3 and 1.27 Mm^3 in 2022 and 2023 respectively.

Figure 10 **|** Hourly Natural Gas Consumption for CHP and Hot Water Boiler

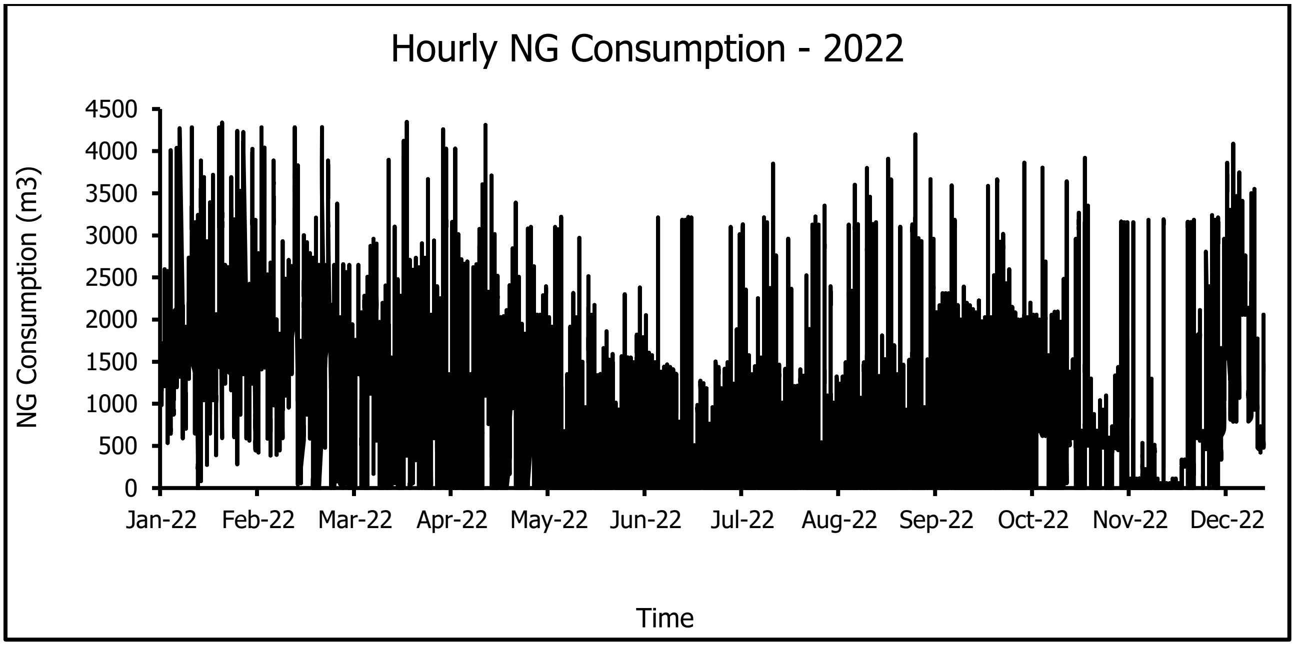


Table 2 **|** Natural Gas Consumption of CHP Engines

CHP Engine Data		2022	2023
Annual Operating Hour (OH)	hr/yr	1,010	484
Electricity Production	MWh	10,336	4,991
Heat Production	MWh	11,172	5,554
Total Energy Output	MWh	21,508	10,545
Overall Efficiency	%	87.6%	87.6%
Total Energy Input	MWh	24,553	12,037
Total Energy Input of CHP	MJ	88,392,986	43,336,150
LHV	MJ/m^3	34.2	34.2
Total Yearly Gas Consumption of CHP engine	m^3/year	2,584,590	1,267,138
(CHP + HWB) Gas Consumption	m^3	8,956,258	7,706,460
HWB Yearly Gas Consumption	m^3/year	6,371,667	6,439,321

4.2.2 Wind Farm Data

Partner wind farms for this study include Kruger Wind Farm at Port Alma and Chatham, Ontario, Canada. The total capacity of wind farm is 200 MW having 101.2 MW at Kruger Energy Port Alma (KEPA) and 99.4 MW at Kruger Energy Chatham (KEC) [26]. **Figure 11 and Figure 12** show the power generation from Wind Farm Phase 1 and 2 in 2022. **Table 3** shows total and average generated power in 2022 and 2021 respectively. In 2022, the average generated power from Wind Farm Phase 1 and 2 was 35.13 MW and 37.98 MW respectively.

Figure 11 **|** Power Generation at KEPA

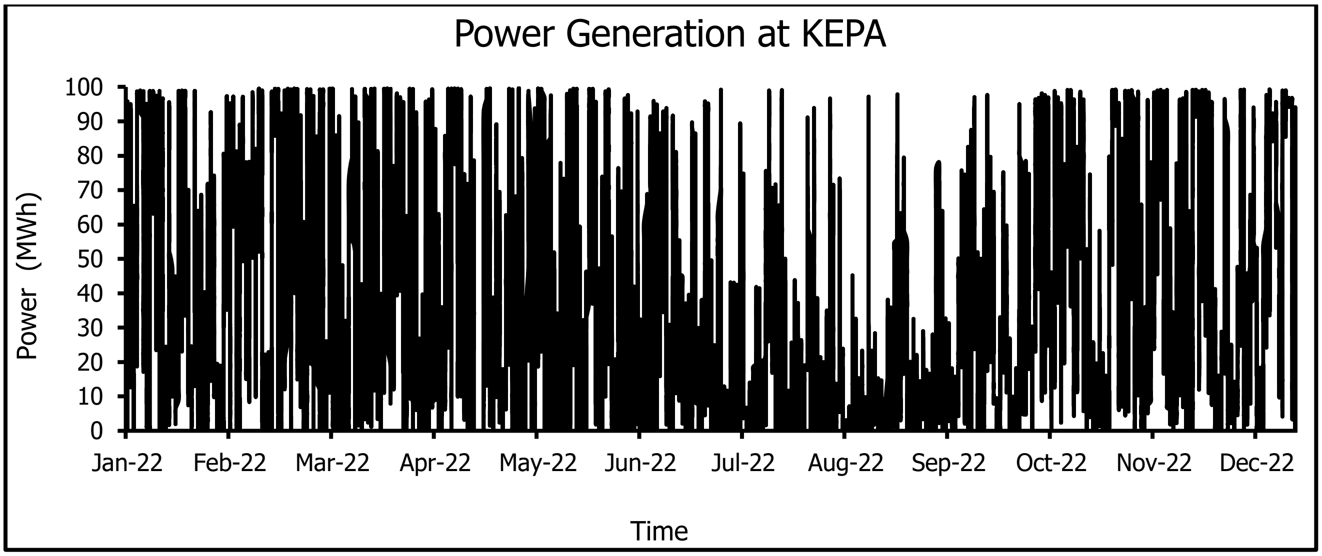


Figure 12 **|** Power Generation at KEC

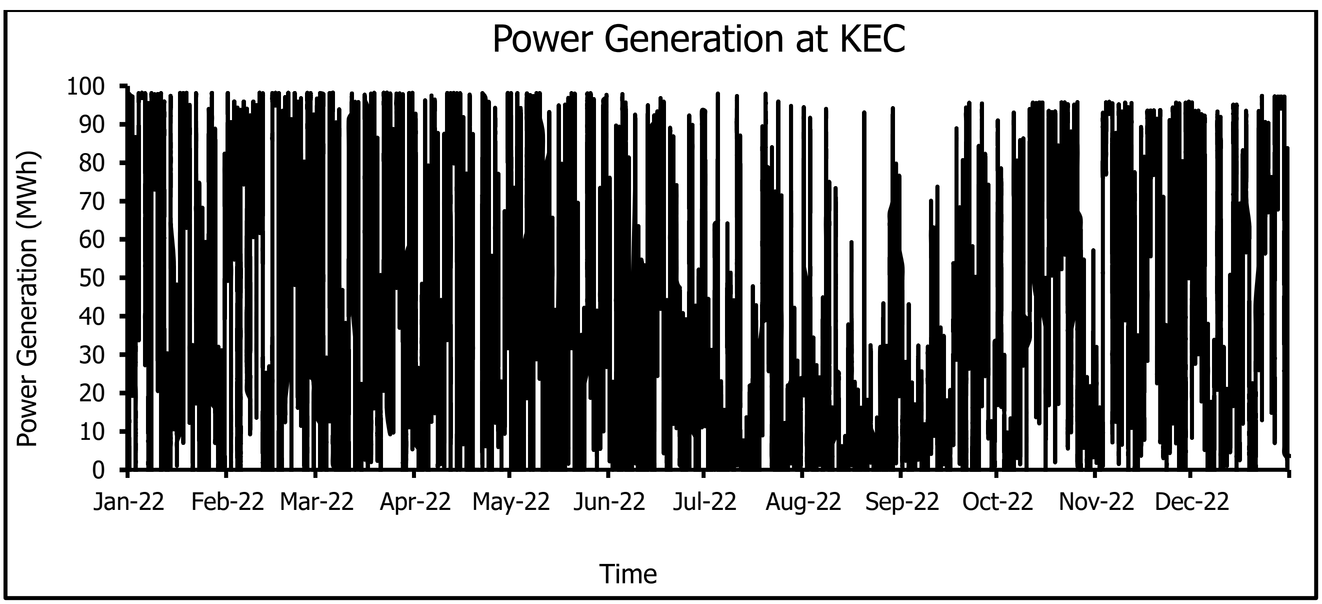


Table 3 | Wind Power Data Summary

Wind Power Data	Unit	2022		2021	
		KEPA	KEC	KEPA	KEC
Total Generated Power	MWh	307,696	332,653	268,020	289,784
Average Generated Power	MW	35.13	37.98	30.59	33.08

4.3 Existing NG Fired and Proposed H_2 Fired CHP Engine Data

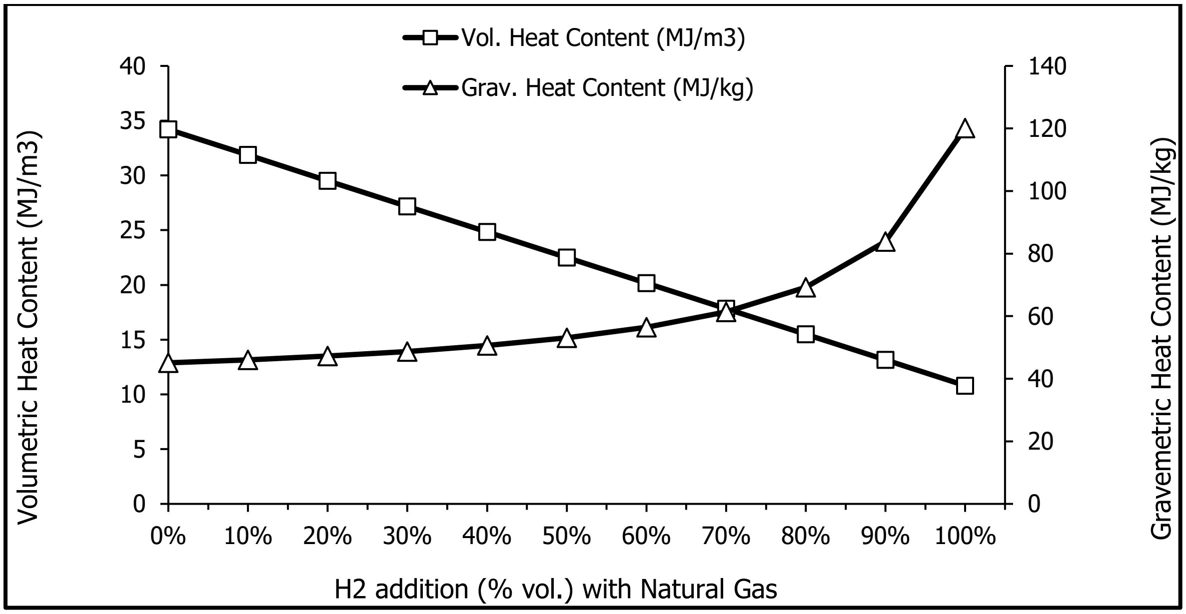
Table 4 shows existing natural gas fired CHP engine data including engine make, model, total electrical output, efficiency, and total heat input to produce 13.3 MW electricity and its corresponding lower calorific value and density of natural gas [25]. The data shows the engine requires 105,929 MJ/hr of heat or 3,097 m^3/hr of natural gas to generate 13.3 MW of electricity at 100% load. The proposed H_2 fired CHP engine has 750kW of electrical output each [27]. Eighteen engines are required to generate same 13.3 MW of electricity. This engine requires 120,604 MJ/hr of heat or 1,003 kg/hr of hydrogen to generate 13.3 MW of electricity considering the density of hydrogen of 0.0899 kg/m^3 [28–31].

Table 4 | Existing NG fired and Proposed H_2 fired CHP Engine Data

Criteria	**Unit**	**Existing NG Fired Engine**	**Proposed H_2 fired Engine**
Make & Model		Jenbacher J620	2G-Agenitor 420
Electrical Output per Engine	kW	3,325	750
Total No of Engine	Nos	4	18
Total Electrical Output	kW	13,300	13,300
Thermal Output per Engine	kW	3,131	687
Electrical Efficiency at 100% Load	%	45.09	39.7
Thermal Efficiency at 100% Load	%	42.5	40.7
Overall Efficiency at 100% Load	%	87.7	80.4
Total Heat Input to produce 13.3MW	kW	29,424	33,501
	MJ/hr	106,187	120,604
Lower Heating Value	kWh/Nm^3	9.5	3
	MJ/Nm^3	34.2	10.8
Density	kg/Nm^3	0.7584	0.0899
Fuel Consumption at 100% Load		100% of NG	100 % of H_2
	m^3/hr	3,097	11,167
	kg/hr	2,349	1,003

4.4 H_2 and Natural Gas Blending Data

Figure 13 | **Heat Content of Blended Gas at Various H2-NG** Mixtures



and Figure 14 show the volumetric heat content, gravimetric heat content and density of blended gas according to the addition of H_2 from 0% to 100% with natural gas. The heat content is based on the lower calorific value of natural gas and H_2 as 34.2 MJ/m^3 and 10.8 MJ/m^3 respectively [25,28–31].

The gravimetric heat content is increased from 10.8 MJ/kg to 120 MJ/kg by increasing the percentage of H_2 from 0% to 100%. On the other hand, the density is decreased by increasing H_2 with natural gas.

Figure 13 **|** Heat Content of Blended Gas at Various H_2-NG Mixtures

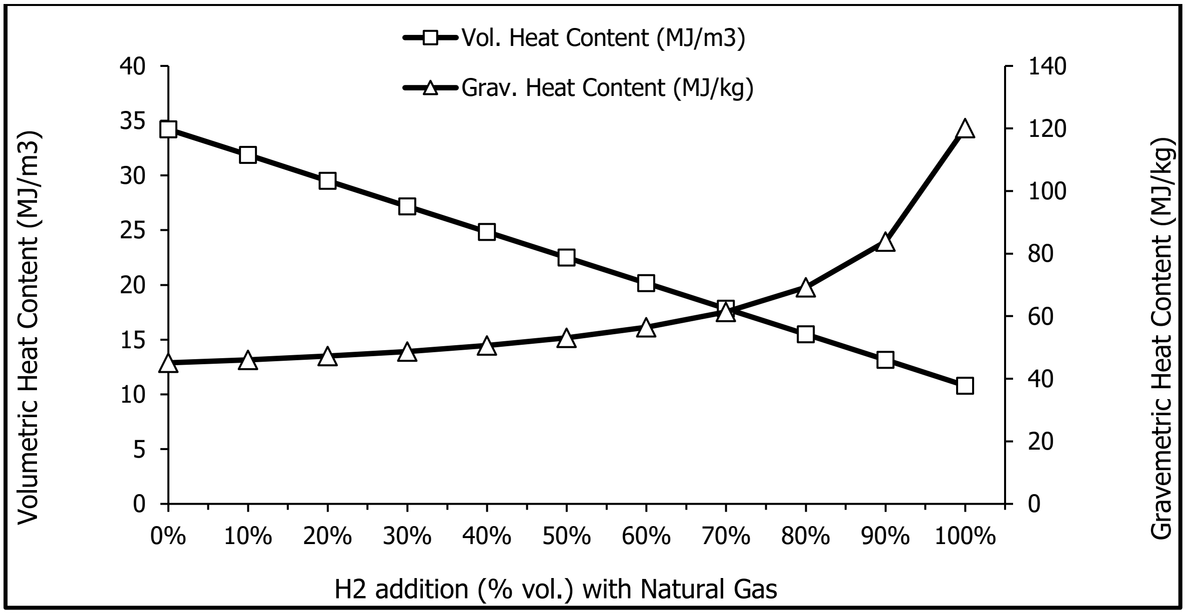
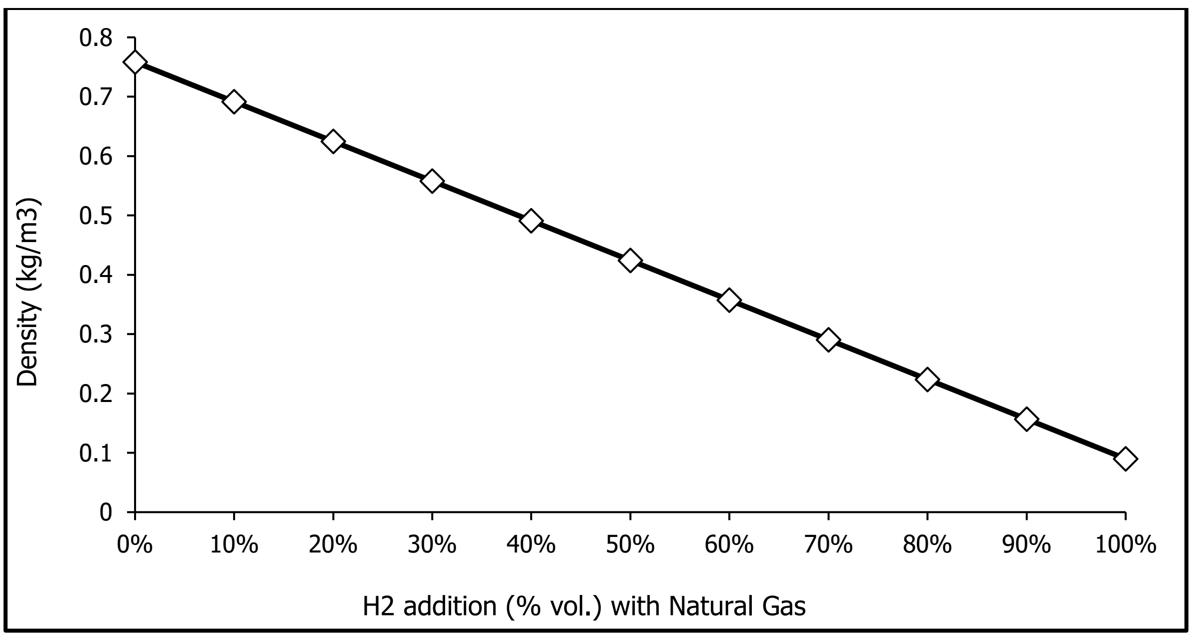


Figure 14 **|** Density of Blended Gas at various H_2-NG Mixture Ratios



5. Techno-economic Parameters

5.1 Levelized Cost of Hydrogen (LCOH)

Assessing the Levelized Cost of Hydrogen (LCOH) is essential for estimating the approximate cost of hydrogen production and understanding the markets where hydrogen may be competitively priced. LCOH serves to evaluate the cost associated with generating a unit of hydrogen over a specific time frame, within a designated production system, following the approach used in numerous studies that appear in literature.

LCOH is articulated as the quotient of the total financial outlay Capital Expenditures (CAPEX) plus Operational Expenditures (OPEX) over the aggregate hydrogen output measured in kilograms (M_{H_2}), as detailed in **equation (1)** [15]. This calculation involves both the numerator and denominator being tallied annually and then discounted to their present value. For the purpose of this analysis, a projection span of 20 years is employed, aligning with the anticipated lifespan of a wind farm, and a discount rate (r) [16] is set at 6%.

$$\mathrm{LCOH} = \frac{\sum_{t=0}^{T} \frac{\mathrm{CAPEX} + \mathrm{OPEX}}{(1+r)^t}}{\sum_{t=0}^{T} \frac{M_{H_2}}{(1+r)^t}} \tag{1}$$

The Capital Expenditure (CAPEX), delineated in **equation (2)**, is the initial investment required for the entirety of the system components at inception, with subsequent years assuming a null value except for instances of technology replacement. Another critical financial aspect considered is the Operational Expenditure (OPEX), delineated in **equation (3)**. This includes the Operational and Maintenance (O&M) costs for each component, the charges for electricity acquired from the central grid, and the profits from electricity supplied back to the grid.

$$\mathrm{CAPEX} = C_{el} + C_{comp} + C_{tank} + C_{pipe} + C_{blend} \tag{2}$$

$$\begin{aligned}\mathrm{OPEX} = {} & \mathrm{O\&M}_{el} + \mathrm{O\&M}_{stack\ repl} + \mathrm{O\&M}_{comp} + \mathrm{O\&M}_{tank} + \mathrm{O\&M}_{trail} + \mathrm{O\&M}_{pipe} + \mathrm{O\&M}_{blend} \\ & + C_{water} + C_{insurance} + C_{elec\ pur} - C_{elec\ sel}\end{aligned} \tag{3}$$

Annual electricity purchase from wind power connected grid is determined from the power consumed by electrolyzer and H_2 compressor as per the following equation.

$$\begin{aligned}&\textbf{Annual Electricity Purchase From Grid or Wind Power}\left(\frac{\textbf{CAD}}{\textbf{yr}}\right) \\ &\quad = \{(\text{Electrolyzer Consumption} + H_2\ \text{Compressor Consumption})\}\left(\frac{\text{MWh}}{\text{yr}}\right) \\ &\quad \times \text{Electricity Purchase Rate}\left(\frac{\text{CAD}}{\text{MWh}}\right)\end{aligned}$$

Annual electricity sold to grid is determined by subtracting the electricity usage and auxiliary consumption in the Greenhouse from total annual electricity generation from CHP engine based on operating hour of 2190 and 1010 hr/yr respectively as per the following equation.

$$\textbf{Annual Electricity Sold to Grid from CHP Engine}\left(\frac{\textbf{CAD}}{\textbf{yr}}\right)$$
$$= \left[\left\{13.3\ \mathrm{MW} \times \text{Annual Operating Hour (OH)}\left(\frac{\mathrm{h}}{\mathrm{yr}}\right)\right\}\right.$$
$$- \left\{(\text{Auxiliary Consumption at Greenhouse} + \text{Electricity Usage at Greenhouse})\left(\frac{\mathrm{MWh}}{\mathrm{yr}}\right)\right\}$$
$$\left.\times \text{Electricity Selling Rate}\left(\frac{\mathrm{CAD}}{\mathrm{MWh}}\right)\right]$$

For the scenarios W-10H_2, W-20H_2, and W-100H_2, the capital expenditure (CAPEX) estimation encompasses the expenses related to the electrolyzer, storage tanks, and blending facilities, as detailed in equation (2). Additionally, the operational expenditure (OPEX) for these cases takes into account the operational and maintenance (O&M) costs associated with the electrolyzer, the cost of stack replacements, storage tanks, blending processes, insurance, and the cost of purchasing electricity. The cost savings from any excess electricity generated are subtracted as per **equation (3).**

In the T-10H_2, T-20H_2, and T-100H_2 scenarios, the CAPEX incorporates the expense of the compression system required to pressurize hydrogen to 500 bar at the wind farm location, as well as the cost of acquiring tube trailers, which is included in **equation (2).** The O&M expenses for both the compressor and the tube trailer are factored into OPEX as outlined in **equation (3)**.

For the pipeline scenarios, both the initial investment in the pipeline infrastructure and the ongoing O&M expenses are accounted for in the CAPEX and OPEX calculations, respectively.

5.2 Payback Period (PBT)

To evaluate the economic feasibility of a project, it is crucial to determine whether the investment including capital, operational, and maintenance costs can be recouped through positive cash flows [4]. Throughout the study, a variety of established methodologies for assessing the economic feasibility of renewable energy projects have been employed, such as Payback Period (PBT), Discounted Payback (DPB), and Net Present Value (NPV), as referenced in numerous instances in the literature. When the system is designed to sell hydrogen to a general market, the Payback Period (PBT) becomes an essential factor in assessing the techno-economic viability of the facility. The PBT is indicative of the time frame required to recoup the initial investment based on the proceeds from selling the hydrogen produced. Payback period is the period of time required to reach the break-even point (the point at which positive cash flows and negative cash flows equal each other, resulting in zero) of an investment based on cash flow [32]. The formula for payback period is **in equation (4)** [32].

$$\mathrm{PBT} = \frac{\mathrm{C_0}}{\mathrm{CF_a}} \tag{4}$$

5.3 Discounted Payback Period (DPB)

A key limitation of the payback period is its neglect of the time value of money concept [32]. The disadvantage of using the simple payback period is its failure to acknowledge the depreciating value of money over time, effectively treating future net cash flows as equivalent in value to current cash flows. This results in an undue emphasis on forthcoming cash flows, potentially leading to an overly optimistic assessment [4]. Moreover, like all payback analyses, the simple payback method falls short in assessing cash flows that occur beyond the payback threshold. This is a particular concern for projects that may have a quick payback time but ultimately a lower Net Present Value (NPV) throughout the entire project life [4]. The formula for Net Present Value is shown in **Equation (5)** [7].

$$\mathrm{NPV} = \sum_{t=1}^{T} \frac{\mathrm{CF_t}}{(1+\mathrm{r})^{t}} - \mathrm{C_0} \tag{5}$$

The discounted payback period serves as a valuable tool for ascertaining investment profitability with accuracy. In comparisons across various investments, those with shorter discounted payback periods are usually more attractive, as they offer a quicker path to recouping the initial outlay [32].

The discounted payback period (DPB) accounts for the time value of money by applying the discount rate 'r' to each period's net cash flows before summing them and comparing them with the initial investment. This calculation presumes that the quantity of hydrogen generated, its selling prices, and the operational and maintenance (O&M) expenses for the electrolyzer, compressor, tube trailer, pipeline, storage tank, and blending remain constant annually. This assumption gives rise to the formula presented in **Equation**

(6**)** for calculating the DPB [4].

$$\mathrm{DPB} = \frac{\ln\left[\dfrac{1}{1-\mathrm{r}\dfrac{\mathrm{C_0}}{\mathrm{CF_a}}}\right]}{\ln(1+\mathrm{r})} \tag{6}$$

5.4 Internal Rate of Return (IRR)

Internal rate of return (IRR) is an expression of the highest possible rate of interest that the investment can earn. As NPV cannot fully consider the difference in investment size between each project, the internal rate of return (IRR) are analyzed [7]. The IRR is the discount rate that makes the final NPV zero; it can be derived from the following **Equation (7)**:

$$\mathrm{NPV} = \sum_{t=0}^{T} \frac{\mathrm{CF_t}}{(1+\mathrm{IRR})^{t}} = 0 \tag{7}$$

The IRR value needs to be higher than the discount rate for profit, and a project with a higher IRR is more competitive. While NPV is crucial for assessing economic feasibility, considering factors like IRR helps with better comparisons and decisions [7].

6. Annual H_2 Demand Calculation for CHP Engines

From **Table 5 and Table 6** and also from the value of LHV of H_2 and NG, total heat to generate 13.3 MW power from the CHP engines is calculated. For each blending criteria, total heat of blended gas is calculated as shown in **Table 5**. The table calculates the H_2 consumption for $10H_2$, $20H_2$, and $100H_2$ as 34.03 kg/h, 73.46, and 1,003.92 kg/h respectively. Throughout this study the annual operating hours for CHP engines are considered as 2,190 hr/yr and 1,010 hr/yr respectively. The OH-2190 is considered based on the assumption that the CHP engines will run as a peaking plant on the basis such as 6 hours per day multiplied by 365 days per year. The OH-1010 is considered based on the data of actual running hours of the greenhouse CHP engines in 2022. Based on these operating hours the annual H_2 demand is mentioned in **Table 6.**

Table 5 **|** H_2 Demand for Each Blending Criteria

$10H_2$ (10% H_2 + 90% NG)									
CHP Engine Output (MJ/h)	Lower Heating Value (LHV) of fuels (MJ/m³)		Blended LHV (MJ/m³)	Blended Gas Consumption (m³/h)	CHP Engine Electrical Efficiency		NG Consumption (m³/h)	H_2 Consumption (m³/h)	H_2 Consumption (kg/h)
A	B_1	B_2	C	D	E_1	E_2	F	G	H
13.3 MW × 3,600 s/h	H_2	NG	(10% of B_1)+(90 % of B_2)	A/C	H_2 fired Engine	NG fired Engine	(90% of D)/E_2	(10% of D)/E_1	G × 0.0899 kg/m³)
47,880	**10.8**	**34.2**	**31.86**	**1,502.82**	**39.7%**	**45.09%**	**2,999.65**	**378.55**	**34.03**
20 H_2 (20% H_2 + 80% NG)									
A	B_1	B_2	C	D	E_1	E_2	F	G	H
13.3 MW × 3,600 s/h	H_2	NG	(20% of B_1)+(80 % of B_2)	A/C	H_2 fired Engine	NG fired Engine	(80% of D)/E_2	(20% of D)/E_1	G × 0.0899 kg/m³)
47,880	**10.8**	**34.2**	**29.52**	**1,621.95**	**39.7%**	**45.09%**	**2,877.71**	**817.1**	**73.46**
100 H_2 (100% H_2 + 0% NG)									
A	B_1	B_2	C	D	E_1	E_2	F	G	H
13.3 MW × 3,600 s/h	H_2	NG	(100% of B_1)+(0 % of B_2)	A/C	H_2 fired Engine	NG fired Engine	(0% of D)/E_2	(100% of D)/E_1	G × 0.0899 kg/m³)
47,880	**10.8**	**34.2**	**10.8**	**4,433.33**	**39.7%**	**45.09%**	**-**	**11,167.09**	**1,003.92**

Table 6 **|** Annual H_2 Demand for CHP Engines

Blending Criteria	Hourly H_2 Consumption (kg/h)	Annual H_2 Consumption (kg/yr)	
		OH-2190	OH-1010
10 H_2	34.03	74,525.7	34,370.3
20 H_2	73.46	160,877.4	74,194.6

100 H_2	1,003.92	2,198,584.8	1,013,959.2

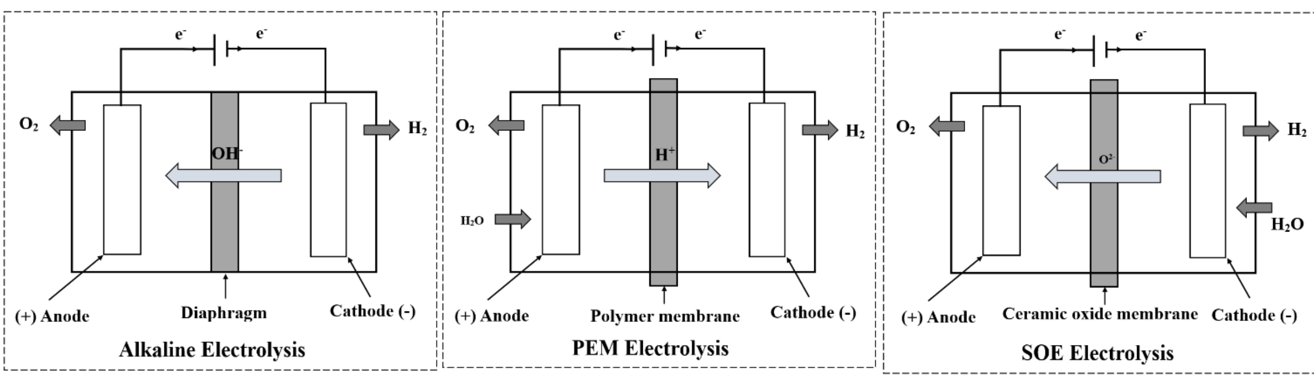
7. Equipment/System Selection

7.1 Electrolyzer

Electrolysis is a process in which an electric current is passed through an electrolyte to cause a non-spontaneous chemical reaction to produce H_2 and O_2 using renewable electricity source such as wind, solar or hydro. There are various electrolysis technologies available and among them Alkaline Electrolyzer (AE), Proton Exchange Membrane (PEM) Electrolyzer and Solid Oxide Electrolyzer (SOE) are the most popular [33]. **Figure 15** shows the working principle of AE, PEM and SOE electrolyzers [34].

Alkaline electrolyzers (AE) operate via transport of hydroxide ions (OH-) through the electrolyte from the cathode to the anode with hydrogen being generated on the cathode side using a liquid alkaline solution of sodium or potassium hydroxide [35]. In PEM electrolyzers, water reacts at the anode to form oxygen and positively charged hydrogen ions (protons). The electrons flow through an external circuit and the hydrogen ions selectively moves across the PEM to the cathode. At the cathode, hydrogen ions combine with electrons from the external circuit to form hydrogen gas [35]. SOE electrolyzers use solid ceramic material as electrolyte. At the cathode, steam (H_2O) is fed into the cell to produce H_2 gas and (O_2) ions which migrates through membrane. At the cathode, (O_2-) combine with electrons (e-) supplied from an external circuit to form (O_2) gas [34].

Figure 15 **|** AE, PEM and SOE Electrolyzers Working Principle.



The summaries of green hydrogen production technologies available, including AE, PEM Electrolysis, and SOE based on several aspects, which showed in **Table 7** [34]. Due to less energy consumption than SOE, compact design, high efficiency, fast response, high current density (above 2 A cm−2), longer lifespan, and more compatible with renewable energy, in this study PEM electrolyzer, particularly Cummins Hylyzer – 1000 is considered [36,37].

Table 7 | Comparison of production technologies of AE, PEM, and SOE [34]

Aspect	**Alkaline Electrolysis**	**PEM Electrolysis**	**Solid Oxide Electrolysis**
Operating Temperature	<100 °C	<100 °C	700-1000 °C
Efficiency	Moderate (60 - 70%)	High (70 - 80%)	High (>80%)
Capital costs	Moderate	Higher	Higher
Durability	Relatively shorter lifespan	Relatively longer lifespan	Longer lifespan
Electrolyte	Alkaline (KOH or NaOH)	Proton exchange membrane (solid polymer)	Solid oxide (ceramic material)
Electrolyte conductivity	Moderate	High	High
Response time	Slow	Fast	Fast
Scale	Industrial scale	Small-scale	Industrial scale
Compatibility with renewable energy	Less compatible	Compatible	Less compatible
Integration with other technologies	Less flexible	Flexible	Less flexible
Heat requirements	Low	Low	High
System complexity	Low	Moderate	High
Fuel purity	High	High	High
Heat management	Simple	Moderate	Complex

7.2 H_2 Compressor

For case scenarios T-10H_2, T-20H_2, and T-100H_2, compressor is required to pressurize the hydrogen up to 500 bar to transport it via tube trailer to greenhouse area. The cost of compression per kg of hydrogen, and energy consumption in terms of kWhr/kg of hydrogen at 500 bar of a generalized hydrogen gas compressor is included in **Table 10.**

7.3 Tube Trailer

Composite Tube Trailer (Type IV) is considered having dimension (W-H-L)=(8'-8'-40'), Payload = 1,100 kg, Pressure = 500 bar, pressure vessel capacity = 9 × 30" dia, loading-3hrs, unloading-1hr [38]. The annual O&M cost of one tube trailer is considered 5% of Trailer CAPEX based on the assumption of fuel efficiency, average trailer speed, labor, fuel cost, number of trips per year [29,30].

7.4 Pipeline Sizing

The optimum diameter of the pipeline should be determined for parameters such as assumed working pressure, length of the pipeline, roughness, etc. [39]. In the analyzed case, the diameter was determined with a function of inlet pressure at the beginning of the pipeline for the assumed outlet pressure at the end of the pipeline of 24 bar (g). The formula for pipeline diameter is based on the General Flow Equation, which is directly stems from the Bernoulli law as showed in **Equation (8)** [39].

$$D = \sqrt[5]{\frac{16\lambda \cdot Z^2 \cdot R^2 \cdot T^2 \cdot L \cdot \dot{m}^2}{\pi^2 \cdot (Z \cdot R \cdot T \cdot (P_1^2 - P_2^2) - 2 \cdot g \cdot P_{av}^2 \cdot \Delta h)}} \quad (8)$$

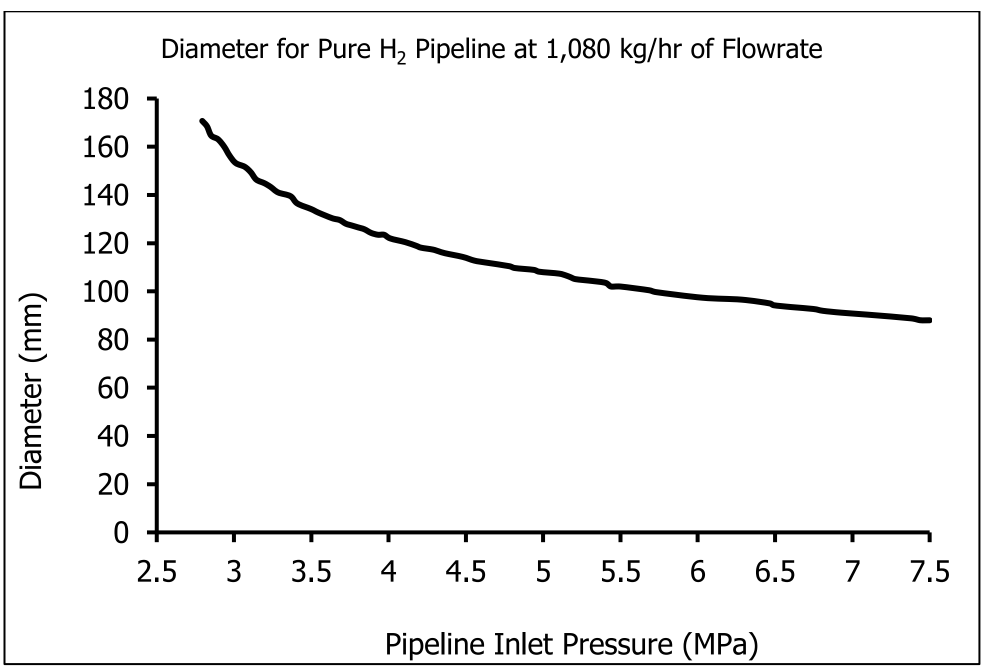
Kuczynski et al. [39] recommended pipeline diameters for the assumed flow rates of pure hydrogen as presented in **Table 8**.

Table 8 **|** Recommended Pipeline Diameters for Pure Hydrogen Transmission.

Volume Flow Rate (Nm^3/hr) of H_2	Pure H_2 Pipeline Diameter (mm)
12,000	100-150
40,000	150-250
80,000	200-300
120,000	250-400

Calculations were also performed by Kuczynski et al. [39] for pure hydrogen and methane/hydrogen mixtures, and the corresponding graphs are showed in **Figure 16.** Based on this graph for pure hydrogen transportation at 1,080 kg/hr of flowrate and 30 bar on inlet pressure, the pipeline size is found to be 155 mm.

Figure 16 **|** Diameter for Pure Hydrogen Pipeline as a Function of Pipeline Inlet Pressure



7.5 Blending Station

The pricing for blending station is considered same for $10H_2$ and $20H_2$ which is collected from [22] which is showed in **Table 10**.

8. Assumptions and Costings Considerations in the Study

Table 10 and Table 11 show the considerations for CAPEX and OPEX costing. The assumptions are given below:

8.1 Assumptions

- The hydrogen demand is determined by the annual operating hours (OH) of CHP engines, which are estimated at 2,190 hours (6 hours per day multiplied by 365 days per year for peaking power plant operation) and 1,010 hours per year for the actual operation of CHP engines at the greenhouse in 2022.
- The storage tank capacity is assumed according to the demand of H_2 to run CHP engines for 10 days and 5 days.
- For T-$10H_2$ and T-$20H_2$ cases the number of only one compressor is considered at 33 kg/hr of flowrate and greater than 500 bar of pressure, but for T-$100H_2$, five compressors are considered as per the storage capacity.
- One tube trailer having a payload capacity of 1,100 kg at 500 bar is considered for T-$10H_2$ and T-$20H_2$, whereas five tube trailers are for T-$100H_2$ as per the storage capacity.
- Annual electricity consumption is determined according to the power consumption of electrolyzer and compressor for each individual case.
- Annual electricity sold to grid is determined by subtracting the CHP auxiliary consumption, greenhouse power usage, electricity consumption for electrolyzer and compressor etc. from total annual electricity generation from CHP engine based on operating hour (OH) of 2,190 and 1,010 hr/yr respectively.

8.2 Electricity Price

In this research, two distinct purchase and selling prices are examined, referred to as Case A and Case B as outlined in **In Case** A, the purchase price is based on the current Kruger Energy Contract price of CAD 83.08/MWh [26], while in Case B, it is derived from the average Hourly Ontario Energy Price (HOEP) from January to September 2024 [40] , which is CAD 33.07/MWh. The selling price for electricity is set at CAD 45/MWh, consistent for both Case A and Case B, reflecting the current selling price to the grid from Under Sun Acres Greenhouse.

Table 9. In Case A, the purchase price is based on the current Kruger Energy Contract price of CAD 83.08/MWh [26], while in Case B, it is derived from the average Hourly Ontario Energy Price (HOEP) from January to September 2024 [40] , which is CAD 33.07/MWh. The selling price for electricity is set at CAD 45/MWh, consistent for both Case A and Case B, reflecting the current selling price to the grid from Under Sun Acres Greenhouse.

Table 9 | Electricity Purchase and Selling Price

Cases		**Purchase**		**Sale**
	Source	**CAD/MWh**	**Source**	**CAD/MWh**
Case A	Kruger Contract Price	83.06	Under Sun Acres sells to Grid	45.00
Case B	IESO HOEP (Buy from Grid)	33.07	Under Sun Acres sells to Grid	45.00

8.3 CAPEX and OPEX Costings

Table 10 | Techno-economic Parameter for CAPEX Costing

CAPEX Costing			
Electrolyzer			**Reference**
Specific Power Consumption of Electrolyzer	kWhr/kg	50	[36,37]
Cost of Electrolyzer	CAD/kW	1,697.19	
Compressor			
Hydrogen Compressor @33 kg/hr and >500 bar	CAD/set	958,991.67	[41]
Electricity Consumption for Compressor at 500 bar	kWhr/kg	6	[29,30]
Storage Tank			
Cost of Hydrogen Storage System at 35 bar	CAD/kg	496.14	[22]
Cost of Hydrogen Storage System at 525 bar	CAD/kg	1,693.06	[22]
Tube Trailer			
Each Tube Trailer Payload Capacity	kg	1,100	[38]
Cost of Composite Tube Trailer	CAD/kg	1,900.28	[38]
Each Tube Trailer Cost	CAD/each	2,090,305.56	
Pipeline			

Cost of H_2 Transportation through pipeline	CAD/cm/km	48,291.67	
Blending			
Blending Cost	CAD	294,444.44	[22]
Analysis Period and Discount Rate			
Period of Analysis	year	20	
Discount Rate	%	6	

Table 11 **|** Techno-economic Parameters for OPEX Costing.

OPEX Costing				**Reference**
O&M of Electrolyzer	$O\&M_{el}$	1.5%	of Ini Inv Cost	[22]
Stack Replacement	$C_{stack\ rep}$	30%	of Ini Inv Cost	[22]
O&M of Compressor	$O\&M_{comp}$	1.5%	of Ini Inv Cost	[22]
O&M of Tank	$O\&M_{tank}$	1.5%	of Ini Inv Cost	[22]
O&M of Trailer	$O\&M_{trail}$	5%	of Ini Inv Cost	[29,30]
O&M of Pipeline	$O\&M_{pipe}$	0.00001%	of CAPEX	
O&M of Blending	$O\&M_{blend}$	1.5%	of Ini Inv Cost	[22]
Insurance Cost	$C_{insurance}$	0.5%	of CAPEX	[42]

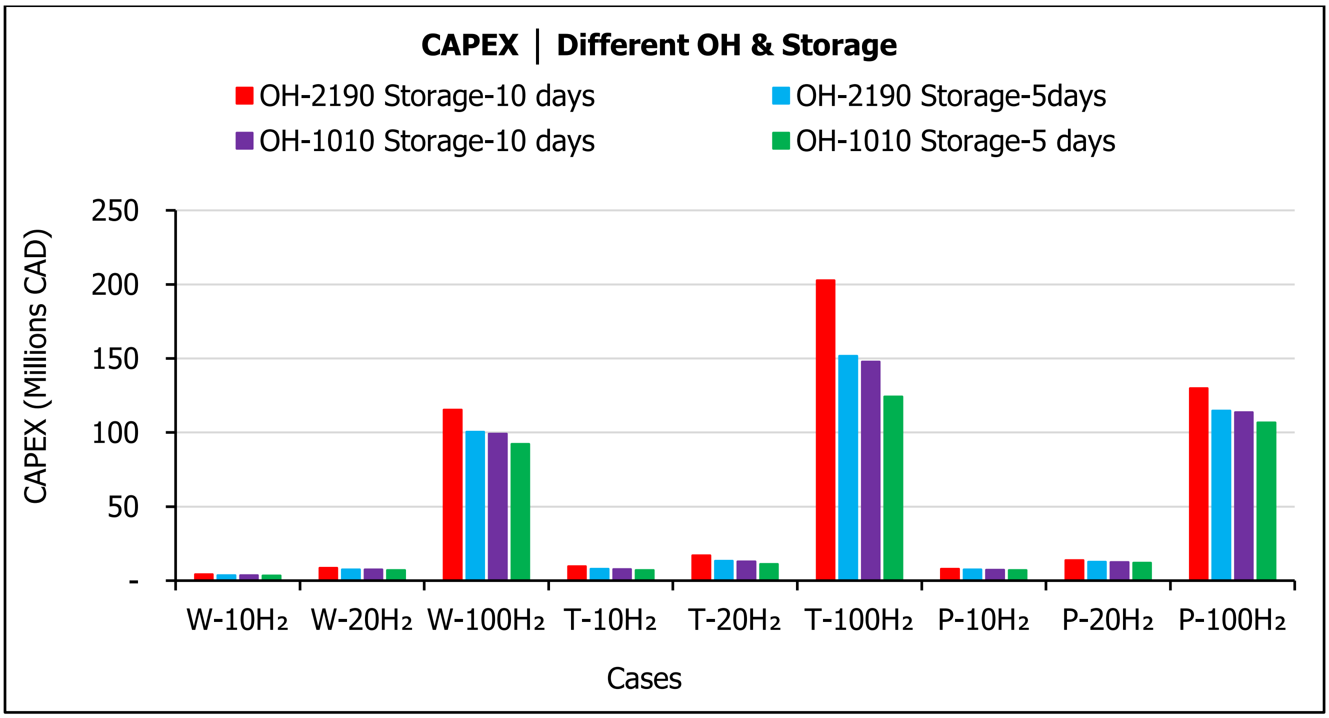
Electricity Consumption, Purchase and Sell			**Reference**
Electricity Purchase Rate From Grid	CAD/MWh	83.06, 33.07	[26,43]
Annual Electricity Generation from CHP Engine	MWh/yr	29,127	
Auxiliary Consumption of CHP Engine	MWh/yr	55.39	[25]
Electricity Usage at Under Sun Acres	MWh/yr	2,153	[25]
Electricity Selling Rate to Grid	CAD/MWh	45.00	[25]
DM Water			
DM Water Requirement	L/kg of H_2	9	[36,37]
Gross Water Cost	CAD/m3	2.58	[22]

9. Results and Analysis

9.1 Results

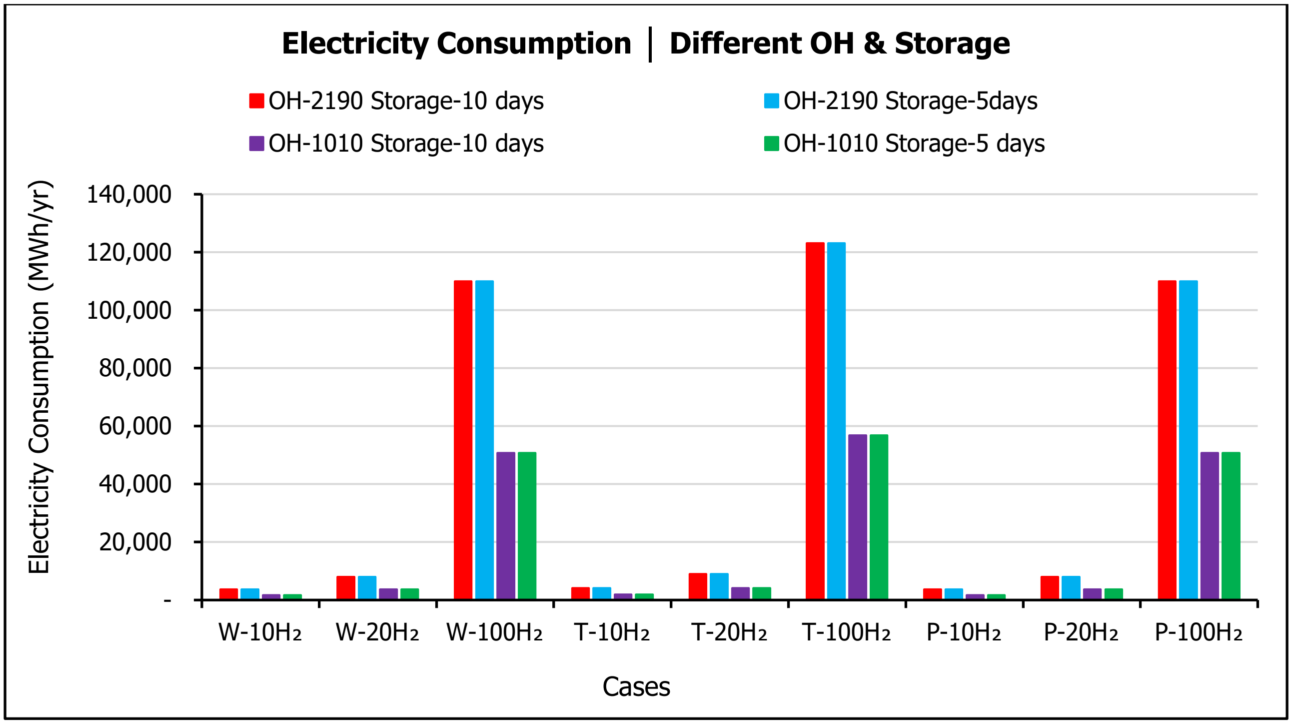
Figure 17 and Figure 18 show CAPEX costs and annual electricity consumption of all the nine cases at OH-2190, OH-1010 and Storage-10, 5 days respectively. T-100H_2 at OH-2190 Storage-10 days has the maximum cost (CAD 202.71 million), and W-10H_2 at OH-1010 and Storage-5 days has a minimum cost of (CAD 3.42 million). This is due to the cost for the tube trailer and its associated compression up to 500 bar. Storage contributes significantly to cost in the case of T-100H_2. On the other hand, W-10H_2 has no cost for the compressor and less cost for the storage tank.

Figure 17 | CAPEX at Different OH and Storage Capacity



When considering electricity consumption, T-100H_2 at OH-2190 and Storage-10 days has the maximum energy consumption (123,120 MWh/yr) due the extra power requirement for compression up to 500 bar which requires 6 kWhr/kg of power to compress H_2 at 500 bar. Conversely, all P-102 at OH-1010 and Storage-10 days have minimum energy consumption (1,718 MWh/yr) due to its no power requirement for compressor. These results lead to significant power consumption for compressor which is for H_2 transportation by means of tube trailer.

Figure 18 | Annual Electricity Consumption at Different OH and Storage Capacity



illustrates the Levelized Cost of Hydrogen (LCOH) for nine cases at OH-2190 & 1, 010 with 10 & 5 days of storage capacity for Case A, where CAD 83.06/MWh and CAD 45/MWh are the electricity purchase and selling price respectively. The W-10H_2 case at OH-2190 with 5 days of storage exhibits the lowest LCOH at CAD 7.10/kg, while W-10H_2 at OH-2190 with 10 days of storage has an LCOH of CAD 7.83/kg. Here, storage duration and operating hours significantly impacts the LCOH. Conversely, T-100H_2 at OH-1010 with 10 days of storage records the highest LCOH at CAD 47.88/kg. This is because the tube trailer transportation includes additionally the compression cost of hydrogen along with its associated storage tank cost at high pressure. The pipeline installation cost increases gradually from 10H_2 to 100H_2 for all cases. Consequently, pipeline cases demonstrate a lower LCOH than tube trailer cases. Ultimately, the blending ratio emerges as a crucial factor influencing the LCOH, along with the transportation mode either tube trailer or pipeline installation, which also significantly affects costs. Among the wired, tube trailer, and pipeline categories, the Levelized Cost of Hydrogen (LCOH) is lowest for the wired option based on their respective blending criteria. More specifically, among the W-10H_2, W-20H_2, and W-100H_2 options, W-10H_2 exhibits the lowest LCOH at OH-2190 with 5 days of storage.

Figure 19 illustrates the Levelized Cost of Hydrogen (LCOH) for nine cases at OH-2190 & 1, 010 with 10 & 5 days of storage capacity for Case A, where CAD 83.06/MWh and CAD 45/MWh are the electricity purchase and selling price respectively. The W-10H_2 case at OH-2190 with 5 days of storage exhibits the lowest LCOH at CAD 7.10/kg, while W-10H_2 at OH-2190 with 10 days of storage has an LCOH of CAD 7.83/kg. Here, storage duration and operating hours significantly impacts the LCOH. Conversely, T-100H_2 at OH-1010 with 10 days of storage records the highest LCOH at CAD 47.88/kg. This is because the tube trailer transportation includes additionally the compression cost of hydrogen along with its associated storage tank cost at high pressure. The pipeline installation cost increases gradually from

$10H_2$ to $100H_2$ for all cases. Consequently, pipeline cases demonstrate a lower LCOH than tube trailer cases. Ultimately, the blending ratio emerges as a crucial factor influencing the LCOH, along with the transportation mode either tube trailer or pipeline installation, which also significantly affects costs. Among the wired, tube trailer, and pipeline categories, the Levelized Cost of Hydrogen (LCOH) is lowest for the wired option based on their respective blending criteria. More specifically, among the W-$10H_2$, W-$20H_2$, and W-$100H_2$ options, W-$10H_2$ exhibits the lowest LCOH at OH-2190 with 5 days of storage.

Figure 19 **|** LCOH (CAD/kg) for All Cases **[Case A: Purchase = CAD 83.06/MWh, Sale = CAD 45/MWh]**

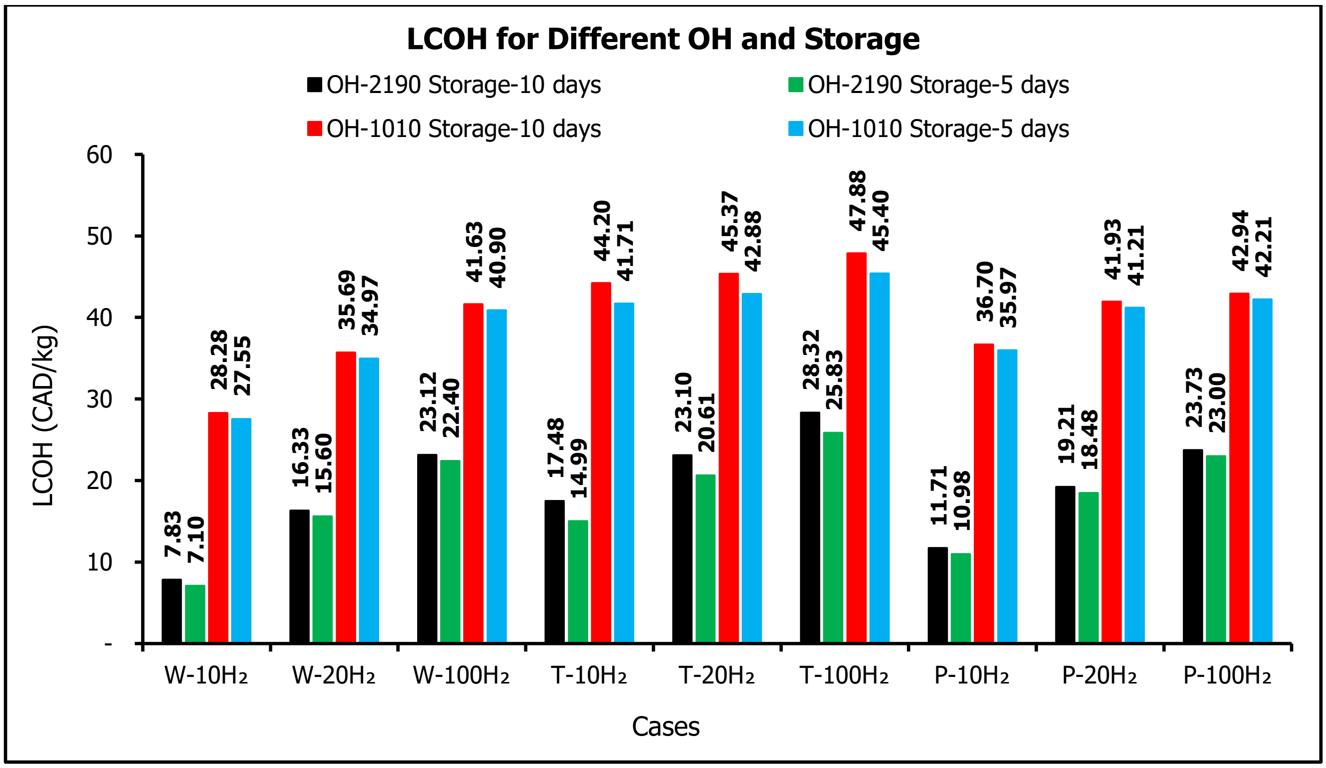


Figure 20 illustrates the Levelized Cost of Hydrogen (LCOH) for Case B, where the purchase price is CAD 33.07/MWh and the selling price is CAD 45/MWh. In this scenario, the purchase price is notably lower than that of Case A. As a result, the output for W-$10H_2$ at OH-2190 with 5 days of storage is CAD 4.60/kg. Additionally, the maximum LCOH is recorded for T-$100H_2$, reaching CAD 45.08/kg.

Figure 20 | LCOH (CAD/kg) for All Cases **[Case B: Purchase = CAD 33.07/MWh, Sale = CAD 45/MWh]**

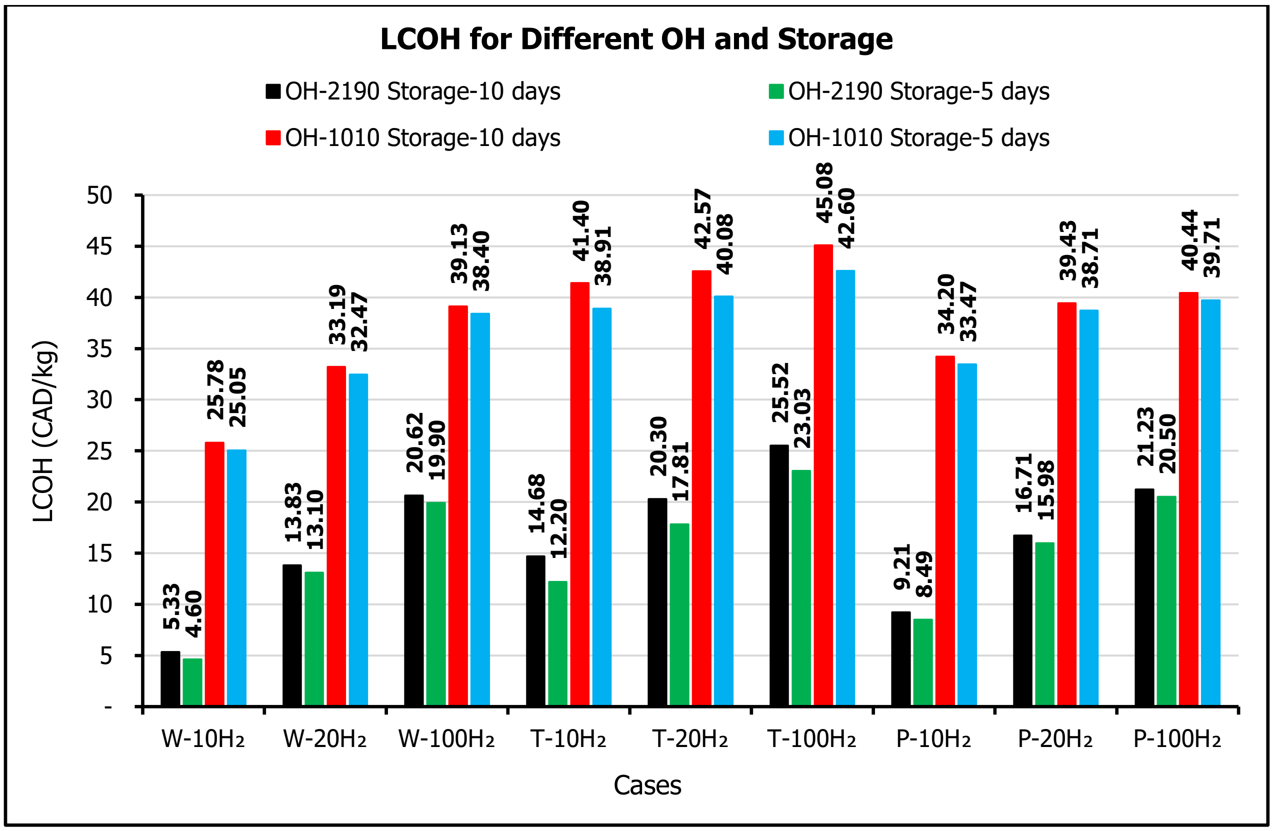
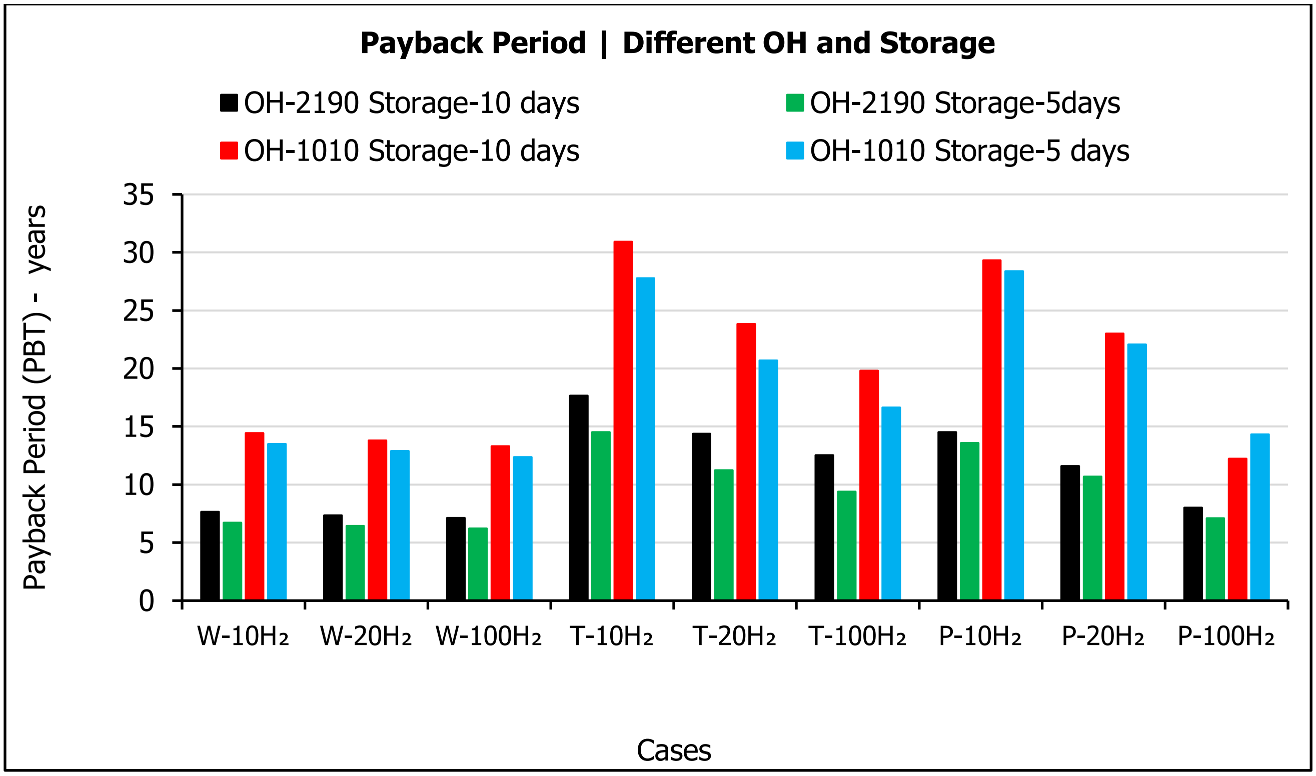


Figure 21 shows the payback period (PBT) for all nine cases. The results indicate that W-100H_2 at OH-2190 with 5 days of storage has the shortest payback period of 6.205 years, attributed to its maximum annual operating hours and suitable storage capacity. Both operating hours and storage capacity significantly influence annual cash flow and initial investment costs. In contrast, T-10H_2 at OH-1010 with 10 days of storage exhibits the longest payback period of 30.93 years, suggesting it is not feasible based on this metric, primarily due to the substantial initial investment required for tube trailer cost, compressor cost, and storage tank cost to the lower cash flow from the 10H2 blending ratio. The shorter PBT for P-100H_2 is a result of its high hydrogen demand. Among the tube trailer cases, T-100H_2 has a lower PBT compared to T-10H_2 and T-20H_2, highlighting the critical role of annual cash flow driven by high hydrogen demand. Overall, W-100H_2 incurs the lowest initial investment while generating the highest annual cash flow.

Figure 21 **|** Payback Period (PBT) for all Nine Cases



The W-100H2 case at OH-2190 with a 5-day storage duration exhibits the highest IRR at 15.16%. However, as indicated in the figure, most scenarios present negative IRR values, suggesting they are not viable options. This implies that the cash inflows are insufficient to cover the initial investment and associated costs over time, considering a discount rate of 6%. Specifically, cases such as T-10H_2, T-20H_2, T-100H_2, P-10H_2, and P-20H_2 show significantly negative IRR values, primarily due to extremely high initial investment costs paired with very low cash inflows. These negative values further indicate that these cases are not financially viable options in terms of IRR.

Figure 22 shows the IRR of various cases. The W-100H_2 case at OH-2190 with a 5-day storage duration exhibits the highest IRR at 15.16%. However, as indicated in the figure, most scenarios present negative IRR values, suggesting they are not viable options. This implies that the cash inflows are insufficient to cover the initial investment and associated costs over time, considering a discount rate of 6%. Specifically, cases such as T-10H_2, T-20H_2, T-100H_2, P-10H_2, and P-20H_2 show significantly negative IRR values, primarily due to extremely high initial investment costs paired with very low cash inflows. These negative values further indicate that these cases are not financially viable options in terms of IRR.

Figure 22 **|** Internal Rate of Return (IRR) for all Nine Cases

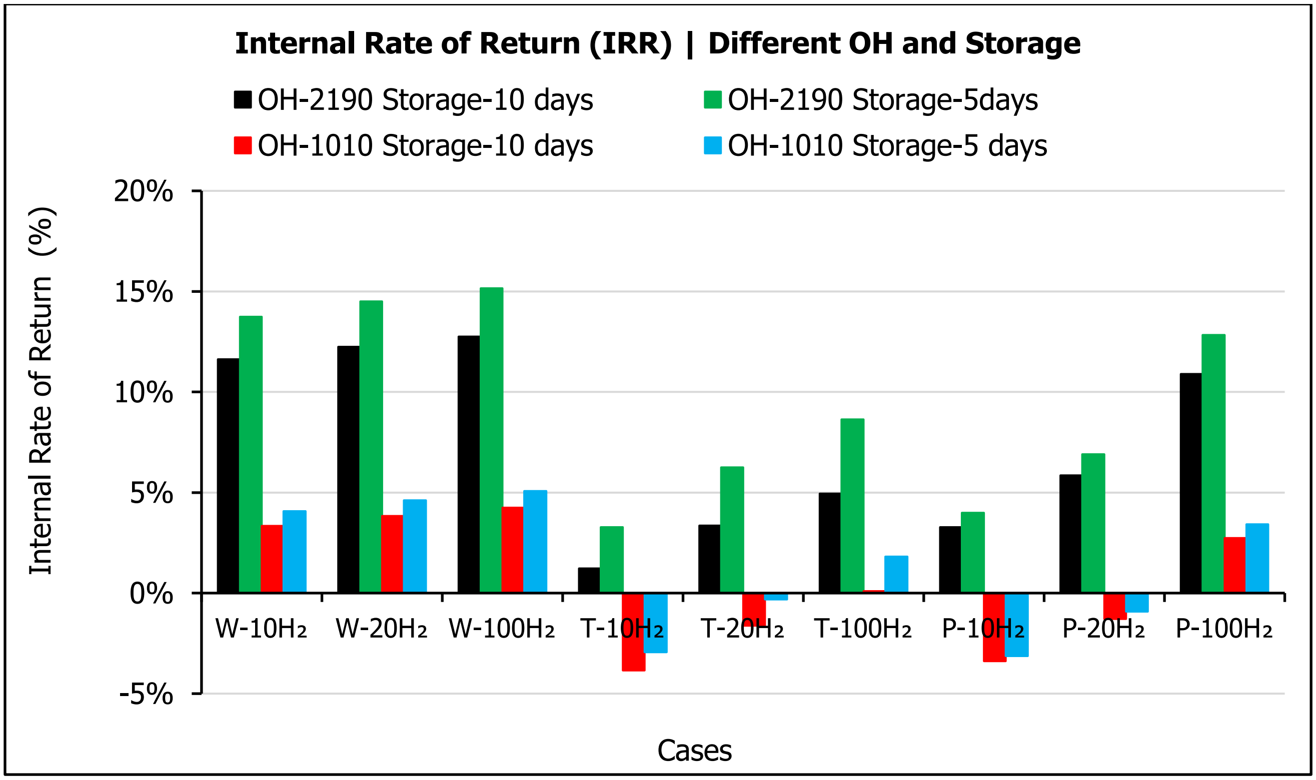
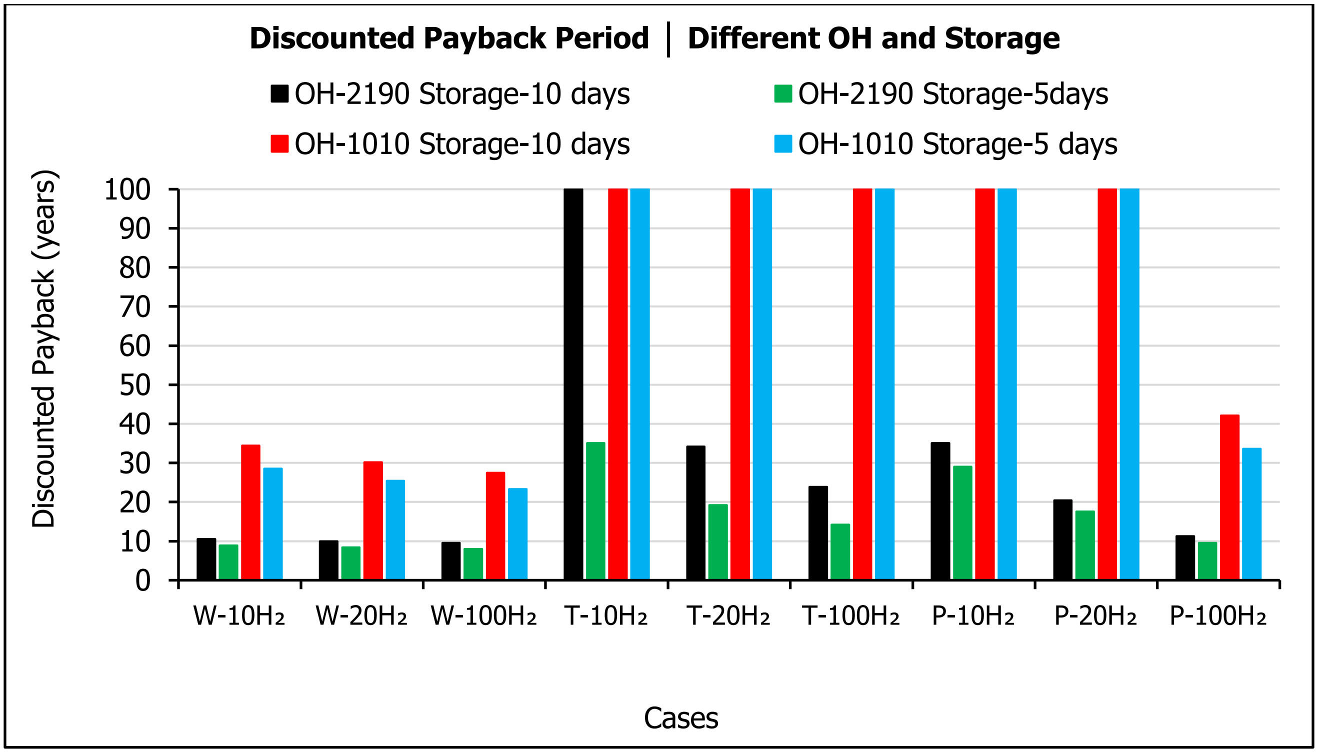


Figure 23 presents the discounted payback period (DPB) for all nine cases across various operating hours and storage durations. Cases that reach the maximum horizontal line indicate infeasibility, meaning the investments in these scenarios will never be recouped at a discount rate of 6%. The W-100H$_2$ case at OH-2190 with a 5-day storage duration shows the minimum DPB of 7.993 years, highlighting that increased operating hours, reduced storage duration, and maximum hydrogen blending are key factors for achieving a lower discounted payback period. Notably, each case except the wired option has at least one infeasible option. Additionally, W-10H$_2$ and P-100H$_2$ with OH-1010 and 10 days of Storage have more than 30 years of DPB due to their excessively high investments relative to low cash inflows.

Figure 23 | DPB at Different OH and Storage



9.2 Sensitivity Analysis

Table 12 shows the assumption for the variables in the sensitivity analysis. For this analysis the variables considered are H_2 storage capacity in terms of days according to the demand of H_2 for running CHP engines and based on the operating hour of those engines. The other variables are annual operating hour, electricity purchasing rate, and discount rate.

Table 12 | Assumption for the Variables in the Sensitivity Analysis

Variables	Minimum Value	Maximum Value	Units
H_2 storage capacity	1	10	days
Annual operating hour (OH)	1,000	2,200	hr/yr
Electricity Price	0	90	CAD/MWh
Discount Rate	2%	20%	%
Electrolyzer Price	650	2,000	CAD/kW

Figure 24 shows the LCOH sensitivity on storage in days at OH-2190. The result shows that the case W-10H_2 at the storage capacity of one day has the LCOH of CAD 4.54/kg which is the lowest value. On the other hand, the case T-100H_2 has the maximum LCOH which is CAD 28.24/kg. It indicates that the storage capacity is an important parameter to increase the CAPEX cost which ultimately increases the LCOH. For all the cases LCOH is increasing with the increase of storage period or storage capacity.

Figure 24 **|** LCOH Sensitivity to H_2 Storage

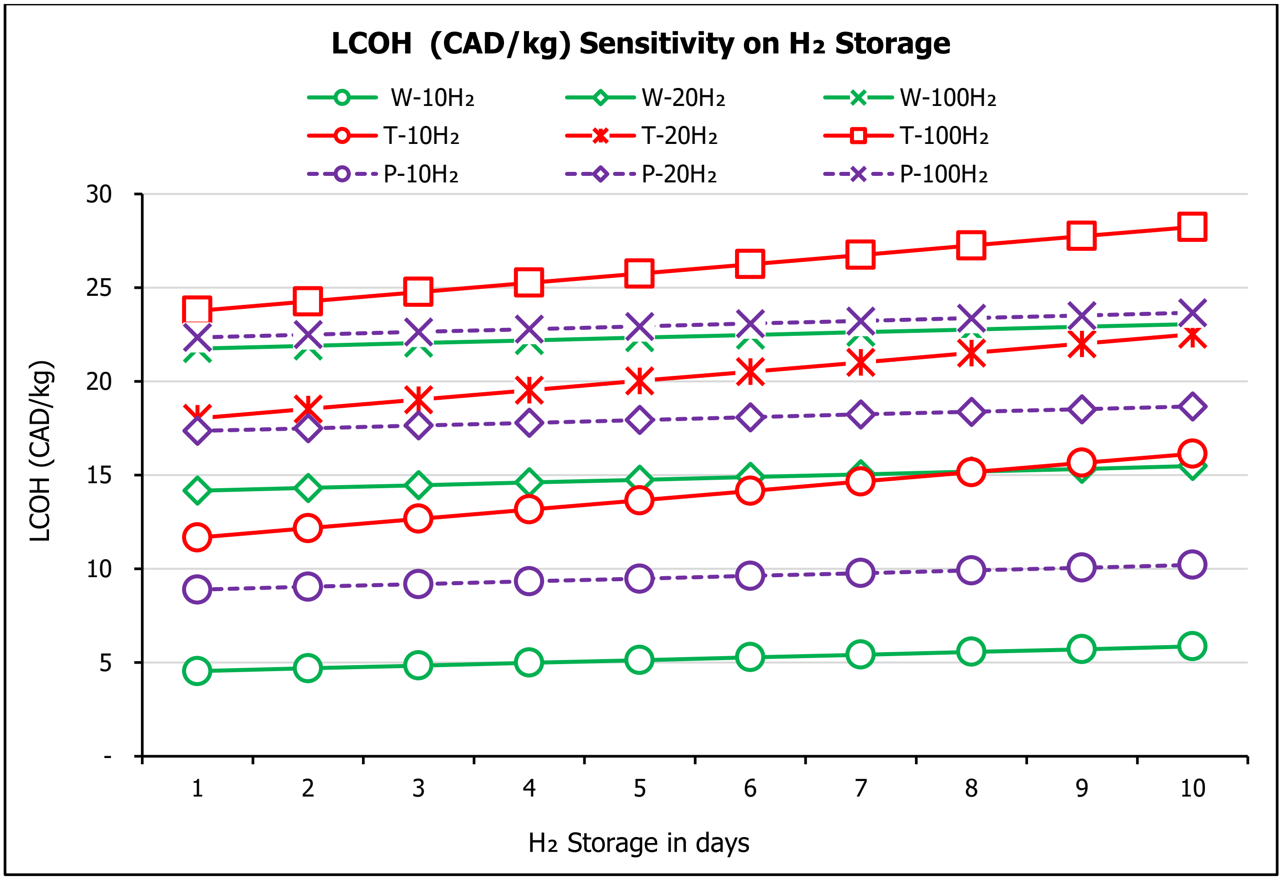
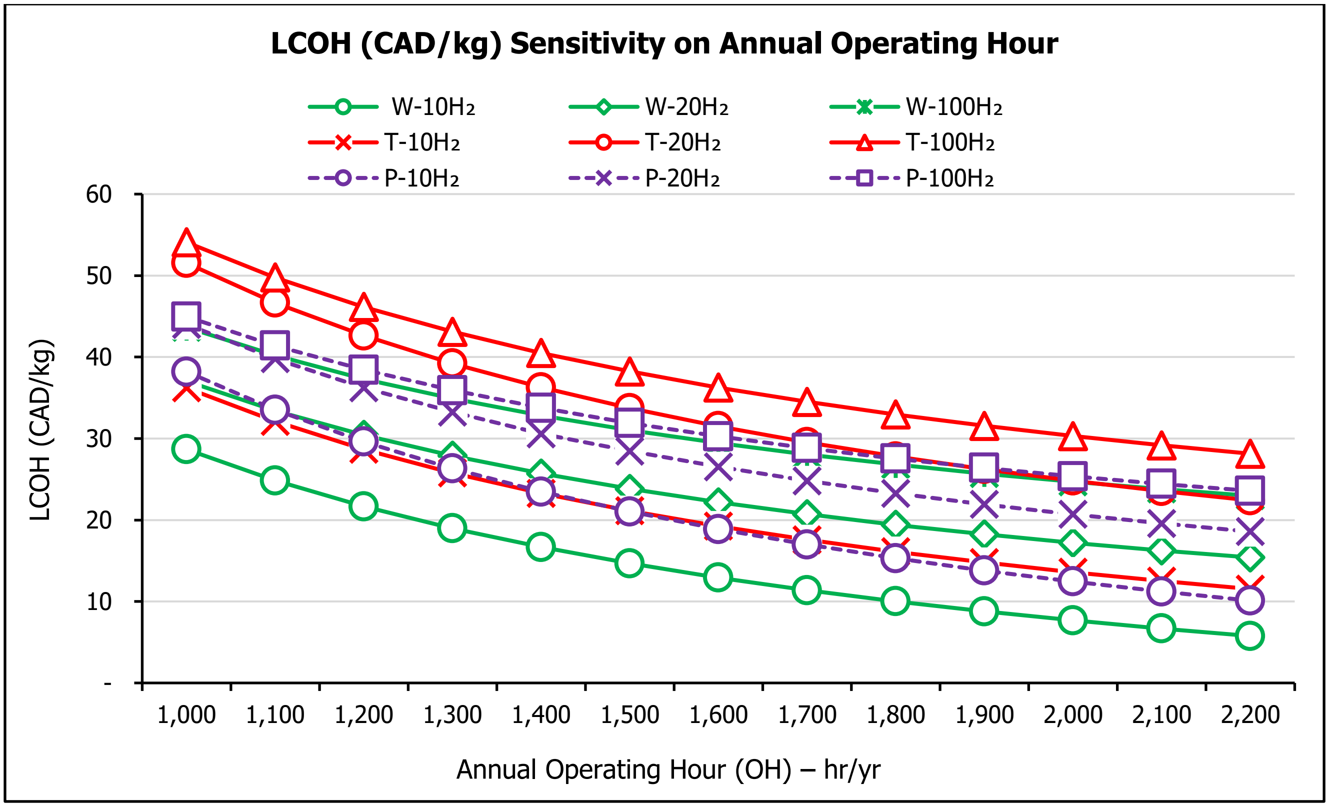


Figure 25 shows the LCOH Sensitivity on Annual Operating Hour at 10 days of storage capacity. W-10H_2 at OH-2200 has the LCOH of CAD 5.76/kg which is minimum and T-100H_2 at OH-1000 has the highest LCOH which is CAD 54.08/kg. It indicates that the higher the operating hour of CHP engines, the higher the requirement of H_2, and the higher the annual hydrogen production to minimize the LCOH. For all the cases LCOH decreased by increasing the operating hour of CHP engines.

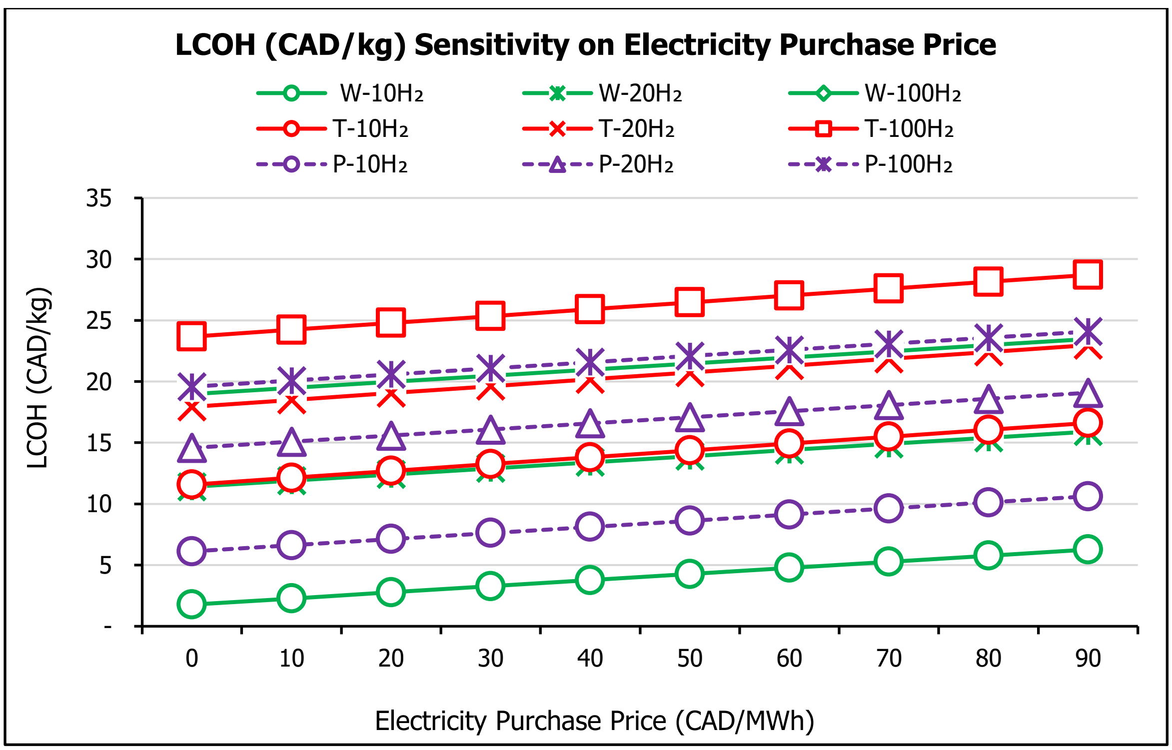
Figure 25 **|** LCOH Sensitivity to Annual Operating Hours



illustrates the sensitivity of levelized cost of hydrogen (LCOH) to electricity prices at OH-2190 with a 10-day storage duration. The W-10H_2 scenario exhibits the lowest LCOH at an electricity price of CAD 0/MWh, while the T-100H_2 scenario has the highest LCOH at CAD 28.71/kg when the electricity price reaches CAD 90/MWh. This indicates that electricity pricing plays a crucial role in determining LCOH, as a substantial amount of electricity is consumed by the electrolyzer and compressor, sourced from the wind farm, which significantly contributes to overall electricity purchase costs.

Figure 26 illustrates the sensitivity of levelized cost of hydrogen (LCOH) to electricity prices at OH-2190 with a 10-day storage duration. The W-10H_2 scenario exhibits the lowest LCOH at an electricity price of CAD 0/MWh, while the T-100H_2 scenario has the highest LCOH at CAD 28.71/kg when the electricity price reaches CAD 90/MWh. This indicates that electricity pricing plays a crucial role in determining LCOH, as a substantial amount of electricity is consumed by the electrolyzer and compressor, sourced from the wind farm, which significantly contributes to overall electricity purchase costs.

Figure 26 **|** LCOH Sensitivity to Electricity Price



shows the LCOH Sensitivity on Discount Rate at OH-2190 and Storage-10 days. The W-10H_2 case at 2% discount rate has lowest value of LCOH (CAD 4.38/kg). On the other hand, T-100H_2 at 20% discount rate has the maximum LCOH (CAD 39.14/kg). As a higher discount rate reduces the present value of future cash inflows from hydrogen production, making them less valuable in today's terms, the future revenues are discounted more heavily, which can lead to a higher overall cost of hydrogen since the profitability of the project is diminished. That's why it clearly indicates that the higher the discount rate, the higher the LCOH.

Figure 27 shows the LCOH Sensitivity on Discount Rate at OH-2190 and Storage-10 days. The W-10H_2 case at 2% discount rate has lowest value of LCOH (CAD 4.38/kg). On the other hand, T-100H_2 at 20% discount rate has the maximum LCOH (CAD 39.14/kg). As a higher discount rate reduces the present value of future cash inflows from hydrogen production, making them less valuable in today's terms, the future revenues are discounted more heavily, which can lead to a higher overall cost of hydrogen since the profitability of the project is diminished. That's why it clearly indicates that the higher the discount rate, the higher the LCOH.

Figure 27 | LCOH Sensitivity to Discount Rate

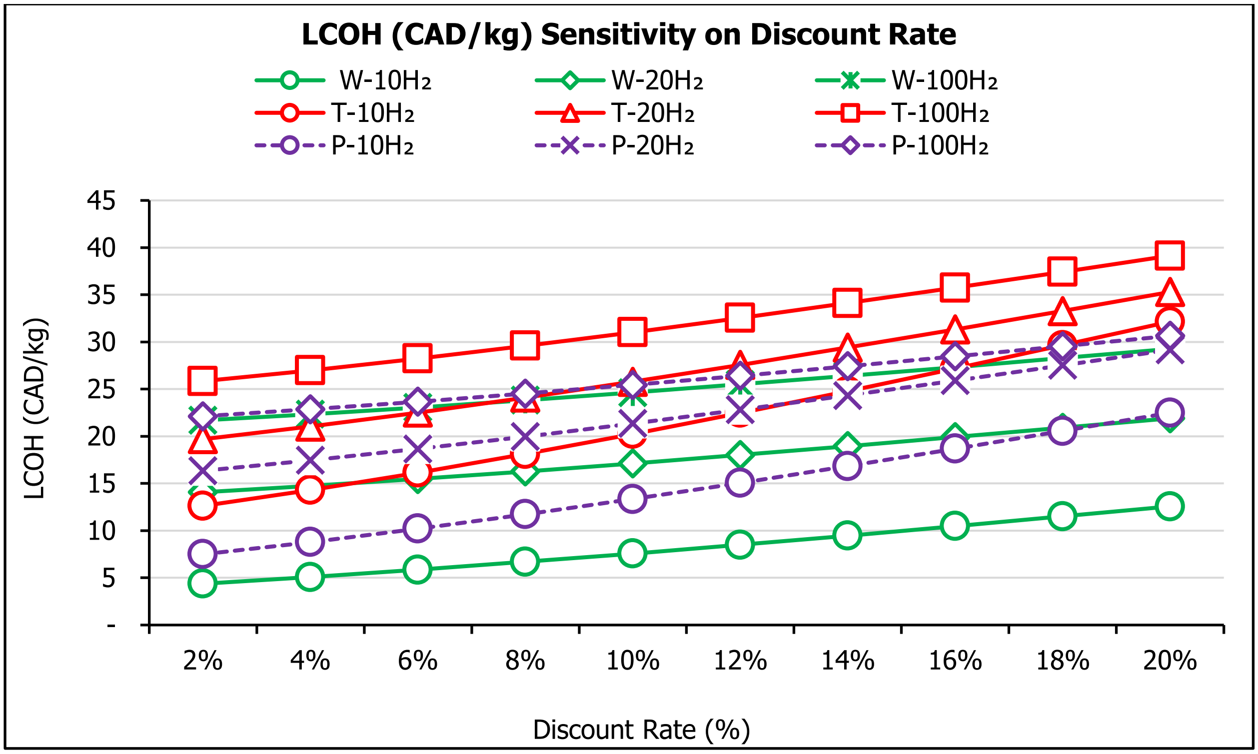
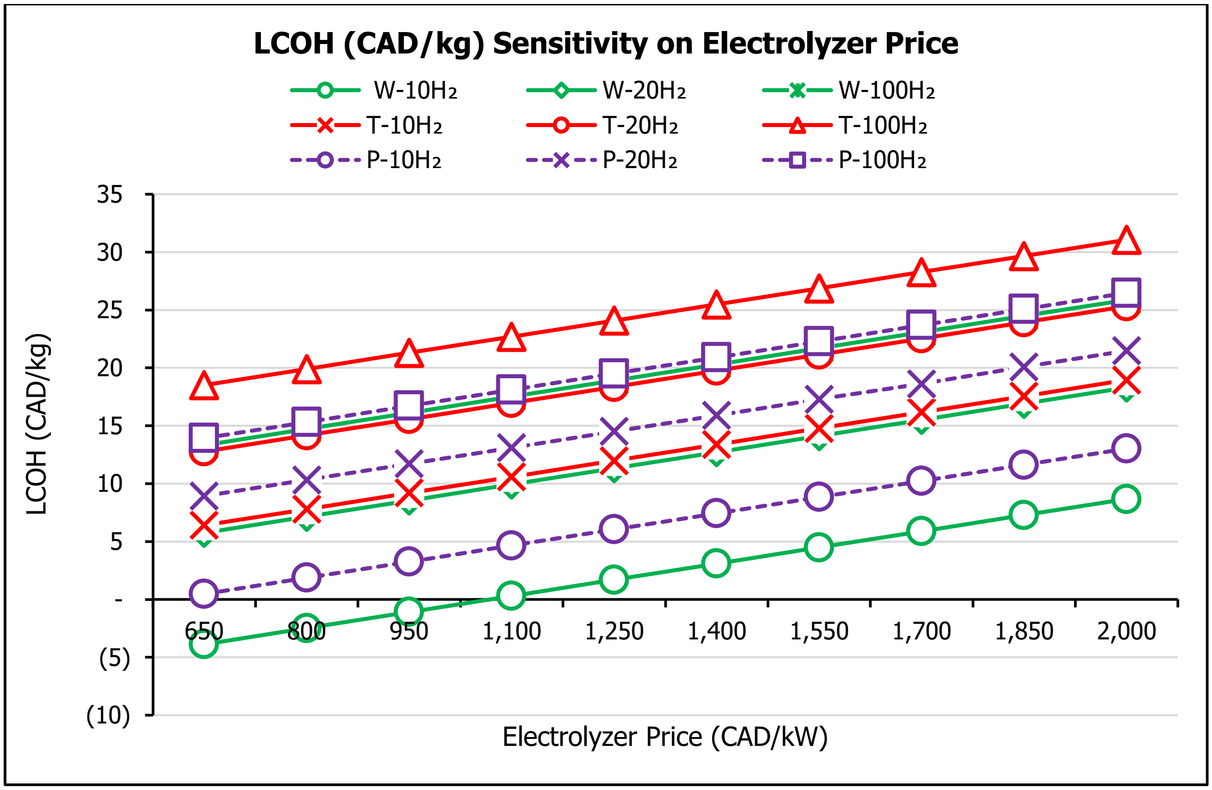


Figure 28 shows the sensitivity of the levelized cost of hydrogen (LCOH) to electrolyzer prices at OH-2190 and a storage duration of 10 days. Franco et al. [2] assessed this sensitivity with electrolyzer prices ranging from CAD 320 to CAD 1,700/kW. Meanwhile, Lucas et al. [6] reported electrolyzer prices between CAD 1,400 and CAD 2,000 per kW. In this study, we explored electrolyzer prices from CAD 650 to CAD 2,000/kW, reflecting literature suggestions that electrolyzer prices are expected to decline due to ongoing research and technological advancements. The results indicate that in the W-10H_2 scenario, at electrolyzer prices of CAD 650, 800, and 900, the LCOH is negative, signifying that hydrogen production is highly profitable, yielding more revenue than the associated costs. Overall, the LCOH increases as the electrolyzer price rises.

Figure 28 **|** LCOH Sensitivity to Electrolyzer Price



10. Discussion (including potential impacts on the Hydrogen Market)

This Discussion Section and the Economic/Technical Impact/Risk Sections are concise, given that much of this content is covered with more appropriate context in the Sections that lead up to this one. However, it is important here to note while some outcomes of this study may seem intuitive to the initiated (trucking hydrogen is prohibitively expensive; building short, small-capacity pipelines are economically ill-feasible, etc.) – there is strategic value in transparently identifying and quantifying the economic gaps that produce these outcomes. This study demonstrates that even without explicit economic incentives, there are business cases that illustrate the potential for CAD 7.1/kg of green hydrogen. This was enabled by minimizing hydrogen transport and producing it at point of use. Based on the comprehensive literature survey of the jurisdictional scan, this represents a very competitive unit price. Blending hydrogen into existing fuel streams like natural gas are very attractive as a transition starting point. Many existing NG CHP gensets are capable of accepting up to 20% blends of H_2 which can be a critical enabler to market entry for greenhouse growers and/or NG CHP operators at large. Beyond this, it should be emphasized that this study was intentionally built on existing assets and available off the shelf (OTS) technologies – specifically we used actual operating assets where possible with data supplied by our industrial partners in wind, hydrogen production, and greenhouse operation. All modeling was done without the consideration of economic incentives. This approach managed pricing and performance uncertainties as we worked from operational data sets, but also leans towards very conservative modeling. The equipment selection has significant room for optimization (choice of electrolyzer size/number, storage type/size, transient operation considerations). The rigor of this fundamental study will serve as a foundation for an optimized, more temporally resolved transient model.

11. Economic/Technical Impact, and Risk Assessments

There is additional novelty in this business case analysis that considers the hybrid performance role of a transmission connected wind farm also acting as a local distribution asset. This creates a space where the IESO contracted wind farm could conceivably honor transmission commitments and when appropriate, produce electricity for a local market (immediate delivery or the driving of an electrolyzer). There is obvious risk in this proposed plan given the lack of regulatory support for such an arrangement. This performance architecture would require the wind farm to act essentially as its own energy utility. Beyond this there must be sufficient capacity and flexibility for the wind farm to honour its commitments. The rigidity of existing power purchase agreements (PPAs) and the province's current strong demand for electricity suggests that there would be little available in way of surplus and/or curtailed wind to supply to a local market. This was not the case several years ago. Finally, there is a fundamental inefficiency in using wind supplied electricity to produce hydrogen to run an engine to again produce electricity. The value of the proposition does begin to improve when the source electricity to produce the hydrogen and the mechanism to store it is cheap and abundant.

12. Lessons Learned

1. Multi-Agency, Multidisciplinary Agency Projects Like HIGH Energy Are Challenged Most by Time. The greatest strength and value proposition of HIGH Energy may be in the composition of its team. Experts from Kruger Energy Wind Farms, Enbridge Markham P2G Hydrogen Blending and Generation, Ontario Greenhouse Vegetable Growers, Under Sun Acres Farms, and the Turbulence and Energy Lab at the University of Windsor converged to build credible data-driven technoeconomic studies for green hydrogen integration into Ontario greenhouses. This enthused coalition also performed an investigation into relevant regulatory and emerging hydrogen market opportunities. However, even when partners are willing, the multiple control layers around data security and simple personnel scheduling for online / in-person meetings and site visits make obstacles for efficient collaboration. Less than 12 months to reach the aspirational milestones posted herein proved to be very challenging. This project, like most, would even further improve its value with more time.

2. You Must Do The Math - Transparently. One of the largest challenges facing the successful proliferation of transition enabling fuels like hydrogen, is the lack of accessible, credible, data-driven accounts prospective application. Subsequently, anecdotal judgements and quips from purported experts can often mislead interested stakeholders and increase uncertainties that discourage investment. Providing credible, data driven calculations that are clear to follow can help to manage risk around hydrogen development. This is particularly valuable when the economics show poorly. Approachable, sufficiently granular calculations can reveal causation and point to the issues that need attention/improvement/technical evolution to improve the solution. For instance, it is fine to suggest that it's obvious that trucking hydrogen is economically impractical in most situations. However, there is merit in its technoeconomic analysis to illustrate the cost drivers and to understand what is required as early adopters "trial" hydrogen blended into their process.

13. Next Steps

1. New Funding. The partners are pursuing additional funding to expand the study into a Phase 2 that will leverage the lessons from Phase 1 to focus on the most promising business cases revealed through this work. Significant relationship building is another outcome of this work, these relationships will be the platform for a potential joint venture between the HIGH Energy partners.

2. Following Future Recommendations in Section 14. Phase 2 will embrace and pursue the Future Recommendations from the following Section 14.

14. Conclusion and Recommendations

Conclusion

Based on the analysis of green hydrogen technology integration into a commercial greenhouse in Ontario, Canada, it was found that using green hydrogen as a replacement for natural gas in CHP engines shows promise as a potentially feasible and sustainable solution. The study rigorously evaluated nine different scenarios and found that Scenario W-10H_2 with a 5-day storage capacity and OH-2190 was the most viable option in terms of LCOH with the lowest LCOH of CAD 7.1/kg. However, in terms of PBT, IRR, and DPB; W-100H_2 with OH-2190 and 5 days storage capacity is the most attractive, where PBT, IRR and DPB for W-100H_2 are 6.2 years, 15.16% and 7.99 years respectively. Conversely, new pipeline installation or transportation via tube trailer over a distance of 26 km is not a feasible option according to the results. Subsequently, the most viable option is to install the electrolyzer and storage tank with an optimum capacity, and the blending station at the greenhouse site to fuel CHP engines. This research provides valuable insights into the feasibility of adopting green hydrogen technology for advancing energy sustainability in the context of a commercial greenhouse.

Future Recommendations

1. Economic penalties for CO_2 emissions could be considered in LCOH calculations. For greenhouses in particular, CO_2 is a consumable input to the growing operation. That said, the use of CO_2 still leads to emissions. The quantification of these emissions is an area of active research. Subsequently, to minimize modeling uncertainties these penalties were not included in the costing calculations. It is likely a conservative assumption that the inclusion of carbon emission penalties would only serve to reduce LCOH for all cases considered. However, these savings are complicated in the Greenhouse Sector in that a reduction in fuel-supplied CO_2 must be replaced by vendor supplied CO2 which in Greenhouse-specific cases – serves to increase the LCOH.
2. Oxygen is a byproduct of the electrolytic production of hydrogen. Sales of green oxygen to convenient markets would increase the overall economic viability of the operation.
3. The hydrogen storage capacity could be optimized with a higher temporal resolution consideration of process transients from the wind farm and CHP operations.
4. Blending of H_2 with natural gas should be optimized to determine the most viable blending option for CHP engines. The blend ratios studied herein were chosen based on the literature and recommendations from our industrial partners. It could be theorized that an optimum blend may be determined that reduces CO_2 production on the downstream side of the CHP such that it is just sufficient to furnish the photosynthetic demands of the crops and minimizes fugitive emissions.
5. For hydrogen-primary CHP engines, heat energy output requires careful calculation as it is the most important factor to maintain an ideal temperature in the greenhouse.

Nomenclature

AE	Alkaline Electrolyzer
C	Cost
C_0	Initial Investment or CAPEX Cost
CAPEX	Capital Expenditure
CF_a	Annual Cash Flow
CF_t	Cash Flow in time t
CHP	Combined Heat and Power
D	Diameter of Pipeline
DPB	Discounted Payback Period
g	Gravity
hr	Hour
HWB	Hot Water Boiler
IRR	Internal Rate of Return
KEC	Kruger Energy at Chatham
KEPA	Kruger Energy at Port Alma
KWh	Kilo Watt Hour
L	Length of Pipeline
LCOH	Levelized Cost of Hydrogen
LHV	Lower Heating Value
M	Million
$\dot{m}$	Mass Flow Rate of H_2 in kg/s
M_{H_2}	Hydrogen production in kg/yr
MJ	Mega Joule
MW	Mega Watt
NG	Natural Gas
NPV	Net Present Value
O&M	Operation & Maintenance
P_1	Inlet Pressure

P_2	Outlet Pressure
P	Pipeline
PBT	Payback Period
PEM	Proton Exchange Membrane
r	Discount Rate
R	Gas Constant
SOE	Solid Oxide Electrolyzer
t	Specified Time in year
T	Temperature, Maximum Time in Year
T	Trucking/Tube Trailer
W	Wired/Existing Grid
yr	Year
Z	Compressibility Factor

Subscripts and Superscripts

blend	Blending
comp	Compressor
el	Electrolyzer
elec pur	Electricity Purchase
pipe	Pipeline Installation
stack repl	Stack Replacement
tank	H_2 Storage Tank
trail	Tube Trailer

Greek Letters

λ	Friction Coefficient
Δh	Elevation Level Difference

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