

Article

Blue Hydrogen Cogeneration as an Energy Vector for a Sustainable Future: A Case for Alberta, Canada

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Abstract

Hydrogen is a promising clean energy vector capable of decarbonizing future energy systems. This study explores blue hydrogen production via a modified autothermal reforming process, integrated with oxy-fuel combustion and carbon capture technologies. The process achieves approximately 99.8% carbon dioxide capture while co-generating electricity, improving both environmental and economic performance. A detailed techno-economic analysis for Alberta, Canada, shows that hydrogen can be produced at a competitive cost of \$1.70 per kilogram, depending on natural gas supply pressure, with CO₂ emissions of just 3.82 kg-CO₂/kg-H₂, meeting stringent international low-carbon thresholds. Key parameters like natural gas supply pressure, oxygen-to-methane ratio, and turbine pressure ratio were optimized for flexibility, efficiency, and cost-effectiveness. Sensitivity analysis identified financial, policy, and grid decarbonization factors as key drivers of production costs. Compared to other methods, this process stands out for its superior environmental and economic outcomes, particularly in regions with ample natural gas and carbon capture infrastructure. The study underscores the importance of process innovation in advancing sustainable blue hydrogen.

Keywords: blue hydrogen; autothermal reforming; oxy-fuel combustion; carbon capture; cogeneration; techno-economic analysis

1. Introduction

To transition from an extractive to a sustainable energy system, the focus shifts from relying heavily on a few dominant energy sources to adopting a diverse mix of locally available energy resources. This system needs energy vectors that allow the transfer of energy across space and time, making it available for use far from its original source [1]. Hydrogen is considered a promising clean energy vector that could help reduce reliance on fossil fuels. Although it is the most abundant element in the universe, hydrogen is hardly in a usable form to be directly extracted from underground for clean energy purposes. To serve as a decarbonized energy vector, hydrogen must be sustainably produced from readily available compounds that contain it in large quantities. Two such molecules are water (H₂O) and methane (CH₄). Current commercial methods for hydrogen production include water electrolysis, which produces hydrogen and oxygen, and methane reforming (via steam, autothermal, or dry reforming), which generates hydrogen and carbon dioxide. The classification of hydrogen currently depends on its production source. Blue hydrogen refers



Academic Editor: Tianqi Wang

Received: 27 December 2025

Revised: 28 January 2026

Accepted: 11 February 2026

Published: 24 February 2026

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to hydrogen produced from fossil fuels with carbon dioxide emissions captured. Green hydrogen is generated using electrolysis powered by clean, renewable energy sources. Grey hydrogen is produced from steam methane reforming without capturing the carbon dioxide emissions generated.

Despite several past setbacks, many countries, such as Canada, Germany, and Japan, are now committing to hydrogen as a key part of their future energy plans. These nations have launched national hydrogen strategies to drive the development of hydrogen as a clean energy vector. These strategies reflect a growing understanding that reducing and eventually eliminating anthropogenic greenhouse gas emissions is essential for preserving life as we know it. Hydrogen is seen as one of the viable alternative energy vectors, if the right policies, incentives, and infrastructure are put in place for its production, distribution, and end-use [2,3].

The production of hydrogen from natural gas in this paper is based on autothermal reforming, where steam, oxygen, and natural gas are mixed. Part of the natural gas is combusted with the oxygen, providing heat for the steam and methane to be reformed into hydrogen and carbon oxides. In its simplest form, the hydrogen is separated from the exhaust stream from this process, and the balance is vented to the atmosphere. To improve the environmental characteristics of the conventional steam methane reforming process, this paper focuses on a modified autothermal process to produce hydrogen in a closed-loop system which enables all the produced CO₂ to be captured from a single point in the process. The combination of emerging technologies in the production of hydrogen makes this process unique, as neither oxy-fuel combustion nor autothermal reforming is currently employed commercially in the production of hydrogen. Furthermore, the process incorporates a cogeneration sub-system to capture some of the waste heat energy and generate electricity.

The objective of this study is to conduct a comprehensive assessment of an alternative blue hydrogen system, determining environmental impacts, as well as techno-economic viability of the proposed process design.

2. Literature Review

Hydrogen holds great potential as a clean energy vector, especially when combined with carbon capture and storage (CCS). Extensive research has been conducted on hydrogen production with CCS, focusing on various aspects of the production value chain. Antonini et al. modelled hydrogen production from natural gas and biomethane using CCS [4]. They found that, under ideal conditions, hydrogen can be produced from natural gas with environmental impacts similar to those of hydrogen produced from renewable electricity. Notably, using biomethane in the process can lead to net negative emissions since the solids digestate can retain additional carbon in the soil when used as fertilizer. Bui et al. [5] reviewed state-of-the-art CCS technologies and noted that while the cost of implementing these technologies is a barrier, other factors, such as political commitment and the industry's preference to maintain the status quo of unabated fossil fuel use, are also limiting CCS adoption. Both Oni et al. [6] and Lewis et al. [7] showed that autothermal reforming (ATR) with CCS is the economically preferred technology for blue hydrogen production when implemented at scale. Okunlola et al. [8] demonstrated that ATR with CCS is economically competitive with other low-carbon hydrogen production technologies for the Japanese and Asian markets, based on the costs, technical readiness, and scalability of the production and transport of hydrogen from Alberta to various global markets. Emerging technologies, such as sorption-enhanced steam methane reforming [9] and integration of concentrated solar for steam generation to replace fossil fuel combustion in the steam methane reforming process [10], also show promise for blue hydrogen production.

Despite advancements in low-carbon hydrogen production technologies, significant barriers remain for its widespread adoption. According to Yue et al. [2] and Rasul et al. [3], the main obstacles to integrating hydrogen into the energy mix include high costs, efficiency limitations, scalability issues, and insufficient policy support. Barriers to large-scale production identified by Agyekum [11] and Litvenko [12] are the absence of a value chain for low-carbon hydrogen, the lack of international standards, and the hazards of hydrogen's flammability, which require strict risk management. Yu et al. [13] also discuss the challenges associated with blue hydrogen as a transitional solution, noting the high costs of CCS and low capture efficiency linked to the risk of CO₂ leakage.

The development of a hydrogen economy is still in its early stages, with wide disparities in how countries are approaching the adoption. Noussan et al. [14] review the hydrogen strategies of leading countries, showing that while Germany is focused on green hydrogen, countries like Japan and Canada are pursuing a broader low-carbon hydrogen approach without strict limitations on hydrogen colour. Jensterle et al. [15] dig deep into the role to be played by both green and blue hydrogen, while others [16,17] question whether blue hydrogen and CCS provide any benefits at all. In *How Green is Blue Hydrogen?*, Howarth and Jacobson [17] argue that “blue hydrogen has large climatic consequences”, emphasizing its ineffectiveness in reducing emissions when used for heating purposes. Hydrogen's potential to decarbonize relies on its efficient use, such as in fuel cells that convert 50–60% of hydrogen's energy into electricity. Japan, for instance, has integrated combined heat and power systems into its hydrogen strategy [18], with over 250,000 units deployed to produce distributed power and meet heating needs in buildings and industry [15]. Howarth and Jacobson's assessment of blue hydrogen as unsuitable for decarbonization largely overlooks these benefits when used in fuel cells, instead focusing on low-efficiency heating applications, leading them to conclude that “blue hydrogen cannot be considered green.” Vogele [16] expands this critique, suggesting that the “future of CCS is gloomy” in terms of ecological impact and societal perception, often leading to the political and legal hurdles that make it financially challenging.

The present study focuses on the Canadian context, highlighting the potential for regional contributions to hydrogen development. Canada's national hydrogen strategy [19] is focused on creating a low-carbon hydrogen economy by using regional resources and implementing carbon pricing policies to cut emissions. Provinces like Alberta [20], British Columbia [21], Ontario [22], and Quebec [23] each have crafted strategies tailored to their unique strengths. In British Columbia, research [24,25] indicates strong potential for blue hydrogen to help decarbonize the economy. However, policies are needed to transition from traditional unabated steam methane reforming to cleaner production methods. Alberta, aiming to integrate hydrogen domestically as a heavy duty vehicle fuel and become a “global supplier of choice in clean hydrogen exports” by 2030, plans to capitalize on its CCS infrastructure and natural gas resources [20]. Ontario and Quebec are focusing on using their clean, affordable electricity in green hydrogen production. Ontario aims to use hydrogen to supplement its natural gas supply for heating and to decarbonize steelmaking [22]. In addition to the aforementioned applications, Quebec also prioritizes high-temperature heating, replacing grey hydrogen in petroleum refining and production of methanol and other synthetic fuels [23]. Sabillon et al. [26] presented hydrogen-powered trains as a low-carbon solution for Ontario public transit, where optimized scheduling could make hydrogen even more cost-effective than direct railway electrification. Saskatchewan and Manitoba are also pursuing hydrogen initiatives, with Saskatchewan's blue “Hydrogen Hub” aiming to leverage its CCS leadership to attract investment [27] and Manitoba partnering with companies like Charbone Hydrogen Corporation to expand green hydrogen production [28].

Federal and provincial carbon pricing policies further support these efforts by making carbon-intensive options more costly, incentivizing cleaner hydrogen production [29]. Together, national and regional initiatives are laying the groundwork for a hydrogen economy that utilizes local resources and builds infrastructure to enable widespread, cost-effective adoption across Canada. While these efforts demonstrate diverse approaches to hydrogen integration and highlight the potential for blue hydrogen as an energy vector in the global market, they also underscore the need for innovations to enhance its sustainability and competitiveness [30].

Although most studies on autothermal reforming rely on oxy-combustion within ATR, and some consider CCS, the preheating step typically involves burning natural gas in air, with the resulting flue gas vented to the atmosphere [6,7]. Very few studies have considered electricity cogeneration [4]. The proposed process combines autothermal reforming with oxy-combustion-based electricity cogeneration and carbon capture. A key feature of this process is that natural gas is first fed to the ATR, where the conversion is carefully controlled, so that the unconverted natural gas, after hydrogen separation, is subsequently used in an oxy-fuel boiler to generate heat and electricity, followed by CO₂ capture. A unique attribute of this process is that it generates virtually no CO₂ emissions to the atmosphere, while efficiently converting natural gas into hydrogen, heat, and electricity.

3. Process Overview and Methodology

The proposed blue hydrogen system follows the block flow diagram in Figure 1.

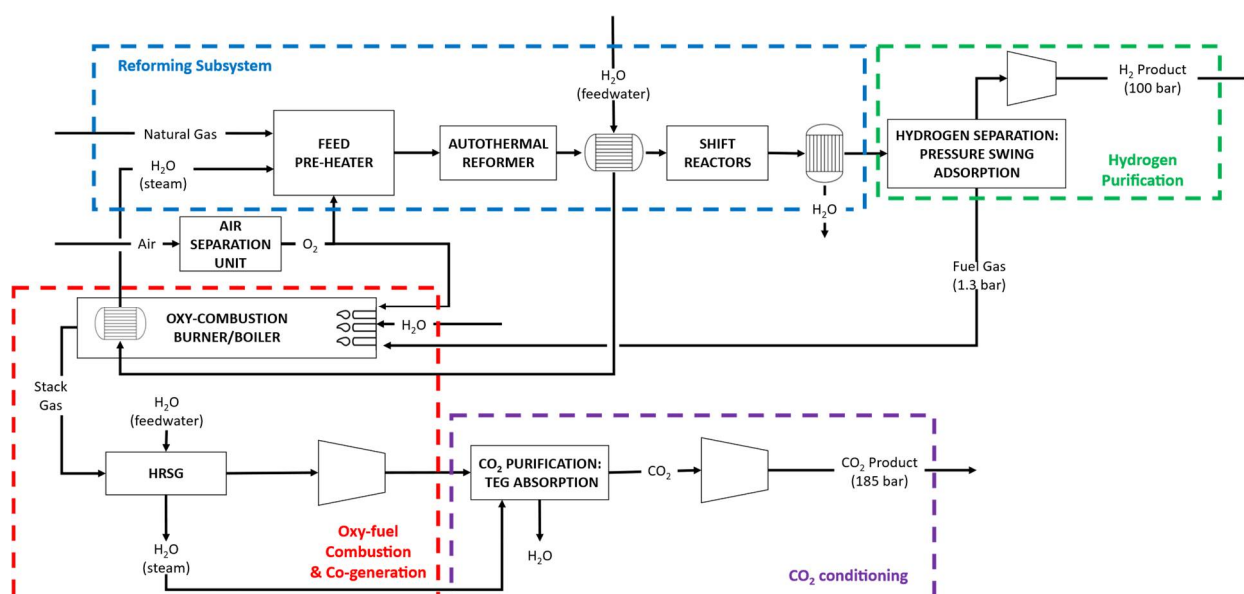
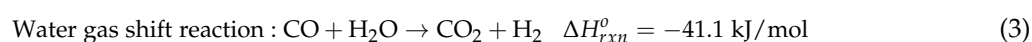
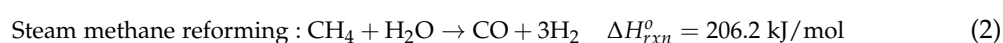
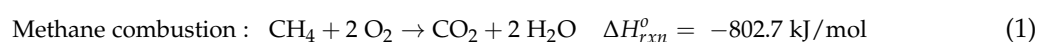


Figure 1. Block flow diagram of the autothermal reforming plant with CO₂ capture.

The main inputs to this process are air, water, natural gas, and electricity, and the outputs are hydrogen, CO₂ ready for pipeline and storage, and some electricity. The natural gas, produced in Alberta, has been sweetened to contain 94.6% methane, 4.4% ethane, 0.2% propane, 0.4% nitrogen, and 0.3% carbon dioxide with other trace elements [31]. The natural gas is considered free of sulphur and supplied through distribution mains to industrial sites at 12–35 bars. All material feed to the process is delivered at an ambient temperature of 15 °C. The oxygen used in the process is supplied by an air separation unit (ASU) that produces oxygen at 99.5% purity and a fixed flow rate of 5000 metric tons per day (mtpd). This production rate serves as the basis for the modelling in this study, as it reflects the capacity of a large-scale ASU.

One objective of this study is to evaluate the net overall CO₂ emissions of the proposed process, including upstream emissions. Although this process handles nearly all (~99.8%) of the emissions generated within the process, the feedstock uses natural gas and electricity generated from Alberta's natural gas-based grid, so it is critical to account for emissions related to utility consumption within the process boundary. The emission intensity of delivered natural gas is 0.575 kg CO₂ e/kg CH₄ [32], evaluated based on the gross heating value of methane. The electricity grid intensity is 0.490 kg CO₂ e/kWh [33].

The natural gas and part of the oxygen are preheated with 800 °C steam from the oxy-fuel boiler and fed with the steam to the autothermal reformer unit, which is modelled based on the patent filed by Haldor Topsoe A/S [34] for large-scale reforming. The apparatus comprises a combustion chamber and a catalytic reactor connected by a duct that delivers the combustion products to the reactors and withdraws the reformed product. The following reactions describe the autothermal reforming process:



Within a single reforming unit, the oxygen is completely consumed by a combustion reaction (Equation (1)) in the combustion chamber to generate the heat needed for the highly endothermic reforming reaction (Equation (2)) in the catalytic reactor. The steam methane reforming (SMR) reaction dictates that one mole of methane requires one mole of steam. Yet, most reforming processes are operated with steam-to-carbon molar ratios between 2 and 4 to reduce soot deposition [35] and ensure excess steam for higher carbon monoxide conversion in the subsequent water–gas shift reactors. In the proposed process, the steam also serves a quenching purpose for the high-temperature oxy-fuel combustion. The combustion in the autothermal reformer, since it occurs in the same chamber, generates more high-temperature steam (700–1000 °C) for the steam methane reformer. Here, the maximum S/C ratio is constrained by the heat available from the cogeneration unit to produce the high-pressure steam. The molar ratio of the oxygen gas to methane (O/C) fed to the autothermal reformer is defined within the range of 0.1 to 1 to control fuel conversion and prevent high-temperature methane cracking. The control of fuel conversion is important here, as the process uses unreacted CH₄ in the oxy-combustion furnace unit to produce steam for the autothermal reformer. The product of the reformer, a mix of unconverted fuel and syngas, is cooled and fed to two water–gas shift reactors in series where more H₂ is generated, and all CO is nearly converted to CO₂. The resulting synthesis gas is cooled to 40 °C to condense out water.

The synthesis gas is delivered to a pressure swing adsorption (PSA) hydrogen purification section. Here, if the pressure is below 11 bar, it should be compressed to 11 bars, but if the natural gas feed is supplied at a higher pressure (>13 bar), the synthesis gas can be directly delivered to the PSA to recover 81% of the hydrogen gas product at 99.9% purity. The H₂ product is further compressed to 100 bars, required for storage or delivery through a transmission pipeline [36]. The storage or site-specific usage of H₂ is not considered in this study. The PSA off-gas, which is composed mainly of H₂O/CH₄/H₂/CO₂, is then compressed to a specified pressure suitable for recycling and directed to the cogeneration section, as seen in Figure 1. The pressure is selected based on the optimal pressure ratio needed for efficient electricity generation.

The off-gas is combusted with the rest of the oxygen from the ASU. The oxygen is compressed and added in stoichiometric quantities to limit methane, oxygen, and hydrogen in the burner stack/flue gas. In air, methane burns at a temperature of approximately

1800 °C, while in an oxy-fuel combustion process, the reaction temperature would increase to approximately 3000 °C. Hence, water is sprayed into the furnace to control the stack gas temperature. The stack gas at elevated pressures and high temperature is expanded to 10 bars in a gas turbine to generate electricity. The heat from the oxy-fuel boiler is used to generate superheated steam at 800 °C for the reformer. The low-pressure stack gas, still hot, is used to generate superheated steam at 215 °C and 20 bars for use in the succeeding CO₂ purification unit.

In the CO₂ purification unit, the stack gas is cooled to 40 °C and water is condensed out. The stack gas is further dehydrated in a triethylene glycol (TEG) dehydration unit using 99.5% mass fraction TEG to meet the CO₂ specification of the Alberta Carbon Trunk Line at a maximum of 160 mg/Sm³ [37]. The stack gas is contacted with the TEG solvent in a scrubber. The TEG is regenerated using a still column with a reboiler at 200 °C and the solvent is further stripped of water using dry nitrogen from the ASU in a stripping column [38,39]. The dehydrated CO₂ gas is compressed to 185 bars in a four-stage compressor.

To understand the energy and material demands of the autothermal reforming process, the models within each subsystem have been modelled in Aspen Plus. Refer to Supplementary Information for the specification details, in particular Section S1, Technical Model Specifications.

Economic Model Specifications

The main economic assessment in this study is the cost of producing hydrogen, which consists of the capital cost annualized over the plant useful life and the annual operating cost, as shown in Equation (4):

$$\text{\$ per kg } H_2 = \frac{CAPCOST * \left(\frac{i * (1+i)^n}{(1+i)^n - 1} \right) + OPCOST}{H2PROD * OPHOURS} \quad (4)$$

where i is the interest rate (in %), n is the plant's useful life (in years), $OPCOST$ is the total annual operating cost (in \\$/year), $CAPCOST$ is the total capital investment (in \\$), and $H2PROD$ is the hourly production rate of hydrogen (in kg/h). The plant useful life is set as 20 years. All costs in this paper are estimated in USD for the cost year 2024. The 2024 exchange rate of 1 USD for 0.74 CAD was used where needed. The interest rate is the weighted average cost of the sources of capital—debt and equity—as shown in Equation (5):

$$i = ((1 - DR) * i_E) + (DR * i_D) \quad (5)$$

where DR is the debt ratio or the % of capital investment covered by debt, assumed as 60%; i_E is the expected return on equity, assumed as 25%; and i_D is the loan interest rate/cost of debt, assumed as 8%.

The total capital investment is based on equipment costs, which are primarily estimated using Aspen Process Economic Analyzer 2019 prices, and adjusted for inflation using the Chemical Engineering Plant Cost Index. The direct cost of each piece of equipment consists of both the equipment and installation costs. The estimation was carried out based on key design characteristics of each piece of equipment, e.g., operating temperature, pressure, flow rate, etc. For specialized equipment not available in the programme, scaled costs are estimated based on similar units published in the literature. The autothermal reformer cost is estimated based on NETL costing reports for blue hydrogen production [7]. The ASU cost is the average of scaled cost reported by two literature sources [40,41]. The total capital investment structure used is shown in Figure 2. The installed cost of the main equipment is shown in Table 1.

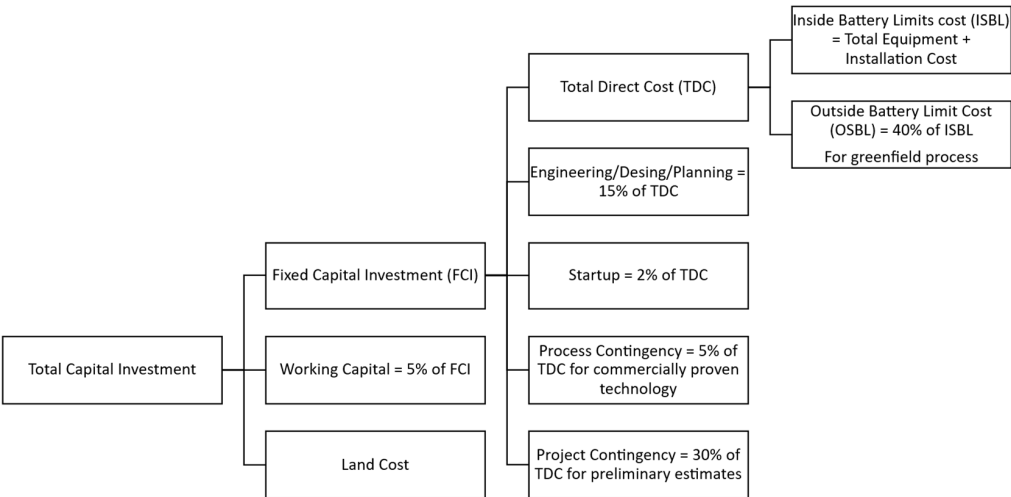


Figure 2. Capital cost levels and elements.

Table 1. Installed cost of main equipment.

	Cost Year	Base Production Rate	Installed Cost	Scale Factor	Reference
Autothermal Reformer	2018	660 MTPD-H ₂	8,955,800	0.84	NETL report [7]
Air Separation Unit—Reference 1	2021	2134 MTPD-O ₂	54,940,000.00	0.6	Young et al. [42]
Air Separation Unit—Reference 2	2018	3214 MTPD-O ₂	176,394,000.00	0.6	NETL report [43]
Air Separation Unit—Reference 3	2003	7920 MTPD-O ₂	155,000,000.00	0.6	Singh et al. [44]
Electrolysis—Reference 1	2016	17.2 MTPD-O ₂	6,500,000.00	0.6	Confidential report—Hydrogenics
Electrolysis—Reference 2	2013	52.6 MTPD-O ₂	13,000,000.00	0.6	Confidential report—Next Hydrogen

The total operating cost accounts for variable and fixed operating costs. The variable operating cost is mostly estimated based on hourly rates from the material balance. It is assumed that the plant operates for 8410 h, equivalent to 96% capacity or all-year continuous operation with 2 weeks of downtime. The variable operating cost includes the cost of all utilities and feedstock to the process. The catalyst and sorbent are assumed to be replaced every 5 years. The catalyst and sorbent prices are estimated based on wholesale supplier’s and Aspen Capital Cost estimator 2019 prices, respectively, adjusted for inflation using the Canadian Industrial Product Price Index. The electricity prices reflect Alberta electricity wholesale prices for oil and gas industrial users. It is assumed that a large body of water is easily accessible to the facility, with onsite cooling towers and treatment facility, so cooling water is not bought. The 2024 USD prices for the feedstock and utilities are shown in Table 2.

Table 2. Feedstock and utility prices.

Feedstock	Unit	Price	Comment
Triethylene Glycol	CO ₂ dehydration	\$1.34/kg	[45]
Catalyst: Ni/MgAl ₂ O ₄	Autothermal reformer	\$55.00/kg	Wholesale suppliers
Catalyst: Fe/Cr ₂ O ₃	High-temperature water–gas shift reactor	\$20.00/kg	Wholesale suppliers
Catalyst: Cu/Zn/Al ₂ O ₃	Low-temperature water–gas shift reactor	\$35.00/kg	Wholesale suppliers
Sorbent: Alumina	Pressure swing adsorber	\$4.09/kg	Aspen Capital Cost Estimator
Sorbent: Activated Carbon	Pressure swing adsorber	\$4.66/kg	Aspen Capital Cost Estimator

Table 2. Cont.

Feedstock	Unit	Price	Comment
Sorbent: CaX zeolite	Pressure swing adsorber	\$6.69/kg	Aspen Capital Cost Estimator
Utilities		Price	
Natural gas		\$0.58/GJ	[46]
Electricity		\$0.05/kWh	[47]

The fixed operating costs include labour, maintenance, and administrative costs. The labour costs were calculated based on the assumption that the plant requires a plant manager [48], an engineer [49], a maintenance supervisor, and three shift supervisors [50] with 12 operators per shift [51]. Their salaries were referenced from similar roles in the Canadian labour market. The annual maintenance cost was calculated as 5% of the fixed capital investment (FCI). Administrative costs and the salary overhead were set to 30% and 60% of the labour plus supervision cost, respectively. The annual insurance and taxes were set to 2% of the FCI.

4. Results and Discussions

4.1. Analysis of Operating Variables

The key performance criteria for the proposed technology are the specific natural gas and electricity consumption, the cost of hydrogen production, and the specific CO₂ emissions. The net CO₂ emissions include mostly the upstream emissions from electricity generation and natural gas production, as the blue hydrogen process captures nearly all the CO₂ generated. We first evaluated the impact of three key operating conditions: reformer feed O₂/CH₄ ratio, the turbine pressure ratio, and natural gas supply pressure. A full factorial design of 18 runs was conducted to study these variables using the values in Table 3.

Table 3. Description of key operating variables.

Variable	Value	Description
Natural Gas Feed Pressure [bar]	{12, 35}	This is the range of supply pressure from the main distribution.
Turbine Pressure Ratio	{3, 5, 10}	The gas turbine's outlet pressure is fixed at 10 bar, so this ratio directly influences the turbine feed pressure.
O ₂ /CH ₄ Ratio	{0.2, 0.45, 0.7}	This is the ratio of oxygen to the methane present in the natural gas that is fed to the reformer. This influences the methane conversion and the operating temperature in the reformer. A 100% methane conversion and unrealistic operating temperatures exceeding 1200 °C are achieved beyond the upper range.

A regression model was constructed to find the optimal operating conditions, and the coefficients of each variable's main and interaction effects were analyzed using an F-test to highlight their relative importance to the results. Table 4 shows the significance value for each effect based on its contribution to the variance of the predicted result. The bolded figures are the values less than 0.05, which are considered statistically significant to the results and must be included in the model equation.

The O₂/CH₄ ratio is statistically significant for each criterion in Table 4. The significance of its second-order effect shows that there exists a ratio that yields the maximum/minimum result in each case. The specific cost is impacted primarily by the O₂/CH₄ ratio. The specific CO₂ emission is dependent on the O₂/CH₄ ratio and the turbine pressure ratio. The same observation can be made for the net electricity consumption. The natural gas consumption depends on all three variables.

Table 4. Effect summary showing the *p*-value of each effect.

Effects	<i>p</i> -Value			
	Specific Cost [\$/kg-H ₂]	Specific CO ₂ Emissions [kg CO ₂ /kg H ₂]	Net Specific Electricity Consumption [kWh/kg H ₂]	Specific Natural Gas Consumption [kg CH ₄ /kg H ₂]
Fuel Pressure (bar)	0.061 *	0.106	0.365	0.000
O ₂ /CH ₄ Ratio	0.000	0.000	0.003	0.000
Turbine Pressure Ratio	0.124 *	0.000	0.000	0.003
Fuel Pressure (bar) × O ₂ /CH ₄ Ratio	0.010	0.902	0.290	0.000
Fuel Pressure (bar) × Turbine Pressure Ratio	0.605	0.009	0.856	0.139
O ₂ /CH ₄ Ratio × Turbine Pressure Ratio	0.073	0.000	0.000	0.000
Fuel Pressure (bar) × O ₂ /CH ₄ Ratio × Turbine Pressure Ratio	0.788	0.382	0.567	0.190
O ₂ /CH ₄ Ratio × O ₂ /CH ₄ Ratio	0.010	0.000	0.025	0.000
Turbine Pressure Ratio × Turbine Pressure Ratio	0.694	0.092	0.090 *	0.539

* included in final model to improve goodness of fit.

Standard regression models, shown in Supplementary Information, Section S3, were constructed with the significant main effects and their interactions as the independent variables to estimate each performance criterion. The high R^2 value and low *p*-value based on the analysis of variance (ANOVA) prove the goodness of fit of the models.

It is not only important that we know what variables are most significant but that we understand how they impact the key performance criteria. The interaction profiles for all the variables are presented in Figure 3 to describe the characteristics of their impact.

In Figure 3A,B, increasing the O₂/CH₄ reduces the cost of H₂ production and the net CO₂ emissions up to a minimum, after which it begins to increase. This minimum coincides with the point at which nearly all the methane (>99%) is converted in the reformer, and an additional increase in oxygen only serves to combust methane and increase the temperature in the reformer rather than generate hydrogen. There is also a different O₂/CH₄ ratio at each fuel pressure that yields minimum cost and emissions. This implies that the distribution of oxygen to thermal energy generation for the autothermal reformer vs. electricity generation requires optimization based on the natural gas supply pressure and the key performance criteria. In Figure 3D, the natural gas consumption is lower at a higher O₂/CH₄ ratio, as more methane gets consumed in the autothermal reactor, as opposed to recycled for cogeneration.

The effect of the pressure ratio is revealed in Figure 3B,C to have a greater impact on the net electricity consumption and the net CO₂ emissions than on the H₂ cost and natural gas consumption. Even though more electricity will be consumed in compressing the fuel and oxygen for the turbine, at higher pressure ratios, more electricity is generated onsite, reducing the net electricity consumption and the reliance on the grid.

The grid emissions were found to account for 38–69% of the total emissions, with higher values achieved when a lower fraction of the electricity is generated onsite. Consequently, the high-pressure ratio reduces the specific emissions. This impact varies depending on the O₂/CH₄ ratio. Figure 3C (sub-figure with the two curves intersecting with each other) shows that at a high O₂/CH₄ ratio, the impact of the turbine pressure ratio on the net electricity consumption is less apparent, whereas at low O₂/CH₄ ratio, the net electricity consumption decreases markedly when increasing the turbine pressure ratio. This is because at a higher O₂/CH₄ ratio, more fuel is converted to hydrogen, and less fuel is recycled to the cogeneration to generate electricity. So, even if more electricity is generated with higher turbine pressure ratios at higher O₂/CH₄, the excess hydrogen generated will reduce the net specific electricity consumption.

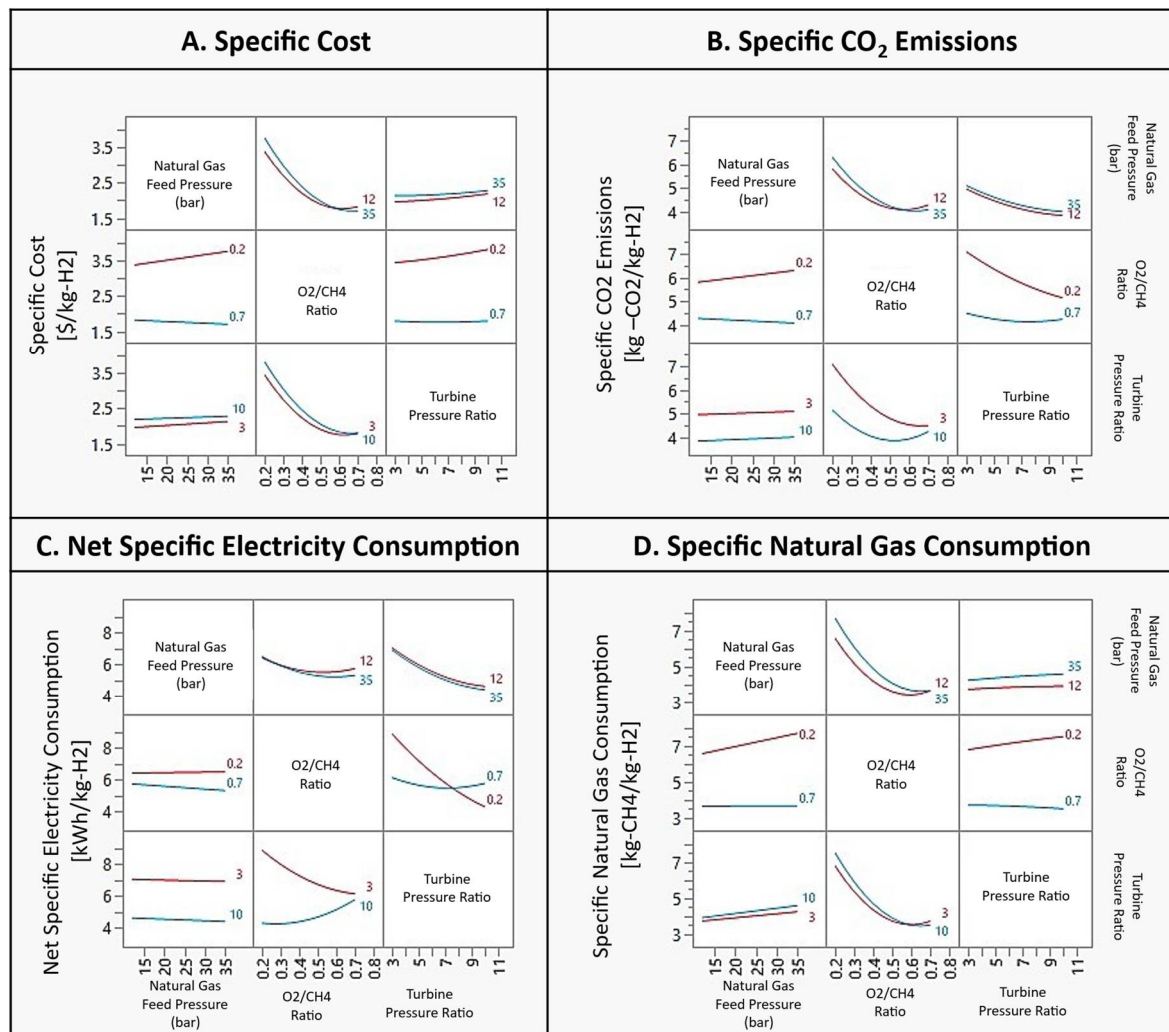


Figure 3. Interaction profiles showing the impact of operating variables on (A) specific cost, (B) specific CO₂ emissions, (C) net specific electricity consumption, and (D) specific natural gas consumption.

Another key point to note is that regardless of natural gas supply pressure in Figure 3A,B, the cost of H₂ production and the net CO₂ emissions remains comparable. From Figure 3D, there is some reduction in natural gas consumption at lower feed pressures owing to the higher conversion at lower pressure in the steam methane reformer. However, this advantage to the final cost is overridden by the additional cost of compressing the synthesis gas for the PSA units and the further compression needed for the hydrogen product.

4.2. Comparative Analysis of Optimized Process

Based on the findings from varying operating conditions and using the cost model developed in Section 4.1, the conditions that were selected to minimize the cost of blue hydrogen production at different natural gas supply pressures are shown in Table 5. The high and low fuel pressure conditions here refer to natural gas supply pressure of 12 bars and 35 bars, respectively.

From Figure 3, it was seen that the feed pressure has a small impact on all key performance criteria (all curves for feed pressure at 12 and 35 bars are “close” to each other). This is reflected in Table 5, where optimized parameters and resulting outputs are not too different for both feed pressures. In both cases, the capital investment accounts for the largest fraction of the blue hydrogen production cost (54–55%). The \$1.6–1.7 billion in

upfront capital investment is comparable to the recent blue hydrogen project commitments in Alberta's Industrial Heartland: \$1.8 billion from Linde [52] and \$1.6 billion from Air Products [40]. Figure 4 presents the breakdown of the capital cost, showing that the largest contributor to the capital cost is the air separation unit, a relatively mature technology for large-scale oxygen production. The next largest is the compression of fuel gas and hydrogen gas for cogeneration and delivery, respectively. This high compression requirement highlights the difference in the two scenarios considered: the higher natural gas supply pressure eliminates the need for extra compressors in the hydrogen purification PSA and product delivery, reducing the cost. The lower fuel feed pressure means that the reformer subsystem requires less material and thinner vessel walls and, consequently, a reduced capital cost, even though more synthesis gas is handled.

Table 5. Model results for cost-optimal high-fuel pressure and a high-fuel-pressure scenario.

Inputs	Unit	Blue Hydrogen—Low Fuel Pressure	Blue Hydrogen—High Fuel Pressure
Natural Gas Supply Pressure	bar	12	35
Turbine Pressure Ratio		5	5
O ₂ /CH ₄ Ratio		0.62	0.67
H ₂ O/CH ₄ Ratio		2.65	3.10
PSA Recovery		81.6%	81.6%
CO ₂ Capture Rate		99.9%	99.9%
Outputs			
Hydrogen Production	MTPD	847	763
Specific Cost	\$/kg H ₂	1.68	1.71
Total Capital Investment (% of specific cost)	\$	1,747,000,000 (55%)	1,570,000,000 (54%)
Operating Cost (% of specific cost)	\$/year	224,000,000 (45%)	210,000,000 (46%)
Specific Net Electricity Consumption	kWh/kg-H ₂	5.02	4.93
Gross Electricity Consumption	MWe	233.6	208.8
Electricity Generation	MWe	56.6	52.3
Specific Natural Gas Consumption	kg-CH ₄ /kg-H ₂	3.37	5.90

As seen in Table 5, the annual operating cost is higher in the low fuel supply pressure scenario. However, it becomes the opposite when considering the specific operating cost, as shown in Figure 5. The reason is the lower hydrogen production for the higher fuel supply pressure. Figure 5 indicates that the maintenance costs account for the largest operating cost (36–38%), which is a factor of the total investment cost and a fixed cost. The electricity cost is the most significant variable cost (29–32% of the total operating cost).

The gross electricity consumption of the proposed process in both scenarios shown in Table 5 is equivalent to about a quarter of the electricity supply of Alberta's largest natural gas-fired power plant [41] and 2% of Alberta's average electricity generation capacity (11,793 MW) [53]. The cogeneration plant contributes about a quarter of the gross electricity consumption. Still, with the expected net load, there might be higher outer battery limit costs associated with dedicated substations, high-voltage transmission lines, and backup power solutions. The electricity consumption is further broken down in Figure 6, which

shows that the cryogenic air separation unit and the compression units are the major consumers. Consequently, any improvements in efficiency to these units could improve the cost. It also emphasizes how critical it is to reduce the specific oxygen consumption for hydrogen production.

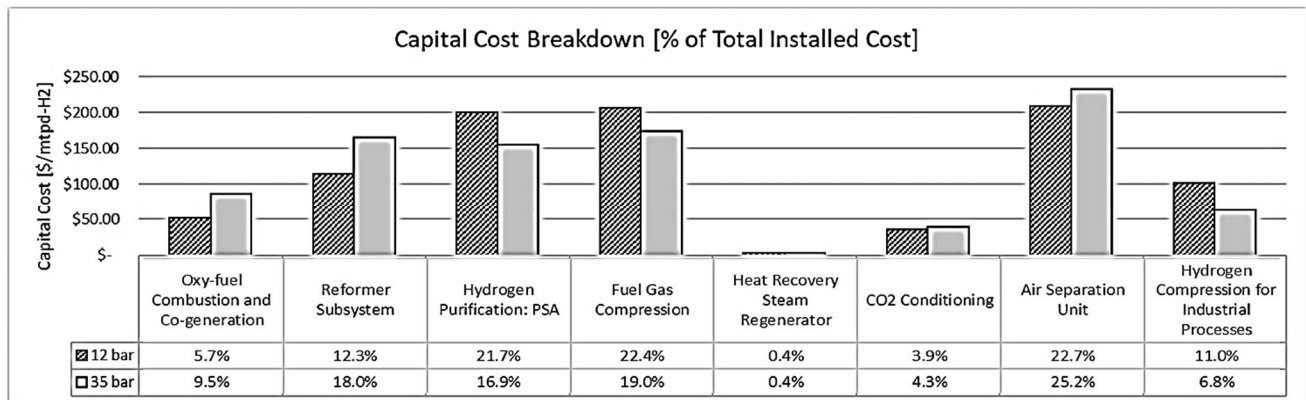


Figure 4. Specific installation cost of each of the blue hydrogen cogeneration processes at different natural gas supply pressures.

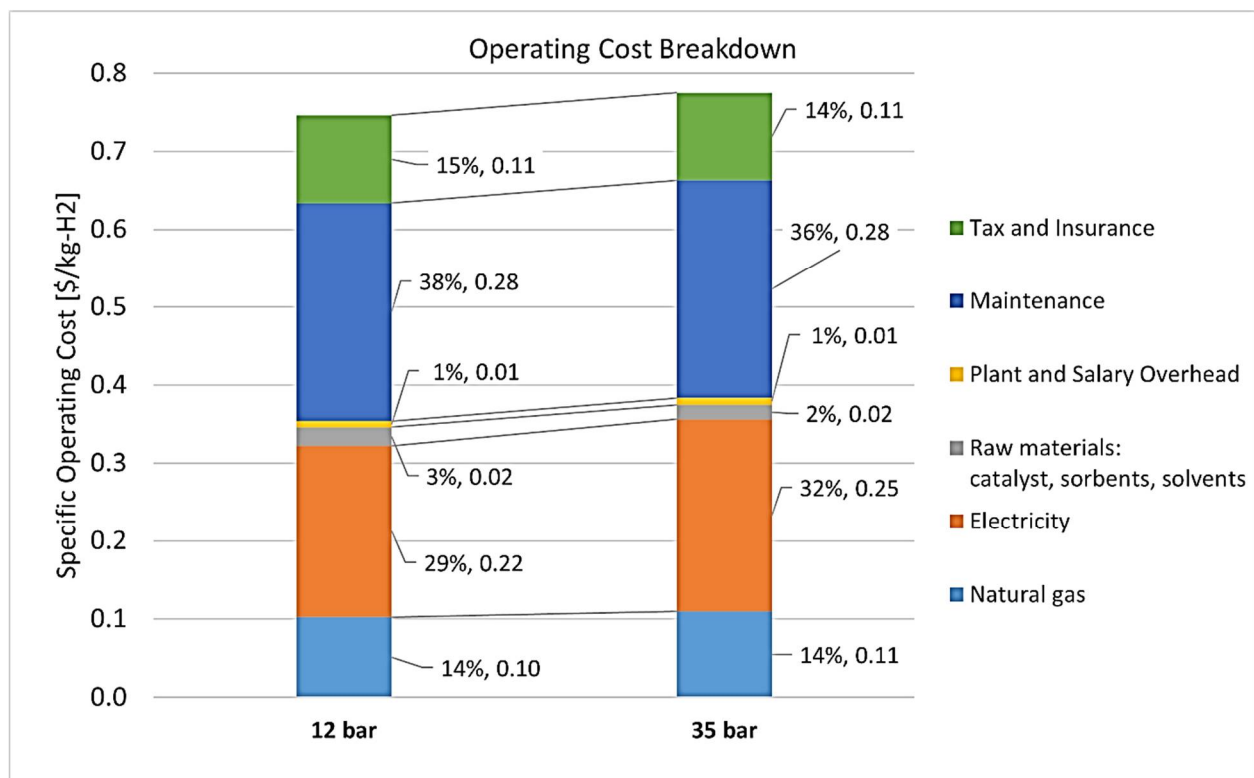


Figure 5. Specific operating cost of the blue hydrogen cogeneration process at different natural gas supply pressures.

From the cost comparisons of the two scenarios considered, we find that the cost of hydrogen production is similar (~ 1.7 \$/kg H_2), regardless of the natural gas supply pressure. So, designing for the available supply pressure to take advantage of the benefits of operating at either end might be preferable instead of introducing wasteful pressure-reducing stations or costly pressure booster stations for the natural gas.

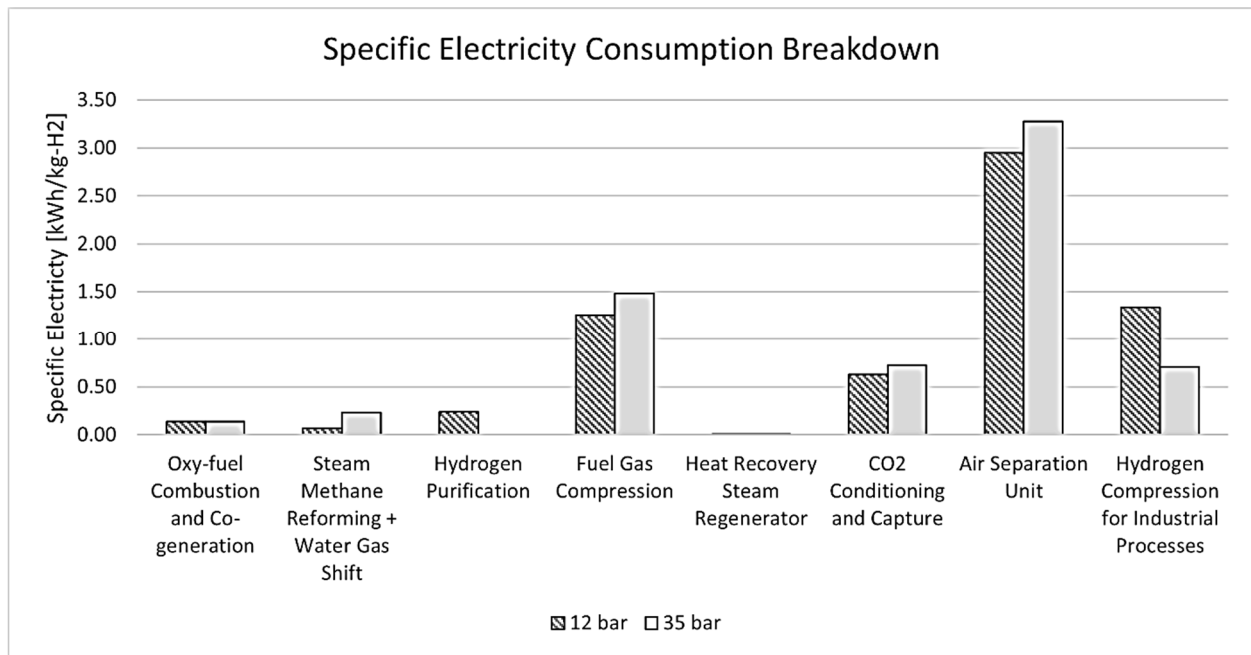


Figure 6. Breakdown of electricity consumption in the blue hydrogen cogeneration process at different natural gas supply pressures.

As one of the key objectives of the blue hydrogen process is to reduce the emissions of conventional “grey” hydrogen, we evaluated the scope 1 (onsite) and scope 2 (purchased energy) emissions of the low fuel pressure case and compared them to different H₂ production methods. The results are shown in Table 6. We assume that there is no fugitive methane emitted within the process and that any CO₂ captured is permanently stored. In Table 6, we compared three hydrogen production processes to the process presented in this work (Case A).

Table 6. Net CO₂ emissions comparison of grey, blue, and electrolytic hydrogen production process.

Inputs	Unit	Case A	Case B	Case C	Case D
Process Description		Blue H ₂ , O ₂ from ASU	Grey H ₂ (No CCS)	Blue H ₂ , O ₂ from electrolysis	H ₂ from electrolysis only
Natural Gas Supply Pressure	bar	12	12	12	-
Hydrogen Production	MTPD	847	847	1472	847
Specific Net Electricity Consumption	kWh/kg-H ₂	4.39	3.76	40.2	52.5
Specific CO ₂ Emission (Scope 1 and Scope 2)	kg-CO ₂ /kg-H ₂	3.82	12.8	12.1	25.7
Onsite Emissions	kg-CO ₂ /kg-H ₂	0.01	9.62	0.01	0.00
Grid emissions @ 490 g CO ₂ e/kWh [33]	kg-CO ₂ /kg-H ₂	2.46	1.84	19.7	25.7
Upstream Natural Gas Emissions @ 0.4 kg CO ₂ e/kg-CH ₄ [32]	kg-CO ₂ /kg-H ₂	1.35	1.35	1.35	0.00
Emission per Lower Heating Value of H ₂ @ 120 MJ/kg H ₂	kg-CO ₂ /GJ	29.2	107	101	214

Table 6. Cont.

Inputs	Unit	Case A	Case B	Case C	Case D
Emission per Electrical Value of H ₂ @ 16.6 kWh/kg H ₂	kg-CO ₂ /GJ	211	772	730	1551
Specific Cost (w/o Emission)	\$/kg H ₂	1.68	1.59	2.10	3.32
Specific Cost (with Scope 1 + 2 Emission Tax @ 170 CAD/mt-CO ₂)	\$/kg H ₂	2.13	3.20	3.62	6.56

In Case B, the CO₂ conditioning and the steam generator units were removed to get the grey hydrogen results. In Case A, the blue hydrogen process yields a 70% reduction in emission from the grey hydrogen process, highlighting the significance of carbon capture in handling the onsite emissions. Although grey hydrogen is about 5% cheaper to produce than the blue hydrogen case, if these emissions are accounted for as a fixed carbon tax [e.g., 170 CAD/mt-CO₂], it becomes 33% more expensive.

In Case C, we substituted the ASU, the highest electricity consumer and capital cost, with electrolysis units. The basis of this process is to use as much oxygen as the blue hydrogen case. The oxygen needed for the proposed process is generated alongside extra hydrogen, making the overall hydrogen production higher than the blue hydrogen process. From Table 6, the specific electricity consumption is nine times that of the proposed process, raising the emissions threefold.

In Case D, the production of hydrogen, equivalent to the base case, is generated only via electrolysis. Here, electricity consumption accounts for all the CO₂ emitted, about seven times the blue hydrogen net CO₂ emissions. Recall that this is assuming Alberta grid emissions. This case is proven more costly than the proposed process, with and without the carbon tax due to the electricity demands on the electrolysis process. Also, the byproduct oxygen could generate extra income.

We considered the environmental implications of using blue hydrogen to replace natural gas. For less exergetically efficient applications like heating, the emissions per lower heating value of blue H₂ is nearly half of the net CO₂ emission of equivalent natural gas at 60.4 kg-CO₂/GJ. If hydrogen is used to generate electricity in a fuel cell operating at 42% efficiency (1/2 the maximum theoretical efficiency of 83.5%) instead of using natural gas with an emission intensity of 490 kg-CO₂/kWh [33], the emission of the supplied electricity could be reduced by 55%. With solid-oxide fuel cells, an even higher efficiency of up to 70% can be achieved, yielding even greater gains in emission reduction.

There is no widely accepted international standard for blue hydrogen, but the EU has rolled out the first guarantee of origin scheme, “CertifHy”, which defines the low carbon hydrogen threshold at 4.37 kg-CO₂/kg-H₂ [54] based on a system boundary that includes electricity generation, fuel generation, and onsite emissions. From Table 6, our proposed process falls below this threshold in each scenario. However, when the transport emissions ranging from 0.5 to 11 kg-CO₂/kg-H₂ [55] are accounted for, whether the hydrogen product will still meet the criteria adequate for low-carbon hydrogen certification would depend on the distance and the method of transport, with gaseous pipeline transport being the preferable choice for distances up to 3000 km [55,56]. Several researchers have proposed and evaluated hydrogen carriers such as ammonia [55] and liquid organic hydrogen carriers like dibenzyl-toluene (DBT) [37] for longer distances and marine transport to limit the CO₂ emission impact.

In Table 7, the proposed process is compared to other published autothermal blue hydrogen simulation results. The NETL process [7] is an autothermal reformer and a carbon capture process, which does not recycle fuel for cogeneration. Oni et al. [6] looked at a hypothetical hydrogen production plant in Alberta producing 607 tonnes/day of hydrogen, similar to the proposed process, but which recycles fuel gas for combustion in an air-fired process to only generate heat for the reformer.

Table 7. Comparison to published autothermal blue-hydrogen process.

		[7]	[6]	Model—12 Bar NG	Model B—35 Bar NG
Cost Year		2018	2020	2024	2024
Hydrogen Production	tonne/day	660	607	847	763
Natural Gas Consumption	kg/h	91,066	137,792	119,265	115,011
Hydrogen Delivery Pressure	bar	65	70	100	100
O ₂ /CH ₄ Ratio		0.530	0.590	0.620	0.670
H ₂ O/CH ₄ Ratio		1.570	1.700	2.640	3.100
ATR Pressure	bar	28	35	12	35
PSA Pressure	bar	24	20	11	30
PSA Recovery		85%	70%	81%	81%
ASU O ₂ Purity		95%	Not Specified	99.5%	99.5%
ATR Outlet Temperature	C	1090	900	878	973
Methane Conversion in ATR		99%	92%	99%	100%
CO ₂ Delivery Pressure	bar	153	85	185	185
Electricity Load	MWe	110	91	234	209
Gross Electricity Consumption	kWh/kg-H ₂	4.00	3.59	6.63	6.57
1st Highest Electricity Load		ASU (51%)	ASU (40%)	ASU (41%)	ASU (41%)
2nd Highest Electricity Load		Hydrogen compression (25%)	Hydrogen compression (18%)	Fuel gas compression (20%)	Fuel gas compression (23%)
3rd Highest Electricity Load		CO ₂ capture (13%)	CO ₂ capture (4%)	H ₂ compression (20%)	H ₂ compression (18%)
Net Electricity Consumption	kWh/kg-H ₂	4.00	3.59	5.02	4.91
Fuel Conversion Efficiency	[HHV-H ₂ /HHV-Natural Gas]	0.78	0.47	0.76	0.71
LCOH—Cost Year 2024	\$/kg-H ₂	2.11	1.69	1.68	1.71
Emission per kg H ₂	kg CO ₂ /kg-H ₂	5.70	3.91	3.82	3.87
Specific Oxygen Consumption	kg O ₂ /kg-H ₂	5.15	3.78	5.90	6.55

HHV = High Heating Value; LCOH = Levelized Cost of Hydrogen.

The air separation unit accounts for the highest electricity load in all cases. The specific oxygen consumption is higher in the proposed process. The fuel gas compression needed for the gas turbine now adds significant electricity load. Even with the higher electrical cost of recycling, the processes with recycled fuel still show comparable levelized cost of production. The specific net CO₂ emissions are comparable to the blue hydrogen process modelled by Oni et al. [6], which is also based on Alberta's grid. The proposed process also maintains relatively high fuel conversion efficiency.

4.3. Cost Sensitivity Assessment

Mission Innovation, a global government initiative for clean energy development launched the Clean Hydrogen Mission to increase the cost-competitiveness of clean hydrogen by reducing end-to-end costs to \$2 per kg by 2030 [30]. The cost of the proposed process within the production boundary falls well below this benchmark cost. However, in the low fuel pressure case, for example, with a CO₂ transport and storage cost of 34 \$/mt-CO₂ (converted from 2021 cost of 30 CAD/mt-CO₂ [37]), equivalent to 0.24 \$/kg H₂, and a pipeline transport cost included at 0.66 \$/kg H₂ for a 1000 km distance [55], the end-to-end

cost comes to 2.58 \$/kg H₂. This falls 29% above the \$2 per kg benchmark cost and the overshoot accounts for 34% of the production cost. So, we studied the sensitivity of this production cost to utility prices, technology changes, or economic analysis assumptions. The cost sensitivity plot for 12 bar natural gas supply scenarios is shown in Figure 7 (very similar plot for the 35 bar case not shown here).

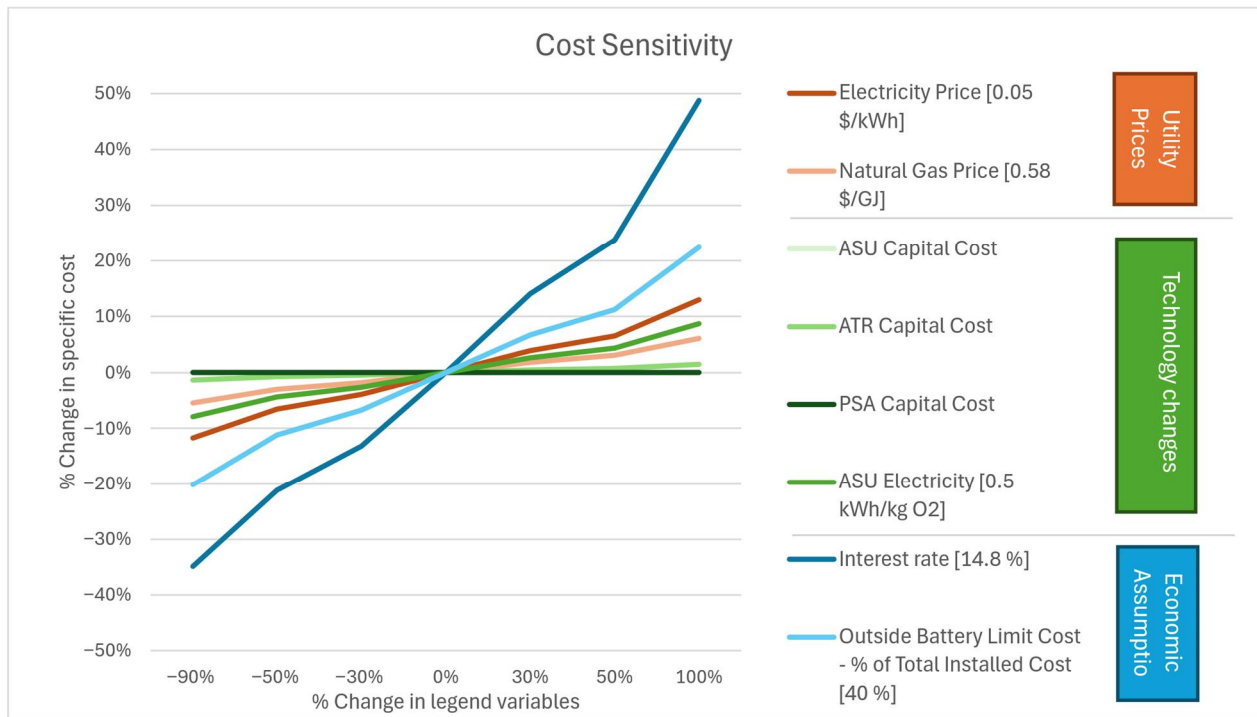


Figure 7. Sensitivity of specific cost of production to techno-economic parameters according to category: utility prices, technology changes, and economic modelling assumptions.

First, comparing all categories shown, the economic assumptions show the greatest impact on the estimated production cost, with the interest rate being the highest. Here, the interest rate refers to the weighted average cost of debt and equity. Capital investment can be greatly reduced with lower interest rates, achieving as low as a 35% reduction in the most optimistic scenario at a 3% debt interest rate and no equity funding. Hence, lower loan interest rates or government loan guarantees and grant-based finance targeted at hydrogen infrastructure projects could achieve the benchmark end-to-end cost of 2 \$/kg-H₂ and incentivise the adoption of this process substantially. If widespread demand for hydrogen, e.g., adoption of fuel cells plants, vehicles and other industrial hydrogen applications remains uncertain [57], profitable production becomes unlikely, making it a high-risk project that attracts higher interest rates. The second most impactful parameter is the outside battery limit (OSBL) cost. If the OSBL cost doubles (i.e., increase by 100%), corresponding to a percentage of the ISBL cost, increasing from the base 40% to 80%, the specific cost of producing H₂ would increase by 20%. Thus, a thorough preliminary assessment of auxiliary units such as substations, transformer upgrades, and water treatment units that could inflate the specific cost should be critically considered.

Significant reduction in the capital cost of the key technology such as the air separation units, the pressure swing absorber, and even newer technology such as the autothermal reformer has a lower impact on the production cost. Conversely, with a focus on operational improvements that improve the efficiency of the conventional ASU process, higher cost reduction can be achieved. Such modifications include multistage compression with an Organic Rankine Cycle (ORC) for energy recovery [42,58,59], using variable-speed drives on

compressors instead of fixed-speed motors [60], energy recovery using expansion turbines for cooling [61], and improving the PSA/TSA unit used for pre-enriching of O₂ in the feed gas [62,63]. Aneke and Wang showed the potential of ORC to achieve 0.2–11.5% reduction in ASU consumption [58]. He et al. proposed integrating ASU with liquid air energy storage system and energy recovery from chilled products to take advantage of fluctuating production capacity and reduce electricity costs by 5.77–7.65% [64,65]. Noting that to achieve just 5% reduction in specific cost, we would need to reduce the ASU energy consumption by 50%, which might be unrealistic. Implementing all these energy-saving measures requires extra investment, which might ultimately make this strategy cost-ineffective and calls for further economic investigation.

In Alberta, 85% of electricity is generated with fossil fuels, with natural gas currently representing 63% of the share [66] and this number is expected to increase as more coal power plants are phased out. Natural gas prices are volatile and subject to global geopolitical changes, increased generation and export, and increased demand for natural gas to replace coal in industrial processes and carbon taxes [67]. From September 2023 to September 2024, commercial electricity rate in Alberta fell by about 59% [47,68], directly reflecting a 81% reduction in natural gas prices in the same period [46]. So, it is not enough to consider the impact of natural gas separately from the electricity prices changes. For example, based on the Alberta Energy Regulator predictions of a 51% inflation of natural gas prices from 2024 till 2030 [67], the cost of H₂ production will go up by 3.5%. But it could also lead to well over double the electricity price, overall leading to, at best, a 10% escalation in the cost of H₂ production.

From Figure 8, we observed that the operating conditions that minimize cost could differ from the conditions that minimize emissions. In Figure 8, we included a fixed carbon tax at 170 CAD/mt-CO₂ on the scope 1 and scope 2 emissions to evaluate how they impact the cost-optimal operating conditions. The plots show the average cost of all the runs at the specified operating conditions. Alberta's grid emission has been trending down in recent years with a 46% reduction in the last 20 years [66]. There has also been a commitment to reducing the fugitive methane emissions associated with natural gas production emissions by 40–45% by 2030 [69]. Thus, the sensitivity of the hydrogen production cost (carbon tax inclusive) to grid and natural gas emission intensity changes is considered.

Comparing both utilities, we find that 50% reduction or increase in grid emission has twice the impact on the cost as the same % change in the natural gas upstream emissions. This suggest that rapidly expanding non-emitting electricity supply in the province would make this project even more attractive and hydrogen produced could be competitive in the export market. While unlikely, there is a possibility that the emission intensity could increase in the future due to the harsh regulatory landscape for renewable energy projects in the province [70,71], the legacy of the 2023 moratorium on such project [72], and a large addition of unabated natural gas-fired generation expected [73].

We also evaluated the impact of the carbon tax and emission intensity on the optimal conditions selected. With the inclusion of carbon tax, the production cost trends remain the same when the O₂/CH₄ ratio and the fuel pressure are changed. This means that regardless of emission changes and carbon tax obligations, the optimal fuel pressure and the O₂/CH₄ ratio would remain the same. In the case where the grid emissions are higher, there is a slight benefit to increasing the turbine pressure ratio up to a minimum cost point seen in Figure 8(1c). This benefit reduces as the grid gets cleaner, at which point the extra turbine electricity generation ceases to yield any cost benefits. Clearly, the proposed process offers the advantage of flexibility to use more internally produced electricity in a location with a heavy emission grid like Alberta.

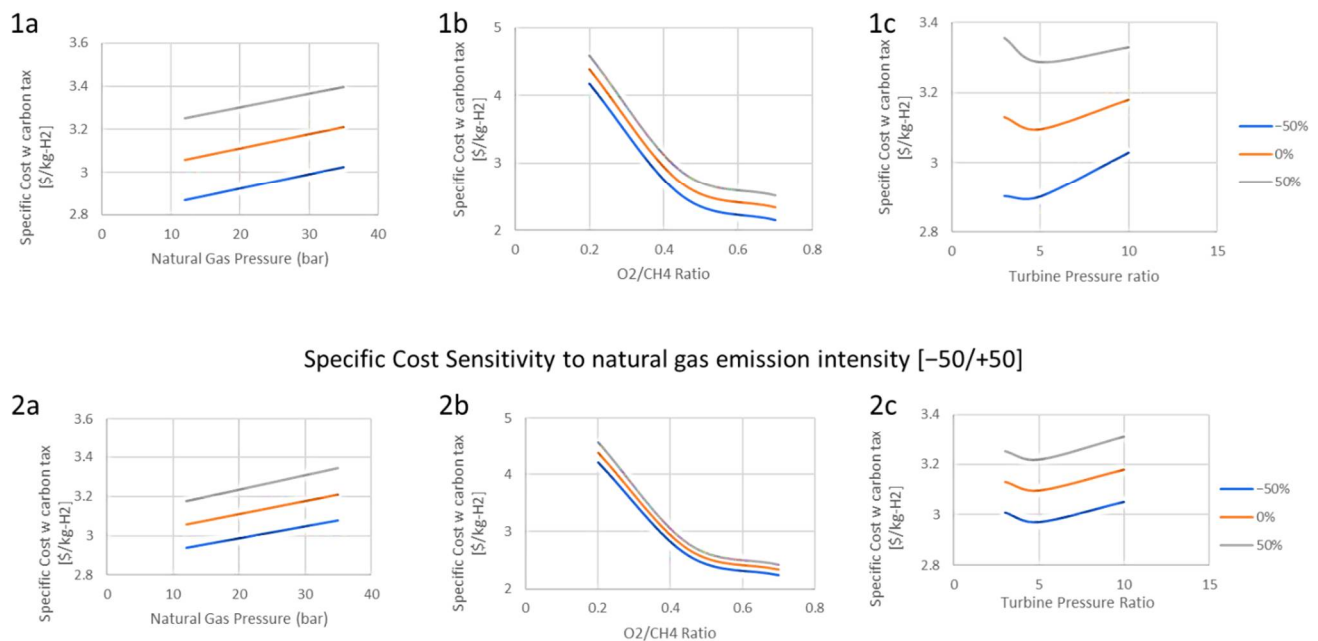


Figure 8. Sensitivity of carbon tax-inclusive cost to operating variables and emission intensity of utilities: (1a) grid emission intensity and natural gas feed pressure, (1b) grid emission intensity and O_2/CH_4 ratio, and (1c) grid emission intensity and turbine pressure ratio; (2a) natural gas emission intensity and natural gas feed pressure, (2b) natural gas emission intensity and O_2/CH_4 ratio, and (2c) natural gas intensity and turbine pressure ratio.

5. Conclusions

The proposed blue hydrogen cogeneration process presents a commercially viable approach to sustainable hydrogen production by integrating the existing autothermal reforming, oxy-fuel combustion, and carbon capture technologies. This process demonstrates the potential to reduce emissions of fossil-based hydrogen compared to conventional methods, meeting stringent low-carbon hydrogen standards while leveraging the existing natural gas infrastructure and large CO_2 storage capacity, such as in Alberta, Canada.

A total of 99.8% CO_2 capture is achieved alongside 76% thermal value conversion of natural gas to hydrogen. Despite challenges such as high initial capital costs of \$1.57–1.75 billion and the dependence on Alberta's carbon-intensive grid, optimization of operational parameters, such as the natural gas supply pressure, O_2/CH_4 ratio, and the internal electricity generation through the turbine ratio, can make blue hydrogen economically attractive at about \$1.7 per kg H_2 , without any CO_2 reduction incentives.

By accounting for the costs of H_2 transport and CO_2 storage, the end-to-end cost increases to \$2.58 per kg H_2 , which is 29% above the Clean Hydrogen Mission benchmark costs of \$2 per kg. The parameters with the largest impact on the cost are the economic factors such as low interest rates and lower offsite costs, followed by the utility prices. Prospective efforts to reduce grid emission intensity and improve the energy efficiency of the ASU, PSA, and compressors can further reduce production costs.

Moreover, as Canadian federal and provincial policies continue to drive cleaner energy solutions through carbon pricing and investment in hydrogen infrastructure, the proposed process aligns with national objectives for decarbonization.

Supplementary Materials: The following supporting information can be downloaded at: <https://www.mdpi.com/article/10.3390/atmos17030228/s1>, Section S1: Technical Model Specifications; Section S1.1: Reformer subsystem; Table S1: Reformer and water gas shift reactor model specifications; Table S2: Steam methane reformer kinetic equations; Table S3: Water gas shift reaction

kinetics; Section S1.2: Hydrogen purification; Table S4: PSA Sorbent requirements and bulk density; Table S5: PSA H₂ separation specifications; Section S1.3: Oxy-fuel combustion and co-generation; Table S6: Heat recovery steam generator equipment specifications; Section S1.4: CO₂ conditioning; Table S7: Triethylene glycol dehydration column and design specifications; Section S1.5: Air separation unit; Section S1.6: Ancillary units; Section S2: Capital Costing Indices; Section S3: Regression Model Building; Table S8: Regression models and summary of fit; Section S4: Process Flow Diagram; Figure S1: Overall Flowsheet; Figure S2: A100—Cogeneration Plant; Figure S3: A200—Reformer Subsystem; Figure S4: A300—Hydrogen Purification; Figure S5: A400—Fuel Gas Compression; Figure S6: A600—Heat Recovery Steam Generator; Figure S7: A600—CO₂ Conditioning; Figure S8: A700—Air Separation Unit; Section S5: Raw data; Table S9: Cost-Optimal Scenario—35 bar natural gas supply pressure; Table S10: Cost-Optimal Scenario—12 bar natural gas supply pressure; Section S6: References [7,42,44,74–83].

Author Contributions: Conceptualization, M.M. and E.C.; methodology, M.M. and A.A.T.; formal analysis, M.M. and A.A.T.; investigation, M.M. and A.A.T.; resources, E.C.; data curation, E.C.; writing—original draft preparation, A.A.T.; writing—review and editing, M.M. and E.C.; supervision, E.C.; project administration, E.C.; funding acquisition, E.C. All authors have read and agreed to the published version of the manuscript.

Funding: This work was partially supported by the Natural Sciences and Engineering Research Council of Canada Alliance Mission Grant ALLRP 570606-2021.

Institutional Review Board Statement: Not applicable.

Informed Consent Statement: Not applicable.

Data Availability Statement: The original contributions presented in this study are included in the article/Supplementary Material. Further inquiries can be directed to the corresponding author.

Conflicts of Interest: The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Abbreviations

The following abbreviations are used in this manuscript:

ASU	air separation unit
ATR	autothermal reforming
CAPCOST	total capital investment
CCS	carbon capture and storage
DR	debt ratio
FCI	fixed capital investment
H2PROD	hourly production rate of hydrogen
HT	high temperature
LCOH	levelized cost of hydrogen
LT	low temperature
OPCHOURS	operating hours
OPCOST	operating cost
PSA	pressure swing adsorption
S/C	steam to carbon ratio
SMR	steam methane reforming
WGS	water gas shift

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