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Feasibility of Green Hydrogen-Based Synthetic Fuel as a Carbon Utilization Option: An Economic Analysis

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Abstract: Singapore has committed to achieving net zero emissions by 2050, which requires the pursuit of multiple decarbonization pathways. CO_2 utilization methods such as fuel production may provide a fast interim solution for carbon abatement. This paper evaluates the feasibility of green hydrogen-based synthetic fuel (synfuel) production as a method for utilizing captured CO_2. We consider several scenarios: a baseline scenario with no changes, local production of synfuel with hydrogen imports, and overseas production of synfuel with CO_2 exports. This paper aims to determine a CO_2 price for synfuel production, evaluate the economic viability of local versus overseas production, and investigate the effect of different cost parameters on economic viability. Using the current literature, we estimate the associated production and transport costs under each scenario. We introduce a CO_2 utilization price (CUP) that estimates the price of utilizing captured CO_2 to produce synfuel, and an adjusted CO_2 utilization price (CCUP) that takes into account the avoided emissions from crude oil-based fuel production. We find that overseas production is more economically viable compared to local production, with the best case CCUP bounds giving a range of 142–148 $/tCO_2$ in 2050 if CO_2 transport and fuel shipping costs are low. This is primarily due to the high cost of hydrogen feedstock, especially the transport cost, which can offset the combined costs of CO_2 transport and fuel shipping. In general, we find that any increase in the hydrogen feedstock cost can significantly affect the CCUP for local production. Sensitivity analysis reveals that hydrogen transport cost has a significant impact on the viability of local production and if this cost is reduced significantly, local production can be cheaper than overseas production. The same is true if the economies of scale for local production is significantly better than overseas production. A significantly lower carbon capture cost can also the reduce the CCUP significantly.

Keywords: synfuel production; alternative fuels; green hydrogen; carbon capture; carbon utilization; economic analysis

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1. Introduction

Singapore's pivot towards achieving net zero emissions by 2050 comes just two years after previously committing to achieving net zero by the second half of the century [1]. The significant stakes raised in this national climate target entail the adoption of multiple decarbonization pathways, many of which may take years to fully mature [2]. Carbon reduction methods consider both CO_2 capture and storage (CCS) or utilization (CCU) [3], with the former focusing on sequestering captured CO_2 and the latter focusing on the usage of captured CO_2, especially in traditionally carbon-intensive industries such as cement [4], steel [5], and fuels [6–9]. CCS has been touted in recent years to be a vital technology for the achievement of net zero targets. Several studies have looked at geological formations [10], saline aquifers/reservoirs [11], and even the seabed [12] as possible avenues for CO_2

storage. Previously used for enhanced oil recovery (EOR), the shift towards CCS as a carbon reduction strategy has led to some conflicting viewpoints regarding this technology [13]. Some studies argue that CCS still lacks the technological maturity and oversight needed to make it a reliable method for CO_2 sequestration due to the possibility of leakage and the subsequent need to monitor storage sites [14–16]. Furthermore, its primary use for EOR can run counter to the goal of achieving negative emissions and may border on greenwashing [17]. A study by the Institute for Energy Economics and Financial Analysis (IEEFA) projects that most CCUS projects in Southeast Asia over the next few decades will focus on gas processing applications, implying that CO_2 storage is unlikely to have significant impact in reducing the region's CO_2 emissions [18].

The aviation sector accounted for 2.4% of total global CO_2 emissions in 2018 [19]. International flight emissions are difficult to account for at the country level due to the difficulty of determining where the jet fuel is actually consumed. Thus, while fuel sales for international flights are recorded, they are not included in the Nationally Determined Contributions (NDCs) for emissions [20]. However, the aviation sector in general remains a target for emission reductions and continues to look for pathways towards decarbonization. One avenue that the sector is looking into is the use of alternative aviation fuels. Chief among these pathways is non-petroleum synthesized jet fuel called sustainable aviation fuel (SAF). Made from waste biomass sources through a variety of biological, thermal, and chemical processes, SAF has the potential to be a low-emission alternative to fossil-based jet fuel. SAF feedstock comes from biomass sources such as waste oil, fats, or wood residues (among others), which are either not available in large quantities (being waste products) or compete with other industries that require the same feedstock (such as ethanol) [21]. The low availability of feedstock coupled with inefficient yields and high capital investment costs makes SAF a costly substitute fuel for airlines [21]. Another alternative would be the use of hydrogen-based synthetic fuels (synfuels), which refer to fuels produced from hydrogen and CO_2 feedstocks through thermal and chemical processes [22]. Similar to SAF, synfuels run into similar issues regarding yield and investment costs. However, hydrogen-based synfuel feedstock can be sourced from industrial CO_2 emissions and the growing hydrogen market. Arguably, there is potential for synfuel production to initially scale faster and synergize with existing infrastructure and carbon reduction efforts [23].

The need to switch to alternative aviation fuels is further enhanced by external pressure from regulators. For instance, the European Commission has recently agreed to new rules that require aircraft departing European airports to start increasing the amount of SAF or synfuel used for refueling [24]. Previous analysis on the use of alternative aviation fuels in Singapore found that synfuels were not viable due to their high cost relative to conventional fuel [25]. Thus, the use of synfuels is largely dependent on the future improvement of technology to drive costs down and thus make it competitive versus fossil-based jet fuel. However, if viewed as a CO_2 utilization method, then one can view the price difference between synfuel and jet fuel as a CO_2 utilization price. Clearly, this approach functions as a single-cycle carbon abatement, as the synfuel is burned in a similar manner to conventional jet fuel. However, if the CO_2 storage cost is prohibitively expensive or impractical by comparison, then the synfuel functions as a relatively cheap and potentially effective method for CO_2 utilization in the interim until technology matures or finds alternative ways to reduce CO_2 emissions. Furthermore, it functions as a more accessible alternative to SAF for lowering aviation emissions. Note that as this functions only as a single carbon abatement option, it can either account for reducing aviation emissions, or for reducing emissions for the processes from which CO_2 was captured, but not both.

The goal of this paper is to evaluate the feasibility of green hydrogen-based synfuel production as a method that can (1) utilize captured CO_2 from different point sources, and (2) provide an alternative to CO_2 storage. Specifically, we propose the following research questions: (1) what is the price of using captured carbon for synfuel production, (2) is local synfuel production more economically viable compared to overseas production (or vice versa), and (3) how do certain cost factors affect the economic viability of synfuel production.

We use Singapore as an example and consider three scenarios: a baseline business-as-usual (BAU) scenario and two synfuel production scenarios, A and B. In the BAU scenario, fossil-based fuel production continues and the aviation sector still relies on fossil-based jet fuel. In Scenario A, synfuel is produced locally via imported green hydrogen and locally captured CO_2. In Scenario B, locally captured CO_2 is exported for offshore synfuel production and the finished synfuel product is shipped back to satisfy local demand. We introduce the *CO_2 utilization price* (CUP), which is the estimated price of utilizing captured CO_2 to produce synfuel, and the *consequential CO_2 utilization price* (CCUP), which is the adjusted CO_2 utilization price that takes into account the avoided emissions of shifting from fossil-based fuel production to synfuel production from green hydrogen and captured CO_2. We use input data from the current body of literature on green hydrogen production and transport, CCUS, and synfuel production to calculate the CUP and CCUP under each production scenario. We then conduct a sensitivity analysis with respect to several parameters of interest, namely the hydrogen and CO_2 feedstock costs, economies of scale, and shipping emissions to determine the feasibility of each scenario.

Given our approach, we find that overseas synfuel production is more economically viable compared to local synfuel production. This is primarily driven by the hydrogen feedstock cost, as it is very expensive to transport under current technology. We also conduct sensitivity analysis on the other cost parameters to determine cases wherein local production can be more viable versus overseas production, or when both production scenarios are very expensive, and provide some future indicators or policies that may signal when these cases can occur.

The rest of the paper is structured as follows. Section 2 describes the methodology for the study. Section 3 discusses the initial results. Section 4 contains the sensitivity analysis for our results. Section 5 concludes and provides our recommendations.

2. Methodology

2.1. Scenario Setting

We begin this section by defining several scenarios based on the production of hydrogen-based synthetic fuels (henceforth referred to as synfuels) as a CO_2 utilization method for the aviation sector. This is followed by the definition of several important variables to be used in the economic analysis. We end the section by discussing the data acquired from the literature that are used to establish the parameter values associated with the defined scenarios revolving around synfuel production. We convert all cost values to USD for uniformity. Afterwards, a quantitative assessment was implemented for each scenario to compare with the baseline scenario and determine each scenario's economic feasibility. Sensitivity analysis was then conducted based on several parameters of interest such as feedstock costs, economies of scale, and shipping emissions to gain further insight on each scenario. Lastly, the implications of these results on future development and/or policy direction are discussed.

To determine the possibility of using synfuels as a CO_2 utilization option for Singapore, we consider one baseline scenario and two production scenarios. First, we consider a baseline or business-as-usual (BAU) scenario wherein synfuel production is not considered at all. Singapore is one of the largest oil trading and refining hubs not just in Asia but in the world [26], with an average refinery throughput of one million barrels per day in 2019 [27]. The country houses a complex infrastructure of refineries and trading centers bolstered by cutting-edge technology, making it a cost-effective location for the petrochemical industry. In the BAU scenario, we consider fossil-based fuel production to continue as-is, while the aviation sector continues to use fossil-based jet fuel. Next, we consider two synfuel production scenarios: local synfuel production with hydrogen imports (Scenario A) and offshore synfuel production with CO_2 exports (Scenario B). In Scenario A, we look into the possibility of producing synfuel locally, wherein the production plant is located in

Singapore with CO_2 feedstock sourced from local industry emissions (e.g., refineries) and hydrogen feedstock is imported from a country with significant renewable energy capacity (e.g., Australia). In Scenario B, we locate the production plant offshore and look at exporting the local CO_2 feedstock and importing the finished synfuel product back to Singapore. Figure 1 illustrates the three scenarios. We look at the economic feasibility of each scenario by considering a range of values for the specified parameters as found in the literature. We then compare the three scenarios with each other to determine the conditions under which one scenario may be favored over the others.

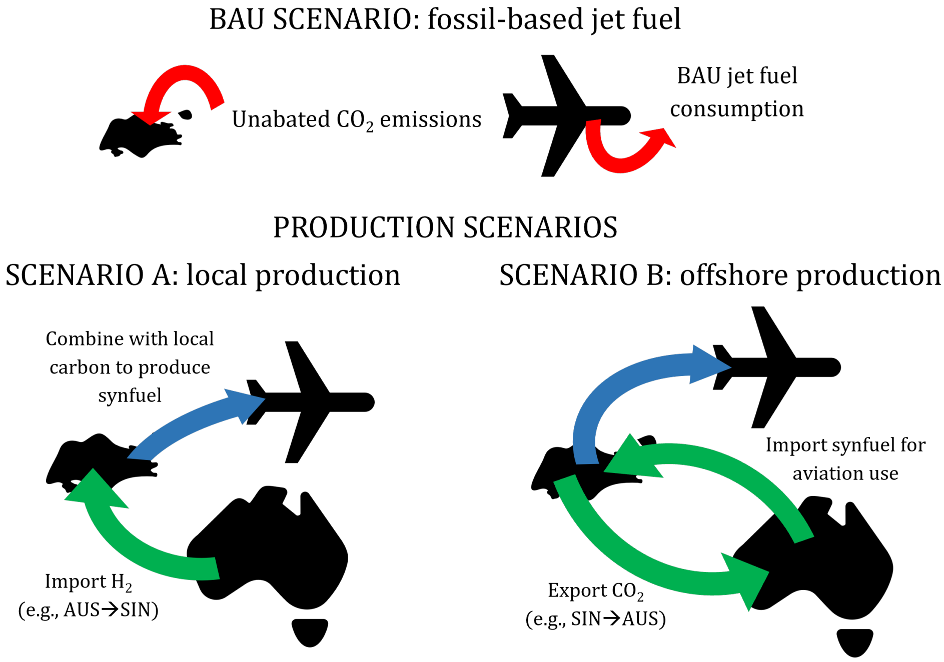

Figure 1. Illustration of scenarios considered in the paper (icons from vecteezy.com) (accessed on 18 July 2023).

For this paper, we focus on green hydrogen-based synfuels produced through the Fisher–Tropsch process due to their compatibility with current petroleum products and minimal need for infrastructure configuration [23] (see Nguyen and Blum [28] or Ram and Salkuti [22] for an overview of synfuels). Several papers on synfuel production have considered centralized systems, integrating several major processes to maximize the potential benefits of system integration. These include the integration of renewable energy sources [6], the hydrogen feedstock production process [8], and the CO_2 capture process [7]. However, given our previously defined scenarios, we need to decouple these processes from the synfuel production itself. Specifically, we need to consider the use of external feedstock sources such as imported hydrogen or CO_2 capture exports. We refer to the work of Zang et al. [9], who develop an Aspen Plus model that simulates the production of synfuels via the Fisher–Tropsch (FT) process with exogenous hydrogen and CO_2 feedstock inputs. They conduct a techno-economic analysis using the simulated production system and find that the hydrogen price has the largest impact on the synfuel production cost. Their study also includes a sensitivity analysis of the other model parameters such as the CO_2 price. Our study builds on their initial assessment by incorporating the current costing literature on hydrogen production, carbon capture and utilization, and fossil-based fuel production to arrive at costing estimates for the aforementioned production scenarios, which include previously unconsidered factors such as the hydrogen transport pathway or shipping CO_2 overseas. This allows us to provide better context for the estimated values and arrive at a more grounded assessment for the potential of synfuel as a CO_2 utilization method.

2.2. Important Variables

To study each synfuel production scenario, we begin with the baseline minimum fuel selling price (MFSP) of USD 5.4/gal for the FT-produced synfuel obtained at feedstock prices of USD 2/kgH_2 and USD 17.3/tCO_2, with H_2 and CO_2 feedstock cost shares at 67.0% and 6.2%, respectively, as found in Zang et al. [9]. This gives us estimated costs of USD 3.618/gal for hydrogen feedstock, USD 0.335/gal for CO_2 feedstock, and USD 1.447/gal for other production costs. We then derive the *feedstock to fuel (FTF)* conversion values for H_2 and CO_2, which we denote by FTF_{H_2} and FTF_{CO_2}, respectively (see Equation (1)).

$$\mathrm{FTF}_{\mathrm{feedstock}} = \frac{\text{total feedstock input}}{\text{total product output}}. \tag{1}$$

These values are the imputed conversion rates to determine the amount of feedstock required (measured in kgH_2 for H_2, tCO_2 for CO_2) to produce a unit of synfuel (measured in gallons).The simulated production plant converts 223 metric tons (MT) of H_2 and 2387 MT of CO_2 into 351 MT of synfuels (90/164/97 MT of naphtha, jet fuel, and diesel, respectively) daily [9]. To determine the effect of feedstock price on the MFSP, we estimate the amount of feedstock required per gallon of synfuel by taking the ratio of the daily feedstock input with the daily synfuel output (converted based on fuel type). We obtain the FTF conversion values of $FTF_{H_2} = 1.919$ kgH_2/gal and $FTF_{CO_2} = 0.0205$ tCO_2/gal for H_2 and CO_2 feedstock. This yields imputed costs of USD 3.837/gal and USD 0.355/gal for H_2 and CO_2 feedstock. We see that the imputed feedstock costs obtained from these conversion values are within 6% of the feedstock costs estimated using the MFSP cost shares from Zang et al. [9], implying that our imputed values will not be significantly different from the previous estimates in the literature. Thus, we will use the FTF to determine the effect of changes in feedstock costs (e.g., production cost changes, additional transportation costs) to the MFSP.

Given the maturity of the fossil-based fuel supply chain, it is clear that synfuel is a very expensive alternative. Hepburn et al. [3] look at fuel production as a CO_2 utilization pathway and estimate the break-even cost at USD 0–670/tCO_2. This is the additional price to pay per tCO_2 to make this pathway become economically viable (for instance, as a subsidy). In line with this metric, we define the *CO_2 utilization price* (denoted by CUP) as the price of using captured CO_2 for synfuel production and consumption (see Equation (2)).

$$\mathrm{CUP} = \frac{\text{MFSP} - \text{price of fuel from crude oil}}{\mathrm{FTF}_{\mathrm{CO_2}}}. \tag{2}$$

Note that the difference between the MFSP and the market price of fuel made from crude oil is essentially the premium paid per gallon for synfuel versus fossil-based fuels. This price is then multiplied by the amount of synfuel produced per unit of CO_2 feedstock (or equivalently, divided by FTF_{CO_2}). Given that the synfuel product is a mix of naphtha, jet fuel, and diesel, we take the projected fuel prices from the US Energy Information Administration (EIA) [29] for motor gasoline, kerosene, and diesel and calculate the fossil-based fuel price as the weighted sum of the product prices based on the plant daily output (26% naphtha, 47% jet fuel, and 27% diesel). We follow the calculations of Zang et al. and use 2019 USD values and recalculate in 2016 USD for consistency. A summary of the values can be found in Table 1. As we are now dealing with CO_2 emission measurements, we note that the plant needs an additional 3.6 MW daily to function [9]. An advanced natural gas combined cycle gas turbine plant in Singapore is estimated to emit 0.335–0.344 tCO_2/MWh [30], which for the synfuel plant translates to an additional 1.21–1.24 tCO_2 in emissions per day. However, we find that the effect on our computations is negligible and ignore it in the subsequent sections.

Note that no CO_2 utilization occurs in the BAU scenario. That is, the CO_2 feedstock for synfuel production is unabated. Furthermore, additional emissions are introduced from conventional fossil-based fuel production. In the pathway to decarbonization and net zero emissions, all the CO_2 emissions in conventional fuel production have to be abated. Thus, this needs to be reflected in the computation of the CUP. We now define the *consequential CO_2 utilization price* (denoted by CCUP) as the effective CO_2 utilization price when the emissions from crude oil extraction and fossil-based fuel production are taken into account (see Equation (3)). The term *consequential* CUP is inspired by the *consequential* life cycle analysis (LCA) methodology, where a marginal analysis is used for assessing life cycle impacts [31].

$$\mathrm{CCUP} = \frac{\mathrm{MFSP} - \text{price of fuel from crude oil} - \mathrm{CO_2}\text{ capture cost} \times \mathrm{WtFP\ CO_2}}{\mathrm{FTF_{CO_2}} + \mathrm{WtFP\ CO_2}}. \tag{3}$$

Table 1. Projected oil product prices [1] (units in 2016 USD/gal [2]).

Fuel Type	2020	2030	2050
Motor gasoline price	2.0	2.2	2.8
Kerosene price	1.7	2.0	2.7
Diesel price	2.2	2.6	3.2
Fossil-based fuel price	1.9	2.2	2.9

[1] Price estimates from EIA [29]. [2] Price estimates in 2019 USD recalibrated following Zang et al. [9].

The CCUP can be understood as follows. Suppose we consider a CO_2 utilization price that takes into account the potential emissions from continued fossil-based fuel production. As mentioned previously, we are dealing with two sources of CO_2 emissions: the unabated CO_2 that would have been used as feedstock for synfuel production, and the well-to-fuel production (WtFP) CO_2 emissions caused by refining crude oil into aviation and other fuels. The first emission source is measured by FTF_{CO_2}, the amount of CO_2 feedstock required per gallon of synfuel produced. We now address the second emission source. First, we introduce the WtFP CO_2 intensity (measured in gCO_2/MJ), which is the amount of CO_2 emissions generated by refining crude from well-to-fuel production per MJ of fuel produced. Gordillo et al. [32] give estimates for refining crude into gasoline, jet fuel, and diesel (see Table 2). Next, we take the lower heating value (LHV) for naphtha, jet fuel, and diesel as listed in Zang et al. [9] measured in MJ/gal (see Table 2). We then take the weighted sum (26% gasoline, 47% jet fuel, and 27% diesel) of the product of the CO_2 intensity and heating value to arrive at an average range for the WtFP CO_2 intensity for fossil-based fuel production of 1.76×10^{-3} tCO_2/gal. If we take the sum of these emissions and multiply by the CCUP, we see that this is the cost per gallon to abate these emissions. However, this is just equivalent to the premium paid for synfuel versus fossil-based fuels, which is the difference between the MFSP and the market fossil-based fuel price, minus the cost of capturing the WtFP CO_2 emissions (which still have to be captured). Taking the ratio yields Equation (3).

Table 2. Fossil-based fuel characteristics.

Fuel Type	WtFP Emissions (gCO_2/MJ) [1]	LHV (MJ/gal) [2]
Gasoline/Naphtha	19.4	116.8
Jet fuel	11.3	123.3
Diesel	15	127.4

[1] WtFP emissions from Gordillo et al. [32]. [2] LHV values from Zang et al. [9].

Intuitively, we see that the CCUP is smaller than the CUP. Furthermore, the CCUP is a more accurate computation of the utilization cost of captured CO_2 for synfuel production as it also takes into consideration the emissions avoided from fossil-based fuel production under a business-as-usual setting.

2.3. Data Gathering

To facilitate our economic analysis, we need to determine the associated costs for the feedstocks and processes utilized in the defined scenarios. We turn to the current literature and collate the necessary cost estimates below. Figure 2 gives a flowchart of the information used to compute the variables described in the previous section.

We begin by looking at the hydrogen feedstock costs. To ensure that emissions are kept to a minimum, we consider green hydrogen as the feedstock for synfuel production. This refers to hydrogen produced from zero-carbon sources and renewable energy sources such as solar and wind or renewable waste sources such as biomass. While many technologies are currently under development, proton exchange membrane (PEM) water electrolysis is typically the preferred method as it is more established and highly efficient [33]. A study by Singapore's Energy Market Authority (EMA) on the country's energy landscape by 2050 projects Singapore as a hydrogen importer, especially with respect to green hydrogen [2]. Hence, we assume that hydrogen feedstock in both synfuel production scenarios is sourced from outside the country. Our initial cost estimates for green hydrogen production are drawn from two sources: a study on hydrogen imports to Singapore commissioned by Singapore's National Climate Change Secretariat (NCCS) [34] and a study by Longden et al. on green hydrogen production in Australia [35], which we summarize in Table 3. Our lower bound uses the cost estimates found in Longden et al. (converted to USD), whereas our upper bound in most cases uses the cost estimates found in the NCCS hydrogen import study. For the 2050 figures, we use the regression model described in Longden et al. wherein each 10 AUD/mWh drop in electricity costs corresponds to a 0.47 AUD decrease in the production cost.

Table 3. Projected overseas hydrogen production (via PEM water electrolysis) costs [1] (units in USD/kgH_2 [2]).

Energy Source	2020	2030	2050
Solar PV	2.15–4.29	1.30–2.95	1.04–2.43
Wind	2.14–4.29	1.66–3.2	1.33–2.87

[1] Cost estimates from from Longden et al. [35] and NCCS [34]. [2] Conversion rates at 1:0.69 USD:AUD when necessary.

Since the synfuel production plant in Scenario A is located in Singapore, we also consider the cost of transporting hydrogen from offshore sources. The NCCS hydrogen import study identifies four viable pathways for hydrogen transport: gaseous hydrogen, liquid hydrogen (LH_2), ammonia (NH_3), and liquid organic hydrogen carriers (LOHCs) [34]. Over long distances, the most cost-effective methods of hydrogen transport are via pipeline or ship, with the latter being more advantageous over larger distances [36]. Since we assume that we are sourcing our hydrogen feedstock from Australia, this implies that our transport method is via ship, which eliminates gaseous hydrogen as a transport pathway. Thus, this paper focuses on the last three transport pathways only (namely, LH_2, NH_3, and LOHC). The hydrogen delivery process can be split into three parts: packing, wherein the hydrogen is transformed into the chosen pathway's transportation medium, shipping, and unpacking, wherein the hydrogen is recovered from the chosen medium for energy use. The pathways vary widely in terms of the technology employed and their efficiency in different aspects of hydrogen delivery. For instance, transforming hydrogen into a liquid state requires significantly low temperatures, which makes the packing cost of liquid hydrogen expensive. On the other hand, "cracking" the ammonia (i.e., unpacking the hydrogen energy from the ammonia) requires large amounts of heat, making the unpacking cost of ammonia expensive. Finally, LOHC is a less efficient hydrogen carrier compared to the other two, which can increase the total cost. Thus, we consider the packing, shipping, and unpacking costs collectively as the transport cost. We summarize the cost estimates in Table 4.

Table 4. Projected hydrogen transport pathway costs [1] (units in USD/kgH_2).

H_2 Pathway	2020	2030	2050
LH_2	4.63	3.79	2.15
NH_3	2.54	2.36	1.93
LOHC	1.49	1.64	1.67

[1] Cost estimates from NCCS [34].

Next, we consider the carbon feedstock costs. Studies have calculated the various CO_2 capture costs depending on the emission source [37]. To estimate the local CO_2 capture cost, we refer to another NCCS study that estimates the weighted average CO_2 capture cost in Singapore at USD 85/tCO_2 [38]. This is in stark contrast to the estimated market price of USD 38.6/tCO_2 [39] or the baseline USD 17.3/tCO_2 (projected from high-purity CO_2 sources) for Zang et al. [9]. Across different point sources, the NCCS study gives a wider range of USD 14–100/tCO_2, with a range of USD 35–100/tCO_2 for refineries [38].

Several studies have looked into the cost of transporting captured CO_2, focusing specifically on pipeline and shipping options, with most of them considering CO_2 transport as a component of CO_2 storage [40–44]. We focus on shipping costs, as our scenario considers exporting captured CO_2 from Singapore for synfuel production in Australia, making shipping a more efficient CO_2 transport method. For our initial cost calculations, we consider estimates from Smith et al. [45] where the CO_2 transport price is at USD 35–64/tCO_2 for 5 Mtpa CO_2.

Finally, we consider the cost of shipping the synfuel product back to Singapore in Scenario B. The cost of shipping oil can be very volatile due to the nature of the market. For this paper, we consider a price point estimate based on 2023 values for Aframax vessels (80,000 MT) shipping from the Southeast Asia region to the east coast of Australia [46]. We estimate the price variability using the week-to-week variance on time charter rates for Aframax vessels from June 2022 to June 2023 [47] and construct lower and upper bounds for fuel price that are two standard deviations from our price point estimate. As these are time-bound (as opposed to voyage-bound) agreements, this can be a good estimate of the price variance. We arrive at an initial shipping cost range of USD 0.112–0.230/gal (or equivalently, USD 4.69–9.67/barrel).

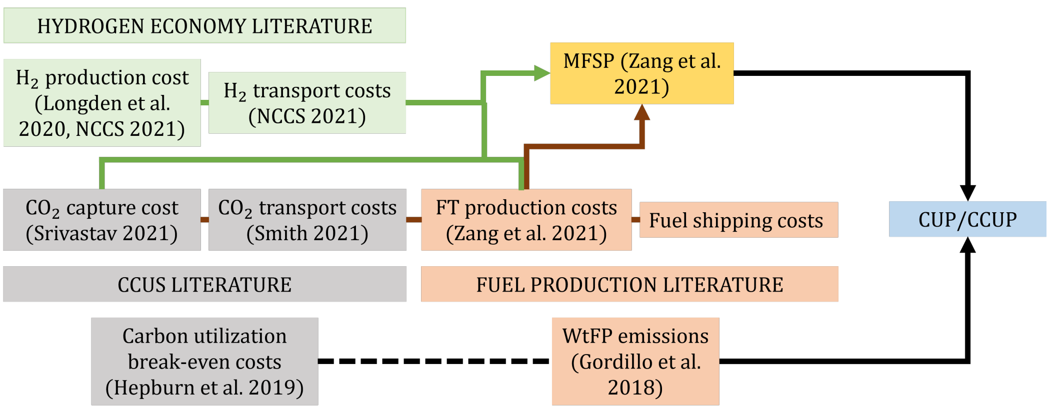

Figure 2. Flowchart of literature used for initial parameter estimates to compute important variables used in the paper [3,9,32,34,35,38,45].

3. Results

3.1. BAU Scenario: Estimating Impact

To determine the potential impact of Singapore's aviation sector on CO_2 emissions, we project the growth of the sector through an estimate of the increase in jet fuel consumption. We use data obtained from the Singapore Department of Statistics to construct our projections. Singapore's jet fuel consumption in 2019 is given at 183.1 thousand barrels per day. This is equivalent to roughly 27.38 million tons of CO_2 per year [48]. We now construct compound annual growth rate (CAGR) estimates to project jet fuel consumption growth under a business-as-usual (BAU) assumption. We consider a lower bound of 4.21% based on flight movement from 2010 to 2019 at Changi Airport, Singapore's main airport, and an upper bound of 5.11% using jet fuel consumption from the same period. Table 5 summarizes our results.

Table 5. Singapore jet fuel consumption projections for 2050.

	2019	2050 (at 4.21% CAGR)	2050 (at 5.11% CAGR)
Barrels (thousands/day)	183.10	557.50	703.20
CO_2 emissions (million tons/year)	27.38	83.33	105.11

CO_2 emissions from the energy and chemical sectors of Singapore were at 38.8 million tons of CO_2 in 2017, with 56% coming from power generation and 24% coming from refineries [38]. Note that jet fuel consumption is comparable to roughly 70% of the measured emissions. We see that the emissions that can be attributed to jet fuel consumption sold from Singapore are quite significant.

3.2. *Scenario A: Local Production with Hydrogen Imports*

We now discuss the cost calculations for Scenario A, where the synfuel production plant is located in Singapore with local captured CO_2 feedstock and hydrogen feedstock imported from Australia. We consider the hydrogen production and transport costs and combine that with the CO_2 capture cost and other fuel production costs to arrive at the new MFSP for synfuel produced under this scenario. A summary of the relevant parameter values is given in Table 6.

Table 6. Summary of parameters used in Scenario A calculations.

Parameter	Value	Source
FTF_{H_2}	1.919 kgH_2/gal	[9] (c.f. Equation (1))
H_2 production cost	See Table 3	[34,35]
H_2 transportcost	See Table 4	[34]
FTF_{CO_2}	0.0205 tCO_2/gal	[9] (c.f. Equation (1))
CO_2 capture cost	USD 85/tCO_2	[38]
Miscellaneous production costs	USD 1.447/gal	[9]
Jet fuel price	See Table 1	[29]

We now combine all the relevant costs to arrive at the MFSP and CUP for Scenario A (see Tables 7 and 8).

Table 7. Minimum fuel selling price (MFSP) for Scenario A (units in USD/gal).

H_2 Pathway	2020	2030	2050
LH_2	16.18–20.31	12.97–16.60	9.32–12.83
NH_3	12.17–16.30	10.22–13.86	8.90–12.40
LOHC	10.16–14.28	8.84–12.48	8.40–11.91

Table 8. CO_2 utilization price (CUP) for Scenario A (units in USD/tCO_2).

H_2 Pathway	2020	2030	2050
LH_2	695–896	524–701	315–486
NH_3	499–700	390–567	295–465
LOHC	401–602	323–500	270–441

We see that LOHC is currently projected to be the most cost-effective hydrogen transport pathway, whereas liquid hydrogen is the most expensive (see Figure 3). For future comparisons, we utilize the calculated smallest lower bound and greatest upper bound regardless of pathway as the range of values to represent Scenario A.

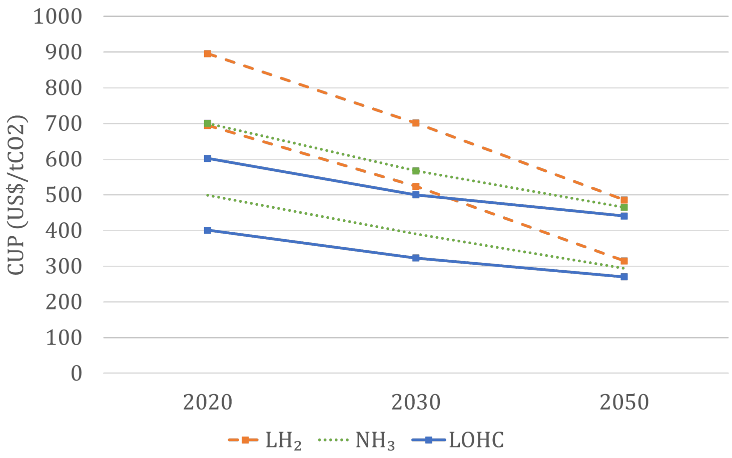

Figure 3. Upper and lower bounds for CUP under Scenario A for all transport pathways.

3.3. Scenario B: Carbon Exports into Fuel Imports

We now discuss the cost calculations for Scenario B, where the synfuel production plant is located in Australia with local hydrogen feedstock and captured CO_2 feedstock exported from Singapore. We consider the hydrogen production cost and combine that with the CO_2 capture and transport costs, fuel shipping cost (from Australia to Singapore), and other fuel production costs to arrive at the new MFSP for synfuel produced under this scenario. A summary of the relevant parameter values is given in Table 9.

Table 9. Summary of parameters used in Scenario B calculations.

Parameter	Value	Source
FTF_{H_2}	1.919 kgH_2/gal	[9] (c.f. Equation (1))
H_2 production cost	See Table 3	[34,35]
FTF_{CO_2}	0.0205 tCO_2/gal	[9] (c.f. Equation (1))
CO_2 capture cost	USD 85/tCO_2	[38]
CO_2 transportcost	USD 35–64/tCO_2	[45]
Miscellaneous production costs	USD 1.447/gal	[9]
Fuel shipping cost	USD 0.112–0.230/gal	[46,47] (c.f. Section 2.3)
Jet fuel price	See Table 1	[29]

We now combine all the relevant costs to arrive at the MFSP and CUP for Scenario B (see Tables 10 and 11).

Table 10. Minimum fuel selling price (MFSP) for Scenario B (units in USD/gal).

	2020	2030	2050
CO_2 transport cost at USD 35/tCO_2	8.13–8.25	6.53–6.64	6.03–6.15
CO_2 transport cost at USD 64/tCO_2	8.72–8.84	7.12–7.24	6.62–6.74

Table 11. CO_2 utilization price (CUP) for Scenario B (units in USD/tCO_2).

	2020	2030	2050
CO_2 transport cost at USD 35/tCO_2	303–308	210–216	155–160
CO_2 transport cost at USD 64/tCO_2	332–337	239–245	184–189

We see that the CO_2 transport cost has a larger effect compared to the fuel shipping costs (see Figure 4). This implies that any technological improvements in CO_2 transport can have a significant impact in lowering the CUP compared to the presence of market fluctuations (as represented in the fuel shipping cost variance). We see that the smallest lower bound can be found when CO_2 transport and fuel shipping costs are low, with the reverse occurring for the largest upper bound. Similar to Scenario A, we take the smallest lower bound and largest upper bound as the range of values to represent Scenario B.

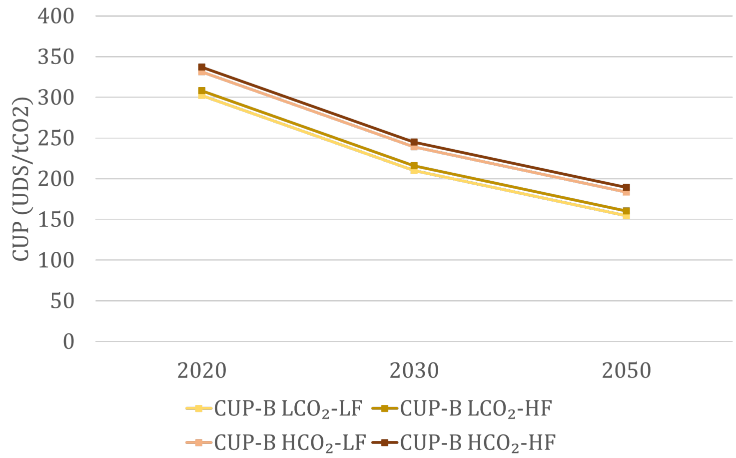

Figure 4. Upper (red) and lower (yellow) bounds for CUP under Scenario B, with L/HCO_2 indicating low/high CO_2 transport costs and L/HF indicating low/high fuel shipping costs.

3.4. Scenario Comparison

We begin the scenario comparison by looking at the MFSP under each production scenario. Figure 5 gives an illustration of the cost distribution. We see that the hydrogen feedstock cost is the most significant cost component, especially the transport cost. As these hydrogen transportation pathways are nascent technologies, current cost estimates assume a lot of inefficiencies that require much development to be addressed. In comparison, CO_2 transport is patterned against more mature technology (e.g., LNG tankers) and is hence not as expensive to implement. Clearly, Scenario A will only be more viable if the hydrogen transport cost is cheaper than the combined costs of CO_2 transport and synfuel shipping.

We expand on this observation by looking at the values of the CUP under each scenario (see Figure 6). We find that even under the most conservative Scenario B setting (high CO_2 transport and fuel shipping costs), no variation of Scenario A will have a lower CUP. We interpret this to mean that under the current estimates available in the literature, local synfuel production may not be economically viable compared to overseas synfuel production. However, as mentioned previously, most of the MFSP revolves around the hydrogen feedstock cost. Thus, this analysis highlights the importance of technology improvements in hydrogen production and transport to improve the viability of synfuel production.

We now estimate the CCUP under both production scenarios for comparison with the BAU scenario (see Tables 12 and 13). As mentioned previously, the CCUP is smaller compared to the CUP. We find a reduction of 16% to 30% across all estimated values. We see that the best-case scenario for synfuel production in 2050 still occurs in Scenario B (overseas production) with low CO_2 transport and fuel shipping costs, giving a CCUP range of USD 142–148/tCO_2. We will utilize the MFSP and CCUP (when relevant) for the rest of the discussion.

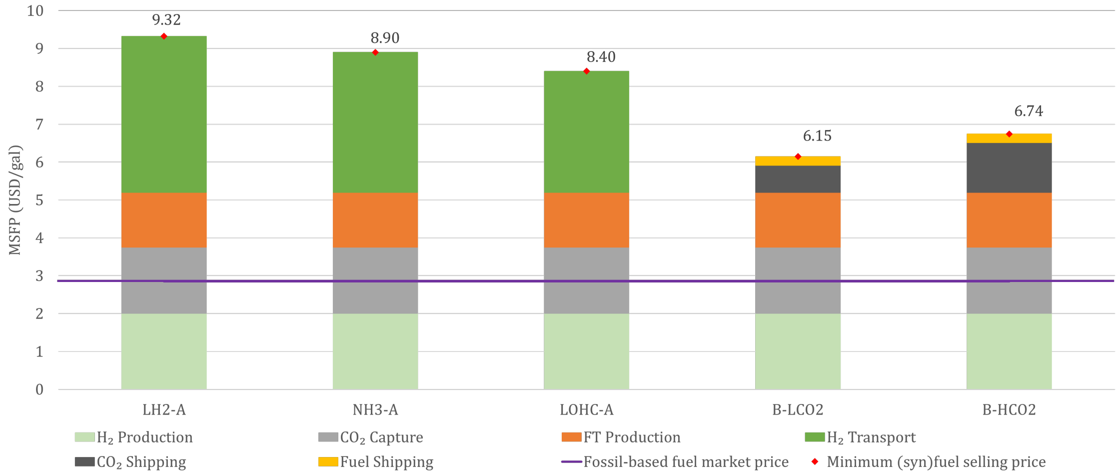

Figure 5. MFSP cost proportions for Scenario A (from left, using liquid hydrogen/ammonia/LOHC transport pathways) and Scenario B (from right, high/low CO_2 and fuel shipping costs) using 2050 lower bound (when necessary) estimates.

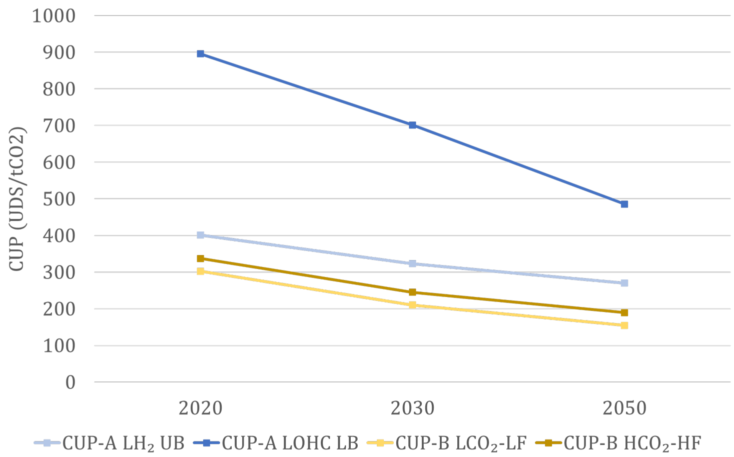

Figure 6. Upper and lower bounds for CUP under Scenario A (blue) versus upper and lower bounds for CUP under Scenario B (yellow).

Table 12. Consequential CO_2 utilization price (CCUP) for Scenario A (units in USD/tCO_2).

H_2 Pathway	2020	2030	2050
LH_2	640–825	482–646	290–447
NH_3	460–645	359–522	271–428
LOHC	369–555	297–461	249–406

Table 13. Consequential CO_2 utilization price (CCUP) for Scenario B (units in SGD/tCO_2).

	2020	2030	2050
CO_2 transport cost at USD 35/tCO_2	278–284	194–199	142–148
CO_2 transport cost at USD 64/tCO_2	305–311	220–226	169–174

4. Discussion

4.1. Sensitivity Analysis

We begin our discussion by looking at the cost parameters associated with our production scenarios and discussing the potential uncertainties regarding their estimated values and their effect on our calculations. Note that we have already accounted for variation in the CO_2 transport and fuel shipping costs in Scenario B by considering ranges for both parameters. Furthermore, the variation in the fuel shipping cost does not have a significant effect on the CUP (and hence the CCUP as well) as seen in the previous section. Thus, this leaves us with the hydrogen production cost, hydrogen transport cost, CO_2 capture cost, and FT production cost. We tackle the FT production cost in the next subsection and focus on the first three parameters in this subsection.

Note that the projections for hydrogen production costs are already quite low. However, several studies have more conservative forecasts for the hydrogen production cost, with Munoz Diaz et al. [49] giving an estimate of USD 3.5/kgH_2 and Breuning et al. [50] giving an estimate of approximately EUR 12.31/kgH_2. Figure 7 illustrates the change in CCUP under these scenarios. Clearly, the viability of synfuel production as a CO_2 utilization method is dependent on the hydrogen production cost being low. Other than technological improvements, government subsidies can be a possible mediating factor to lower the hydrogen production cost. For instance, the Inflation Reduction Act in the United States projects to give subsidies of up to USD 3/kgH_2, which can significantly lower production costs [51].

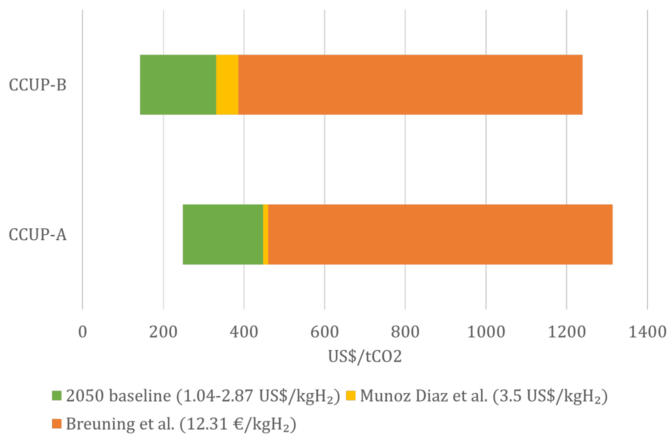

Figure 7. CCUP for both production scenarios under varying hydrogen production costs [49,50].

We now look at the hydrogen transport cost. Recall that LOHC was projected in the aforementioned NCCS study [34] to be the most cost-effective hydrogen transport pathway. Thus, we look into cost variations for LOHC. The NCCS study assumes the LOHC transport medium to be dibenzyltoluene (DBT). Niermann et al. [52] consider several other LOHCs, including N-ethylcarbazole (NEC) and toluene (which combines with hydrogen to form methylcyclohexane (MCH)). Teichmann et al. [53] perform an economic analysis of LOHC for renewable energy transport from North Africa to Europe using NEC as the transport medium. Wijayanta et al. [54] perform an economic analysis for shipping hydrogen to Japan using the three hydrogen transport pathways (LH_2, ammonia, and LOHC), where MCH was the LOHC. In addition, they provide lower cost projections for ammonia that go below the corresponding LOHC cost. Figure 8 gives an illustration of the CCUP variation under these new transport costs. Similar to the previous result, the hydrogen transport cost can significantly affect the viability of synfuel production. In fact, we already see local synfuel production potentially being cheaper than overseas production (should hydrogen transport costs be lowered significantly).

Lastly, we look at the CO_2 capture costs. As mentioned previously, the NCCS study [38] considers a range of USD 35–100/tCO_2 for capturing carbon from refineries.

Furthermore, it is projected that advancements in CO_2 capture technology can lower costs in the next 10–20 years by as much as 30–50% [39]. Figure 9 illustrates the CCUP variation under this range of values, with the lower bound scaled further by 50%. We see that should CO_2 capture costs be lowered significantly, it is possible to lower CCUP for overseas production below USD 100/tCO_2.

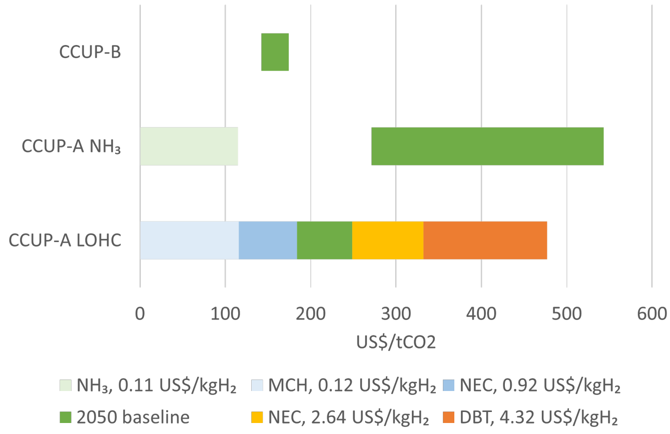

Figure 8. CCUP for Scenario A under varying LOHC and ammonia costs.

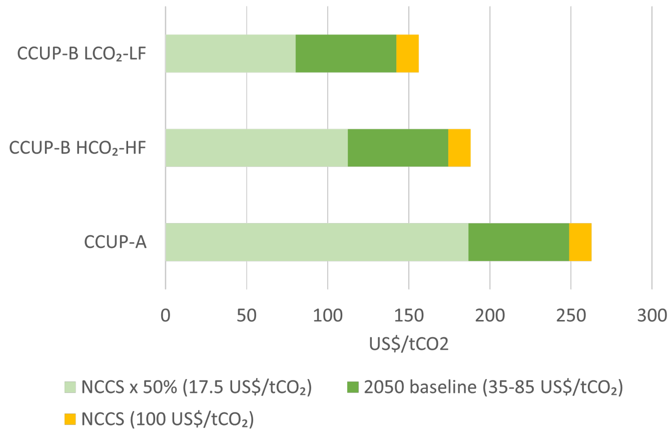

Figure 9. CCUP for production scenarios under varying CO_2 capture costs, with L/HCO_2 indicating low/high CO_2 transport costs and L/HF indicating low/high fuel shipping costs.

4.2. Economies of Scale

Australia has an oil refining capacity of 235 thousand barrels per day as of 2022, roughly 18% of Singapore's 1302 thousand barrels per day [27]. Thus, while Australia has an advantage with respect to access to renewable energy sources (and hence, hydrogen feedstock), one can argue that Singapore has a different competitive advantage with respect to scaling up synfuel production through economies of scale and better access to current technology. To study this effect, we scale the overseas FT production cost by a multiplier to indicate the relative inefficiency versus local production. Figure 10 provides an illustration.

Under our 2050 estimates, we find that setting the local fuel production cost to be 2.15 times the normal production cost will make the Scenario B upper bound just as expensive as the LOHC pathway for Scenario A, with higher values yielding lower prices for Scenario A versus Scenario B. This assumes an extreme difference in terms of the scalability of operations between the two countries. Note that Zang et al. [9] only account for investment costs at the plant level. That is, additional infrastructure to link feedstock to the plant (e.g., CO_2 pipelines, trucks), which can also take considerable investment, are not considered in the current MFSP computations. Given the advanced infrastructure and close proximity of Singapore's port and refining hub, it is feasible that local production can achieve significant economies of scale when these factors are taken into consideration.

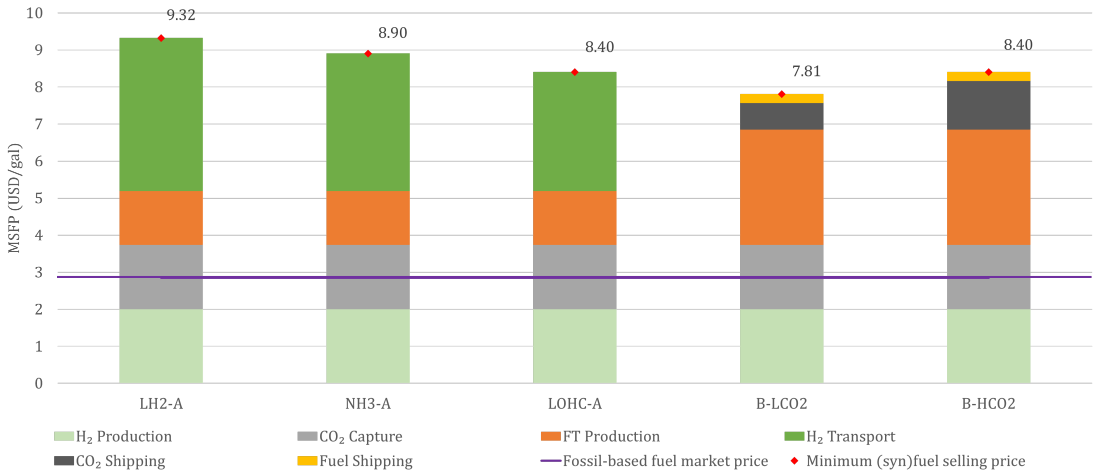

Figure 10. MFSP cost proportions for Scenario A (from left, using liquid hydrogen/ammonia/LOHC transport pathways) and Scenario B (from right, high/low CO_2 and fuel shipping costs) using 2050 lower bound (when necessary) estimates with 2.15× fuel production cost multiplier for overseas production.

4.3. Shipping Emissions for Feedstock and Imported Synfuel

In this paper, many of our estimates are based on the literature surrounding current technologies. In particular, shipping costs are computed based on existing maritime technology (e.g., oil or LNG tankers running on fossil-based fuels), which can be carbon-intensive as well. Clearly, these emissions are not necessarily within the direct purview of any of the concerned parties (synfuel producer, airline, and/or local government), falling under Scope 3 emissions. However, given the novelty of the suggested CO_2 utilization method and the goal of achieving carbon abatements, it is important that we avoid greenwashing and ensure that our approach does not actually end up being more carbon-intensive than the status quo. We now consider the effect of incorporating the shipping emissions on the MFSP and CUP.

Singapore has put into place a carbon pricing scheme since 2019, starting at SGD 5/tCO_2 with the goal of increasing it to SGD 25/tCO_2 by 2024, SGD 45/tCO_2 by 2026, and SGD 50–80/tCO_2 by 2030 [55]. We use these as the baseline by setting 5/50/80 as the carbon tax price for 2020, 2030, and 2050, respectively, and converting to their USD equivalent (see Table 14).

Table 14. Carbon tax estimates (units in USD/tCO_2) [1].

2020	2030	2050
3.8	38	60.8

[1] Conversion rates at 1:0.76 USD:SGD when necessary.

We now recalculate the hydrogen transport costs for Scenario A by adding the transport emissions associated with each hydrogen pathway as mentioned in the NCCS hydrogen import study [34] (see Table 15) priced at the corresponding carbon tax in addition to the base transport cost. Note that these include the packing and unpacking emissions for each transport pathway (e.g., hydrogen liquefaction for LH2, ammonia cracking).

Table 15. Projected hydrogen transport pathway emissions [1] (units in tCO_2/kgH_2).

H_2 Pathway	2020	2030	2050
LH_2	7.30×10^{-3}	6.56×10^{-3}	5.13×10^{-3}
NH_3	5.10×10^{-3}	4.71×10^{-3}	3.93×10^{-3}
LOHC	2.56×10^{-3}	2.56×10^{-3}	2.56×10^{-3}

[1] Emission estimates from NCCS [34].

Next, we estimate the shipping emissions in Scenario B for both the CO_2 transport and synfuel importation, which are typically measured in CO_2 per distance travelled (in nautical miles), or sometimes in ship size (in dead weight tons) multiplied by the distance travelled. For the CO_2 transport, we consider emission values for LNG tankers (38,000 MT) undertaking similar route distances (2000–4000 nautical miles, depending on whether the east or west coast of Australia is chosen) [56,57]. Our calculations yield estimates of 7.95×10^{-3} to 1.10×10^{-2} tCO_2/gal. Similar to the previous approach, we then incorporate this into the base transport cost by multiplying by the corresponding carbon tax (see Equation (4)).

$$CO_2 \text{ shipping tax} = \text{carbon tax} \times \frac{CO_2 \text{ emissions/trip}}{\text{average load}} \times \frac{\text{total } CO_2 \text{ input}}{\text{total product output}}. \quad (4)$$

For the synfuel import, we look at the emission values for oil tankers that are roughly equivalent in size to the aforementioned Aframax vessels (80,000–120,000 MT) and plying similar distances [56,58]. We arrive at estimates of 2.74×10^{-5} to 1.13×10^{-4} tCO_2/gal. Once again, we incorporate this into the base shipping cost by utilizing the corresponding carbon tax (see Equation (5)).

$$\text{fuel shipping tax} = \text{carbon tax} \times \frac{CO_2 \text{ emissions/trip}}{\text{average load} \times \text{synfuel proportions}}. \quad (5)$$

We see that the MFSP, CUP, and CCUP values will increase upon recalculation of our production scenarios with the taxes taken into account. Figure 11 provides a comparison of the increase for both scenarios versus their non-tax counterparts. We find that the taxes can decrease the gap between the two scenarios by 11%.

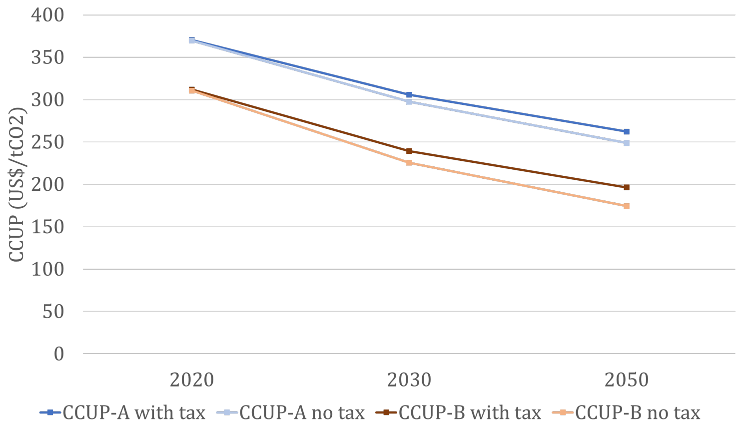

Figure 11. CCUP for Scenario A (blue) and Scenario B (red) using 2050 lower bound (when necessary) estimates with shipping emissions taxes at 60.8 USD/tCO_2 (light color) versus no taxes (dark color).

Lastly, we point out that the maritime sector, like the aviation sector, is also looking towards pathways to decarbonization. Similarly, the use of alternative fuels has also been suggested as a possible avenue to decarbonize the sector. However, these technologies (e.g., hydrogen, ammonia) are still in their infancy and as such it will take time for them to develop into economically viable alternatives [59,60]. Should these technologies mature, then they can significantly lower the shipping emissions associated with our synfuel production scenarios.

5. Conclusions

Given the strong commitment to achieving net zero emissions by 2050, Singapore cannot afford to lag behind in the pursuit of decarbonization across many sectors. Singapore's status as a world-renowned oil refining and trading hub makes its petrochemical sector a large and vital part of its economy. However, it is also an industry with intense CO_2 emissions. The aviation sector as a whole is also pursuing several decarbonization pathways, one of which is the use of alternative fuels.

This paper looks into the possibility of using green hydrogen-based synthetic fuel production as a CO_2 utilization method. This can function as a carbon abatement method for the petrochemical sector or the aviation sector. We consider three scenarios of interest: a BAU scenario wherein no carbon reduction occurs and fossil-based fuel production and consumption continues as-is, Scenario A, wherein local captured CO_2 is processed alongside imported hydrogen feedstock to produce synfuel locally, and Scenario B, wherein local captured CO_2 is exported to an overseas plant with green hydrogen access and the finished synfuel product is imported back for consumption. We use this framework to answer the following research questions: (1) what is the price of using captured carbon for synfuel production, (2) is local synfuel production more economically viable compared to overseas production (or vice versa), and (3) how do certain cost factors affect the economic viability of synfuel production.

To determine the associated CO_2 price of synfuel production, we introduce the CO_2 utilization price (CUP), which is the price of using captured CO_2 for synfuel production, and the consequential CO_2 utilization price (CCUP), which is the effective CO_2 utilization price that accounts for the avoided emissions of fossil-based fuel production. Using the current literature, we estimate the associated costs and emissions under each scenario to calculate the corresponding CUP and CCUP.

Using our estimates, we find that overseas synfuel production is more economically viable compared to local synfuel production, with the best-case CCUP bounds giving a range of USD 142–148/tCO_2 in 2050, wherein CO_2 transport and fuel shipping costs are low. This is primarily due to the high cost of hydrogen feedstock, especially the transport cost (regardless of pathway), which can offset the combined costs of CO_2 transport and fuel shipping.

In general, we find that any increase in the hydrogen feedstock cost can significantly affect the CCUP under Scenario A. While technological improvements can certainly drive down hydrogen costs, governments can also play an active role in lowering costs by providing subsidies (e.g., the Inflation Reduction Act in the US) to incentivize investment in hydrogen production. However, future improvements on the CO_2 feedstock cost should not be overlooked either, as our analysis shows that driving down CO_2 costs can also increase the economic viability of synfuel production. Incorporating emission taxes (such as taxing shipping emissions) shows the potential effectiveness of CO_2 penalties in incentivizing carbon utilization methods such as synfuel production. This is important, as carbon utilization methods have the potential to not only incentivize compliance with carbon abatement measures but also provide intermediate methods to smoothen the transition of industries (e.g., petrochemical, aviation) towards net zero targets. Lastly, we also investigate the effect of economies of scale on synfuel production, emphasizing the importance of existing infrastructure and policies for the synfuel production supply chain to drive down synfuel production costs (or avoid increasing them any further). In particular, major refining hubs such as Singapore may find synfuel production a more viable prospect compared to a country like Australia, where fuel production exists at a significantly lower scale.

Our study incorporates many cost parameter variations as informed by the current literature. However, this also restricts the granularity of our scenario estimates. For instance, infrastructure such as ports and plants can be placed sufficiently far enough from each other to require the use of land transport systems such as pipelines and trucks, which can considerably increase costs. Future studies can also consider other potential overseas sites, which may have different infrastructure and policy structures that can signficantly alter the parameter estimates. Another extension of our study can consider a similar analysis for other CO_2 utilization methods.

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