TECHNO-ECONOMIC ANALYSIS OF A BIOMASS-GAS-AND-NUCLEAR-TO-LIQUID POLYGENERATION PLANT

TECHNO-ECONOMIC ANALYSIS OF A BIOMASS-GAS-AND-NUCLEAR-TO-LIQUID POLYGENERATION PLANT

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# Lay Abstract

This paper examines a system producing a combination of transportation fuels including diesel, gasoline, methanol (MeOH), dimethyl ether (DME) and electricity from biomass, natural gas and hydrogen. The design of the system units used in the process was done in a previous study, this work expands on the design looking specifically at locating the plant in Ontario and Alberta for their raw resources, electricity grids, and current production methods of fuel. Variations of the plant are compared to each other and current fuel and electricity production with an aim of reducing the cost and emissions created while producing and using the fuels. It is found that increasing the amount of biomass used significantly reduces the emissions but does not create a competitive process due to how expensive it is. Results show that this type of system can decrease transportation sector emissions with a similar additional cost as other current alternatives.

# Abstract

Due to the advancement of global warming internationally, increasing emphasis is being placed on the environmental accountability of everyone from countries to processes. This study presents novel research on the environmental impacts and economic trade-offs for a processes co-producing electricity, methanol, dimethyl ether (DME) and Fischer Tropsch (FT) fuels from different feedstock ratios of biomass, natural gas, and nuclear hydrogen generated through a CuCl cycle are analyzed for operation in Canada to produce transportation fuels. This study also considers the use of carbon capture and sequestration (CCS), the location of the plant in either Ontario and Alberta, and the input ratio of the feedstocks. This combination of carbonless heat and a “carbon neutral” biomass feedstock would contribute to the net reduction of greenhouse gas (GHG) emissions. In Part I of this work, the model for this BGNTL process was developed. This work expands on the model and evaluates the economics and environmental impacts this plant would have in both Ontario and Alberta based on their local costs, resource availability, and current electricity grid contributions. The analysis investigates the effectiveness of the emission reduction of the products and processes when compared to their cost. It is shown that an increase in the ratio of biomass to natural gas in feedstock, the use of a solid oxide fuel cell (SOFC), and the production of additional electricity while reducing the emissions of the process, increases the cost of CO2e avoided. The results show that the BGNTL concept can be an economically attractive way of reducing net transportation sector GHG emissions in both Ontario and Alberta in meaningful quantities. Optimal cases for both biofuel and FT fuel production contain a single output fuel production process, produce fuels over electricity where possible, and use a gas turbine (GT) for the electricity production that occurs.

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# List of Abbreviations

API Application Programming Interface

ASU Air Separation Unit

ATR Autothermal Reformer

BGNTL Biomass Gas and Nuclear to Liquid

CCA Cost of CO2 Avoided

CCS Carbon Capture and Sequestration

CO2e Carbon Dioxide Equivalent

CuCl Copper-Chlorine

DME Dimethyl Ether

eTEA eco Techno-Economic Analysis

FT Fischer-Tropsch

GHG Greenhouse Gas

GT Gas Turbine

GWP Global Warming Potential

HHV Higher Heating Value

HRSG Heat Recovery Steam Generation

IR Integrated Reformer

MeOH Methanol

NPV Net Present Value

PSO Particle Swarm Optimization

RSC Radiant Syngas Cooler

SMR Steam Methane Reformer

SOFC Solid Oxide Fuel Cell

TCI Total Capital Investment

WGS Water Gas Shift

# Declaration of Academic Achievement

All content in this work was published in the Canadian Journal of Chemical Engineering [1] and appears here largely verbatim, except the sections key challenges, research suggestions, and all of chapter 5 which have not been published previously. While the majority of the work done was mine there were a few other authors who contributed as listed below:

|  |  |
| --- | --- |
| Madison Glover: | Formal analysis, Investigation, Methodology, visualization, Writing – original draft, Software |
| Leila Hoseinzadeh: | Investigation, Software contribution |
| Thomas Adams II: | Conceptualization, Project administration, Resources, Supervision, Writing – review & editing |

# Chapter 1 Introduction

## 1.1 Background

International recognition of the adverse effect of greenhouse gases (GHG) produced by carbon emissions has led to a global demand on the energy sector to reduce emissions and find low-carbon solutions. Biomass and nuclear as fuel sources are attractive options in Canada because of the regional availability and low carbon footprint. The use of biomass in particular would reduce overall provincial emissions as currently 90% of Canadian biomass is exported to Europe for consumption, primarily in energy production [2]. The United States also exports over 70% of wood pellets produced, almost exclusively to the European Union (99.1%) [3]. This availability of local, inexpensive, and ecologically friendly fuel provides an opportunity to improve our power and fuel generation processes environmentally and economically.

The largest volumes of biomass produced in Canada are energy crops and logging residues [4], with approximately 2.9 million tonnes of wood pellets generated per year accounting for 11.9% of global exports [5]. Although both Canada and the international community are working towards a higher biomass contribution to energy and heat production, it still accounts for only 2% global power generation [6] and 6.1% of electricity and heat generated in Canada [5]. As an alternative to exportation, high biomass production areas in Canada could consider using this resource as a feedstock for liquid fuel and power generation alone or in conjunction with other inputs such as natural gas to reduce GHG emissions in these processes. These would have the added benefit of reducing transportation emissions both for the biomass being exported, and the transportation of alternative fuels for the heat and electricity production required. With transportation emissions accounting for approximately 27% of Canada’s GHG emissions [7], an increase in use of local materials could significantly impact the total GHG emissions nationwide.

As carbon prices rise and carbon taxation becomes more aggressive, the use of biofuels can be an effective GHG mitigation strategy for both liquid fuel and electricity production [8]. However, biofuel costs are generally quite high, and prior work has shown that the use of biomass-gas-and-nuclear-to-liquid (BGNTL) fuels made from a combination of biomass, less expensive resources such as natural gas, and alternative carbonless sources of energy could balance the trade-offs reducing overall costs while still reducing emissions compared to petroleum-derived fuels [9]. In this study we use a combination of biomass, natural gas, and nuclear hydrogen generation for syngas synthesis to explore the economic and environmental changes as compared to current fuel production methods in the Canadian provinces of Ontario and Alberta.

Polygeneration is an adaptation popularized by the increasing need of more efficient lower emission production processes. Polygeneration systems can significantly increase the efficient use of natural resources [10] and can reduce CO2 emissions of processes simultaneously generating heat, power, and energy products in a single process [11]. Some key design decisions of a polygeneration plant and in particular a BGNTL plant are the feedstocks and the products. Considerable work has been done on optimization of these decisions in energy systems, fuel production, and on smaller scales utility production [12] [13]. The impact of the process decisions are complex, affecting almost every part of the process. The ability of polygeneration to exploit synergies and take advantage of wastes and excesses is what generally allows it to compete with single production processes and overcome the increases in capital and operation costs when requiring more units and complex design. For example, one can use process waste streams for heating in other locations or combine certain streams to avoid the need for water gas shift (WGS) units.

The use of polygeneration in the coproduction of liquid fuels, electricity, and heat has been the subject of considerable study, and the reader is referred to [14] for a detailed explanation and review. A variety of feedstocks have been considered including coal [15] [16], natural gas [17], biomass [18], and combinations of resources such as coal and biomass [19] and natural gas and biomass [20]. The use of an additional hydrogen source can be incorporated to provide carbonless H2-rich syngas particularly for methanol and dimethyl ether (DME) production using both steam methane reforming (SMR) [9] and a Copper-Chlorine cycle (CuCl) [21]. The effects of varying feedstock ratios to produce a variety of products have been studied in coal-biomass polygeneration [22], petroleum coke-natural gas [23], and petroleum coke-natural gas-biomass [24]. In particular, the petroleum coke-natural gas-biomass study found the use of the Fischer-Tropsch (FT) unit increased thermal efficiency and increasing the biomass ratio significantly reduced the profitability. The Li et al. study of the production of methanol and power using biomass and natural gas found an optimal ratio of 2:1 of inputs and that 9.5% of material inputs were saved in the use of polygeneration systems in comparison to the use of individual systems [20].

This is the second part of a study which examines the BGNTL concept in the context of Ontario and Alberta, Canada, considering various feedstock combinations of natural gas, biomass, and nuclear energy to produce possible outputs including FT fuels, methanol, DME and electricity. This particular combination was chosen because they are the most suitable resources in Canada based on availability, cost, energy security, and energy policy. In Part I of this study, the polygeneration flowsheet superstructure was proposed, and a detailed chemical process simulation model was created in Aspen Plus and released to the public [25]. In this work (Part II), a rigorous eco-technoeconomic analysis (eTEA) was performed in which optimal BGNTL process designs were determined by optimization in the context of the two Canadian provinces of Ontario and Alberta which have characteristically different electricity grids and resource availability. In particular, a particle swarm optimization (PSO) algorithm was used to determine the optimal unit operation selection, design parameters, feed portfolio, and product portfolio considering both economic and environmental impacts at current market conditions. A further analysis considers the impact this type of process could have on fuel production in Ontario. Part II also contains some updates of the model in Part I. This is to the best of the authors’ knowledge the first such eTEA of BGNTL with CuCl cycles for hydrogen production and with feed ratio variability and optimized production decisions. As noted in Part I of this work, an eTEA of a similar process was presented in a thesis [26], but was discovered later to be based on some erroneous design parameters that therefore required a complete re-evaluation in Part I and in this present work.

## 1.2 BGNTL Superstructure Overview

The BGNTL process superstructure and corresponding model developed in Part I of this study [25] is shown in Figure 1. The process begins with pulverization of woody biomass chips by crushing. The crushed wood is injected into a downward entrained-flow gasifier using CO2 as the fluid conveyance, where it is then reacted with steam and high purity O2 from the air separation unit (ASU), producing syngas. The raw syngas produced is then cooled by some combination of radiant steam cooling and integrated reforming (IR) using an integrated steam methane reformer (SMR) and radiant syngas cooler (RSC).

Water and ammonia are then directly condensed out of the raw biomass-derived syngas without desulphurization (since the sulfur content of biomass is so low), after which the syngas is mixed with the gas-derived syngas from the RSC, and potentially streams from the autothermal reformer (ATR), nuclear-derived H2 from the CuCl cycle, and/or shifted syngas from the water gas shift (WGS). After shifting it is mixed into a 2.01 H2/CO molar ratio and set to either MeOH/DME synthesis or the FT section, or it is mixed (with an H2/CO ratio that can vary) and sent to the power generation system. The power generations system is comprised of two sections, gas turbine (GT) and solid oxide fuel cells (SOFC) as well as heat recovery and steam generation (HRSG) for process steam generation and a bottoming cycle for additional electricity production from excess heat. Because this is a process superstructure, the decisions about how much of certain streams are sent to one process vs. another, or whether a process would exist at all, are determined by optimization.



**Figure 1** Overview of process model of the BGNTL process superstructure. © 2018 Canadian Society for Chemical Engineering [25].

This plant was modelled in Aspen Plus, and the reader is referred to Part I of this work for a detailed explanation [25]. Described briefly, most of the unit operations were modelled using native Aspen Plus unit operation models, with some notable exceptions: (1) The CO2 capture section was rigorously modeled using BR&E ProMax, using first principles unit operations models with physical property models tailored to CO2 capture specifically. A reduced model consisting of polynomial basis functions was created from the ProMax model, which was implemented as a CALCULATOR block in Aspen Plus. (2) The integrated radiant syngas cooler model was developed in gPROMS using a multi-scale modelling approach that considers spatial gradients and temporal dynamics within the device by Ghouse et al. [27] and adapted for this application [25]. A finite differences approach was used for spatial numerical derivatives resulting in a system of approximately 100,000 equations. A reduced order model was made using a steady-state version of the gPROMS model, resulting in a series of equations with polynomial basis functions. These too were implemented as a CALCULATOR block in Aspen Plus. (3) The ASU and CuCl process sections used simple reduced models similarly derived from rigorous system studies in other works and were implemented as CALCUALTOR blocks as well. These reduced models were used to reduce convergence times while maintaining the important nonlinear characteristics of the block, as with the optimizer running hundreds of Aspen Plus calls this significantly decreased the optimization time.

We note that the model as designed in Part I of this work has been updated to the most recent version of Aspen Plus (v12) and is posted to the LAPSE repository online with public availability (http://psecommunity.org/LAPSE:2018.0393). Minor changes were made, with the only significant change being some modifications to flow rates to produce simulations for each biomass ratio discussed in this work.

## 1.3 Modelling Errors

As described in Part I, the process models are varied and complex. Because the plant as a whole has never been constructed, it is impractical to validate the model of the process as a whole or even individual units against experimental (pilot plant) data. Instead, individual pieces of the model can be validated where possible.

The underlying thermodynamic models on which all process models are based (that is, the physical property packages in Aspen Plus such as steam tables, PR-BM, NRTL-RK, and PSRK) were each selected based on their accuracy when used in particular circumstances. For example, PSRK was found to be the most accurate model for predicting fluid phase equilibria of H2O + CO2 systems at high pressure when comparing against experimental data, and NRLT-RK was the preferred model for DME and methanol systems. As such, the best physical property package was selected for each unit, as described in Part I of this work such that the underlying thermodynamics should have high accuracy.

The reduced order models, such as for the internal reformer, are based on classic regression with the structure, basis functions, and parameters selected to minimize error while avoiding spurious characterizations. These models carry some error from the more rigorous simulations, but were carefully selected to be small. The details concerning these reduced models, including the error quantification, are described in Part I.

The multi-scale rigorous models developed in gProms (the internal reforming) on which the reduced models were based were validated against experimental data and employed numerical methods which ensured a minimum accumulation of numerical error, such as ensuring mass and energy balances are closed [28].

The built-in Aspen Plus models of the rest of the unit operations (pumps, compressors, distillation columns, flash drums, etc.) are based completely on first principles such as mass and energy balances, phase and chemical equilibria, and others. These are in widespread use and commonly accepted as being correct, whose accuracy depends primarily on the accuracy of the underlying thermodynamic physical property models. Since those underlying thermodynamic models were validated against experiment, the results of the Aspen Plus models are widely considered predictive and accurate enough for conceptual design studies like this one, when experimental validation of the device itself is not possible.

## 1.4 Research Outline

The objective of this study is to determine the optimal design of a BGNTL plant in Canada and provide a techno-economic analysis of the optimal designs and the economic and environmental trade-offs to optimize the cost of CO2e avoided.

*Chapter 2.* This section describes the methodology used to evaluate each plant variation economically and environmentally. This includes a description and quantification of CO2e emissions, comparison of costing between polygeneration plants and the comparison of the polygeneration plants to “status quo” production of liquid fuels, and the method for calculating cost of CO2 avoided (CCA) as used in this paper. It also includes a description of the algorithm used to evaluate the plant as designed in the Aspen Plus file.

*Chapter 3.* The identification of the optimal cases and the economic comparison and results for those cases are described in chapter 3. The optimal decision combination as well as characteristically different optimal cases for different product portfolios are shown with their capital costing and cost streams.

*Chapter 4.* The environmental analysis and cost of CO2 avoided for the optimal cases chosen previously are discussed in chapter 4. The CCA is shown for a wider variety of cases to show why some variations including BGNTL without CO2. The regional variations in emissions and price are also discussed in this section using the CCA environmental and economic values.

*Chapter 5*. The sensitivity analysis of key values used in the design and optimization of the polygeneration plant are analyzed and discussed in chapter 5. The effect of economic parameters on the cost of CO2e avoided on the plant are shown and discussed.

*Chapter 6.* The main conclusions of this work and research suggestions are described in chapter 6.

## 1.5 Key Challenges

1) Industrial Data Availability

The ability to compare the economics of these systems is currently very limited, as it is difficult to obtain reasonable pricing or net present value (NPV) data for industrial plants. The comparison of net revenue requirement of a BGNTL plant with an NPV of zero to wholesale prices was our best approximation, however these are not perfectly equivalent values.

2) Lack of Standardization

Beginning with the use of “techno-economic” and “tecno-economic” there is very little standardization within polygeneration studies making comparing data and outcomes for academia or industry extremely difficult. The definition of metrics (e.g. CCA), basis of comparisons, economic parameters, and design decisions are incredibly varied and make any determinations between studies a study in and of itself. Some work is being done on this in ISO 14076.

3) Design Space

The large range of design combinations we wanted to include was a considerable hurdle with such a complex flowsheet. Balancing initialization states, run times, and model errors required considerable manual testing for the number of combinations of decision variables we wanted to include. The best solution found was for different Aspen files to be created with different initialization states and values. This reduced errors and solution time most notably with different feed input ratios, however ideally a single flowsheet could be used.

# Chapter 2 Methodology

## 2.1 Framework

We used a framework in which Aspen Plus simulations were automated through a Python Application Programming Interface (API). Aspen plus received instructions from a Python script to modify certain parameters (the decision variables), run the simulation, and then report back key stream conditions and block results to the Python script. The Python script then uses this information to compute economic or environmental metrics, as described next. The economic and environmental metrics can then be used to compute objective functions within an optimization algorithm, also implemented in Python.

The key metric used for optimization and comparisons between processes is the cost of CO2 avoided (CCA). In this work, we use the following definition of CCA:

$$CCA=\frac{Cost of Products of Proposed Process-Cost of Status Quo Products}{GWP of Status Quo-GWP of Proposed Process}$$

Where GWP is the life cycle Global Warming Potential of the process measured in CO2e (carbon dioxide equivalents). Because the purpose of the BGNTL process is to displace greenhouse gas emissions from the transportation sector, the objective of the optimization problem is to find a solution that minimizes CCA. Essentially, we want to spend the least amount of money possible per tonne of CO2e avoided (1 tonne = 1000 kg). Because the product portfolio may contain multiple products, and because each candidate process may have different amounts of each product or not have some products at all, the numerator is computed through a lumped sum approach. The minimum total revenue required for a particular process to achieve a net present value (NPV) of $0 is taken as the costs of the products of the proposed process. This avoids the need to allocate costs or revenue between different products if more than one is produced. The cost of the status quo product is simply the amount of money required to purchase the same basket of products at wholesale prices. The numerator should normally be positive because the BGNTL process, as a green process, should be expected to cost more than classic petrochemical routes, and therefore the numerator is the extra cost required to “be green.” The wholesale revenues are obtained using assumed wholesale prices shown in Table 1. For comparison purposes, finding the minimum total revenue required to achieve an NPV of $0 is a reasonable equivalent to setting an average lifetime wholesale price for the BGNTL cases. It is not clear whether wholesale prices of the BGNTL products would be higher or lower than those at NPV, because it depends on the assumed economic parameters used such as equity and loan interest rates, and other finance terms (see Table 2). Therefore, it must be understood that there will be some uncertainty in the resulting CCA values themselves but the overall comparative conclusions of the study will not change.

**Table 1** Wholesale prices of products of BGNTL plant with specific locations given where it significantly affects local cost.

|  |  |  |  |
| --- | --- | --- | --- |
| Product  | Cost | Unit | Source |
| Methanol | 1.83 | $/gal | [29] |
| DME | 0.7 | $/kg | [30] |
| Ontario Specific Costs |
| Diesel | 100.48 | c/L | [31] |
| Gasoline | 90.27 | c/L | [31] |
| Alberta Specific Costs |
| Diesel | 98.67 | c/L | [31] |
| Gasoline | 87.94 | c/L | [31] |

**Table 2** Assumed economic parameters for NPV calculations within optimization.

|  |  |
| --- | --- |
|   | Value |
| Plant Lifetime | 30 |
| Debt to Equity Ratio | 50% |
| Debt Interest Rate | 9.5% |
| Equity Interest Rate | 13% |
| Inflation Rate | 1.13% |
| Operational Hours per Year | 8000 |
| Depreciation Rate  | 30% |
| Tax Rate  | 38% |
| Basis Year | 2018 |

Similarly, the GWP of the proposed and status quo processes consider the cradle-to-product life cycle impacts of the product portfolio as a whole. For a polygeneration process with multiple products, this means that allocations do not need to be used; one number can be used for the GWP of the process as whole (both indirect and direct). The GWP for the status quo case is likewise the total direct and indirect emissions of producing the same basket of products using conventional petrochemical routes. Combustion and downstream use of the fuels are not considered in this analysis, as they would not differ much between the green case and the status quo. Different factors were compared when looking for the optimal design of a BGNTL plant including types of fuel produced, location, type of feedstocks, and the use of CO2 sequestration. The two main factors compared in this work are the feedstock ratio of natural gas and biomass, and the location of the facility – either in Ontario or Alberta. The feedstock ratio changes the requirement for units due to the difference in the hydrogen content of the syngas produced, the indirect emissions associated with the feedstock, and the cost, emissions, and electricity of the preprocessing required for the particular feed.

In this work we investigate four main factors that affect the emissions and economics of the BNGTL plant: the location, the use of CO2 removal and sequestration, the feedstock ratio, and the optimization decisions. Ontario and Alberta are both viable locations for the BGNTL plant; Ontario is in proximity to all the required resources, while Alberta has lower prices relating to FT production. However, unlike Ontario, Alberta does not have any nuclear capability at present. It is therefore assumed that no nuclear plants would be constructed in Alberta. Instead, for the Alberta cases, nuclear-derived hydrogen would be transported to Alberta from facilities in Ontario and the non-nuclear portions of the BGNTL facility would be constructed in Alberta. The feedstocks are determined by process requirements and the chosen feedstock ratios. Natural gas through the ATR and biomass through the IR are chosen, while the natural gas through the IR and hydrogen added from the CuCl cycle are based on process requirements to produce the required heat for biomass gasification and syngas H2/CO ratio requirements for product synthesis, respectively. We chose natural gas and biomass mass feed ratios of 1.5:1 and 1:1 as two example cases for this work. These ratios were chosen to use a significant amount of biomass as it is locally available and has two sources of reductions–both the use of carbon neutral resources and reduction of biomass shipping quantities. Studies have been done using lower amounts of biomass in these ratios (10-25% total input as biomass) [20] [24] but in this study we chose to look at the viability of higher quantities.



(a)

**Figure 2** Simple transportation supply chain considerations for proposed BGNTL plant in both Alberta and Ontario. BC = British Colombia, the province to the west of Alberta.

Assumptions and Imposed Restrictions:

* All simulations are scaled to a basis energy output of the products (DME, methanol, naphtha, diesel, electricity) and net electricity generation of a combined 500 MW using a higher heating-value (HHV) basis for the liquid fuels.
* Biomass and hydrogen used in Ontario and natural gas in both Ontario and Alberta are assumed to be available locally and have negligible transportation costs. Biomass and H2 transportation costs for Alberta are listed in the supplementary material.

## 2.2 Algorithm Development

A parallelized particle swarm optimization (PSO) script was developed in Python which uses classic weighting parameters and makes direct calls to Aspen Plus when computing the objective function [32]. The PSO was run using parallel computing on a 64-core cluster to reduce the solution time. Because of the black-box nature of Aspen Plus operating in sequential-modular mode, classic mathematical programming methods are not possible. PSO was selected over other derivative-free methods due to extensive in-house experience indicating superior performance in general over other methods (e.g. genetic algorithms, simulated annealing, differential evolution, etc.) in other process superstructure applications [33], although other methods can certainly be used to arrive at the same solutions. Although the global minima cannot be guaranteed with this method, steps were taken to drastically increase the likelihood of the PSO finding them, as described later. Repeat runs of the PSO to account for stochasticity was not necessary as optimal solutions always converged to feasible space boundaries, as explained later.

The optimization problem is briefly described as follows:

* The objective function is to minimize the CCA of a given case study.
* The decision variables are the percentages of certain streams that are sent to one part of the process versus another. These decisions effect not only the percentages of products produced, but the existence of certain units as well. Specifically, the existence of FT synthesis, methanol/DME production, GT, and SOFC sections are determined by these values.

The eight decision variables, which are all continuous, are:

1. Percentage of biomass syngas produced in the IR sent to liquid fuel versus electricity production. *(FUEL vs POWER)* In the range of 0 to 100%.
2. Percentage of natural gas syngas produced in the IR sent to liquid fuel versus electricity production.

*(FUEL vs POWER)* In the range of 0 to 100%.

1. Percentage of natural gas syngas produced in the ATR sent to liquid fuel versus electricity production.

*(FUEL vs POWER)* In the range of 0 to 100%.

1. Percentage of syngas sent to liquid fuels used to produce methanol/DME versus FT fuels.

*(BIOFUEL vs FUEL)* In the range of 0 to 100%.

1. Percentage of unreacted syngas produced from FT fuel synthesis recycled versus purged to electricity production.

*(RECYCLE vs POWER)* In the range of 0 to 99%.

1. Percentage of unreacted syngas produced from methanol and DME synthesis recycled versus purged to electricity production.

*(RECYCLE vs POWER)* In the range of 0 to 99%.

1. Percentage of fresh syngas sent to electricity production used in the SOFC versus GT.

*(SOFC vs GT)* In the range of 0 to 100%.

1. Percentage of syngas sent to methanol/DME synthesis producing methanol versus continuing to DME production.

*(MeOH vs DME)* In the range of 0 to 100%.

Some values are limited to a maximum 99% because certain process sections require a purge stream to avoid the buildup of light gases.

The equality constraints are:

1. Material and Energy balances, and all model equations, associated with the process flowsheet in Aspen Plus.
2. Total energy of produced products = 500 MWHHV
3. Case-specific parameters (fixed biomass to natural gas ratios, Province-specific information)

Inequality constraints:

1. Negative CO2e emissions avoided are not permitted, since the purpose of this BGNTL plant is to reduce emissions in an economically efficient way. The inequality constraint is enforced through a penalty method in the PSO objective function. This constraint was not active for any of the optimal results, but aided PSO convergence.

To improve the chance of finding the global minimum, we first enumerated and simulated 256 candidate solutions using the binary combinations of the 8 decision variables, where each variable is either at its minimum (0/1%) or its maximum (99/100%). This is because a previous extensive review of the polygeneration literature has shown that for polygeneration superstructure optimization problems in general, the optimal superstructure often has only one liquid product unless there are specific synergies that can be exploited in making multiple [14], and so it is likely that the optimum could occur on one of these “corners”. The top four optimal values from this were used as the starting point for some of the PSO particles when solving the full optimization problem, with the rest of the particles initialized randomly. This allows us to run all extreme decision cases and use the best results of those as inputs to the optimization algorithm, to better cover the decision space. Each objective function evaluation takes approximately 33 seconds, but since the algorithm is parallelized, all particles finish about simultaneously. The total run time, including first computing the 256 “corners” and then the PSO optimization this takes approximately 151 minutes, where 140 minutes is taken up by the corners. The PSO required only approximately 20 iterations before termination criteria are reached.

The length of time spent so significantly being skewed towards the corners is predominantly due to the Aspen code and solution method. Aspen initially uses the previous simulation solution to attempt to find a new solution with any changes that may have been made. The changes between calls to Aspen in the optimization section are very small and therefore solve similarly to their previous iteration, however the initial “corners” runs are different paradigm and do not solve neatly from estimates using previous values. The “corners” therefore take orders of magnitude longer to solve than the optimization, due to the connection of Python to Aspen (comm interface) and the required initialization of the Aspen through python taking significant amounts of time.

The termination criteria for the PSO were 10 iterations without improvement, or if all particles reached a group consensus of the best position within 0.005 of each other, although the iteration limit was always the termination criteria reached.

To check that we simply did not bias the optimization toward early termination by initializing some of the particles to the best of the corners, we ran several repetitions of the PSO with entirely random starting positions for the particles each time. Additionally, the initial positions of the PSO particles were always random, with the optimal corners being determined only after the initial positions and velocities were set. This required large numbers of iterations, and particles always tended toward one of the corners. Thus, the likelihood that there is a missed interior global minimum is small.

# Chapter 3 Economics

Four different plant designs were examined in this study, plants located in Ontario and Alberta, and biomass to natural gas feed ratios of 1 and 1.5 for each plant location. The optimization described in Section 3.4 was repeated for each of these four cases. In each case, the optimal decision ends up being one of the “corners”—specifically, the production of FT fuels as the sole product, with excess recycle syngas producing power through GT. Thus, the biomass ratio or geographical location did not have an impact on the final flowsheet structure.

For comparison purposes, three selected candidate flowsheet structures are listed in Table 3, for the “Alberta 1” scenario. Case 1 is the best overall design which is the production of FT fuels, case 2 is the best biofuel production case, and case 3 requires a mixed production of biofuels and FT fuels. In all cases the CCA for Alberta 1 was lower than Alberta 1.5 or the two Ontario scenarios. We note that for these top three cases, the maximum permitted (99%) syngas recycle to liquid fuel recycle is chosen, with the remainder sent to power production using the GT.Also we note that the following tables show only the Alberta 1 scenario unless otherwise specified.

**Table 3** Some decision variables for three BGNTL plant design candidates; Case 1 is the global optimal. Cases 2 is the next-best choice that is characteristically different. Case 3 is a suboptimal point in-between Case 1 and 2 for comparison purposes. All three are for the “Alberta 1” scenario.

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | 1 IR Biomass | 2 IR NG | 3 ATR NG | 4 Fuel type | 5 FT Rec. | 6 BIOFUEL Rec. | 7 SOFC/GT | 8 MeOH/DME |
| Case 1 | Max FUEL | Max FUEL | Max FUEL | Max FT | Max RECYCLE | - | GT | - |
| Case 2 | Max FUEL | Max FUEL | Max FUEL | Max MeOH/DME | - | Max RECYCLE | GT | MeOH |
| Case 3 | Max FUEL | Max FUEL | Max FUEL | 0.25 MeOH/DME0.75 FT | Max RECYCLE | Max RECYCLE | GT | MeOH |

The results for the energies and efficiencies for the best case in each configuration are shown in Table 4. The thermal efficiency is a measure of the energy present in the feedstocks compared to the energy in the products for use. The carbon efficiency is a measure of the carbon used in the process still present in the products versus carbon that is either emitted via waste in some form or sequestered as CO2. By using an energy output basis we can see a change in input energy based on the products produced, with a significant increase of input for case 2 as methanol production has a lower carbon and thermal efficiency.

**Table 4** Flow Rates and Efficiencies for Optimal Case per Configuration. All three are for the “Alberta 1” scenario.

|  |  |  |  |
| --- | --- | --- | --- |
|  | Case 1 | Case 2 | Case 3 |
| Energy Input (MWe or MWHHV) |
| Biomass | 266 | 318 | 261 |
| NG | 609 | 729 | 599 |
| Nuclear Heat | - | 40 | - |
| Electricity | - | - | - |
| Energy Output (MWe or MWHHV) |
| Naphtha | 161 | - | 114 |
| Diesel | 344 | - | 243 |
| DME | - | - | - |
| Methanol | - | 285 | 104 |
| Electricity | 2.6 | 157 | 38 |
| Thermal Efficiency (HHV) % | 58 | 41 | 58 |
| Carbon Efficiency % | 62 | 29 | 57 |

Capital costs *C* for each unit/process section are computed using the power law method (equation 1), where *CA*, *SA*, *X* are taken from literature and provided in the supplementary data. *f* is the output scaling factor, *CA* is the base cost of the unit or process section, *SA* is the base size of the unit/section which has cost *CA*, $X$ is the power law scaling parameter (usually between 0.5 and 0.9). This approach takes detailed cost estimates made at one scale (the base scale) and then estimates the cost of that same unit or process section at a different size considering nonlinear economies of scale. The smooth, continuous form is also particularly appropriate for use within an optimization framework where unit size is not known *a priori*. The NPV is calculated using a plant lifetime of 30 years and the tax information is taken from Canadian corporate rates. The full list of parameters is available in the supplementary material.

$C=C\_{A}\left(f\frac{S}{S\_{A}}\right)^{X}$ (1)

The polygeneration plant in this study operates under a variety of configurations which can include different possible units (FT synthesis, SOFC, etc.). If a unit is not used in a particular configuration of the plant the cost of the unit is not included. The economic calculation data includes the unit costing in Table 6, plant data and costing parameters in Table 2, resource/feedstock costs in Table 5, cost of transportation when required (see Figure 2) in Table 7, and wholesale prices of products in Table 1.

**Table 5** Feedstock costs of products of BGNTL plant with specific locations given where it significantly affects local cost.

|  |  |  |  |
| --- | --- | --- | --- |
| Resource | Cost | Unit | Source |
| Biomass | 110.6 | $/tonne | [34]  |
| Nuclear Hydrogen (CuCl) | 3.8 | $/kgH2 | [35] |
| Natural Gas | 0.081496 | $/m3 | [36] |
| Ontario Specific Costs |
| Electricity | 0.0878 | $/kWh | [37] |
| Alberta Specific Costs |
| Electricity | 0.211 | $/kWh | [38] |

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Unit | Base Cost ($M) | Base Size | Scale Factor | Installation Factor | Base Year | Source |
| ASU | 141 | 52 kg O2/s | 0.5 | 1 | 2007 | [39] |
| Gasifier Island | 120.05 | 730 MWth LHV of biomass | 0.7 | 1 | 2006 | [40] |
| COS Removal | 2.949 | 1 kmol/hr COS feed | 0.65 | 1 | 2012 | [41] |
| Water Gas Shift Reactor | 9.02 | 8819 kmol/hr of CO + H2 | 0.65 | 1.81 | 2002 | [42] |
| CO2 Removal Section | 43.38 | 327 CO2 removed in t/hr | 0.67 | 1 | 2002 | [43] |
| CO2 Compression | 9.52 | 13 Mwe of power | 0.62 | 1.32 | 2007 | [39] |
| FT Reactor | 10.5 | 2.52 million scf/hr of feed | 0.72 | 1.52 | 2003 | [44] |
| Pressure Swing Absorption Column | 5.46 | 0.294 purge gas flow kmol/s | 0.72 | 1.52 | 2003 | [44] |
| Pressure Swing Adsorption Purge Compressor | 4.83 | 10 Mwe power | 0.67 | 1.52 | 2003 | [44] |
| Pressure swing Absorption CO2 Rich Compressor | 4.83 | 10 MWe power | 0.67 | 1.52 | 2003 | [44] |
| FT Hydrocarbon Recovery Unit | 0.56 | 14.44 thousand lbs/hr feed | 0.7 | 1.52 | 2003 | [44] |
| FT Hydro Treater | 7.21 | 8.984 thousand lbs/hr feed | 0.7 | 1.52 | 2003 | [44] |
| FT Autothermal Reformer | 29.9 | 365 million scf/day feed gas | 0.67 | 1.32 | 2007 | [45] |
| Methanol Reactor | 81.77 | 10.81 kmol/s syngas | 0.65 | 1 | 2002 | [43] |
| Methanol Seperator | 1.72 | 4.66 kg/s MeOH produced | 0.291 | 1 | 2002 | [43] |
| DME Reactor | 15.8 | 2.91 kmol/s feed to reactor | 0.65 | 1.52 | 2003 | [44] |
| DME Separation | 21.3 | 6.75 kg/s DME produced | 0.65 | 1.52 | 2003 | [44] |
| Plant Compression | 6.3 | 10 Mwe power | 0.67 | 1.32 | 2007 | [39] |
| HRSG Steam Turbines and Condenser | 66.7 | 275 Mwe power generated | 0.67 | 1.16 | 2007 | [39] |
| HRSG Heat Exchangers | 41.2 | 355 MWth duty | 0.67 | 1.16 | 2003 | [44] |
| Cooling Plant | 1.7 | 3.3 MWe of cooling | 0.7 | 1.32 | 2007 | [39] |
| Gas Turbine | 73.2 | 266 MWe power generated | 0.75 | 1.27 | 2007 | [39] |

**Table 6** Unit sizing and pricing information for individual sections of a BGNTL plant.

**Table 7** Transportation costs of transporting resources to BGNTL plant with specific locations given where it significantly affects local cost.

|  |  |  |  |
| --- | --- | --- | --- |
| Resource  | Cost | Unit | Source |
| Hydrogen | 3.22 | $/kgH2 | [46] |
| Ontario Specific Costs |
| Biomass | 5 | $/tonne | [47] |
| Alberta Specific Costs |
| Biomass | 30 | $/tonne | [47] |

Feedstock costs for the BGNTL plant in each location are shown in Table 5 in CAD. Biomass, natural gas, and nuclear hydrogen purchase prices were assumed to be identical in Ontario and Alberta, with additional transportation costs for Alberta hydrogen and biomass to account for the lack of local availability. For Alberta, it is assumed the biomass comes from neighbouring British Columbia, and the nuclear hydrogen comes from Ontario and is shipped by truck, transportation costs are listed in Table 7. Capital costing is done using the Guthrie/Seider method with unit costing done using assuming 85% total capacity usage and power law to scale up the unit as seen in equation 1.

## 3.1 Economic Results

Table 8 shows the capital costing and sale requirements for the three selected cases. FT synthesis has the lowest cost to build and also requires the lowest revenue per year to maintain an NPV of zero. We also see that the cost and revenue requirement both increase with an increase in alternative fuel production, from case 3 to case 2.

**Table 8** Economic results for the three selected cases, for the Alberta 1 scenario.

|  |  |  |  |
| --- | --- | --- | --- |
|  | Case 1 | Case 2 | Case 3 |
| *Direct Capital Cost ($M)* |
| ASU | 108 | 132 | 107 |
| Gasifier | 82 | 93 | 81 |
| WGS | 3.2 | - | 3.3 |
| CO2 Removal & Compression | 24.8 | 27 | 22 |
| FT | 167 | - | 134 |
| DME | - | - | - |
| MEOH | - | 84 | 58 |
| Compressors | 9.5 | 9.7 | 9.2 |
| GT | 7.8 | 48 | 40 |
| SOFC | - | - | - |
| HRSG | 27 | 38 | 27 |
| HX Network | 61 | 87 | 56 |
| Cooling Towers | 2 | 2.4 | 2 |
| TCI ($M)  | 2,514 | 3,126 | 2,759 |
| Minimum Annual Sales ($M) | 669 | 851 | 707 |

# Chapter 4 Environmental

The comparison of the carbon emissions between processes are done using a cradle-to-product life cycle analysis. Greenhouse gas emission midpoints are calculated using the International Panel on Climate Change’s Fifth Assessment Report (AR5) GWP tables using the 100-year basis. The product-to-grave is not included as the polygeneration plant and status quo processes produce very similar products and will therefore have similar emissions downstream. The cradle-to-gate-entrance (a.k.a. indirect) emissions considered include the emissions associated with the electric grid; biomass growth and harvesting (which has net negative emissions on this step when accounting for removal from the atmosphere during growth); natural gas drilling, production, and transport; nuclear hydrogen production; and hydrogen and biomass transportation, where appropriate (Table 9).

**Table 9** Cradle-to-gate emission sources of the BGNTL plant feedstocks.

|  |  |  |  |
| --- | --- | --- | --- |
| Feedstocks | Value | Units | Source |
| Natural Gas | 3.74 | kgCO2e/MMBtu | [48] |
| 0.000106 | kgN2Oe/MMBtu | [48] |
| 0.469 | kgCH4e/MMBtu | [48] |
| Wood Pellets | -1.84 | kgCO2e/kgbiomass | [49] |

Possible direct emission sources for BGNTL processes come from wastewater (we assume all CO2 dissolved in wastewater eventually is emitted to the atmosphere), gas turbine exhaust emissions, and SOFC exhaust emissions. Note that off-gases from the FT and/or DME/methanol synthesis sections are routed to either the gas turbine or SOFC. These direct emission calculations for the BGNTL plant were determined from the simulation. The status-quo comparative product revenue and emissions used to calculate the CCA use emission data given in Table 10.

**Table 10** Direct emissions caused by production in status quo production, location specified where significant differences in values exist.

|  |  |  |  |
| --- | --- | --- | --- |
|  Product | Value | Units | Source |
| Methanol | 3.82844 | gCO2e/L | [50] |
| Nuclear H2 | 0.5 | kgCO2e/kg H2 | [51] |
| DME | 39.8 | kgCO2e/GJ | [52] |
| Ontario Specific Emissions |
| Electricity | 0.134 | kgCO2e/kWh | [52] |
| Diesel | 76 | gCO2e/MJ  | [53] |
| Gasoline | 88 | gCO2e/MJ  | [53] |
| Alberta Specific Emissions |
| Electricity | 0.543 | kgCO2e/kWh | [54] |
| Diesel | 110 | gCO2e/MJ | [53] |
| Gasoline | 108 | gCO2e/MJ | [53] |

The additional cost of transportation of hydrogen for the Alberta cases essentially doubles the cost of the hydrogen, however this could change in the future as Canada is considering implementing hydrogen pipelines [55] which could considerably reduce the cost of hydrogen and make greener alternatives (e.g. nuclear generated hydrogen) much more viable. Hydrogen production through the CuCl cycle has no associated capital costs, as the hydrogen is treated as a feedstock or commodity such that the purchase price includes the all associated business costs (capital, operating, taxes, profits, etc.).

## 4.1 Emission Results

The emissions from the BGNTL plant including cradle to gate emissions, direct emissions, and sequestered emissions from the CO2 sequestration are shown in Table 11. Net negative GHG emissions are possible due to the combination of carbon capture and the net negative indirect emissions of upstream biomass production. The significantly higher cradle-to-gate and sequestered emissions in case 2 are due to the increase in mass input to that plant to produce the same fuel energy due to the lower carbon efficiency of methanol production.

**Table 11** Environmental results for each optimal BGNTL plant design for the three selected cases, for the Alberta 1 scenario.

|  |  |  |  |
| --- | --- | --- | --- |
| (tCO2e/year) | Case 1 | Case 2 | Case 3 |
| Direct GHG emissions  | 303,500 | 124,000 | 576,100 |
| Cradle to plant gate entrance GHG emissions  | -702,400 | -836,300 | -690,900 |
| Sequestered  | 661,400 | 1,367,700 | 564,500 |
| Net Cradle-to-product GHG emissions | -398,900 | -712,300 | -114,800 |
| Net CO2 Avoided  | 2,172,900 | 1,665,200 | 1,580,200 |

## 4.2 Cost of CO2 Avoided Results

Table 12 shows the CCA – the optimization minimization objective of each scenario, the difference in cost, and the difference in emissions between the BGNTL plant and status-quo. The cases with a 1.5:1 ratio of biomass to natural gas show a much larger reduction in GHG emissions, however the increased revenue required makes them more expensive per tonne of GHG they avoid than the 1:1 ratio cases.

**Table 12** Overall economic and environmental metrics and CCA for selected cases and scenarios.

|  |  |  |  |
| --- | --- | --- | --- |
|  | CO2 Avoided(MtCO2e/year) | Additional Revenue required by BGNTL ($M/year) | CCA($/tCO2e) |
| Case 1 – Alberta 1.5 | 2.8 | 339 | 119 |
| Case 1 – Alberta 1 w/o CCS | 1 | 241 | 231 |
| Case 1 – Alberta 1 | 2.2 | 190 | 87 |
| Case 1 – Ontario 1 | 2.1 | 194 | 90 |
| Case 2 – Alberta 1  | 1.7 | 230 | 138 |
| Case 3 – Alberta 1 | 1.6 | 195 | 122 |

The second row of Table 12 is for a case in which the CO2 compression and sequestration steps have been removed and the associated CO2 is instead vented to the atmosphere. CO2 is still avoided in this case compared to petroleum fuels because of biogenic nature of the biomass and low-carbon nature of the nuclear energy used. However, the CCA is worse than in the CCS-enabled cases since waste CO2 must still be removed from the fuel synthesis reactor feeds anyway, so spending the relatively small extra cost on the compression and sequestration is a good environmental investment.

The difference in CCA between Alberta and Ontario is relatively small, and so the geographical impacts in this instance are negligible. Compared to Ontario, the gains made by displacing electricity in Alberta (which has a high power grid carbon intensity) is mostly offset by additional CO2 emissions associated with transportation of raw materials to Alberta from afar. As such, the net benefit to both provinces within the economic assumptions of this study is essentially the same.

The Case 2 and Case 3 designs which are qualitatively different in structure have both worse CCAs but also lower GHG emissions as well. There is little reason to consider these processes under the current economic assumptions when considering BGNTL for CO2 abatement purposes. Under different market conditions, this conclusion could change.

In no case was it optimal to have multiple products or to split streams toward multiple processes. This is in line with almost all other “optimal polygeneration superstructure” type studies when those processes are “static”, meaning that they have one fixed design. However, flexible designs in which products can be changed during operation (perhaps daily or seasonally) in response to changing market conditions could be superior to a static design, but this is a study for future work.

# Chapter 5 Sensitivity Analysis

The optimization portion of this study determined several design and operation conditions which provided optimal economic and environmental results. The sensitivity analysis is done on the best design cases produced as a result of the optimization and is not further optimization itself. Therefore, these changes are not intended to provide additional optimums and are a comparison of fluctuations that may occur (e.g. due to feed price changes) or situations that would be investigated before production (e.g. equity interest rate) in one static design. The factors compared are the FT to MeOH production ratio, the price of gasoline, the price of biomass, the equity rate of return, and the price of electricity. The values used for comparison of these factors are selected based on information from literature, while all other decision variables in the process are held constant with a basis combining Case 1 and Case 2 from Table 3. Consistent with the cases chosen, the data used will be for Alberta, with a 1:1 wood to natural gas ratio using carbon capture and sequestration.

 The sensitivity analysis illustrates the effect of four key inputs on the optimization of the process. These figures give a visual comparison of the effect on different configurations of the plant, and the different impact based on how significant it is to different process configurations. For each comparison the fraction of MeOH versus FT fuels is shown compared to the CCA, where the altered parameter options are given in the legend. In each case an increase in the cost (or equity interest rate) or an increase in the MeOH fraction of the products results in an increased cost of CO2 avoided.

 Figure 3 (a-c) show changes in feedstock/product prices, with electricity acting as a product in this case with every combination of FT/MeOH synthesis netting positive electricity. In figure 3 (a) the CCA of high fraction MeOH production is more impacted by increasing biomass cost because of the higher volume required of all feedstocks required to produce the same energy output. In figure 3 (b) the CCA of 99% MeOH production has no change with the price of gasoline since none is being produced. The production of FT fuels however shows a decreasing CCA with increasing gasoline price, as the required revenue for the plant becomes closer to the profit of selling the fuels at the “status quo” or adjusted price. This effect is also seen in figure 3 (c) with changes in electricity price for both MeOH and FT fuel production, with more pronounced effect on MeOH because of the higher fraction of electricity in the output energy. Figure 3 (d) shows the effect on the CCA of the equity rate of return. The range of 10-30% is common in industry, with 10% or lower used in the utility sector, and 18% or higher in technology or retail businesses [56]. The most notable result of this sensitivity analysis is if financing a MeOH (biofuel) plant and an FT fuel plant have different economic parameters, specifically different equity interest rates, this could change the optimal product decisions.



(a)

(b)



(c)

(d)

**Figure 3** The effect of varying (a) price of biomass ($/tonne) (b) price of gasoline ($/L) (c) price of electricity ($/kWh) (d) equity interest rate (%) on the CCA of a BGNTL plants producing a combination of MeOH and FT fuels from 1-99%, for the Alberta 1 scenario.

 Economic factors were chosen for this analysis as local resource availability is unlikely to significantly change, and since the aim is to lower the CCA by reducing GHG emissions, reductions to the economic portion of the calculation would meet our goals the most effectively. Comparison of multiple factors or optimization under uncertainty are left to future study.

# Chapter 6 Conclusions

In this work novel polygeneration plants for producing liquid fuels and electricity are compared and assessed on a basis of environmental and economic metrics. The different designs compare fuels produced, resources used for syngas production, and the production or purchase of electricity under current market conditions. The key conclusions of the study are listed below:

* The BGNTL design with the lowest CCA was the one that maximized FT production and had about an equal amount of biomass and natural gas by mass, with a CCA of about $90/tCO2e. This is one of the lowest CCAs for transportation fuel alternatives and deserves further examination and consideration. The CCA number is sensitive to economic assumptions, and so could be higher with different financing considerations, such as a higher equity return rate requirement.
* There was little impact on CCA by locating the BGTNL plant in Alberta vs. Ontario. The benefits of displacing high-carbon electricity in Alberta were mostly offset by extra transportation costs.
* Net negative cradle-to-product emissions are possible with the use of carbon sequestration and biomass feedstock.
* An increase in the ratio of biomass feedstock to natural gas significantly reduces emissions but is more expensive to reduce each tonne of emissions than with a lower biomass ratio of feedstock. Thus, when constructing BGNTL facilities for the purposes of avoiding CO2 emissions, it may make sense to use the design with the lower biomass proportion.
* In optimization of static polygeneration systems product decisions end with a single optimal choice due to the significant capital cost required to build additional units, and with no price flexibility one product will be optimal.

## 6.1 Research Suggestions

1) Flexible Design

Flexible design would allow a variety of additional factors to be incorporated in the optimization of this process that are not feasible in a static status quo comparison. Changes to carbon taxes and fluctuations in resource and transportation costs could influence the design enough for a multi-output system to be optimal for production over a plant lifetime.

2) Self Sufficiency

Current political environmental regulations globally look at individual countries’ emissions for setting regulations. If the emphasis on reduction is significantly increased in the future this could lead large exporters to reduce exportation production, forcing countries to become more self sufficient. The ability to produce a flexible amount and variety of fuels to meet local and national needs using available resources could be invaluable.

Additionally, looking at the increasingly frequent conflicts occurring globally and the shortages this causes with very little notice for those affected, the ability to be self sufficient when required could prevent shortages of resources or products we currently depend on imports for.

3) Unit Reuse

If in a flexible design, economic changes can cause a complete production switch in a plant between two products, for example from making all MeOH to all FT fuels. Instead of purchasing two complete sets of equipment, the reuse of duplicated pieces or small sections is a possibility since a shutdown/start-up process would need to be completed for the product changeover. This reuse could significantly reduce the cost of equipment while potentially only requiring a small complexity increase in plant design, and small increase in turnover time between products.

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|  |  |
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