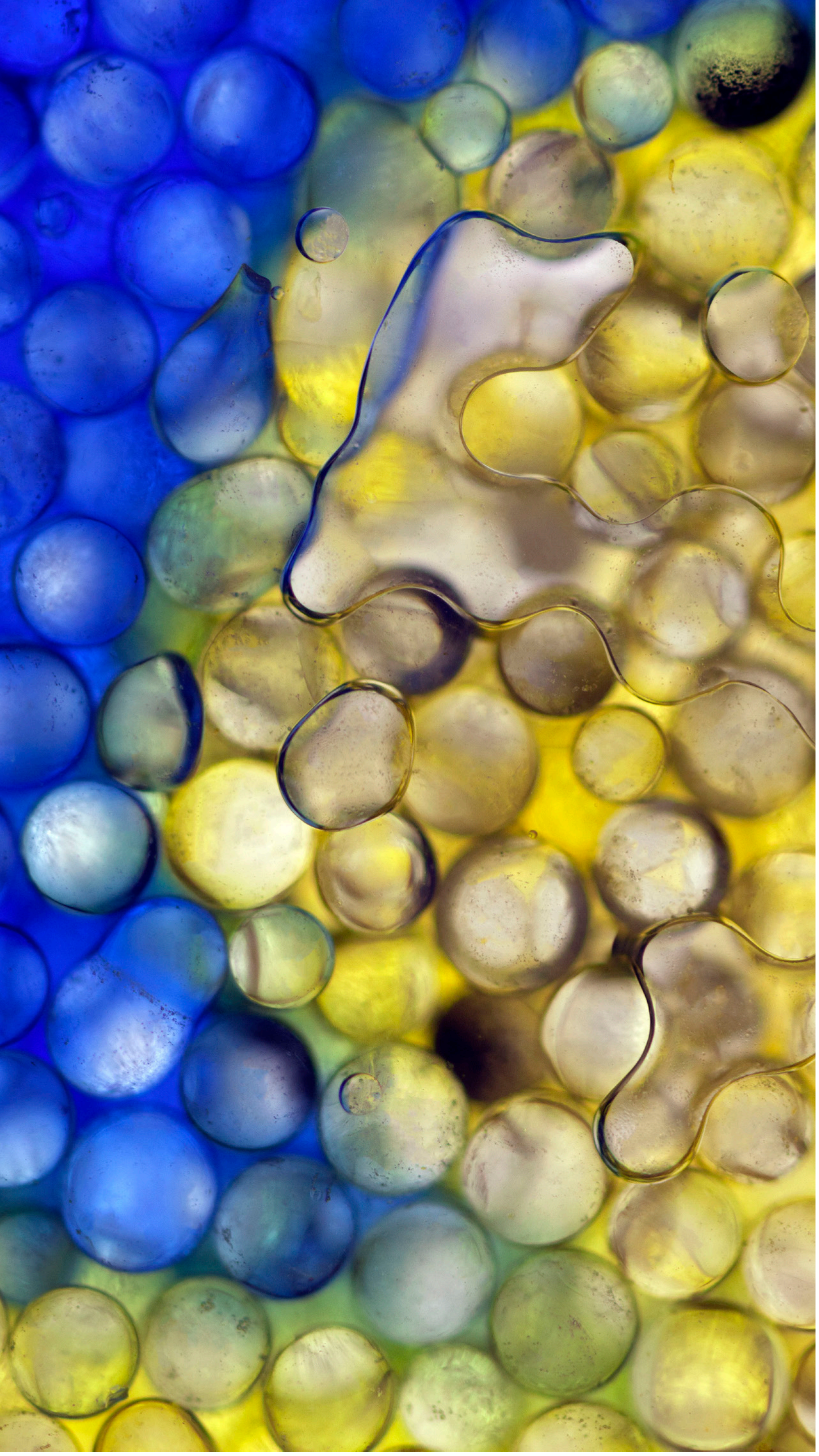

Biomass to Liquid Fuels Pathways:

A Techno-Economic Environmental Evaluation

An MIT Energy Initiative Report

March 2015

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Disclaimer

This report is based on information and data gathered from public domain sources. While the authors have used their best-efforts to assess the quality of the inputs, we could not verify all the information. Also, results presented herein are based on numerous assumptions embedded in the developed models and tools. The results presented and conclusions drawn in this report should not be used or extrapolated beyond the purpose for which they were generated.

This report includes results from various timeframes during the development of the computer models. Therefore, these results may not be entirely consistent. Also, results generated with earlier versions of the models may not be reproducible using the final version of the models.

March 2015

Executive Summary

This report summarizes the findings from the Techno-Economic-Environmental Analysis of Biomass to Liquid Fuel Pathways project, part of the BP-MIT Energy Initiative (MITEI) Conversion Research Program. In this project an array of simulation and modelling tools were developed to analyze biomass production, processing, transport, gasification and conversion to liquid fuels, lifecycle greenhouse gas (GHG) emissions, and project economics.

A variety of pathways were analyzed using the models. Key variables studied include feedstocks (woody biomass, herbaceous biomass, Municipal Solid Waste (MSW), and natural gas), gasifiers (fluidized bed, entrained flow, plasma), tar handling technologies, scale (i.e., size of plant), and the implications of adding carbon capture.

In the models, woody biomass was represented by loblolly pine and herbaceous biomass was represented by switchgrass. Switchgrass bales were about $20/dry tonne more expensive at the farm gate, than loblolly pine woodchips at the forest gate. This cost gap is mainly due to higher switchgrass production costs.

For biomass-to-liquid plants (BTL), biomass will generally be transported by truck and sourced within 60 miles of the plant. For large plants (20,000 bbl/day), longer distances for biomass transport will be required. For long-haul transport (>300 miles) of biomass, rail or barge may provide an economic alternative to trucks.

Biomass feedstocks can be densified into pellets. This can significantly lower the conversion plant capital costs by increasing the gasifier throughput (see Figure ES.1). Additionally, if pelletization occurs close to the biomass source, it can reduce transport costs. However, in-field pelletization significantly increases feedstock costs. Therefore, unless transport distances are large (>500 miles), we find that pelletization at the conversion plant site is a more cost-effective strategy.

MSW is gaining interest as an alternative feedstock. Small commercial plants exist today that can convert MSW to liquid fuels. The biggest economic advantage is the additional revenue from the tipping fee.

Both fluidized-bed and entrained-flow gasification technologies have the potential to be utilized for economic production of fuels from biomass, but their deployment has been limited and they cannot yet be deemed commercial. Based on our analysis of current technology, the estimated fuel production cost is lower for fluidized-bed gasifiers when compared to entrained-flow gasifiers. For conversion of waste, plasma gasification technologies are attractive because of their unique abilities to cope with the large variability in particle size, moisture, energy content, and composition of the waste stream. However, plasma gasification is currently less energy efficient than the other gasifiers.

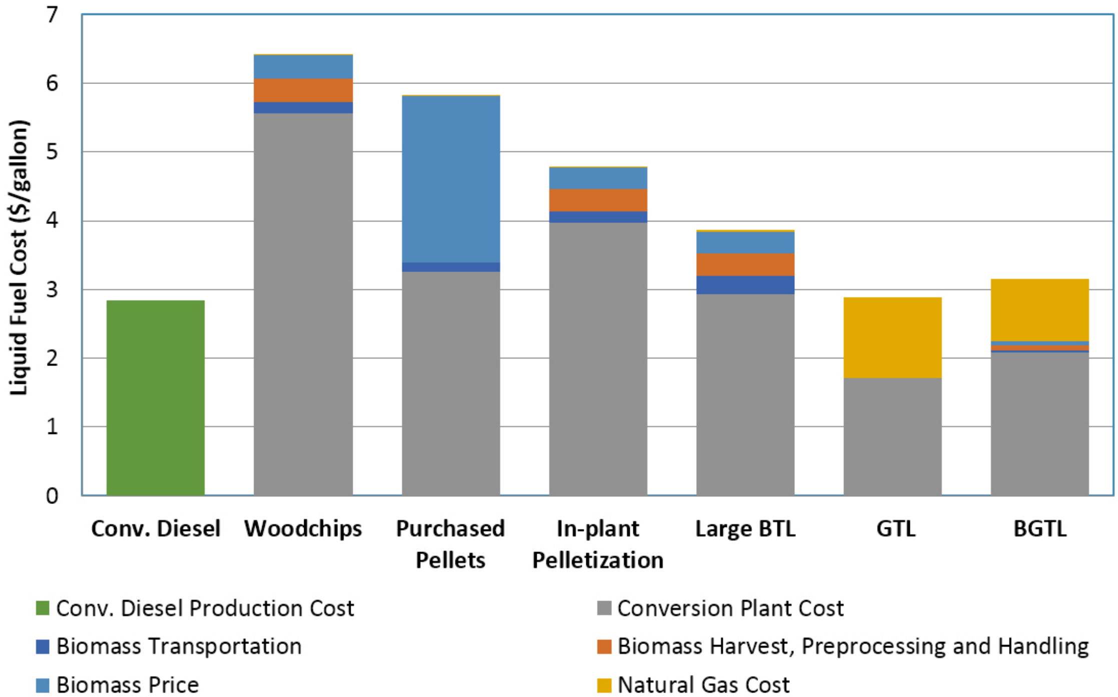

Figure ES.1 | Comparison of the fuel production cost breakdown for a range of scenarios investigated in this study. Assumed biomass feedstock: loblolly pine. Assumed purchase pellet price: \$150/tonne$_{dry}$. Assumed natural gas price: \$5/MMBtu. Assumed crude oil price: \$100/BBL; Plant capacities: Woodchips: 3,700; Purchased Pellets and In-plant Pelletization: 4,100; Large BTL: 16,400; GTL: 18,900; and BGTL: 18,600 (all in bbl/day).

For removal of tars from the syngas produced by fluidized-bed gasifiers, we found thermochemical technologies the preferred route. While more costly than scrubbing processes, they are a less risky approach for reducing the tar components to the low levels required for Fischer-Tropsch synthesis applications. If demonstrated at scale, operating the freeboard of the gasifier at higher temperatures (~1,200°C) can potentially be the most cost-effective approach in removing the tars.

Due to economies of scale, as the size of the BTL plant increases, the processing costs decrease (see Figure ES.1). However, feedstock delivered costs will rise as the biomass feedstock needs to be sourced from more distant locations. Therefore, the advantages of scale plateau beyond plant sizes of ~20,000 barrel per day due to the increased distance and cost of biomass transportation cancelling out the savings from going to larger scale.

One way to achieve economies of scale without requiring large amounts of biomass is through a hybrid BTL and gas-to-liquids (GTL) plant (referred to as a BGTL plant). Given the mid-2014 prices of oil ($100/BBL) and natural gas ($5/MMBtu) in the United States, liquid fuel from GTL plants is competitive with conventional fuels (see Figure ES.1). The hybrid BGTL plant has higher capital cost compared with the GTL plant, but lower costs than BTL plants of similar sizes. BGTL plants also have reduced production costs compared to BTL plants, and can provide significant advantages in addressing the technical and financial risks associated with large-scale deployment of BTL technology.

A major driver of BTL technology is the lowering of the carbon footprint of liquid fuels. While BTL fuels are more expensive than conventional fuels, there are policies in place to incentivize BTL plants. Given mid-2014 prices, we found that with biofuel credits of $\$0.60/\mathrm{gal}_{RIN}$, BGTL and large BTL plants are competitive with conventional diesel (see Figure ES.2).

Choice of feedstock affects the carbon footprint. We found that BTL plants using switchgrass had higher greenhouse gas emissions compared with plants using loblolly pine. This is due to the nitrogen content of switchgrass being several times higher than pine, resulting in a much higher nitrogen depletion rate which must be replenished with nitrogen fertilizer to maintain soil productivity. Another key consideration is whether there are any direct or indirect impacts from land-use change associated with the biomass feedstock.

Since BTL plants generate a high purity stream of CO_2, carbon dioxide capture and storage (CCS) can be added with no significant impact on the plant economics. CCS can significantly decrease the carbon footprint of the produced liquid fuels, as well as lowering the overall cost of avoided CO_2.

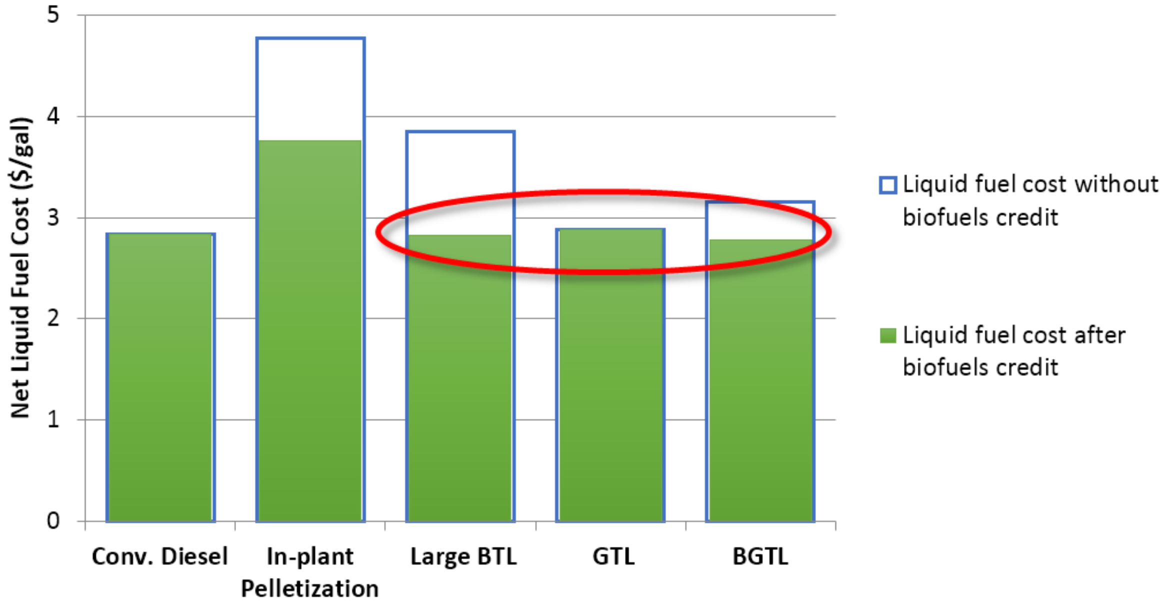

Figure ES.2 | Effect of biofuels credit on the net production cost of liquid fuels from different BTL, GTL, and BGTL plants. Assumed RIN price: $0.60/gal$_{RIN}$. Assumed biomass feedstock: loblolly pine. Assumed natural gas price: $5/MMBtu. Assumed oil price: $100/BBL; Plant capacities: In-plant Pelletization: 4,100; Large BTL: 16,400; GTL: 18,900; and BGTL: 18,600 (all in bbl/day).

Given current energy prices (including biomass price), the climate policy situation, and state of conversion technologies, large BTL projects are extremely challenging from an economic viewpoint. This report shows some BTL pathways which could potentially produce liquid fuels that compete with conventional fuels. However, these projects would be considered very financially risky today. The following items will improve the prospects for BTL plants: lower biomass prices, growth of biomass commodity markets, improved thermochemical conversion technologies, stronger climate policies in regard to transport fuels, and higher petroleum prices.

Abbreviations

AGR	Acid gas removal unit
AP	Aspen Plus
APEA	Aspen process economic analyzer
AR	As received
ASU	Air separation unit
ATR	Auto-thermal reforming / reformer
BAU	Business as usual
bbl	Barrel
BGTL	Hybrid natural gas- and biomass-to liquid fuels
BMP	Best management practices
BOP	Balance of plant
bpd	barrel per day
BTL	Biomass-to-liquid fuels
Btu	British thermal unit
BTX	Benzene, Toluene, and Xylene
CCS	Carbon capture and storage
CM	Custom model
CND	Syngas conditioning unit
CO	Carbon Monoxide
CO2	CO_2 conditioning and compression unit
CONV	Conventional fuel
CRP	Conservation reserve program
CTL	Coal-to-liquid fuels
CU	Columbia University
DFC	Distance fixed cost
DQ	Direct quench
DVC	Distance variable cost
EF	Entrained-flow
EFG	Entrained-flow gasification / gasifier
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
FB	Fluidized-bed
FBG	Fluidized-bed gasification / gasifier
FT	Fischer-Tropsch
FTS	Fischer-Tropsch synthesis unit
G&A	General and administrative expenses

GAS	Gasification island
gCO_2e	Gram of CO_2 equivalent
GHG	Greenhouse gas
GREET	Greenhouse gases Regulated Emissions and Energy in Transportation
GTL	Natural gas-to-liquid fuels
H2P	Hydrogen production/separation unit
HHV	Higher Heating Value
HTW	High temperature Winkler
IGT	Institute of Gas Technology
INL	Idaho national laboratory
IRR	Internal rate of return
$kgCO_2e$	Kilogram of CO_2 equivalent
LCA	Life-cycle analysis
LHV	Lower Heating Value
MESD	Minimum Economic Shipping Distance
MIT	Massachusetts Institute of Technology
MMBtu	Million British thermal unit
MS	Microsoft corporation
MSW	Municipal solid waste
NG	Natural gas
NGR	Natural gas reforming unit
NPV	Net present value
OLGA	Dutch acronym for oil-based gas scrubber
PNNL	Pacific northwest national laboratory
POX	Partial oxidation
PRENFLO	Pressurized entrained-flow
PRP	Feed preparation
RFS	Renewable fuel standard
RIN	Renewable identification number
RXR	Reactor
SMR	Steam methane reforming / reformer
SR	Steam reforming
SRU	Sulfur recovery unit
STM	Steam and power island
TAR	Tar and methane handling unit
TASC	Total as-spent cost
TEE	Techno-economic-environmental
TOR	Torrefaction unit
tpa	ton per annum

tpd	ton per day
U.S.	The United States of America
UHTW	Ultra high temperature Winkler
WGS	Water-gas-shift unit
WTE	Waste-to-energy
WTL	Waste-to-liquid fuels
WTR	Water management unit
XTL	everything (coal / biomass / natural gas / waste)-to-liquid fuels

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1. Introduction

The purpose of this report is to document the main results from the "Techno-Economic-Environmental Analysis of Biomass to Liquid Fuel Pathways" project, hereafter referred to as the "Project." The Project was one of the many projects within the BP-MIT Energy Initiative (MITEI) Conversion Research Program, hereafter referred to as "Program," which began in 2007. The main research objectives of the Project were:

- Develop, maintain, and enhance the developed simulation system (process and cost estimation) for evaluation of various thermochemical BTL pathways;
- Perform a techno-economic-environmental analysis of potential thermochemical pathways for converting biomass to liquid fuels;
- Investigate alternative liquid fuels production pathways including BTL and hybrid (biomass and natural gas to liquids) and evaluate various feedstocks, process configurations, etc.
- Identify the most promising candidates.

This report is focused on summarizing the main outcomes from the Project. The detailed documentation of the techno-economic-environmental (TEE) analysis tool developed during the Project is provided separately as Model Documentation. The Model Documentation includes the methodologies used in and assumptions made in developing various components of the TEE analysis tool, hereafter referred to as TEE model.

Chapter 2 of this report provides an overview of the TEE model structure and briefly describes the various TEE model components.

Chapter 3 describes various types and formats of biomass feedstock, which are evaluated in the Project. Chapter 3 also presents the results of analyses and case studies on various types and formats of biomass feedstock.

Conversion of municipal solid waste (MSW) to liquid fuels is discussed in Chapter 4. In addition, the results of studies on MSW availability in terms of generation rate as well as its geographical distribution in the United States are summarized in Chapter 4. Although both biomass and MSW were evaluated in this research, conversion of biomass to liquid fuels was the focal point of the Project.

Chapter 5 includes descriptions and comparisons of some of the technologies utilized for biomass to liquid conversion. The main technologies groups discussed in this chapter are gasification (for both biomass and municipal waste) and tar handling.

Chapter 6 discusses another route for production of alternative fuels, conversion of natural gas to liquid fuels (GTL). Chapter 6 also includes evaluation and comparison of various natural gas reforming technologies and their effect on liquid fuel production cost. Also included in this chapter is the techno-economic-environmental evaluation of a GTL scenario. Most of this chapter (starting with Section 6.2) is focused on the hybridization of biomass and natural gas to liquid fuels (BGTL). Various design strategies for development of such plants are evaluated including greenfield and retrofit options. Operational flexibility of hybrid conversion plants is also covered in this chapter.

Chapter 7 summarizes the results of the GHG emissions of the main scenarios discussed in prior chapters. This chapter also briefly discusses the results of the dynamic GHG emissions of a typical BTL plant. The Renewable Fuel Standard (RFS) is discussed in Section 7.6, including the methodologies used for determining the renewable potion of a hybrid plant product. The chapter also includes discussion of how renewable fuel credits affect the economics of the BTL and hybrid plants.

2. Techno-Economic-Environmental Model Overview

The purpose of this chapter is to briefly familiarize the reader with the methodologies and assumptions used for evaluation of various BTL pathways. Describing all the inputs and assumptions used in the development of the Techno-Economic-Environmental (TEE) model is outside of the scope of this report. For more information regarding assumptions and methodologies of the TEE model please refer to model documentation.

2.1. TEE Model Architecture

The TEE model uses Microsoft Excel® as its main user interface and it integrates various modeling components into a unified system. Figure 2.1 depicts the TEE model structure and its components (sub-models). Different sub-models represent biomass production, biomass logistics (including biomass harvest, in-field operations and storage), biomass transportation, and biomass conversion to liquid fuels. Transportation of the final fuel product is not modeled explicitly in the TEE model. Figures from literature are used to account for cost, energy demand, and associated emissions of transportation of liquid fuel from the conversion plant to market.

The biomass production, biomass logistics, biomass transportation and GHG emissions calculation tools were developed in Excel. The conversion plant is simulated using Aspen Plus® process simulator. The capital and operating cost estimation of the conversion plant is performed using a combination of Aspen Process Economic Analyzer (APEA) and customized tools developed in Excel based on publicly available data. The results generated from these sub-models are used for the estimation of capital and operating costs, mass and energy balances, life-cycle GHG emissions, and financial analysis of various BTL scenarios. Also, scenarios for conversion of natural gas to liquid fuels are defined and investigated in the Project using the developed tools. For detailed information regarding methodologies and assumptions used in the TEE model, refer to the model documentation.

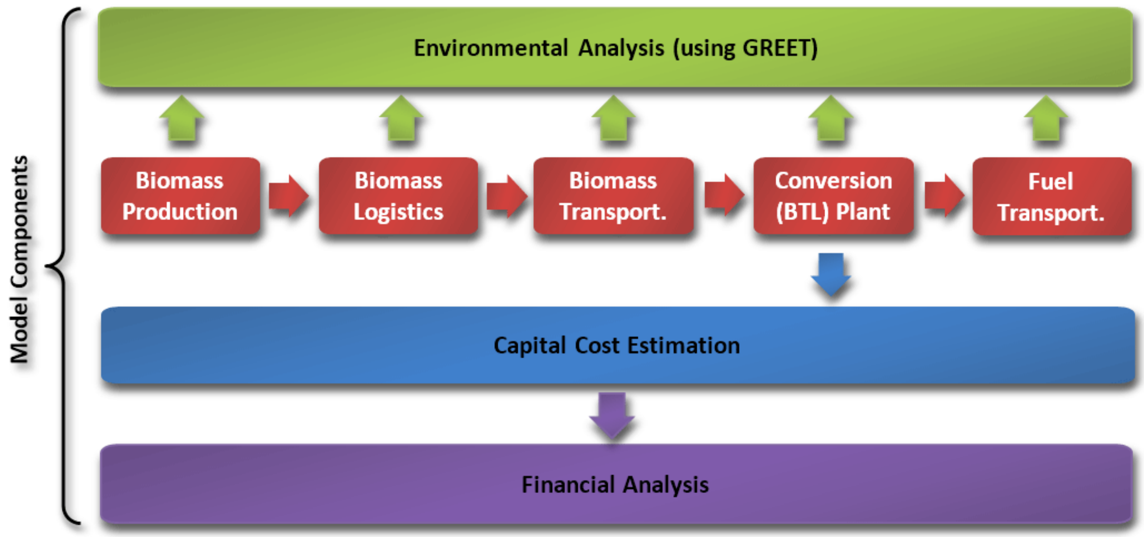

Figure 2.1 | TEE Model Architecture

2.2. Range of Options

The TEE model is capable of evaluating various biomass to liquid fuels scenarios. For example, users can choose from various biomass types and forms, in-plant feedstock preparation, and gasification technologies options. Figure 2.2 shows various options available within the TEE model. Users can specify a specific configuration and obtain the results of the techno-economic-environmental analysis for that scenario.

The following sections in this chapter briefly describe various components of the TEE model and include main assumptions made for each model component. Finally, Section 2.9 presents the assumptions and results for the Reference case to showcase the capabilities of the TEE model.

2.3. Biomass Logistics Model

Five biomass formats (whole-tree woodchip, clean woodchip, wood pellet, square bale, and round bale) and three transportation modes (truck, rail, and barge) were considered for the development of the biomass logistics and transportation models. As main outputs, the model evaluates the logistics costs and energy uses for different feedstocks and operation equipment. The Greenhouse gases Regulated Emissions and Energy in Transportation (GREET) model developed by Argonne National Laboratory [1] is then used for estimating the GHG emissions based on logistics model outputs.

The overall structure of the biomass logistics model is shown in Figure 2.3. Model inputs include biomass production, the operation window, equipment data, and biomass information such as dry matter loss and bulk density. The logistics model has two separate modules for modeling in-field operations for woody and herbaceous biomass.

The logistics model also includes different biomass storage methods for herbaceous-type biomass. Biomass handling and processing within the conversion plant is not within the scope of the logistics model.

The in-field logistics model estimates costs and energy consumption including biomass harvest, collection, preprocessing, and storage. Cost estimating methodologies used for agricultural and forestry equipment are derived from Turhollow and Sokansanj [2] and forest harvesting publications [3], [4]. The in-field logistics costs are categorized as ownership costs and operating costs, which are typically represented in $/h. Equipment ownership costs including capital depreciation, interest, insurance, housing (e.g. equipment shed), and taxes are calculated based on equipment purchase price, salvage value, operation window, and machine lifetime. Operating costs consist of machine repair and maintenance, fuel and lubricant, material (e.g. baling net), and labor, which are heavily dependent on machine performance.

In this model, equipment purchase price and performance data are sourced from literature, machine operation manuals, and manufacturer quotes. Empirical factors and equations are used for estimating equipment repair and maintenance costs and fuel consumption when such data are inaccessible [2], [5]. The total costs are then divided by the equipment in-field capacity (dry tonne/h), determined by factors such as equipment condition, field condition, dry matter loss, and operator skill level, to provide the biomass in-field logistics cost ($/dry tonne). All the costs presented in this chapter are in 2012 dollars.

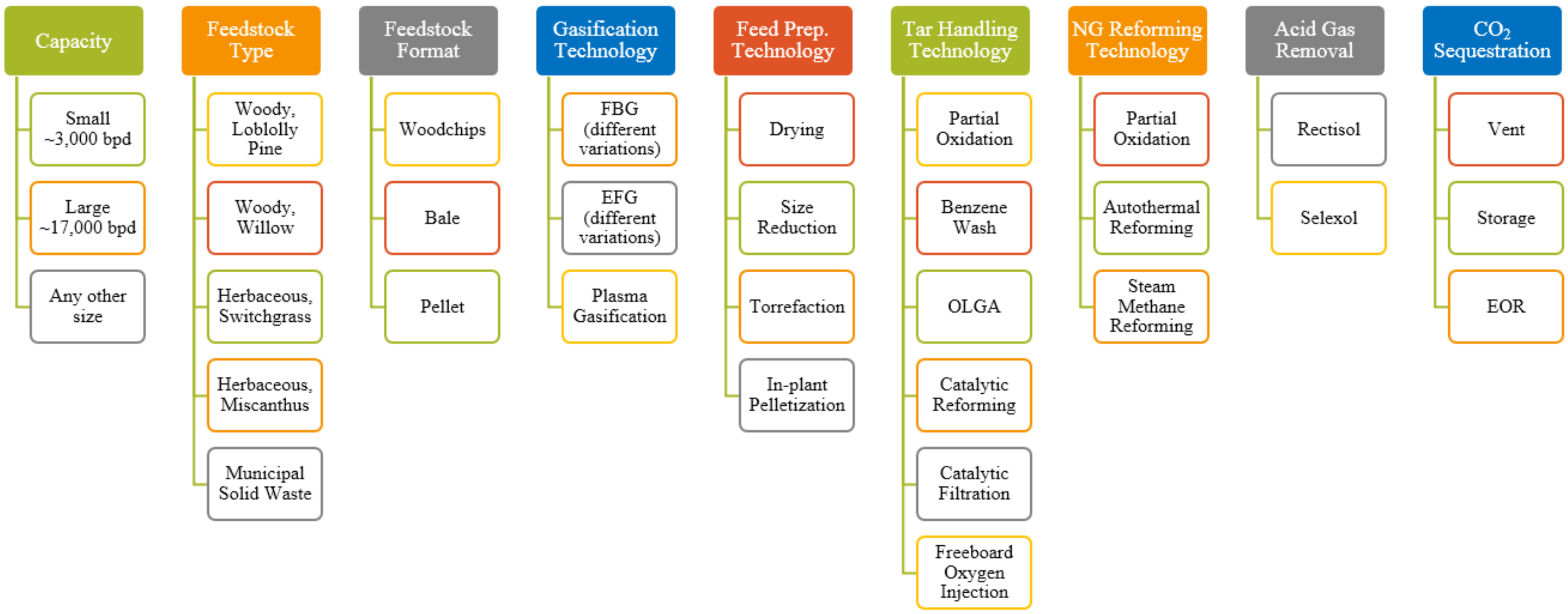

Figure 2.2 | Range of options available in the TEE model, which can be used to define various scenarios.

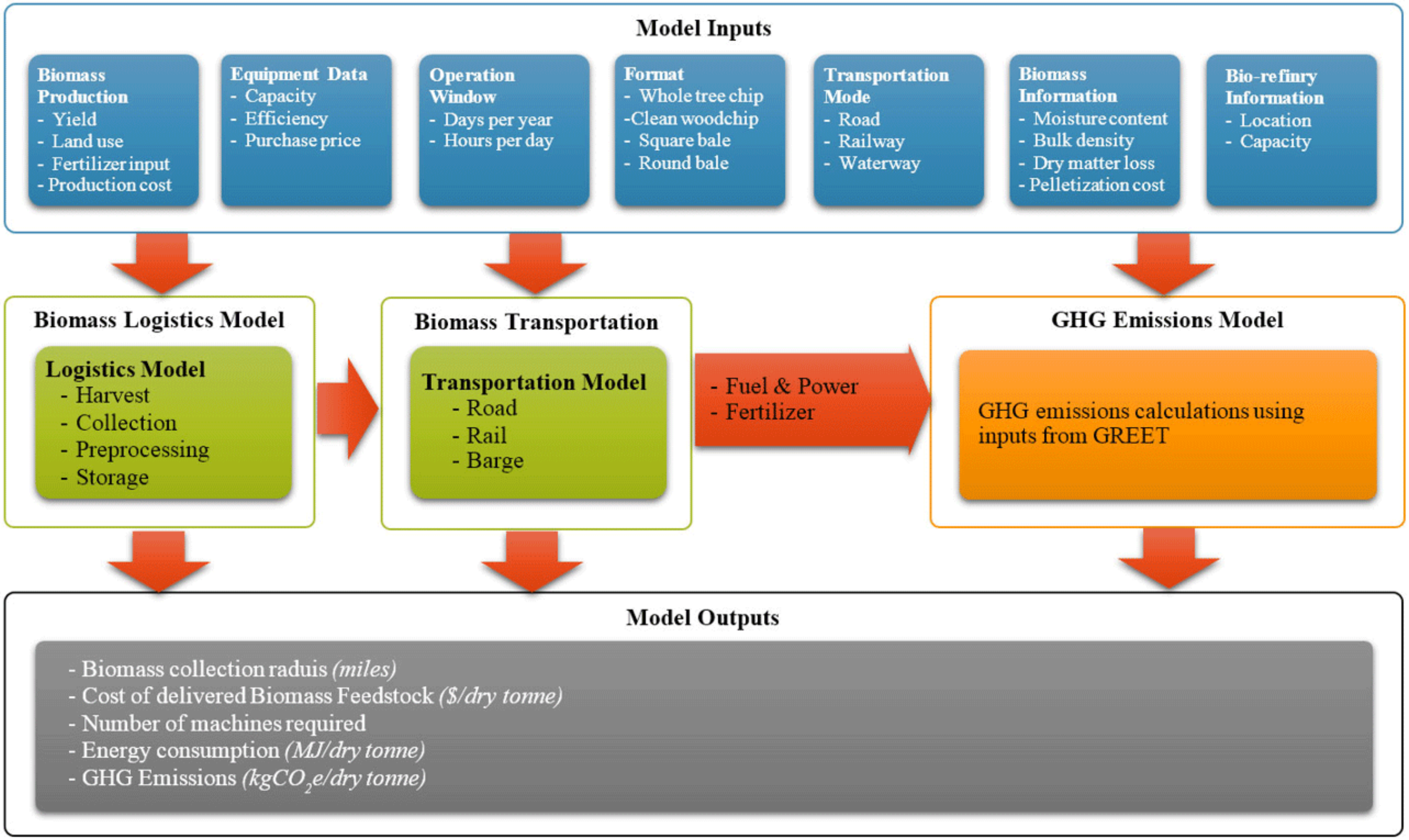

Figure 2.3 | Developed Framework for Biomass Logistics (production and in-field operations) and Transportation.

2.4. Biomass Transportation Model

In the transportation model, cost and energy consumption calculation methods depend on the transportation mode. Three transportation modes, truck, rail and barge, were considered for biomass shipment. Truck transportation cost is estimated based on the same methodology as in-field operation by defining the average travel speed and transportation distance, which is determined by biomass yield, dry mass recovery efficiency, and fraction of land used for biomass cultivation. For railway and waterway, biomass transportation cost is estimated from literature and carrier quotes.

The biomass transportation cost ($/dry tonne) is evaluated as the sum of the variable and fixed costs. For truck transportation, the total biomass shipment costs are derived from literature sources, using the same methodology as in-field operation equipment cost estimation. Biomass rail and barge cost is estimated by using online quote tool from CSX and Terral River Service, respectively [6], [7]. The model also includes factors such as biomass forms, bulk density, and moisture content in calculating the transportation cost.

The strategies used for biomass transportation are shown in Figure 2.4. Truck transportation is first used to collect woodchips and bales due to the dispersed nature of biomass production. The collected biomass is then either delivered directly to the biorefinery or to the transshipment terminal for long distance shipment. Thus the intermodal transportation typically takes advantage of the low variable costs for rail or barge transportation and high flexibility of road transportation. Another option is to transport biomass to a pellet mill nearby for densification and the pellets are then shipped to the biorefinery instead. Here we assume the pellet mill and biorefinery are located close to railway tracks or waterways with existing infrastructure such that no third leg of transportation is needed.

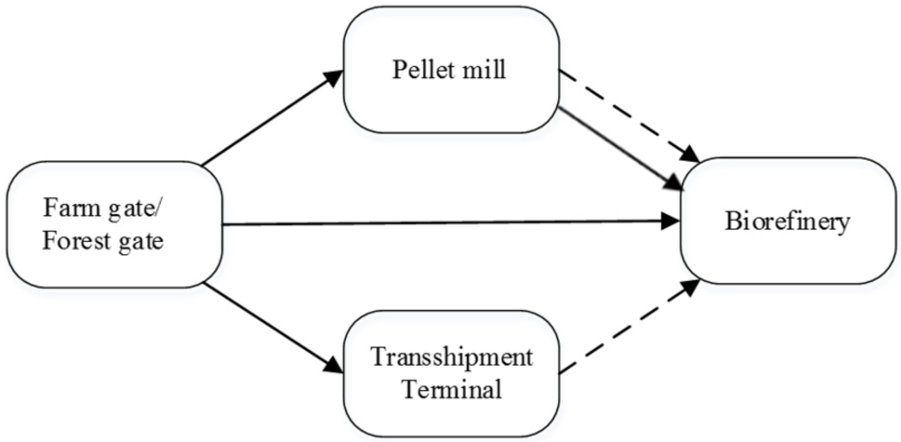

Figure 2.4 | Schematic illustration of strategies for biomass transportation; solid lines depict truck transportation while dash lines are rail or barge.

2.5. Conversion Plant Process Model

The conversion process model in Aspen Plus simulates the entire BTL plant. The process model is flexible and can take various configurations (see Figure 2.2). The conversion plant process model is comprised of various sub-models (hierarchies) simulating different processing units in the plant. The model also includes sub-models for main utilities needed for such plants, such as steam and power generation units and cooling water system. Figure 2.5 shows the major process units of the conversion plant model developed in Aspen Plus.

The conversion plant model is interfaced with Microsoft Excel and is capable of taking input from and sending results to the Excel interface. A set of results from the process model is sent to the main interface in Excel to be used for capital and operating cost estimation of the conversion plant.

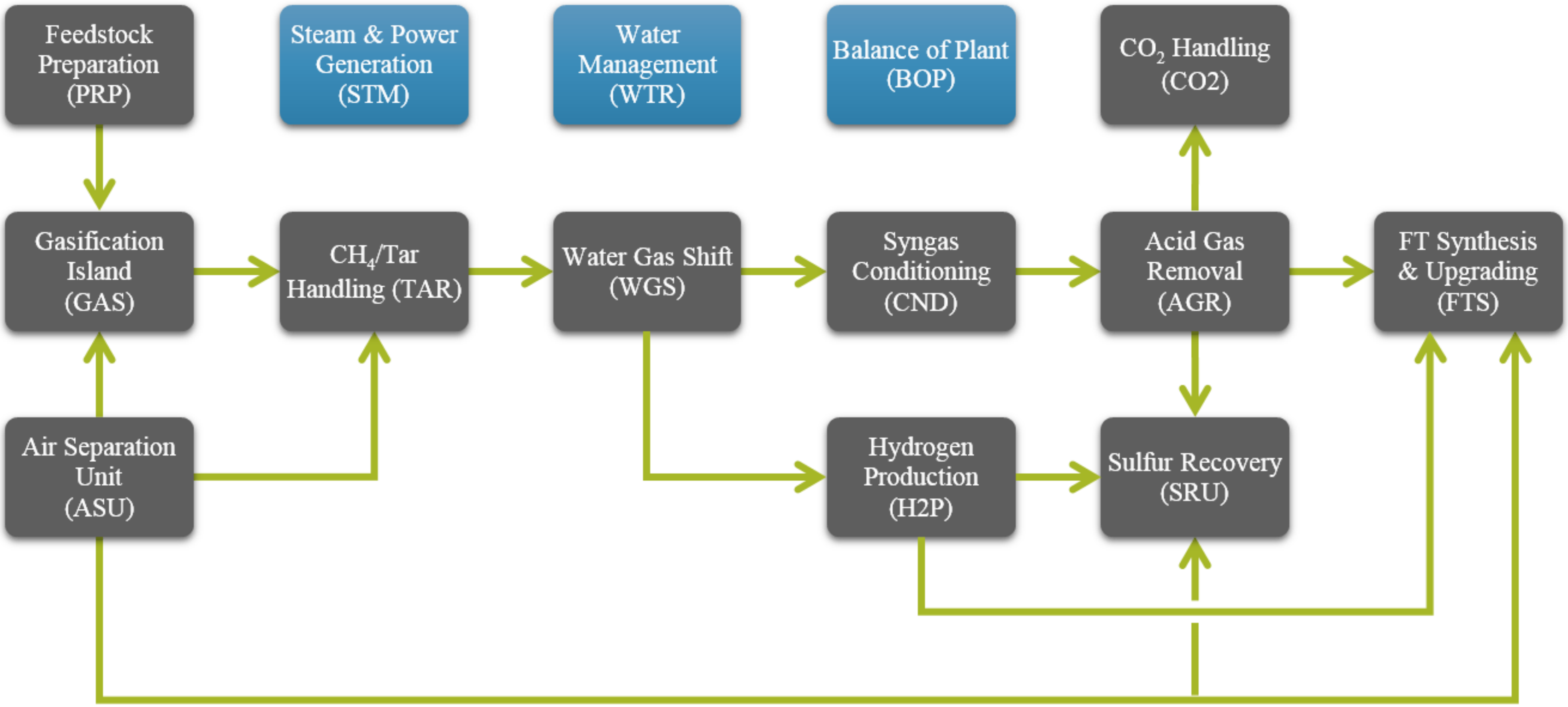

Figure 2.5 | Processing units of the conversion plant as simulated in Aspen Plus.

Figure 2.6 represents the distribution of tasks within the developed framework for process simulation, cost estimation, and financial analysis of the biomass to liquid fuels plant (conversion plant). As shown, the process simulation provides the mass and energy balance for the selected configuration of the conversion plant. The process data from the process simulation is exported to Aspen Process Economic Analyzer (APEA), where different pieces of equipment can be sized and the installed cost of each be estimated. In addition, other cost components of a typical conversion plant, such as buildings, are accounted for in APEA. The cost estimation results from APEA are transferred to Excel, which houses the main TEE model interface and its Excel-based components. The cost estimation of the conversion plant is further refined (especially those related to specialized pieces of equipment such as gasifiers). The installed capital costs are used to calculate the total plant cost and total capital investment. In addition, the operating cost is calculated based on the process simulation and the cost estimation results. Cost estimation and financial models are further discussed in Sections 2.6 and 2.7, respectively,

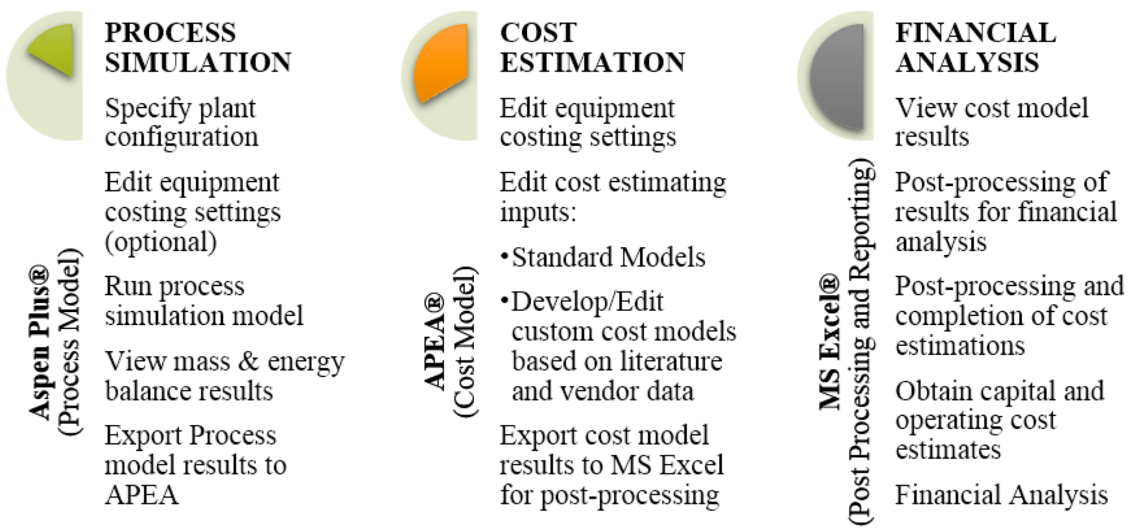

Figure 2.6 | Framework for process simulation, cost estimation and financial analysis of biomass conversion to liquid fuels (conversion plant).

2.6. Conversion Plant Cost Estimation Model

For standard equipment, volumetric models available in APEA are used to size and cost the equipment and calculate erection costs. For non-standard equipment and processing units, data from the literature and/or vendors are used to calculate/specify equipment sizes or train capacities as well as their installed capital costs. The comparison of these methods is graphically depicted in Figure 2.7.

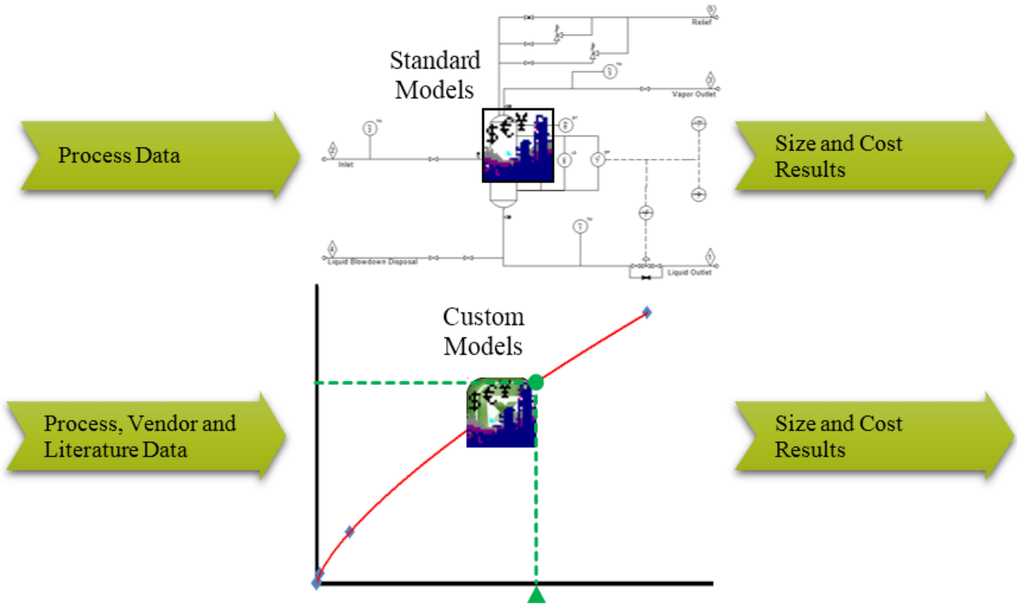

Figure 2.7 | Methodologies used for capital cost estimation of equipment and processing units of the conversion plant.

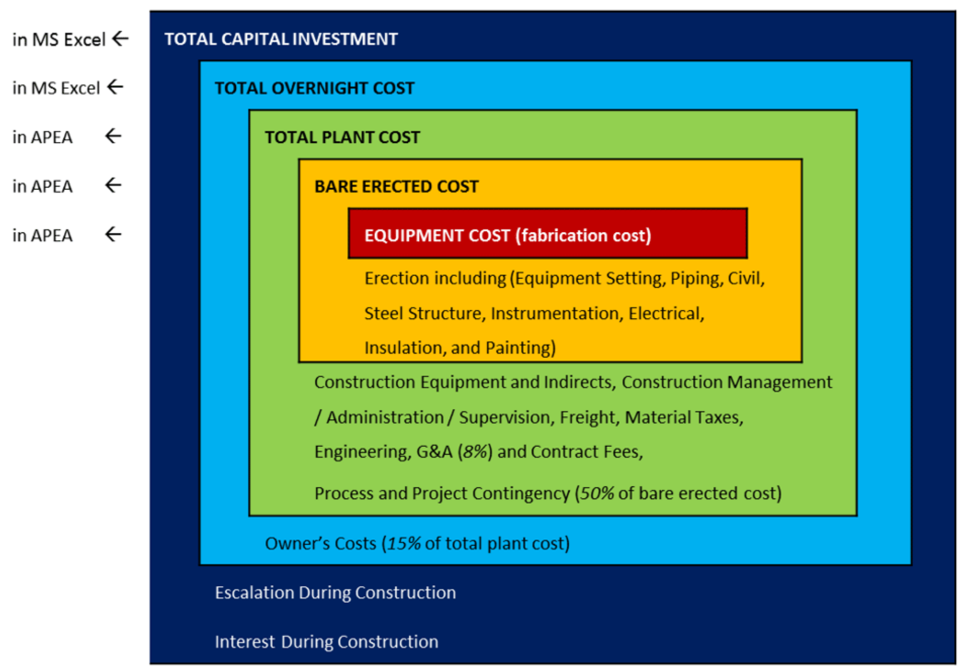

Figure 2.8 | Capital cost structure used for estimating the total investment cost of the conversion plant.

Of course, the cost of a BTL conversion plant is substantially higher than the bare erected cost of the equipment. As can be seen in Figure 2.8, capital costs such as engineering, G&A, contingencies, and owner's costs must be included. These costs are project and location specific, but for this analysis we use the factor costing method to generate an order-of-magnitude estimation of such costs.

2.7. Financial Model

The financial analysis module of the TEE model was developed in Excel and includes the following calculations:

- Performs financial analysis for different pathways (scenarios) in a single file
- Calculates Cash Flow, Internal Rate of Return (IRR), and Payback Period
- Performs financial analysis in two modes:
    - Net Present Value (NPV) Mode
    - Product Price Mode
- Performs sensitivity analysis for change in:
    - Raw material, product, and electricity prices
    - Fixed Operating Costs
    - Capital Cost
    - Discount Rate

The delivered biomass feedstock cost is an input to the financial analysis model and is calculated using biomass logistics and transportation models.

Table 2.1 lists the major assumptions used for financial analysis of various configurations of the biomass to liquid fuels conversion plant.

Table 2.1 | Major assumptions used for the financial analysis of the conversion plant.

Parameters	Value
Plant Lifetime	20 years
Electricity Cost	Retail Price (if purchased): 100 $/MWh Wholesale Price (if sold): 50 $/MWh
Escalation Factor	1%
Plant Operating Rate	8,000 hours/annum (corresponding to 91% availability)
Operation Labor	~40 People (Supervision, Administration, Operation)
Discount Rate	12%
Depreciation Rate	20%
Tax Rate	35%
Working Capital	Equal to 60 days of total operating cost

The delivered biomass feedstock cost is an input to the financial analysis model and is calculated using biomass logistics and transportation models.

2.8. GHG Emissions Model

Fuel consumption from the logistics and transportation models along with fertilizer used for biomass production is imported into the GREET model [1] to estimate GHG emissions throughout the supply chain. Model outputs include cost ($/dry tonne), energy consumption (MJ/dry tonne), and GHG emissions (kgCO_{2e}/dry tonne, based on 100-year global warming potential) in biomass production, in-field operation, and transportation. These outputs are reported per delivered dry tonne after accounting for dry matter losses throughout the biomass supply chain. Four forms of biomass for in-field collection (whole-tree woodchip, clean woodchip, round bale, and square bale) are examined. Biomass in the form of pellets is also investigated to examine the effect of biomass bulk density on transportation.

2.9. Reference Scenario

Table 2.2 lists the main assumptions and results for the reference scenario. Loblolly pine woodchips are the biomass type and format for the reference scenario. The gasification technology is High-temperature Winkler (HTW).

Figure 2.9 depicts the breakdown of the production cost of liquid fuel and its comparison with conventional diesel based on US average wholesale diesel prices in March 2014 [8]. As can be seen, the overall production cost of biomass-derived liquid fuel is significantly higher than conventional diesel. Different components of this cost were examined and investigated in this project in search for opportunities to reduce the production cost. The chapters of this report look into these cost reduction opportunities, e.g., reducing feedstock and conversion plant capital costs.

Table 2.2 | Main assumptions and results for the reference scenario

Technical Parameters	**Value**
Assumptions	
Feedstock type	Loblolly Pine
Feedstock Format	Woodchips
Gasification Technology	Fluidized-bed (HTW)
Production rate (*bbl/day*)	3,700
Results	
Biomass Feedstock ($tonne_{Dry}/day$)	2,570
Conversion Yield ($kg_{Fuel}/kg_{Dry\ Feed}$)	17%
Net power (*MWe*)	+9
Total Plant Cost (million *USD Q1 2013*)	916

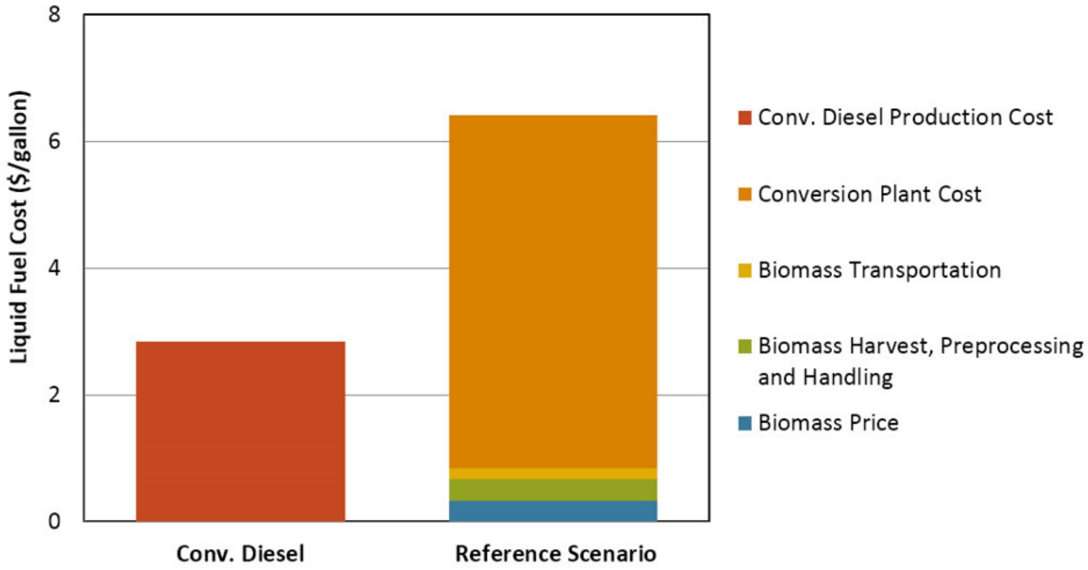

Figure 2.9 | Breakdown of production cost of biomass-derived liquid fuels (reference scenario).

Figure 2.10 shows the breakdown of the installed cost of the conversion plant for the reference scenario. As shown, the gasification island, Fischer-Tropsch synthesis and air separation units have the highest capital cost.

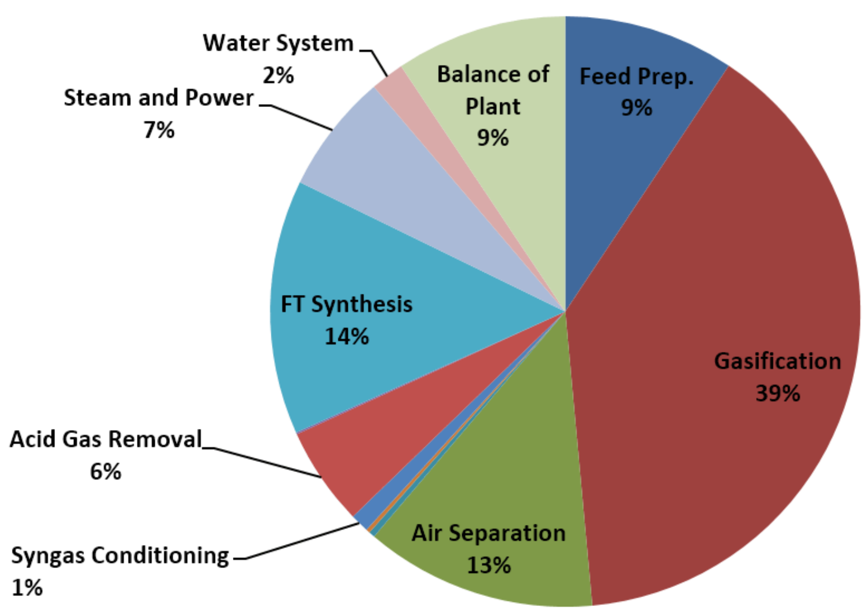

Figure 2.10 | Breakdown of the installed cost of the conversion plant divided into major plant areas for the reference scenario.

3. Biomass Feedstocks

In this study, woody biomass was represented by loblolly pine and herbaceous biomass was represented by switchgrass. Switchgrass bales were about $20/dry tonne more expensive at the farm gate, than loblolly pine woodchips at the forest gate. This cost gap is mainly due to the higher switchgrass production costs.

For biomass-to-liquid plants, biomass will generally be transported by truck and sourced within 60 miles of the plant. For large plants (20,000 bbl/day), longer distances for biomass transport will be required. For long-haul transport (>300 miles) of biomass, rail or barge may provide an economic alternative to trucks.

Biomass feedstocks can be densified into pellets. This can significantly lower the conversion plant capital costs by increasing the gasifier throughput. Additionally, if pelletization occurs close to the biomass source, it can reduce transport costs. However, in-field pelletization significantly increases feedstock costs. Therefore, unless transport distances are large (>500 miles), we find that pelletization at the conversion plant site is a more cost-effective strategy.

Two types of energy crop, switchgrass and loblolly pine, were considered as representative of herbaceous and woody biomass in the Project. Also, four formats of biomass for in-field collection (whole-tree woodchip, clean woodchip, round bale, and square bale) are examined. Biomass in the form of pellets is also investigated to evaluate the effect of biomass bulk density on transportation costs. This project was focused on biomass as the main feedstock, but two other feedstocks (natural gas and municipal solid waste) were investigated for conversion to liquid fuels, and these are discussed in Chapters 4 and 6. In addition, hybridization of biomass and natural gas to liquid fuels is addressed in Section 6.2.

This chapter presents some results of an investigation performed as part of the Project on different types and formats of biomass feedstock as well as possible transportation methods for hauling biomass feedstock from production source to BTL plant. Please refer to Lu et al. [9] for a complete description of the assumptions, methodology, and results of this study.

3.1. Loblolly Pine

"Loblolly pine is an abundant softwood species and important source for saw timber and pulp wood. Young loblolly pine trees grow rapidly if disease-free and if competing hardwood vegetation is controlled. In Georgia, U.S., managed short rotation loblolly pine plantations with different management intensities and rotation ages (5 to 15 years) have been reported to have average annual yield ranging from 3.3 to 8.5 dry tonne per acre" [9].

3.1.1. Clean Woodchip and Whole Tree Woodchip

Two types of woodchips are investigated in this study: whole-tree woodchips and clean woodchips. The whole-tree woodchips are made of the entire tree including branches and bark while clean woodchips are only made of tree trunk after delimbing and debarking. Figure 3.1 shows pictures of whole-tree woodchip and clean woodchip, respectively.

Different trees will produce chips with varying particle-size distributions, depending on the tree species, age, moisture content, and weather conditions, among other factors. In this study, it is assumed that the loblolly pine trees have a moisture content of 35% when they are chipped. In the whole-tree chipping case, the whole tree is comminuted and therefore the chips will be a mixture of needles, bark, wood, and contaminants such as dirt.

Figure 3.1 | Examples of whole tree woodchip and clean woodchip.

The in-field chipping allows recovery of small diameter trees and slash which also increases the efficiency of transportation and handling [10]. Dry bulk density of 170 *kg/m*^{3} is used here for both types of woodchips, although the whole-tree woodchip has a higher bulk density in practice due to the large portion of fine particles. In general, woodchips are blown directly from a chipper into a truck trailer. The woodchips are then delivered to a biorefinery or other facilities for further storage and processing. The choice of whole-tree woodchips versus clean woodchips depends mostly on the end-use requirements.

3.1.2. Woodchip Storage

Woody biomass normally has a wider harvest window compared with herbaceous biomass because tree felling can be conducted most of the year if weather allows. To guarantee an uninterrupted delivery of woodchips from forest to the biorefinery, the woodchips may have to be stored in the plant for a long period during certain times of the year. Supply interruptions may be expected due to the limited seasonal access. The inventory time could vary from less than 15 days to as long as 30 days based on the survey from wood-consuming mills [10].

Storing the woodchip outdoors, uncovered and unprotected, is referred to as open-air storage. Open-air storage of woodchips should be avoided because of imminent risk of damage from moisture exposure; however, this remains a popular storage strategy due to the low cost and generally quick turnover of woody biomass at refineries (such as paper mills, etc.). Uncovered piles may also dry, depending on the ambient conditions, including rainfall, temperature, and humidity. Initial pile heating from bacterial and fungal activity will cause some drying; however, fire hazard is a risk due to the pile self-heating.

To guarantee an uninterrupted delivery of forest chips to the users, the woody biomass may have to be stored for several months during certain times of the year. Supply interruptions may be expected due to limited seasonal access or unexpected due to truck supply (road closures, organizational hold ups such as a strike, etc.). McDonald and Twaddle conducted a survey of 191 wood-consuming mills in the United States and found that around 60% had a maximum inventory time of less than 15 days, 15% had a maximum inventory time of 15 to 30 days, and 12% had a maximum inventory time of more than 30 days [11].

Dry matter loss is particularly a problem in chipped material storage because chipping increases the surface area on which microbial activity can occur. The smaller particle size restricts air flow and prevents heat dissipation, and chipping releases the soluble contents of plant cells providing microbes with nutrients. The presence of nutrients such as leaves/needles further increases the rate of bacterial degradation and results in more dry matter loss and quality reduction. Bio-refineries should maintain a proper feedstock inventory time and manage the woodchip pile based on the "first in, first out" principle.

3.2. Switchgrass

"Switchgrass is a perennial, deep-rooted warm-season grass native to North America that has traditionally been used for soil erosion control, forage, wildlife habitat, and landscaping. It can be adapted in marginal land and survive periods of drought and low soil nutrient concentration. There are two main types of switchgrass, upland and lowland, with annual average yields of 3.5±1.8 and 5.2±2.4 dry tonne per acre, respectively. Switchgrass is slow to establish, often requiring two to three growing seasons to become a dense and vigorous stand with full productivity. After establishment, the plant can be productive for 10-15 years with some projections estimated for even longer periods of time" [9].

Figure 3.2 | Examples of square and round bales.

3.2.1. Square Bale and Round Bale

Baling is the most common method for herbaceous biomass collection and it is carried out by a baler pulled behind a tractor. Round and square balers have been developed for commercial hay harvesting with typical bale size of 5.5×4 ft. and 3×4×8 ft., respectively [12] as shown in Figure 3.2. The "square" bales are actually rectangular cuboids, but they are commonly referred to as square bales. In some regions, the round bale may be the bale of choice over the square bale, while in other regions, the results may be the opposite. Much of this is due to the effects of different climates on the bales themselves.

The round bale has many properties that make it very useful in the region with high average annual rainfall. The first property that makes the round bale successful is the way the bale is made. It is well known that the round bale is very good at shedding moisture off the rounded top when the bales are placed in single layer ambient storage. This is due to the way the bale is wrapped, layer after layer, and the outer layer thatches to shed water. The square bale, due to the way it is baled, may be described as a sponge when it comes in contact with water. Square balers essentially smash layer upon layer as the biomass is forced into a bale chamber with a plunger. This results in causing many of the stems to point outwards, thereby providing a pathway for moisture penetration. Many researchers have found that the round bale outperforms the square bale when placed in ambient storage. If square bales are stored outside, the stack must be covered and the bottom bale must be set on a surface that breaks ground contact. Otherwise, moisture will permeate from the ground into the bale.

For the transportation of bales, the square bale has an advantage over the round bale. The square bale is currently being used for most of the commercial hay harvest in the Midwestern and Western United States. This is largely due to the low amounts of rainfall that minimize moisture problems, and the ability to quickly stack and secure the bales for shipping. The round bale, on the other hand, can be very difficult to handle and is typically not transported long distances. (The round bale is widely used by cattle farmers in the Southeast. They typically use the bale as feed on the farm, or in the community, where it is produced, thus hauling is not a big issue.)

Current experience with switchgrass indicates that round bales may not be suitable for large scale biomass transportation and handling due to their shape and tendency to deform. Dry bulk densities of 144 kg/m^3 and 182 kg/m^3 are used in this study for round bales and square bales, respectively.

3.2.2. Bale Storage

For switchgrass, due to its narrow harvest window, substantial amounts of switchgrass will need to be safely stored on a year-round basis. So it is very important to protect the bales from weather or other environmental conditions, while storing them in a stable condition until needed by the biorefinery. To maintain high-quality bales, these stacks are typically stored in a well-drained, protected environment. In most regions, this requires covering the stacks (e.g., traps, pole barns, plastic wrap, etc.) to prevent weather damage.

Biomass quality and dry matter loss are the two major concerns during switchgrass storage. Biomass material changes due to microbial deconstruction, fractionation, and consumption can affect the quality of the bales and result in significant dry matter losses during storage.

In general, shed storage offers the least dry matter loss (< 3%) and greatest switchgrass value. Plastic wrapping with less than 5% dry matter loss offers the next least loss. However, high capital or operating cost is required for both methods. In contrast, tarping is much less expensive but has a higher dry matter loss, typically 5-25% when bales are stored year round [2], [12]. When weather allows, tarping is often adopted as the main protection method. This strategy is implemented in this study with dry matter loss of 6.5% and 10% during storage of round and square bales, respectively. The bales are then stored along the roadside year round until needed by the biorefinery. Overall, determining the best storage protection strategy depends on local conditions, feedstock quality requirement, and sometimes, a tradeoff between costs and dry matter loss.

It is worth noting that the integrity of the bale becomes a concern if the bale decomposes. Bales that have been stored in sheds do not typically fall apart, while bales that are uncovered may begin to have problems. Ensuring that a bale holds its shape while being moved three times, or more, is a significant issue in the design of the logistics system. Generally, low dry matter losses imply that the bale will still be well formed while high dry matter losses imply that the bale is more likely to lose shape.

Biorefineries in the United States are expected to keep only an average of 72-hours feedstock in-plant inventory with the remaining feedstock inventory at the edge of field or at satellite storage facilities which provide the buffer for uninterrupted feedstock delivery [12]. Offsite switchgrass storage management is critical to maintain feedstock quality and to ensure feedstock access under variable weather conditions. Overall, the management and reduction of biomass dry mass loss, caused either by biological degradation or mechanical movement during in-plant and offsite storage, are challenges.

3.3. Comparison of Different Types and Formats of Biomass Feedstocks

This section presents the results of the case study comparing delivered costs of different types and forms of biomass. In this study, loblolly pine and switchgrass, as representative of woody and herbaceous biomass, respectively, are examined as feedstocks for liquid fuels production. The overall results contain two parts: biomass in-field operation (including production, harvest, collection, preprocessing, and storage) and biomass transportation the results of which are presented in section 3.4.5. The first part is independent of BTL plant location while the second one is determined by plant location, capacity, and biomass transportation mode. All cost figures presented for this study are in 2012 US dollars.

Major inputs for loblolly pine and switchgrass production and in-field logistics operations used in this study are summarized in Table 3.1.

Table 3.1 | Main inputs used for loblolly pine and switchgrass production and logistics modeling

Parameter	Biomass Type	
	Switchgrass	Loblolly pine
Average annual yield (*dry tonne/acre*)	3.9	4.5
Harvest frequency (*year*)	1	14
Plant lifetime (*year*)	12	14
Annual N fertilizer input (*kg/acre*)	40	5
Fuel consumption for biomass production (*gal/acre/rotation*)	1.1	5.0
Production cost (*$/dry tonne*)	32	20
Delivered format	3×4×8 *ft*, square bale 5.5 × 4 *ft*, round bale	Clean woodchip Whole-tree woodchip
Moisture content at delivery (%)	12%	35%
Operation window (*days/year, hours/day*)	36, 14	220, 8
Protection method in storage	Tarping	-
Dry bulk density (*kg/m^3*)	Round bale, 144 Square bale, 182	Woodchip, 170
Dry matter recovery efficiency (%)	Square bale, 73% Round bale, 76%	Clean woodchip, 72% Whole-tree woodchip, 81%

Based on a literature review, the annual average yields of 4.5 and 3.9 dry tonne per acre were assumed for loblolly pine and switchgrass, respectively. A rotation age of 14 years was selected for loblolly pine, while switchgrass is harvested once per year with a plant lifetime of 12 years. Four biomass in-field collection forms (whole-tree woodchip, clean woodchip, round bale and square bale) were examined.

The in-field dry matter recovery efficiencies for both feedstocks are presented as the percentage of the overall original above ground biomass [10], [13]. As can be seen from the table, loblolly pine delivered in the form of whole-tree woodchip results in the highest dry mass recovery efficiency at 81%, followed by switchgrass round bale at 76% and square bale at 73%. Clean woodchip has the highest dry mass loss with recovery efficiency of only 72% due to the removal of slash and bark. It is assumed that there is no dry matter loss during transportation.

3.3.1. Comparison of Forest/Farm Gate Costs

Figure 3.3 shows the gate cost breakdown associated with biomass production and in-field logistics operations with the four biomass formats. . Adding the production cost and in-field logistics cost together gives the farm and forest gate cost of switchgrass bale and loblolly woodchip, respectively, which is independent of biorefinery size and transportation distance.

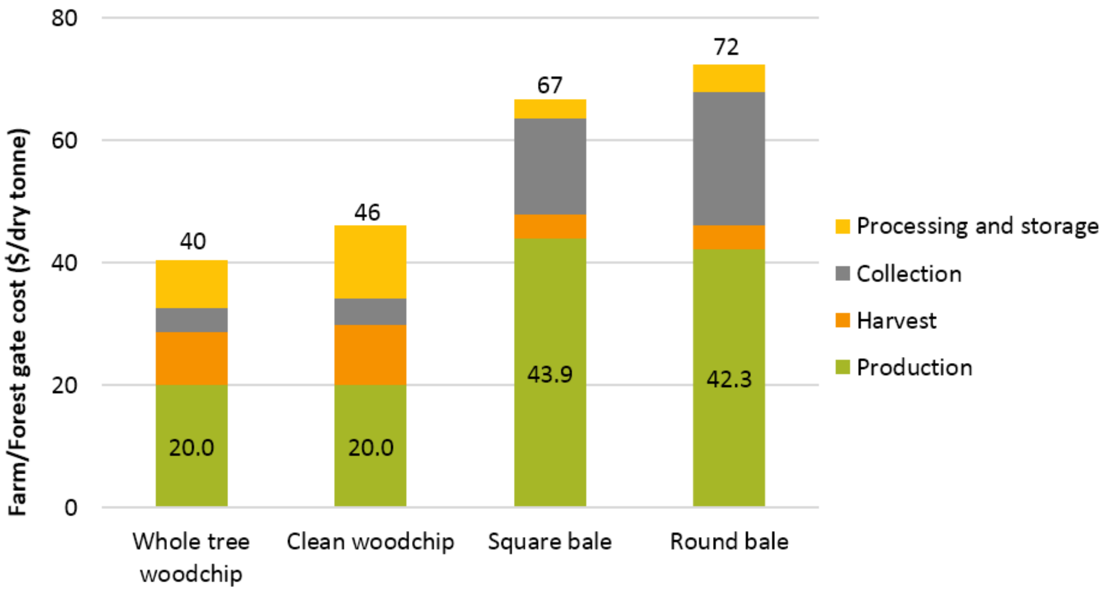

Figure 3.3 | Gate cost breakdown of loblolly pine woodchip and switchgrass bale.

Loblolly pine whole-tree woodchip has the lowest cost at $40/dry tonne and switchgrass round bale has the highest at $73/dry tonne. The cost gap is mainly caused by the higher cost of switchgrass production.

In all cases, loblolly pine whole-tree woodchip has the lowest in-field logistics cost at $20/dry tonne, followed by switchgrass square bale at $23/dry tonne and clean woodchip at $26/dry tonne. Switchgrass round bale has the highest cost at $30/dry tonne. High dry matter recovery efficiency and less machinery operation are the main reasons for the low cost of whole-tree woodchip since there is no need for debarking and delimbing. The round bale has less dry matter loss compared with square bale, however, the lower baling capacity results in a higher logistics cost.

The market for loblolly pine has been well developed in the United States for a long time in the pulp & paper and timber industries. However, there is minimal data available on the cost for large-scale switchgrass production as an energy crop.

Considerable research has been done in estimating switchgrass production cost from trial plots and the results range from $25/dry tonne to as high as $60/dry tonne [14], [15]. In general, switchgrass production cost consists of two parts: materials, labor, and equipment costs, and land rent charge. Depending on land fertility, the land rent may account for a large fraction in overall switchgrass production cost with 2010 nationwide average land rent of $102 and $11 per acre for cropland and pasture, respectively [16]. Growing switchgrass on grassland and Conservation Reserve Program (CRP) land is one of the strategies to reduce the production cost. However, higher in-field logistics cost may result due to the low biomass yield, low machine in-field capacity, and limited road accessibility of these lower quality lands. It is expected that further improvements in switchgrass yield could decrease the production cost dramatically and the production cost could reduce to $25/dry tonne and $19/dry tonne (2006 dollar) when the yield increases from 4.0 to 8.1 and 12.1 dry tonne per acre, respectively [17]. If such low production costs could be achieved, switchgrass as an energy crop could be more competitive for biofuel production compared with woody biomass. In addition, use of various types of woody or herbaceous feedstocks, such as corn stover, wheat straw, or forest residues, is another potential strategy to reduce biomass delivered cost and mitigate the risk of feedstock supply shortages.

For both woody and herbaceous feedstocks, it is expected that the development of more advanced equipment could reduce the in-field logistics cost significantly. This is especially true when the biomass stand density and yield exceed the efficient handling capacity of conventional equipment. In addition to equipment specifications, the experience level of the operators also contributes to the logistics cost to some extent. For example, the feller buncher operator directly influences the productivity of the skidders because the operator determines the bunch size set out for the skidder. In other words, skillful operators are desirable in order to achieve a high operation capacity and thus reduce the cost.

3.4. Biomass Feedstock Transportation

This section includes the results for the calculated delivered cost of biomass feedstock to the conversion plant. The effect of biomass type and format, conversion plant size and transportation mode on the biomass delivered cost was investigated in this study.

3.4.1. Biomass Feedstock Collection Radius

The biomass collection radius estimation assumes that sufficient biomass quantities can be accessed within a cost-effective transportation radius of a centrally located biorefinery delivery point. Forester and farmer participation in biomass production are assumed to be equally distributed throughout that radius. Land utilized for loblolly pine and switchgrass cultivation (cultivation sparsity) within the collection area is set as 6% and 4%, respectively. Figure 3.4 shows the collection radius dependence on the biorefinery capacity. The collection radius increases as the size of a biorefinery increases. Biomass for a larger-scale biorefinery is drawn from a wide area and thus, has longer collection distances. The shortest collection radius is obtained when whole-tree woodchips are used as feedstock, while the longest collection radius is obtained when switchgrass delivered in the form of square bales is used as feedstock. The difference in collection radius between switchgrass and loblolly pine can be explained based on cultivation sparsity, average annual yield, and dry matter recovery efficiency, as shown in Table 3.1. In general, higher yield and dry matter recovery efficiency are desired to reduce the collection radius.

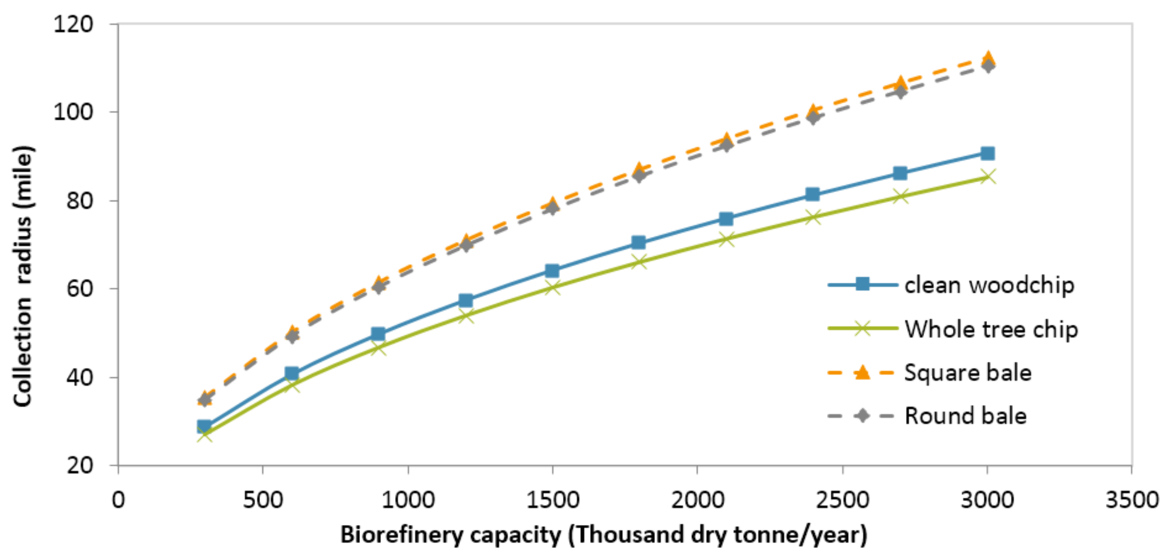

Figure 3.4 | Biomass collection radius with different biorefinery capacity.

3.4.2. Effect of Conversion Plant Capacity on Cost of Truck-delivered Biomass

Figure 3.5 shows the biomass delivered cost of loblolly pine whole-tree woodchip and switchgrass square bale by truck. It is assumed that sufficient biomass quantities can be accessed within a transportation radius of a centrally located biorefinery delivery point. Forester and farmer participation in biomass production are equally distributed throughout that radius. Winding road factors of 1.5 and 1.4 are used to calculate actual woodchip and bale transportation distances, respectively. As shown in Figure 3.5, biomass delivered cost increases with plant scale and this cost increment is due to the additional biomass transportation distance required.

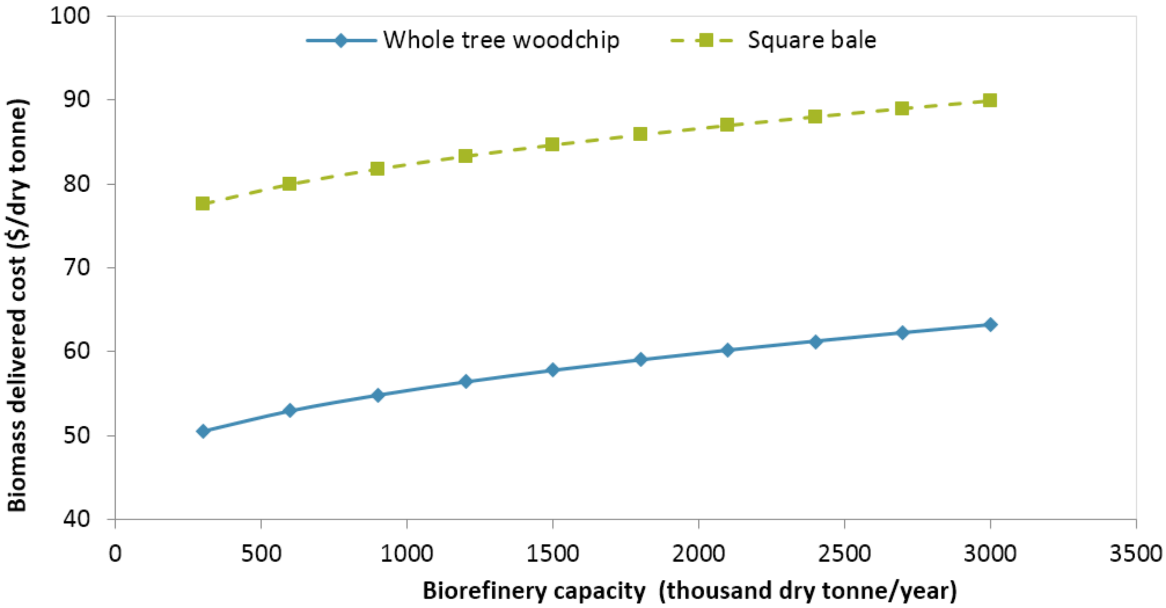

Figure 3.5 | Cost of truck-delivered biomass with different biorefinery capacities.

As mentioned earlier, dry matter loss during in-field logistics operations plays a very important role in determining collection radius and logistics cost. It may be argued that most of the losses are desirable because biomass left behind can help maintain soil productivity. However, uncontrolled loss is never desirable and further improvements in equipment design and management practice could reduce the losses to a controllable level and thus further reduce the transportation cost.

3.4.3. Transportation Modes

In this study, biomass transportation cost is categorized as Distance Fixed Cost (DFC) and Distance Variable Cost (DVC). The DFC includes infrastructure costs, such as construction and maintenance costs of the facilities (e.g. piers and cranes) and structures, transshipment costs for loading and unloading freight, and administration costs. DFC is independent from the length of the eventual trip and plays a very important role in determining the competitive position between the modes. Because of the high freight terminal costs, barge and rail are unsuitable for short-haul trips. In contrast, DVC is the incremental cost per mile of transportation and covers all costs that are roughly proportional to the transportation distance including capital recovery and depreciation of equipment, labor, maintenance, and fuel The DFC and DVC for biomass transportation are given in Table 3.2.

Table 3.2 | DFC and DVC for different biomass transportation modes.

Transportation mode	Format	DFC ($/dry tonne)	DVC ($/dry tonne.mile)
Truck	Woodchip	4.32	0.216
	Bale	5.17	0.171
	Pellet	3.05	0.141
Rail	Woodchip	44.68	0.075
	Bale	43.40	0.044
	Pellet	17.91	0.028
Barge	Woodchip	33.44	0.040
	Bale	36.53	0.042
	Pellet	13.98	0.016

The DFC and DVC for the three modes can change significantly depending on origin and destination, carrier, route, and time of shipment. For example, barge transportation cost fluctuates with market demand which is at its lowest in the first half of year and reaches the highest level during and after the harvesting season due to the increase demand [18]. The shippers that do not have alternative route options or have very limited intra-modal competition will pay more in shipping biomass than those near rivers or close to rail lines with viable options. The difference in DFC here also explains why most short haul of bulk goods is by truck and long haul is by rail and barge. It is also observed here that shipping pellets has a lower DVC due to the high dry bulk density.

Figure 3.6 and Figure 3.7 show the transportation cost as a function of transportation distance for shipping woodchips and bales using truck, rail, and barge. It is assumed that the woodchips and bales are collected and delivered to the transshipment terminal by truck with an average transportation distance of 60 miles (~100 km).

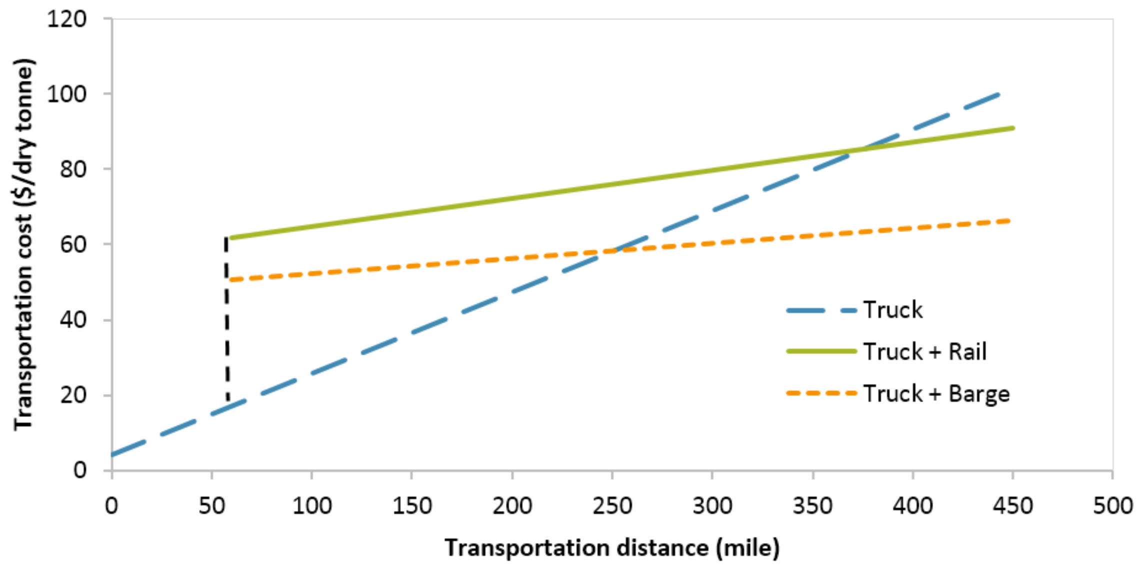

Figure 3.6 | Woodchips transportation cost vs distance using truck, rail, and barge.

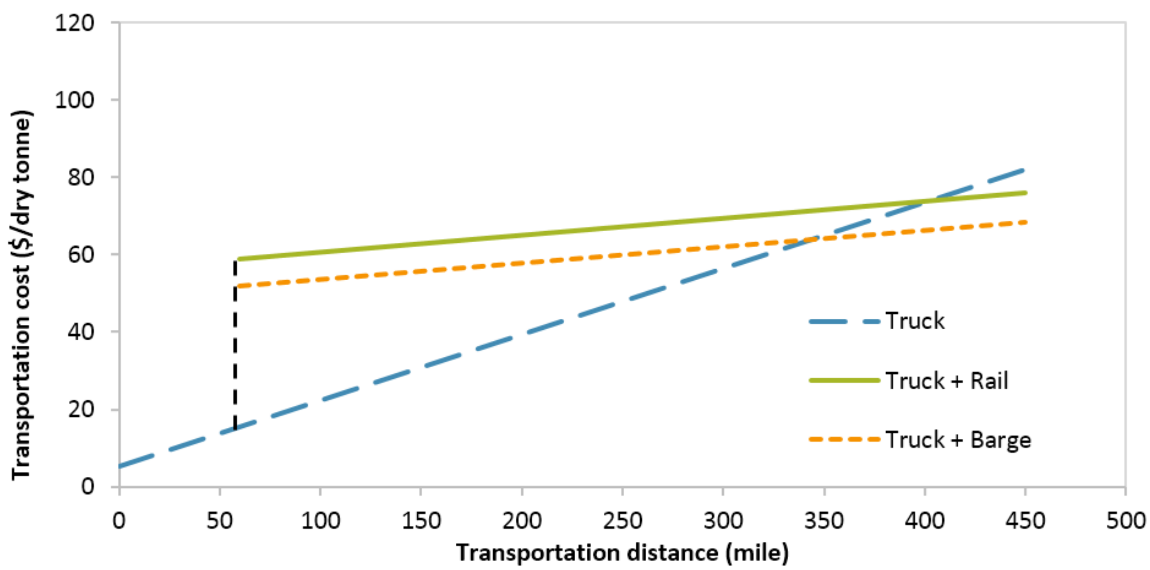

Figure 3.7 | Bales transportation cost vs distance using truck, rail, and barge.

This multimode transportation incurs addition DFC for the transfer at the transshipment terminal. Such additional costs can only be offset by the lower DVC of the second transportation mode. Now the question becomes how far the rail or barge shipment distance has to be to justify the additional DFC of a second transportation mode. In this study, this distance is called the Minimum Economic Shipping Distance (MESD), which is the minimum distance for which transshipment is economic. As can been seen from the crossover points, the MESD for woodchip is about 380 miles and 250 miles using rail and barge as the secondary transportation mode. For bale transportation, the MESD is about 400 miles and 340 miles for transshipment from truck to rail and barge, respectively.

Due to the high distance-fixed cost of transporting biomass using rail and barge, these modes of transportation are economic only when long distance transportation of biomass is required.

3.4.4. Effect of Pelletization of Biomass Transportation Cost

Key drivers of biomass transportation cost are feedstock bulk density and moisture content. In most cases, the amount of biomass that can be delivered is largely dominated by the volume constraint of the transportation equipment rather than the weight limit due to the bulky nature of biomass. This is especially true when biomass is transported by rail and barge since low density materials greatly underutilize the high payload capacity.

One strategy to reduce the transportation costs is to densify the biomass via pelletization. Shipping high bulk density pellets enables much better utilization of weight payload capacities of rail and barge transportation modes. Because pelletization results in both densification and drying of the biomass, the overall benefit is that the variable cost per GJ-mile is reduced by a factor of 2.7 for rail transport and 2.5 for barge transport. The assumed values for the moisture content and dry bulk density of loblolly pine woodchips, switchgrass square bales, and pellets are summarized in Table 3.3.

Table 3.3 | Moisture content and dry bulk density of biomass with different forms.

Parameter	**Biomass Format**		
	Woodchip	Square bale	Pellet
Moisture content (%)	35%	12%	8%
Dry bulk density (dry tonne/m^3)	170	182	598

The downside of distributed pelletization is the additional capital investment and operating cost for each pelletization mill. These costs can vary significantly with raw material used, pellet mill capacity, and process configuration [19], [20]. Pelletization costs of $50 and $40 per dry tonne are assumed in this study for loblolly pine woodchips and switchgrass bales, respectively (raw material cost is not included). The max payload for each truck, railcar, and barge is given in Table 3.4. The corresponding capacity after accounting for volume constraints, biomass density and biomass moisture is also reported on a dry mass basis for each biomass in Table 3.4.

Table 3.4 | Max payload (wet tonne) and net payload (dry tonne) of each truck, railcar and barge for square bale, woodchip, and pellet. Net payload values represent the maximum weight of dry biomass after accounting for the volume constraint and moisture content.

Transportation mode	Max payload	Net payload		
		Square bale	Woodchip	Pellet
Truck	23	17	15	21
Rail	100	39	39	90
Barge	1600	443	460	1387

Pelletization cost is added to the DFC when biomass is densified. The question now is how far the transportation distance has to be so that it can offset the high biomass pelletization cost, compared with undensified material. Figure 3.8 and Figure 3.9 show the transportation cost of shipping pellets, woodchips, and square bales as a function of transportation distance using rail and barge, respectively.

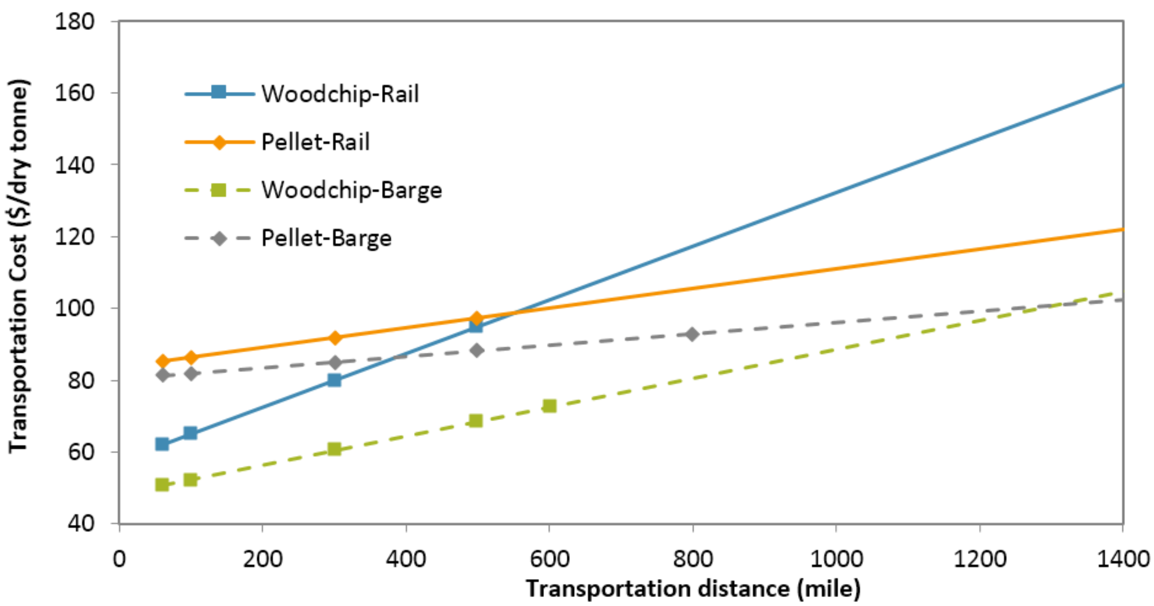

Figure 3.8 | Loblolly pine woodchip and pellet transportation cost *vs.* distance using rail and barge.

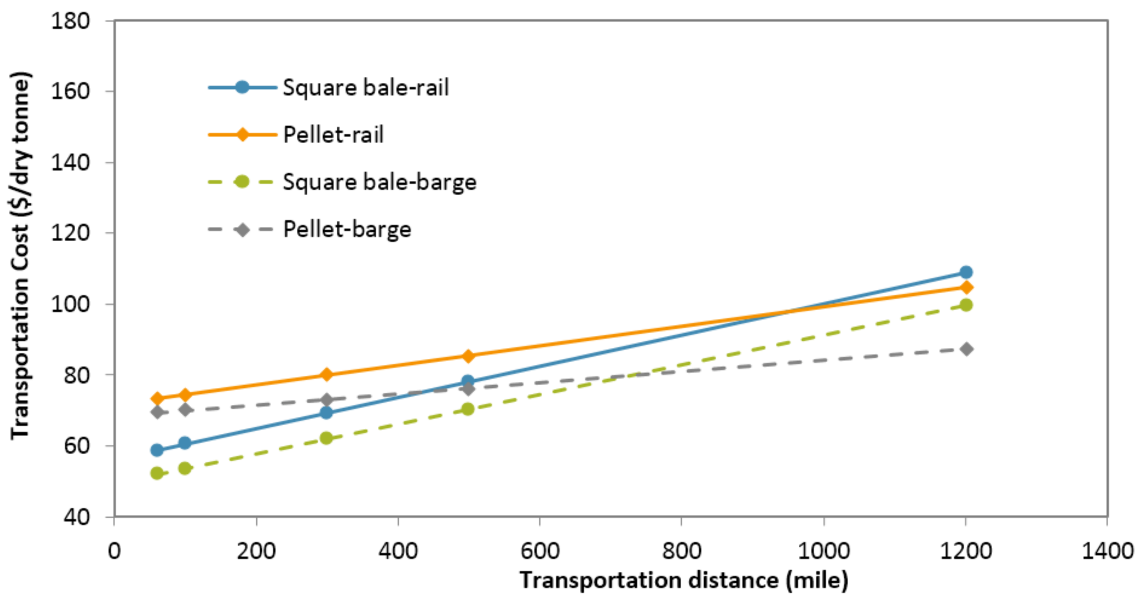

Figure 3.9 | Switchgrass square bale and pellet transportation cost *vs.* distance using rail and barge.

Our analysis indicates that when shipping by rail, the minimum distance at which the savings in transportation cost offsets the pelletization cost is approximately 550 miles for loblolly pine pellets and 950 miles for switchgrass pellets. When barge is used, the pelletization of biomass is cost effective at transportation distances greater than 1310 miles and 730 miles for loblolly pine pellets and switchgrass pellets, respectively. Overall, when a biorefinery sources biomass from remote supply areas, pelletization has the potential to reduce the cost of delivered biomass by improving efficiency of long-distance transportation.

Overall, the optimum biomass transportation methods should be determined case by case. Intermodal transportation combining multiple transportation modes may be the solution, but may also require the development of facility or infrastructure for biomass storage and distribution.

3.4.5. Comparison of Delivered Cost of Different Biomass Types and Formats

Figure 3.10 shows the comparison of delivered biomass cost for different types and formats of biomass feedstock. Also, it illustrates the effect of pelletization on the delivered cost of biomass feedstock.

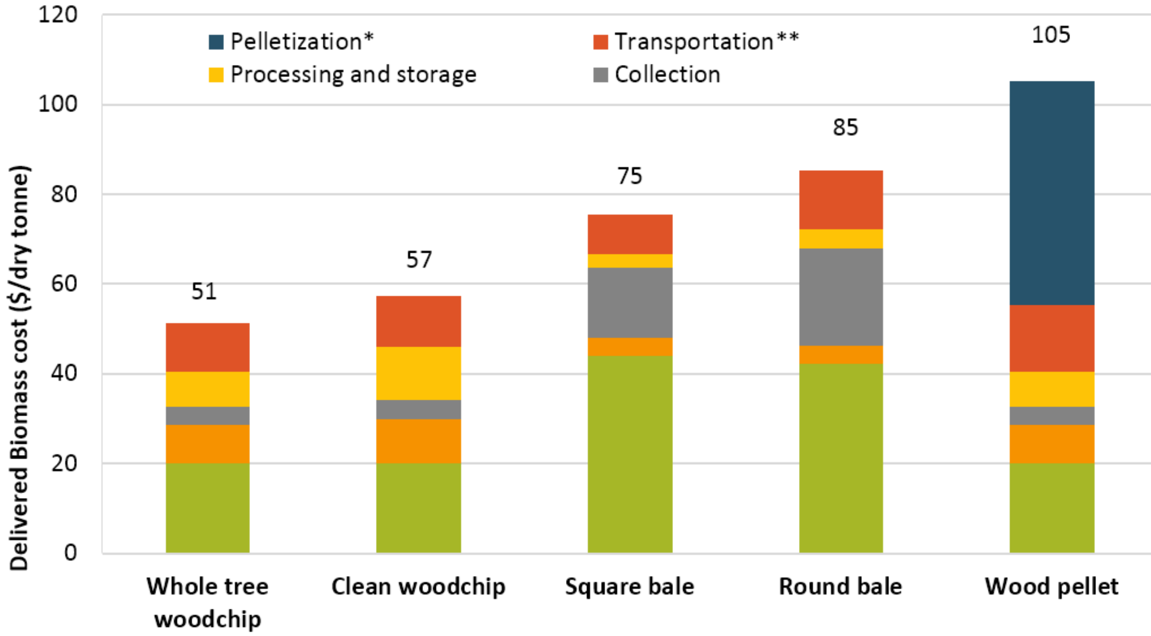

Figure 3.10 | Breakdown of delivered biomass cost for different types and formats of biomass feedstock. *Woodchips are pelletized in a standalone pellet mill. **Transportation cost is calculated for a conversion plant with biomass feedstock demand of 2,600 $\text{tonne}_{\text{dry}}$/day transported using trucks.

In general, transshipment from truck to any other mode of transportation only makes sense if the second mode has a lower DVC than truck transport. The determination of MESD for transshipment for a given situation can vary significantly depending on the origin and destination, carrier, route, and time of shipment, etc. For example, biomass transportation costs are often lower when intermodal and intra-modal competition is present. Therefore building biorefineries next to inland ports or rail terminals is one location strategy that could drastically reduce transportation costs.

Pelletization could be a good option for biomass transportation, but the high cost of making pellets may require a long deliver distance to offset it. In addition, using high-quality pellets for biofuel production can result in a reduction in biomass in-plant handling and processing cost (e.g. no need for cleaning, drying, and possibly grinding in the plant). Savings by increasing in-plant equipment throughput is another potential benefit when biomass bulk density is the bottleneck of the operation (e.g. feeding system of gasifier). These benefits could shorten the offset shipping distance, shown in Figure 3.8 and Figure 3.9, to some great extent and make pellets more favorable for biofuel production. These in-plant savings from using pellets are discussed in section 3.6.

3.5. Comparison of Fuel Production from Loblolly Pine and Switchgrass

After investigating various aspects of production, logistics, and transportation of different types and forms of biomass feedstocks, we studied the effect of feedstock type on the production of liquid fuels in the conversion plant. The detailed information regarding the technologies used for the conversion process is provided in Chapter 5. Two cases were considered for these analyses. In the “Loblolly Pine” case, the feedstock format is whole-tree woodchips. In the “Switchgrass” case, the biomass feedstock is delivered to the conversion plant as square bales. In both cases the biomass feedstock is delivered to the conversion plant by trucks. The considered capacity of the conversion plant in both cases is assumed to be ~3,000 bbl per day of FT liquid products.

Figure 3.11 shows the bare erected cost of the most capital-intensive processing units within the conversion plant for the Loblolly Pine and Switchgrass cases. As shown, the bare erected costs of different units of the conversion plant are similar for the two cases. Due to the slightly lower quality of switchgrass (higher ash content and lower heating value), a larger feed throughput is required to produce the same amount of liquid fuels. Therefore, the bare erected cost of most units within the plant is higher for the switchgrass case with the exception of the feed preparation unit, which is more expensive for the Loblolly Pine case. The capital cost of feed preparation for loblolly woodchips is higher because it requires shredding, drying, and grinding, while switchgrass only needs grinding. The overall bare erected cost of the conversion plant is slightly higher for the switchgrass case as shown in Figure 3.11.

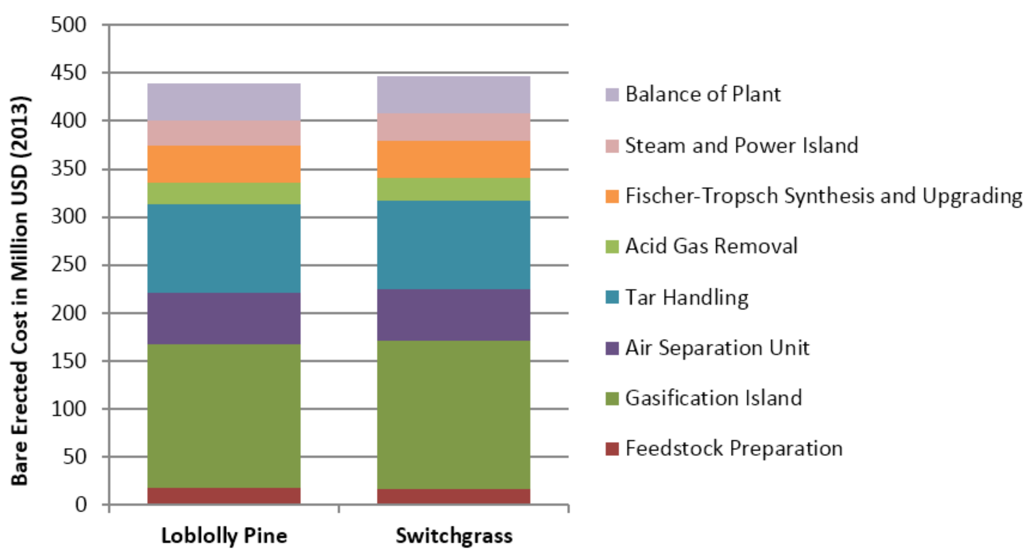

Figure 3.11 | Bare erected cost of the most capital-intensive units of the conversion plant for Loblolly Pine and Switchgrass cases.

Figure 3.12 shows the comparison between the breakdown of the production cost of liquid fuel from loblolly pine and switchgrass feedstocks. The fuel production cost is higher for switchgrass because of its higher production (harvest, preprocessing, and handling) as well as conversion plant costs.

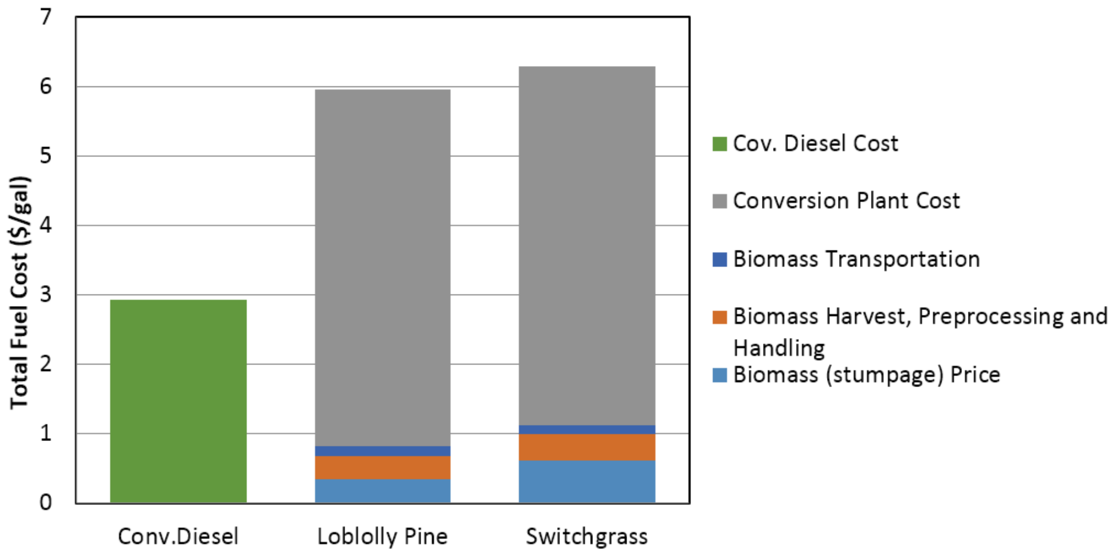

Figure 3.12 | Comparison of liquid fuel production cost breakdown – loblolly pine (woody biomass) *vs.* Switchgrass (herbaceous biomass).

From the farmer's perspective, in addition to the delivered cost and GHG emissions, there are other factors affecting the decision on selecting the type of energy crop (woody versus herbaceous) for a bio-refinery. The decision may ultimately hinge on land-use history and landowner preference. Currently, availability and low forest gate cost may favor woody biomass, especially in places with existing underutilized managed forests. The technologies for producing and hauling woodchips, either for pulp or for energy purposes, are well established. On the other hand, herbaceous energy crops may be preferred in areas where land has been cleared for field crops or pasture.

The supply, demand, and price of biomass vary regionally. Constraints on infrastructure, seasonal demand, and regulations can also result in significant regional differences in the biomass market. But this can change if biomass is traded as a commodity like grain and other agricultural products. Idaho National Lab (INL) proposes a commodity-based biomass supply chain design concept to support the production of biofuels [10]. This advanced design moves the preprocessing operations to earlier in the supply chain where biomass is densified into a uniform format in local processing facilities (see section 3.6). By using the high-capacity handling and transportation equipment, the commodity system can greatly enable the expansion of the potential collection radius of the biorefinery, reduce feedstock supply risks, and introduce additional resources into the biomass market in the future. In the near term, given the regional differences in biomass resources and the high cost of long-distance transportation, biomass markets are expected to be largely regionally oriented.

3.6. Effect of Pelletization of Biomass Feedstock on Fuel Production Cost

One of the main limiting factors for the throughput of biomass gasifiers is the biomass feeding rate due to the low biomass bulk density. One of the solutions for overcoming this challenge is to densify the biomass feedstock in a process called pelletization.

In the pelletization process, the biomass is first dried and then ground. Using mechanical force, the ground biomass is then extruded into pellets. There has been extensive research on the pelletization process with the objective of producing high-quality pellets that have high mass densities and mechanical robustness to avoid breakage during transportation and feed handling.

To investigate the effect of pelletization on the conversion plant cost and the fuel production cost, we compared three cases: Woodchips (reference) case, Purchased Pellets case, and In-plant Pelletization case. The conversion plant capacity for all cases is assumed to be the same, ~4,000 bbl/day. In the Purchased Pellets case, the biomass feedstock is purchased in the form of wood pellets at the price of $150/dry tonne. In the In-plant Pelletization case, the biomass feedstock is purchased in the form of woodchips and is then converted to wood pellets using in-plant operations.

Figure 3.13 shows the specific installed cost for the most-intensive processing units of the conversion plant for the three cases. As shown, the cost of the gasification island is decreased significantly for Purchased Pellet and In-plant Pelletization cases as densification of feedstock (pelletization) increases the throughput per gasification train and fewer gasification trains are required. In the Purchased Pellet case, the feed preparation cost is also reduced as the purchased feedstock in pellet format requires less preparation (no drying or shredding). The cost of feed preparation for the In-plant Pelletization case is considerably higher as the unit operations for the pelletization process need to be included in the feed preparation unit.

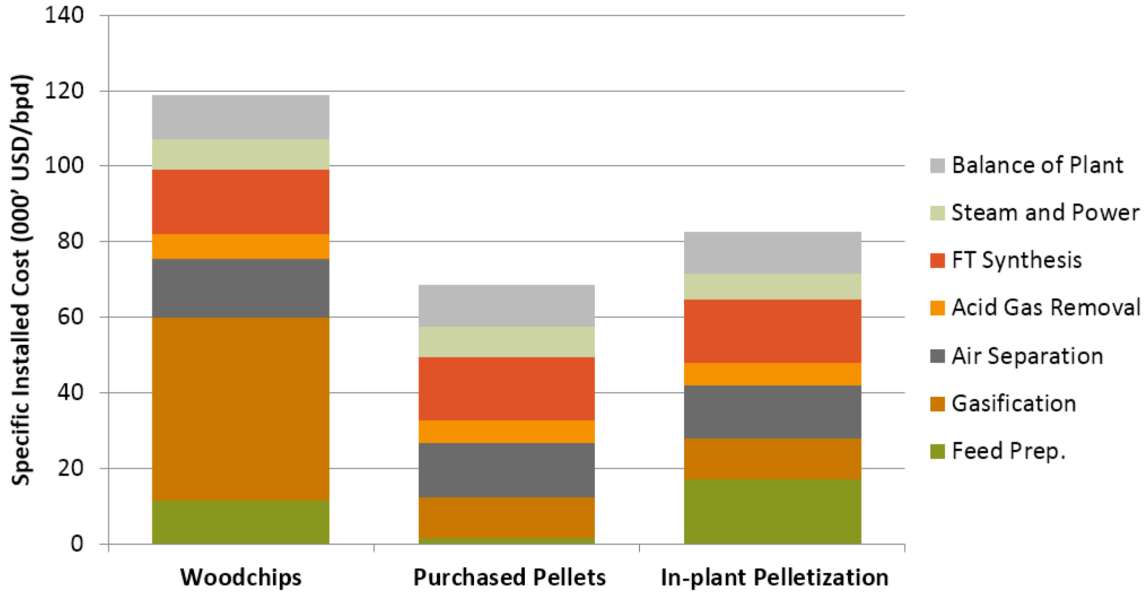

Figure 3.13 | Effect of pelletization on specific installed cost of different areas of the conversion plant.

As shown in Figure 3.14, changing the feedstock format from woodchips to purchased wood pellets decreases the plant cost, but this reduction in the plant cost is almost entirely offset by the increased cost of the delivered feedstock. The overall fuel production cost of the Purchased Pellet scenario is almost the same as the reference case. With regard to the In-plant Pelletization case, despite the increased capital and operating costs of feed preparation operations, the savings from having fewer gasifiers along with maintaining the low cost of feedstock (by purchasing woodchips) drives the fuel production cost to less than that of both the Woodchips and Purchased Pellet cases.

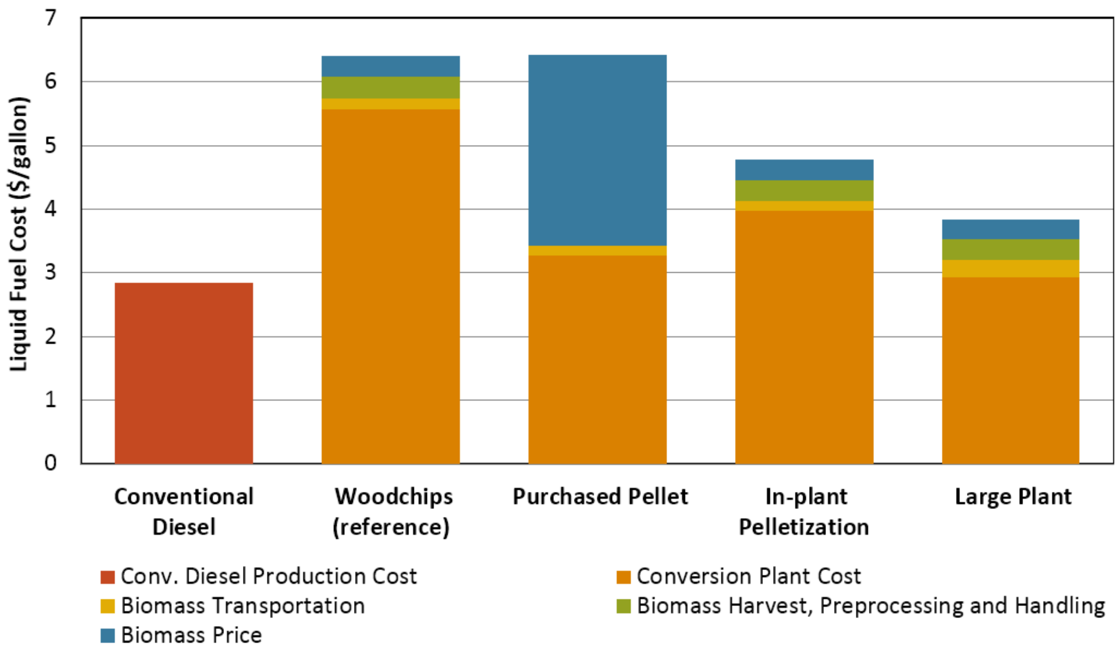

Figure 3.14 | Effect of pelletization on production cost breakdown.

As shown, In-plant Pelletization is the most economic scenario because it maintains the low cost of woodchip feedstock (compared with purchasing wood pellets) while decreasing the conversion plant cost by increasing the throughput of biomass gasifiers. For small-scale BTL plants, the cost of biomass feedstock transportation is not a major cost component of the delivered cost of different biomass feedstock types and formats. For large plants, densification of biomass feedstock (pelletization) can reduce feedstock transportation costs.

We also included the Large Plant scenario in Figure 3.14, which is similar to the In-plant Pelletization case but at a larger scale (~17,000 bbl/day). As shown, due to economy of scale, the production cost of product fuel decreases significantly to below $4/gal.

It also worth noting that feeding wood pellets to biomass gasifiers instead of woodchips incrementally improves the gasifier performance due to the lower moisture content of wood pellets.

3.7. Other Feedstock Options

One of the factors hindering large-scale production of biofuel is biomass availability. Focusing only on local resources may result in a high uncertainty in plant utilization when biomass supply is insufficient or the delivered cost is too high. In this case, the high raw material cost combined with low production can result in a negative return on equity, as happened to the Iowa corn ethanol industry in 2012 when corn price bumped up to as high as $7-8 per bushel due to the unprecedented drought.

One possible solution to mitigate biomass supply risk is to use a hybrid plant configuration in which the biofuel production process is integrated with an alternative fuel process using an abundant feedstock such as natural gas or coal. The concept here is to take the advantage of abundant fossil fuel reserves while minimizing the biomass supply uncertainty. The highly integrated hybrid plant will maintain relative stable fuel production rate even when biomass supplies are limited or expensive. Although the hybrid plant may need additional capital investment, it could reduce the process uncertainty and thus reduce the investment risk. Moreover, the hybrid plant configuration also provides a highly flexible operation in respond to the market and policy. For example, when the biofuel credit price is low or the biomass delivered cost is too high, the hybrid plant can switch to using fossil fuels as feedstock and remain profitable.

The hybridization of biomass and natural gas to liquid fuels and its operational flexibility are discussed in detail in Section 6.2. Municipal solid waste (MSW) discussed in Chapter 4, is another feedstock option. Also, Section 7.6 discusses the effect of biofuel credits on the economics of BTL and hybrid plants.

4. Municipal Solid Waste

MSW is gaining interest as an alternative feedstock. Small commercial plants exist today that can convert MSW to liquid fuels.

Due to its variability, the processing of MSW is more costly and challenging than the processing of biomass feedstocks. The biggest economic advantage in using MSW as a feedstock is the additional revenue from the tipping fees.

This chapter discusses the use of municipal solid waste (MSW) as a feedstock for production of liquid fuels. The discussion in this chapter is from a US perspective.

4.1. MSW Data sources for the United States

In order to investigate the possibility of using MSW as a feedstock for production of liquid fuels, we searched publicly available data sources to assess the generation rate and characteristics of MSW in various regions in the United States. Three data sources were found and considered for this study: US Environmental Protection Agency (EPA) Facts and Figures 2012 [21], the bi-annual survey of Columbia University [22], and Pacific Northwest National Laboratory (PNNL) report on MSW [23].

EPA MSW Facts and Figures

EPA uses a *material flow methodology*, which uses a mass balance approach to estimate the amount and type of MSW produced in the United States. In this methodology, data gathered from government and industry entities and businesses are used to estimate the tonnage of different materials produced, recycled, or discarded [24]. These data include production data for various materials, adjusted by import and export figures. In the case of materials used in products with a long lifetime, appropriate allowances are considered. Also, compiled data from a range of waste sampling studies are used to account for food scraps, yard trimmings, and a small amount of some other inorganic wastes [24]. Figure 4.1 shows the methodology used by EPA for estimation of waste generation, recovery, and disposition in the United States [25].

The results reported using EPA's methodology can be used to represent a national average. However, at the state or local level, there might be major differences between EPA's estimate figures and those obtained from more accurate ways of estimating the generated MSW, such as counting or weighing the waste or recycle streams. EPA lists the following as specific reasons that its data may be different with regional figures [24]:

- Variation in climate and local waste management practices
- Difference in scope of streams, for example many waste landfills accept construction and demolition debris as waste but it is not considered MSW
- Variance in waste generation per capital from region to region. The per capital waste generation rate used by EPA is a national average.
- Variance in the level of commercial and economic activity from region to region
- Difference in State and local regulations and practices.

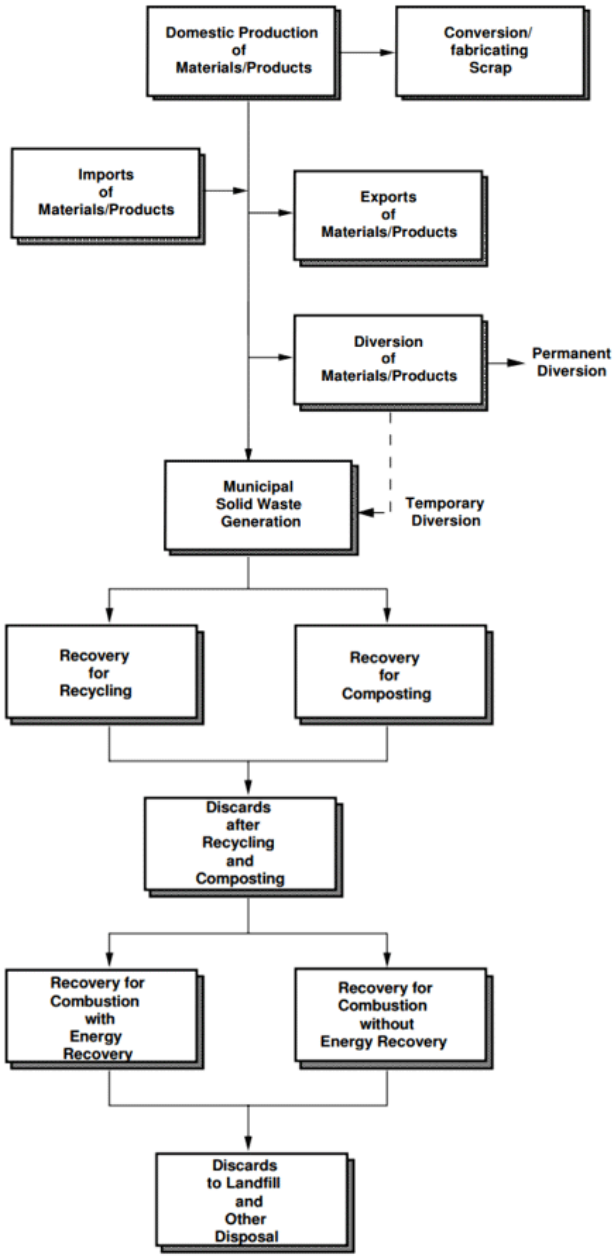

Figure 4.1 | Material flow methodology used for estimation of waste generation, recover, and disposition [25].

As the composition of MSW varies significantly region to region and even time to time, EPA has adopted the following definition of MSW in its publications: "MSW includes wastes such as product packaging, newspapers, office and classroom papers, bottles and cans, boxes, wood pallets, food scraps, grass clippings, clothing, furniture, appliances, automobile tires, consumer electronics, and batteries [24].” This definition of MSW does not include construction and demolition debris, bio-solids (sewage sludge), waste from process industry, and some other types of waste that in reality may end up in waste landfills.

In addition to type of waste, the source of waste generation is also contained in EPA’s definition of MSW. According to EPA, MSW only includes the solid waste from homes, institutions, commercial sources and small businesses, and some industries. By this definition, other types of waste, such as automobile bodies, municipal sludge, combustion ash, and industrial process wastes are not included in MSW figures reported by EPA [24].

Columbia University Survey

The Earth Engineering Center at Columbia University, in collaboration with *BioCycle* magazine conducts a bi-annual survey on MSW generation and disposition in the United States. The latest survey was carried out in 2013, solely by the Earth Engineering Center. The survey compiles and analyzes the data provided by waste management agencies of 50 states in the United States. Since there are significant discrepancies between the EPA reported figures and those obtained from the bi-annual survey in the past years, one of the objectives of the recent survey was to understand the reasons for these discrepancies [22]. To this end, Columbia University adopted a similar definition for MSW as EPA and has processed the data from the waste management agencies to exclude the tonnage of waste that does not fall into EPA’s definition of waste. Even after making such adjustments, the difference was about 113 million tonnes. Columbia University listed the following speculative reason for the discrepancy among others [22]:

- Residues from the recycling facilities that end up in waste landfills
- Waste materials that are not accounted for in EPA methodology such as packaging of imported goods
- Other residues such as automobile shredder and ash residues
- Household construction projects

Pacific Northwest National Laboratory Report on MSW

In 2008, PNNL investigated the availability of MSW as feedstock for liquid fuels synthesis [23]. PNNL also identifies the great difference between the data collected from local governments on landfills and those from EPA. The main difference between Columbia University and PNNL seems to be that PNNL has not adjusted the data from individual landfill sites to exclude non-MSW portions and therefore reports even higher rates than those reported by Columbia University. In the PNNL report, the higher estimates based on landfills data are attributed to the following:

- Non-MSW waste, such as construction and demolition debris, entering landfills
- Inaccurate estimation methods used in landfills without scales
- Inaccuracies in EPA's methodology such as those concerning products' lifetime
- Diversion of waste material after entering the landfill sites

Comparison of Different MSW Data Sources

Special care has to be taken when comparing the above mentioned data sources for MSW generation and disposition in the United State as the three data sources have different definitions of MSW. Table 4.1 and Figure 4.2 show the difference in what is included in the MSW figures by EPA, Columbia University, and PNNL.

Table 4.1 | Comparison of different sources as what is included in the reported figure as MSW generation in the United States

Waste Type	Data Source		
	EPA	CU	PNNL
Commercial	√	√	√
Residential	√	√	√
Institutional	√	√	√
Industrial	×	?	√
Construction and demolition debris	×	?	√
Agricultural waste	×	?	√

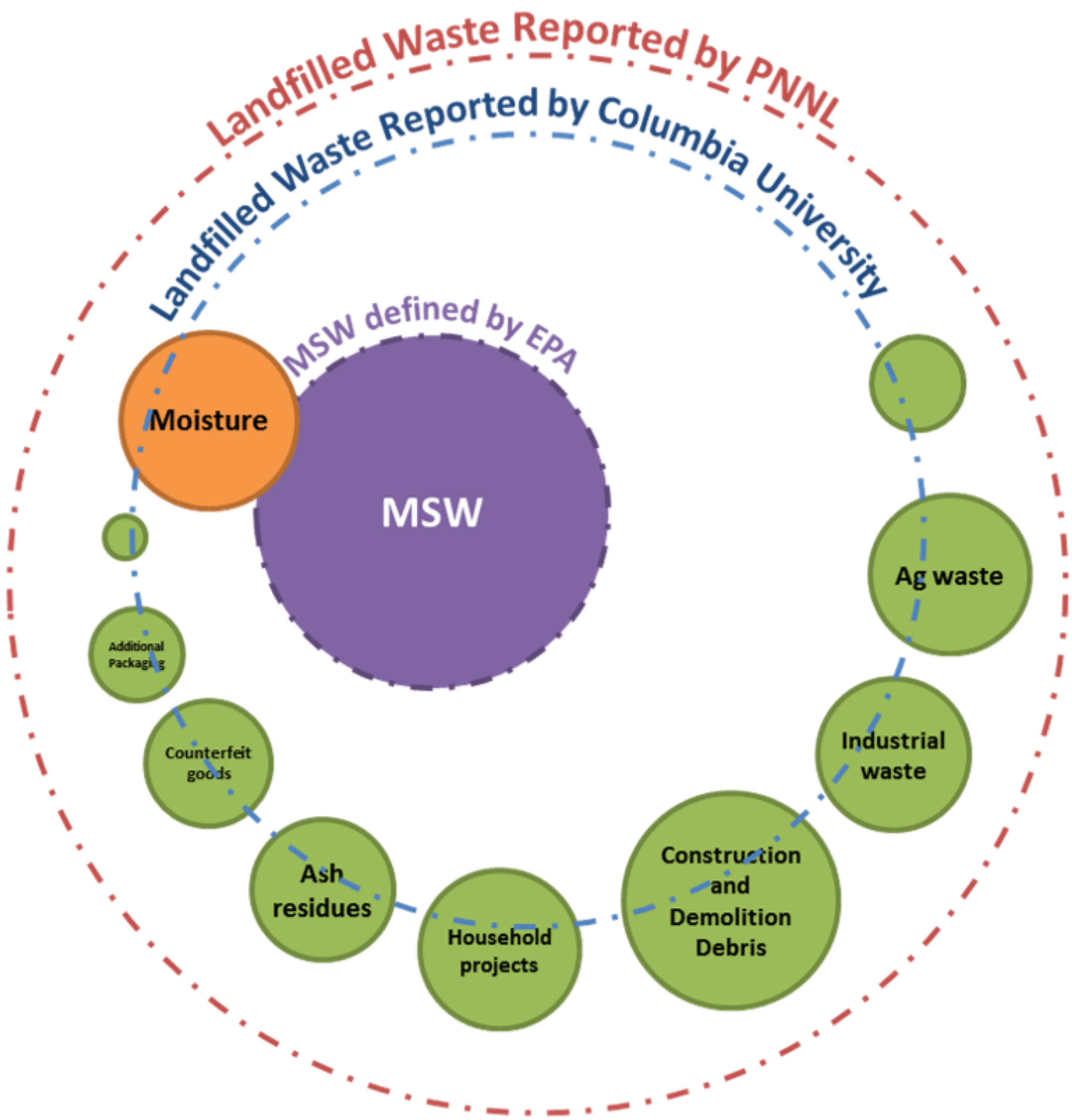

Figure 4.2 | Graphical representation of inclusions/exclusions of what is considered MSW by different sources.

Due to differences in the definition of MSW, the sources report significantly different figures regarding to MSW generation in the United States. Table 4.2 compares the estimated tonnage of different waste streams in the United States by different sources. As expected, EPA and PNNL estimate the lowest and highest waste generation rate, respectively.

Table 4.2 | Estimated components of waste as estimated by different data sources.

Stream (million ton per year)	EPA	CU	PNNL
Recycled	66	88	N/A
Composted	21	25	N/A
WTE	29	30	N/A
Landfilled	134	247	341
Total Generated Waste	**250**	**389**	**N/A**

4.2. Geographical distribution of Waste Generation in the United States

EPA uses a per capita MSW generation rate to estimate the tonnage of MSW generated in the United States. This per capita rate is a national average and, as stated earlier, the actual MSW generation rate varies by region and is affected by factors mentioned in section 4.1. Using a similar approach, we attempted to estimate the waste generation rate for the top ten most populous metropolitans in the United States. Similar to EPA [25] and Columbia University [22], MSW generation rate of 7 lb. per person per day and a national average landfill rate of 67% was used to calculate the waste landfilling rate for different metropolitans in the United States. We found that 27 municipalities have MSW landfill rates of more than 3,300 tpd (criterion used in the PNNL report). The population data for the municipalities was obtained from [26]. Table 4.3 shows the estimated waste landfilling rate for the top ten municipalities in the United States.

Intuitively, we might expect large landfill sites to be in the vicinity of the most populated areas. However population density is only one of the important factors affecting the location of the landfill sites. Table 4.4 lists the ten largest active landfills in the United States.

Table 4.3 | Population-based estimation of waste landfilling rate for the top ten metropolitans in the United States

Metropolitan Name	Population (million) [26]	Landfilled Waste (tpd)
New York-Newark-Jersey City, NY-NJ-PA	19.6	43,600
Los Angeles-Long Beach-Anaheim, CA	12.8	28,600
Chicago-Naperville-Elgin, IL-IN-WI	9.5	21,100
Dallas-Fort Worth-Arlington, TX	6.4	14,300
Houston-The Woodlands-Sugar Land, TX	5.9	13,200
Philadelphia-Camden-Wilmington, PA-NJ-DE-MD	6.0	13,300
Washington-Arlington-Alexandria, DC-VA-MD-WV	5.6	12,600
Miami-Fort Lauderdale-West Palm Beach, FL	5.6	12,400
Atlanta-Sandy Springs-Roswell, GA	5.3	11,800
Boston-Worcester-Providence, MA-RI-NH-CT	4.6	10,100

Table 4.4 | Ten largest active landfill sites in the United States. [27].

No	Location	Capacity (tpd)	Remaining Life (yrs)	Operator
1	Apex Regional Landfill, NV	10,400	> 50	Republic Services
2	Newton County Landfill & Apex Waste Center, IN	9,100	> 30	Republic Services
3	Sunshine Canyon Landfill, CA	8,400	> 20	Republic Services
4	Roosevelt Regional Landfill, WA	8,300	> 35	Republic Services
5	McCarty Road Landfill, TX	7,200	> 10	Republic Services
6	Atlantic Waste Disposal, VA	6,000 - 8,000	> 40	Waste Management
7	Pine Tree Acres, MI	6,000 - 8,000	> 10	Waste Management
8	Columbia Ridge Landfill, OR	6,000 - 8,000	> 100	Waste Management
9	Denver Arapahoe Landfill, CO	6,000 - 8,000	> 100	Waste Management
10	EI Sobrante Landfill and Recycling Center, CA	6,000 - 8,000	> 50	Waste Management

Figure 4.3 depicts the locations of the ten largest active landfills as well as the ten most populous metropolitans in the United States. As can be seen, there is no a clear correlation among these locations.

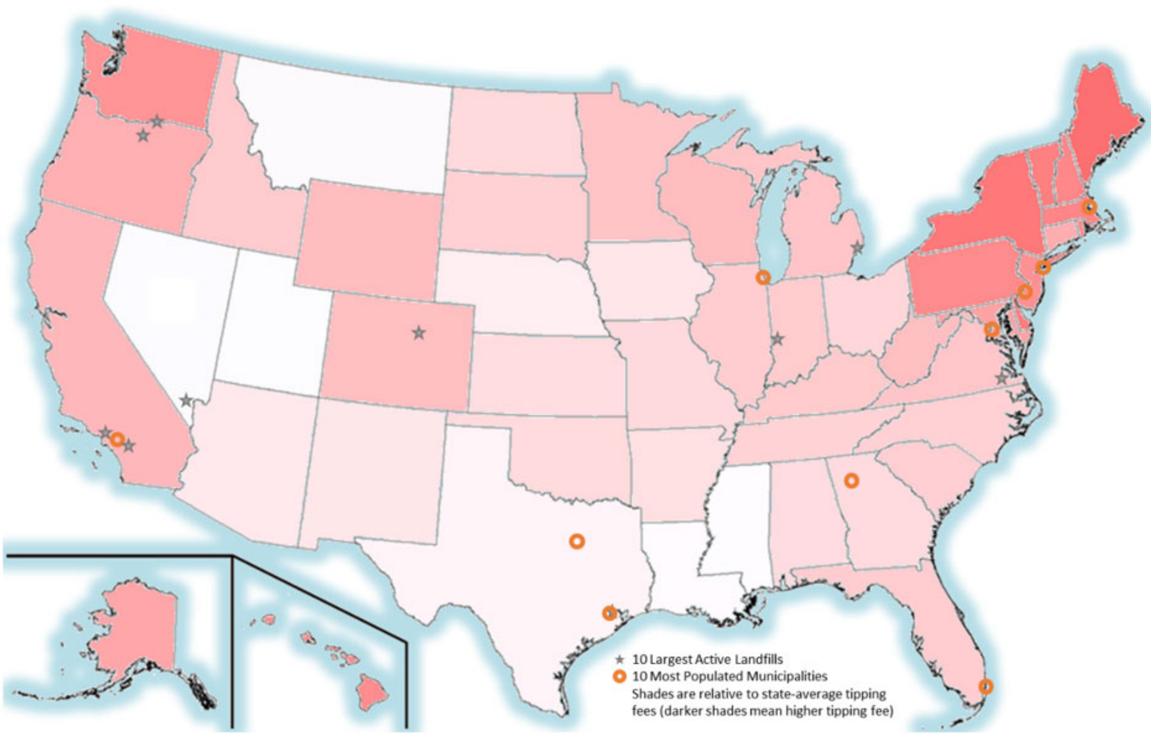

Figure 4.3 | Locations of the ten largest landfills and ten most populated metropolitans in the U.S. The shade corresponds to the average tipping fee on waste landfills in each state.

Other factors affecting the location of landfills, besides regional population, include the environmental (soil, water, etc.) and waste management regulations of state and local governments, cost of land, tipping fees, the availability of transportation modes (e.g., road and rail), and the availability of other means for waste management.

Similarly, the maximum economic transport distance of waste to a specific landfill is affected by factors, such as landfill's locations and accessibility via different transportation modes as well as its tipping/gate fees. In addition, the maximum waste transportation distance depends on the types of facilities and services, which exist in landfill sites. This fact is shown in Figure 4.4; the top image shows the tonnages and source locations of waste streams going to a medium-size landfill while the bottom image depicts the same data for a large-scale integrated landfill and recycling facility. Tonnages and locations from which waste is transported to the landfills are taken from [28].

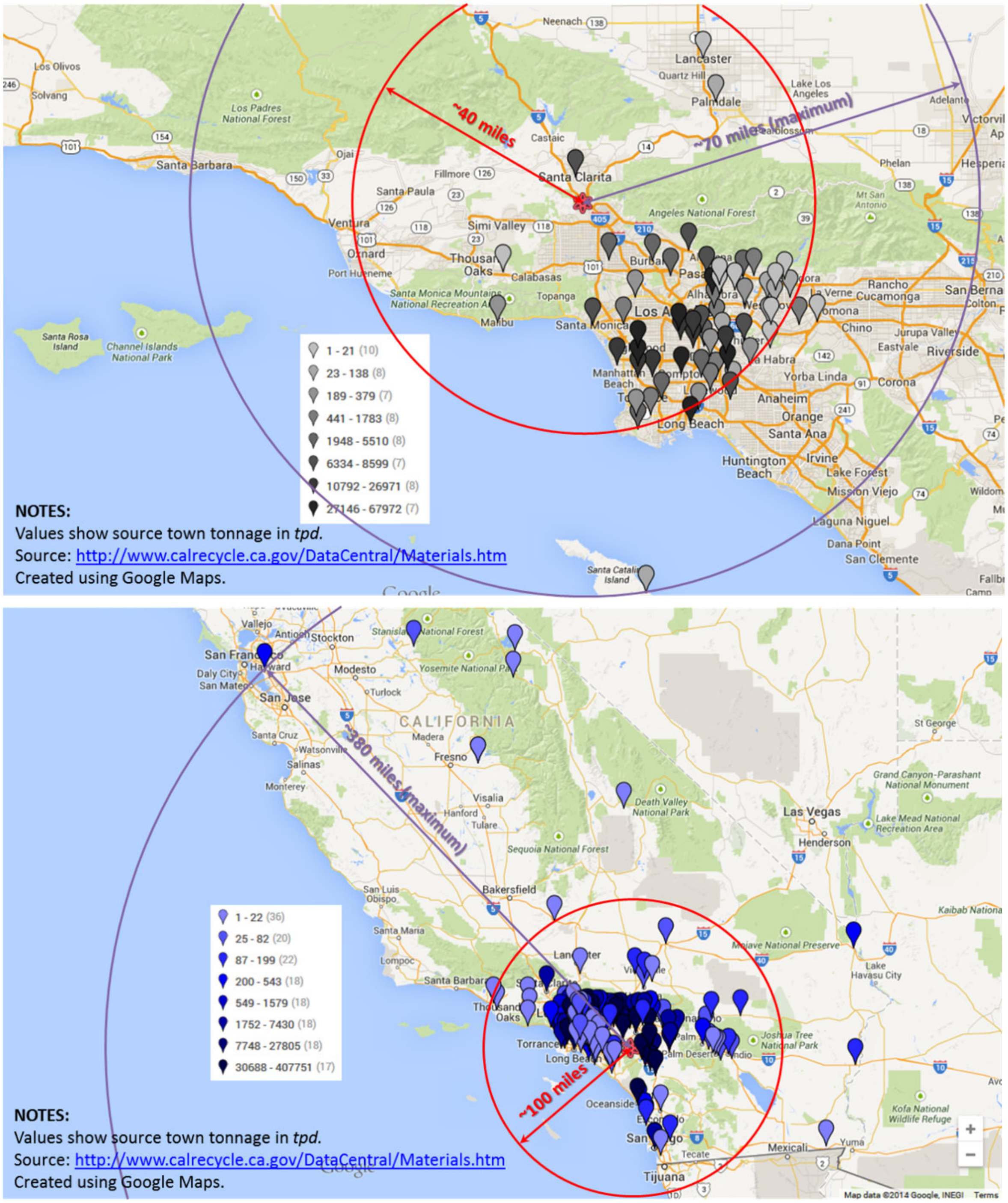

Figure 4.4 | Tonnage and radius from which waste is transported to two landfills. Top) Sunshine Canyon landfill with 0.7 million ton per year capacity; Bottom) El Sobrante landfill and recycling facility with 2.3 million ton per year capacity. Data from [28].

As another example, there is a concentration of waste to energy facilities in New England that provides another means for the disposition of waste besides landfilling. Also, due to the effect of such factors, municipalities and waste management companies often transport waste from the generation region to disposition location. In 2008, more than 27 million ton of waste was imported from one state to another [29].

In this study, we assumed that only the landfill-destined portion of waste, which is not recovered through recycling or waste-to-energy routes, can be used for production of alternative fuels. Therefore, estimating the maximum potential for production of liquid fuels from waste requires obtaining data on the quantity and characteristics of the landfilled waste from individual landfill sites.

The PNNL report, based on data gathered from waste management agencies on 50 states from individual landfill sites, identifies 47 landfill sites in the United States with capacities greater than 3,300 ton per day (tpd). Based on the individual landfill site data, these 47 landfills have an average capacity of 5,700 tpd [23].

As part of our attempt to better understand the state of MSW generation and disposition of MSW in the United States, we looked at the most recent data from waste management agencies of some states that release the detail data at landfill level [30], [31], [32], [33], [34], [35], [36], [37], and [38]. The number of landfill sites in these states with capacities greater than 3,300 tpd are also shown on Figure 4.5 (red underlined values). Please note that the number of sites reported for Florida is based on waste generation data from counties not actual landfill sites.

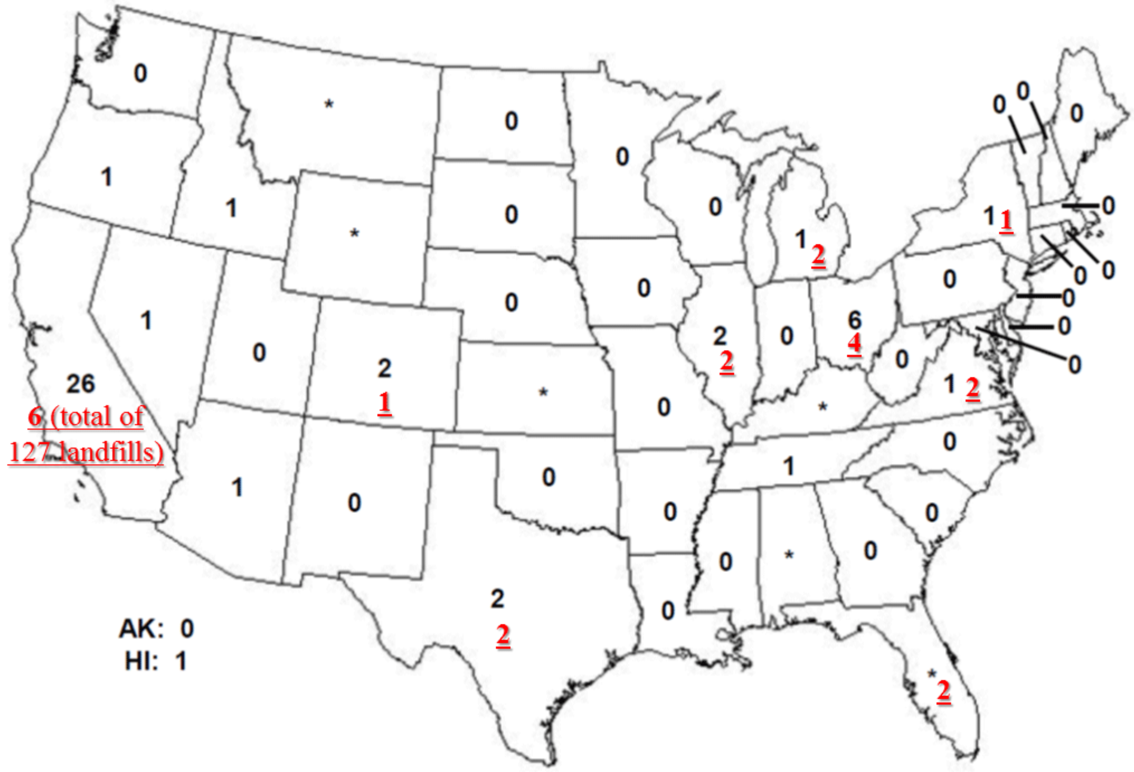

Figure 4.5 | Number of landfill sites with daily capacity of greater than 3,300 tpd. PNNL and MIT figures are shown in black and red (underlined), respectively. Original figure from [23].

Since the PNNL report was prepared in 2008, it was expected that there would be some inconsistencies when the data are compared to the most recent data (mostly for FY2012) due to closure of old landfills and the opening of new ones. As shown in Figure 4.5, there is a significant discrepancy in the number of large (> 3,300 tpd capacity) landfill sites in California. PNNL reports 26 landfill sites of this size, which translates to a waste generation capacity greater than what was reported for the entire state in 2012 (26 × 3,300 tpd >31 million ton per annum). A closer look at the waste generation data in California revealed that in 2012, only 6 out of 127 landfill sites in the state were of this size.

4.3. Availability of MSW for fuel production

The PNNL report identifies 47 landfill sites in the United States with capacities greater than 3,300 tpd. Based on the individual landfill site data, PNNL reports that these 47 landfills have an average capacity of 5,700 tpd. Using the PNNL assumed conversion yield of 1.16 barrel of ethanol per ton of MSW, these 47 landfills can provide feedstock for production of 310,000 bbl_{EtOH}/day. As shown above, the number of the large landfills (at least for the state of California) is not consistent with the recent data from landfill sites. Also, the PNNL assumption that 100% of landfilled waste can be used for fuel production is not realistic, especially if the waste tonnages reported by landfills are considered as the basis for available amount of waste. As mentioned above, in addition to MSW, other wastes such as construction and demolition debris enter the landfills. Only some of these wastes can be used for fuel production. Based on the average composition of waste, we estimate that only 70% of landfilled waste can be used as feedstock [25], [22]. Table 4.5 shows the comparison of the assumptions and the results of the estimated production capacity of liquid fuels from waste in the United States.

Table 4.5 | Estimated capacity of producing liquid fuel from waste in the United States.

Parameter	**This Study**	**PNNL Report [23]**
Diversion Rate of Waste for Conversion	70%	100%
Number of plants with >3,300 tpd capacity	27 [a]	47
Average Plant Capacity (tpd)	7,600	5,700
Total Diverted Waste for Conversion (tpd)	205,000	268,000
Assumed Conversion Yield	0.88 bbl_{FT}/ton [b]	1.16 bbl_{EtOH}/ton
Total Production Capacity	180,000 bbl_{FT}/day [c]	310,000 bbl_{EtOH}/day [c]

NOTES:

[a] Assuming one conversion plant per metropolitan.

[b] Based on assumed moisture content of 25% and 19% hit on yield compared with biomass due to heating value difference. Assumed conversion rate for biomass: 1.45 bbl_{FT}/ton_{dry}.

[c] Energy content of FT products are on average 1.7 times that of ethanol.

After making adjustments to the number of landfill sites (>3,300 tpd capacity) and the waste to feedstock diversion rate, we estimated the total potential capacity for production of liquid fuels from waste in the United States to be 180,000 bbl/day of FT liquids, equivalent to 306,000 bbl/day of ethanol. Although this figure is comparable to the estimated production capacity by PNNL, the assumptions used for this analysis are significantly different and the similarity of obtained results is accidental.

4.4. Economics of Waste-to-Liquid Fuels (WTL) Plants

We investigated the economics of WTL fuel plants using the same tools developed for the techno-economic evaluation of BTL fuels. In this exercise, we assumed that the number of processing units needed for the conversion of waste to FT liquid fuels is the same as those needed for production of biomass-derived fuels. We made adjustments for the heating value of waste (vs. biomass) without explicitly simulating the conversion process of waste. We also assumed that the typical size of a waste-to-liquid facility is smaller than a biomass-to-liquid facility to reflect the constraints regarding collection and transportation of waste to the conversion plant. We assumed the throughput of a typical WTL facility to be 100,000 tonne per year (~275 tpd) of dry waste, similar to Enerkem's Alberta Biofuels facility in Edmonton, Canada [39]. Furthermore, we assumed a tipping fee of $75 per dry tonne of MSW feedstock. Figure 4.6 shows the effect of plant size on the production cost of waste- and biomass-derived liquid fuels. Our estimated capital costs for the small and large WTL conversion plants are $190 million and $450 million, respectively. The large WTL plant is assumed to have a feed throughput of 1,000 tonne per day of dry waste. The feedstock of the Reference case is loblolly pine woodchips that are gasified using a fluidized bed gasifier. Please see Chapter 5 for more information of gasification technologies studied in this project.

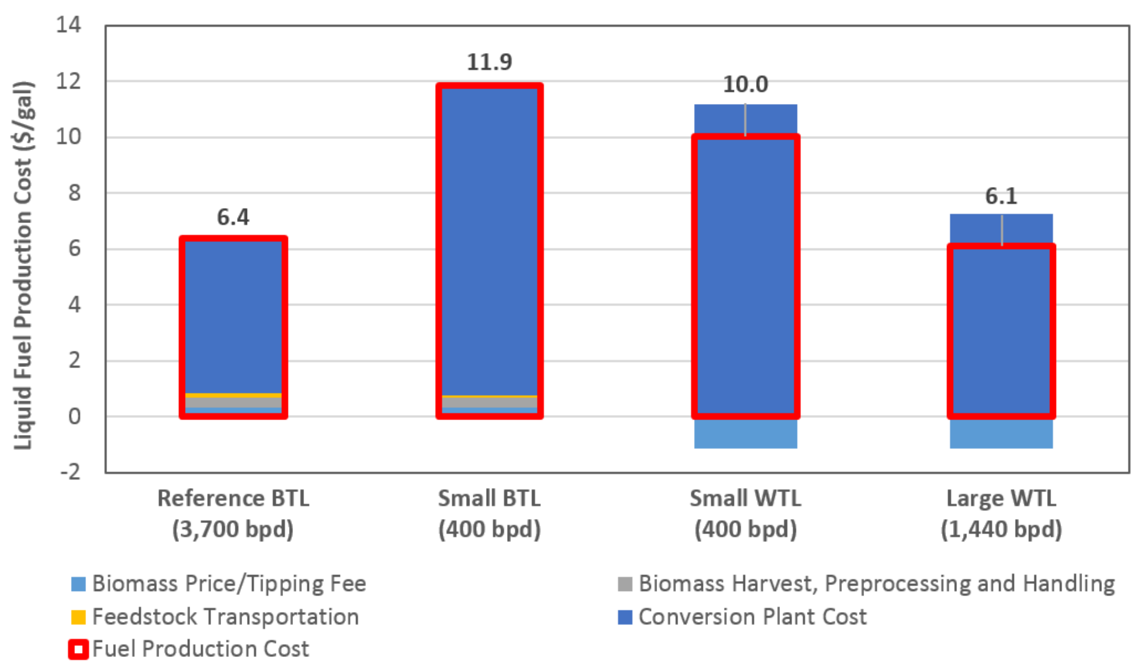

Figure 4.6 | Comparison of cost of fuel production from biomass and MSW.

As shown in Figure 4.6, the production cost of liquid fuel from biomass increases by more than 85% (from \$6.4/bbl to \$11.9/bbl) when the plant size in reduced from 3,700 to 400 barrels per day (bpd) due to economy of scale effect. Due to the higher moisture content, lower heating value, and disperse generation source, the collection, pre-processing (sorting), and transportation of waste is more costly than that of energy crops (e.g., loblolly pine). The “Small WTL” case was defined to investigate the effect of a smaller size of a typical WTL plant (400 bpd) in comparison with the reference BTL case (~3,000 bpd). The production capacity of 400 bpd corresponds to feed throughput of 100,000 tonne per year of waste, typically generated by a community of 370,000 to 700,000 people. After considering the tipping fee for a WTL plant of the same size (400 bpd) the fuel production cost drops by \$2 to \$10 per barrel of fuels products. Due to the benefits of the economy of scale, the fuel production cost for a large WTL plant with feed throughput of 1,000 dry tonne per day is \$6.1/bbl which shows ~40% drop compared to the small WTL plant. As shown in Figure 4.6, the liquid fuel production cost of a 1,440 bpd WTL plant is almost the same as on a 3,700 bpd BTL plant with much higher capital cost. In other words, in comparison with the reference BTL plant, the negative effect of the smaller sized WTL plant is compensated by the additional revenue from waste tipping/gate fee. This comparison also illustrates the magnitude of tipping/gate fees on the economics of WTL plants.

With respect to fuel production cost, the additional revenue from tipping fees can put a smaller WTL plant on par with a larger BTL plant by making up for the increased per unit cost due to smaller size. In this sense, a WTL plant offers a vehicle for demonstrating conversion technologies without the larger financial risk of building a large BTL plant.

4.5. Siting of Waste-to-Liquid Plants

Given the generally dispersed availability of waste generation (with the exception of densely populated areas), its low heating value, and high transportation costs, siting of WTL plants is very important and greatly effects the economics of the plant. The question is what is the best siting option for a typical WTL plant considering the current flow of waste from the generation source (mostly populated area) to the disposition site (landfills)?

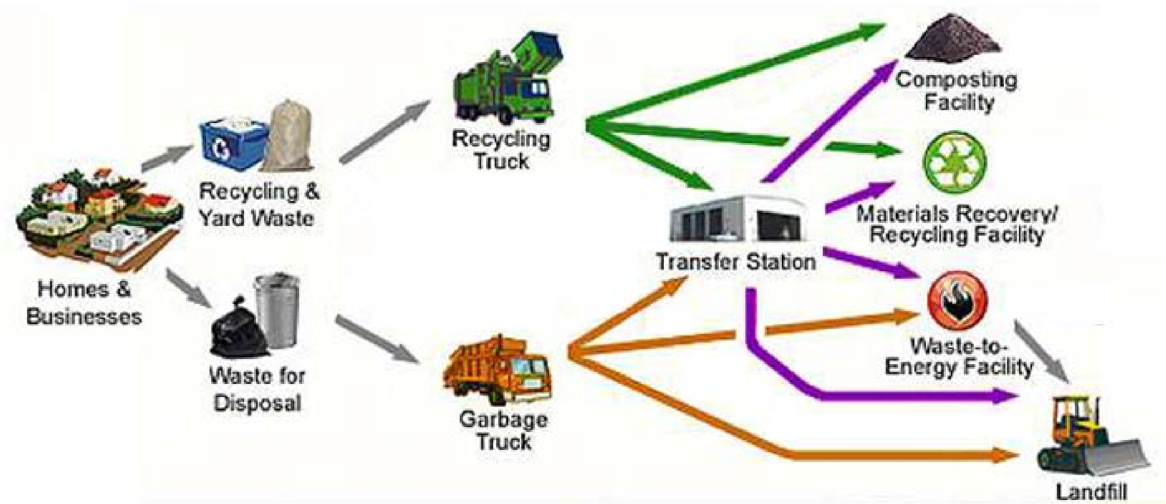

Figure 4.7 | Waste destinations between generation (population centers) and disposal (landfill) sites [40]. Image is altered for clarity.

Figure 4.7 shows the various paths of MSW from generation source to disposition site [41]. Due to the high costs of infrastructure and facilities needed for transporting and processing of MSW, proximity of the WTL conversion plant to all or some of these facilities will result in significant infrastructure and transportation cost savings. In assessing the siting of a typical WTL conversion plant, we considered the following options:

- Next to an integrated material recovery and landfill complex
- Next to a landfill
- Next to a material recovery and/or transfer station
- Greenfield development

Currently, some large metropolitan areas have integrated facilities, to which collected waste is transported. In these facilities various materials handling techniques separate different materials such as metals, plastics, and glass for recycling. Also, the organic part of waste can potentially be used for composting to produce soil conditioner, which is a valued product. The remainder of the waste is taken to the on-site landfill. The other possible scenario is co-location of the material recovery and transfer stations. After materials recovery, the remaining waste is loaded at the transfer station for transportation to an offsite landfill, which can be a long distance away. The other possible option is siting a WTL conversion plant next to a landfill (only) site. This scenario does not have all the obvious advantages of the previous scenarios, but it eliminates the need for the transportation of the unused portion of waste from the WTL to an offsite landfill. A greenfield plant development might be necessary if development of the WTL plant in proximity of the existing facilities is constrained; for example, due high land cost, environmental regulations, or public opposition.

Table 4.6 | Comparison of various potential locations for WTL plants.

Advantage	Siting WTL Plant Next to			
	Integrated Mat. Recovery and Landfill	Material Recovery and/or Transfer Station	Landfill	Greenfield Development
Reduction of waste feed transportation cost	√	√	√	site-specific
Reduction of rejected waste transportation cost	√	site-specific	√	site-specific
Reduction of fuel product(s) transportation cost	site-specific	site-specific	site-specific	site-specific
Reduction of capital / operating costs by using the existing infrastructure	√	√	site-specific	site-specific
Ease of permitting due to proximity to an existing operation	√	site-specific	√	site-specific
Public acceptance (being away from areas of environmental concern)	√	site-specific	√	site-specific

Table 4.6 summarizes the advantages of siting a WTL conversion plant for these scenarios. As mentioned earlier, in this study we assume only landfill-destined waste is used for production of liquid fuels. There exist other scenarios in which waste destined for incinerated or conversion to energy (waste to energy) can be used as feedstock for fuel production. Such scenarios and corresponding siting options were not considered here.

Some large metropolitan areas have established sorting and materials recovery practices that affect the logistics of waste management and subsequently the siting of the conversion plant. Furthermore, the existing financial structure (tipping/gate fees, waste collection cost, etc.) can potentially affect the siting of the conversion plant. To illustrate this fact, Figure 4.8 shows the average tipping fee in various regions. Siting of the WTL conversion plant should be addressed on a case-by-case basis as the existing infrastructure and logistics for processing and transporting waste vary from one location to another.

Recent trends in industry indicate that developers of waste to energy (particularly WTL) plants are showing increasing interest in developing small facilities to minimize the technological and financial risks. They are instead putting a lot of effort in optimizing the feedstock quality to maximize technical performance and economic viability of such plants. To this end, there have been significant efforts in the enhancement and optimization of waste sorting and material recovery practices in order to produce uniform waste-derived feed streams with low moisture content and acceptable heating value for use as feedstock in waste to energy and WTL conversion plants.

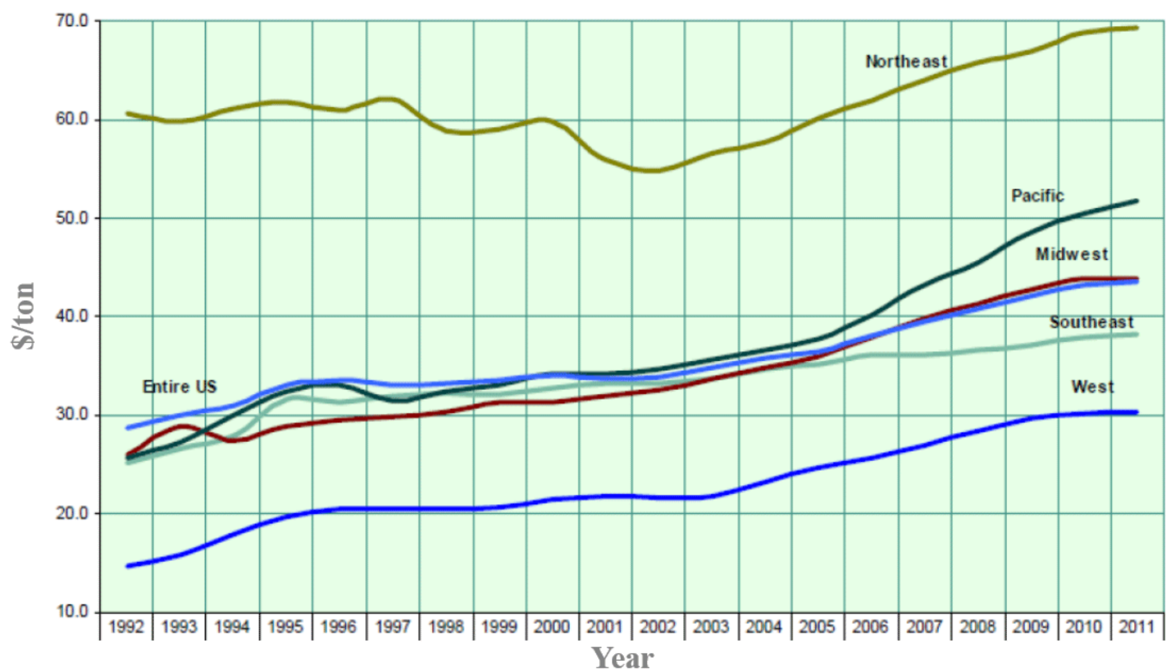

Figure 4.8 | Historic tipping fees in various regions of the United States [42].

5. Conversion Technology

Both fluidized bed gasification (FBG) and entrained-flow gasification (EFG) technologies can potentially be utilized for the economic production of fuels from biomass, but their deployment has been limited and they cannot yet be deemed commercial. Based on our analysis of current technologies, the estimated fuel production cost is lower for FBGs compared to entrained-flow EFGs. For the conversion of waste, plasma gasification technologies are attractive because of their unique abilities to cope with the large variability in particle size, moisture, energy content, and composition of the waste stream. However, plasma gasification is currently less energy efficient than the other gasifiers.

For removal of tars from the syngas produced by FBGs, we found thermochemical technologies to be the preferred route. While more costly than scrubbing processes, they are a less risky approach for reducing the tar components to the low levels required for Fischer-Tropsch synthesis applications. If demonstrated at scale, operating the freeboard of the gasifier at higher temperatures can potentially be the most cost- effective approach for removing the tars.

Due to economies of scale, as the size of the BTL plant increases, the processing costs decrease. However, feedstock delivery costs will rise as the biomass feedstock needs to be sourced from more distant locations. Therefore, the advantages of scale plateau beyond plant sizes of ~20,000 bpd due to the fact that the increased distance and cost of biomass transportation cancel out the savings from going to larger scale.

This chapter includes the results of case studies that compare various technology options that can be utilized in a typical biomass or waste to liquids conversion plant. We focus on two groups of technologies in this chapter. First, the results of comparing two gasification for conversion of biomass to liquids, entrained-flow and fluidized bed gasification technologies, are presented. Then, we present the results of different case studies that compare the performance of various tar handling options in a typical BTL facility. At the end of the chapter, we present the results of our analysis on the effect of the economy of scale of a typical BTL plant.

5.1. Biomass and Waste Gasification Technologies

For conversion of biomass to liquid fuels, two main categories of gasification technology were considered in this project: entrained-flow gasification (EFG) and fluidized-bed gasification (FBG) technologies. In addition, we reviewed various gasification technologies, with a focus on plasma gasification, for conversion of MSW to liquid fuels.

5.1.1. Comparison of EFG and FBG for Biomass Gasification

Early in the Project, the BTL process and costing models were used to evaluate and compare the techno-economic performance of two gasification technologies for conversion of woody biomass (willow) to liquid fuels. The two gasification technologies investigated in this study were EFG (PRENFLO Direct Quench) and FBG (High-Temperature Winkler).

Since EFG and FBG have distinctly different feed characteristic requirements and produce biomass-derived syngas streams of different quality, the configuration of the conversion plant for each of these technologies is different. Figure 5.1 depicts the assumed process configuration for EFG and FBG cases.

One of the main characteristics of EFG technologies is the very short residence time of feed particles in the gasifier. To ensure fast and near complete conversion of carbon in the feed, the biomass particle size must be reduced significantly, to ~100 micrometers (μm). This is a common practice for gasification of coal using Entrained flow (EF) gasifiers, but the fibrous nature of biomass feedstock makes it difficult to reduce the particle size of biomass feedstock. The energy requirement for grinding biomass feedstock particle size to ~100 μm is in the same magnitude as the heating value of the biomass feedstock which makes this approach impractical. The alternative approach for gasification of biomass feedstocks using EF gasifiers is to pretreatment biomass. Pretreatment of biomass (e.g., using the torrefaction process) converts it to a coal-like carbonaceous material with vastly improved grindability. The torrefaction process improves characteristics of biomass by increasing its grindability and heating value as well as reducing it moisture content.

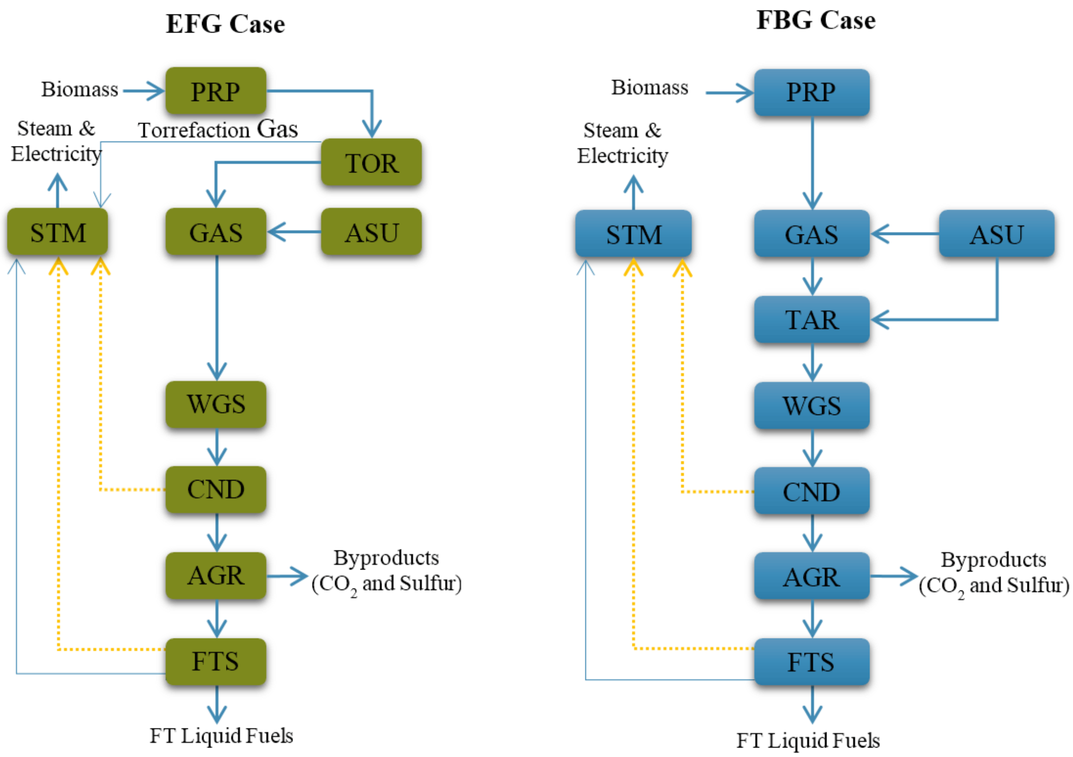

Figure 5.1 | Process configuration for conversion of woody biomass to liquid fuels - entrained-flow vs. fluidized-bed gasification.

Compared to EFG, FBG has a much longer residence time for solids. Therefore, the FB gasifiers are less sensitive to feed particle size. The feed particle size for FB gasifiers can be in the millimeter to centimeter range.

EFG and FBG technologies are also different with respect to the quality of syngas they produce. EF gasifiers usually operate at higher temperatures and therefore produce a syngas product of higher quality with little to no tar components. FB gasifiers operate at lower temperature and are prone to the formation of methane and tar components in the gasification unit. Due to this difference in syngas quality, the syngas treatment and conditioning steps needed for these two technologies are different as well. In order to compare the overall performance and cost of these technologies, we considered and compared two process configurations – one based of EF and the other based on FB gasification technology. Figure 5.1 depicts the considered process flow diagram for these cases. As shown, the biomass feedstock is treated using torrefaction in the EFG case. The FBG case includes a tar removal unit down-stream of the gasifier to handle the tar components formed in the FBG gasifier.

The breakdown of the fuel production cost of the two cases is shown in Figure 5.2. Although EFG is capable of producing higher-quality syngas compared to FBG, the higher cost of feedstock pretreatment and the gasifier itself (higher plant capital cost) result in higher production cost of liquid fuels.

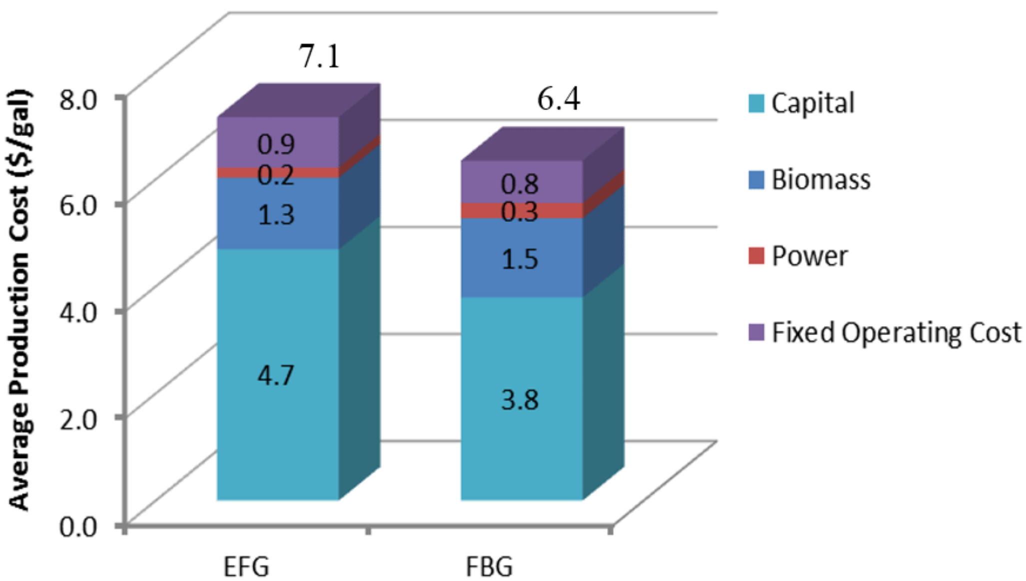

Figure 5.2 | Liquid fuel production cost breakdown – entrained-flow vs. fluidized-bed gasification.

The assumptions and detailed results of this case study are documented in a report "Techno-economic Evaluation of Biomass-to-liquids Pathways – Case Study: Entrained-flow Gasification (EFG) *vs.* Fluidized-bed Gasification (FBG)" in summer 2012 [43].

As shown, both FBG and EFG technologies have the potential to be utilized for economic production of fuels from biomass. The estimated fuel production cost is lower for the FBG case compared to the EFG case.

5.1.2. Waste Plasma Gasification

Plasma technologies have been used for over 30 years in a variety of industries, including the chemical and metals industries. Historically, the primary use of this technology has been to safely decompose and destroy hazardous wastes, as well as to melt ash from mass-burn incinerators into a safe, non-leachable slag. Electric power requirements for treating waste have been reported in the range of 0.34–4.4 MMBtu (360-4,600 MJ) per ton of waste [44], [45].

Among the different types of technologies used for waste gasification, plasma gasification is one that stands out. In plasma gasification, electric energy is used to generate a plasma region with extremely high temperatures, inside the gasifier, which ensures the complete melt and/or destruction of various components that exist in the waste. In addition, plasma gasification reduces the need for the pretreatment of waste feedstock required for other gasification technologies. Utilization of plasma in gasification processes has two applications: 1) providing high-temperature heat to the gasification reactions to assist the gasification of low-quality or variable-quality feedstock (plasma-assisted gasification) and 2) treating the gasification products (i.e., syngas and ash/slag.) In the latter, plasma creates a high-temperature region at the gasifier outlet(s) so that unwanted products, such as tar components in the syngas or unconverted carbon in ash, are converted to desired products. Also, applying plasma to the bottom of a gasifier can ensure that the inert portion of feedstock (e.g., ash and remaining metals in waste) is melted and leaves the gasifier as a continuous molten stream. The advantages of plasma gasification come at the cost of using high-value electric energy for generation of plasma. The pros and cons of plasma gasification are listed in Table 5.1.

Table 5.1 | Pros and cons of waste plasma gasification.

PROs	CONs
Capable of handling hazardous waste	Increased power demand
Reduced preprocessing requirements by making the conversion process more flexible (feedstock flexibility)	Cost of plasma torches
Increased syngas yield	Increased capital cost (increased thermal and volumetric requirements) due to higher operating temperatures
Decreased oxygen demand and ASU cost	
Decreased syngas volume and size of units downstream of gasifier	
Improved syngas quality (reduced tar etc.)	

There are many plasma technologies for gasification of waste, but the details of these technologies are not in the scope of this report. After reviewing various waste gasification technologies, we selected the Westinghouse Plasma gasifier for further analysis of waste to liquid fuel applications. This gasification technology can be used for a wide range of feedstocks, including auto-shredder, biomass, and plastics. There are commercial installations of this technology in Japan, India, Canada, and the United States. The schematic of AlterNRG (Westinghouse) plasma gasification technology is shown in Figure 5.3.

In order to quantify the effect of using electric energy in plasma gasification process, we conducted a case study using the developed process model for the project. In this case study, we compared performance of High Temperature Winkler (HTW) gasification vs. AlterNRG plasma gasification technologies for both biomass and MSW feedstocks. The assumptions and results of this case study are summarized in Table 5.2.

Figure 5.3 | AlterNRG (Westinghouse) plasma gasification technology [46].

As shown in Table 5.2, plasma gasification increases the desired product (H_2+CO in syngas) at the cost of consuming extra electric energy that can amount to 3%-6% of the thermal energy content of the feedstock on a Higher Heating Value (HHV) basis. Adjusting for the conversion of thermal to electric energy increases this fraction to 10% or more.

Table 5.2 | Comparison of gasification of woodchips and shredded MSW using HTW and AlterNRG plasma gasification technologies.

		Feedstock			
		Woodchips		MSW	
Gasifier Type	-	UHDE HTW	AlterNRG	UHDE HTW	AlterNRG
Feed Rate (AR)	kg/hr (tpd)	36,860 (1,082)			
HHV (dry)	MJ/kg	20.0	20.0	17.4	17.4
Feed Rate	MWth	143	143	87	87
As Received Moisture	wt.%	30	30	51	51
Gasifier Feed (dried)	kg/hr	28,046	28,046	19,793	19,793
Oxygen Demand	kg/hr	11,786	10,805	16,018	15,050
ASU Power Demand	MWe	4.7	4.3	6.4	6.0
Number of Torches	-	-	6	-	6
Plasma Power Demand	MWe	-	4.8	-	4.8
Syngas Flow	kg/hr	1,324	1,385	687	747
Syngas composition					
H_2	mol%	26	28	17	19
CO	mol%	29	30	22	23
CO_2	mol%	14	13	21	19
H_2+CO Flow	kmol/hr	1,324	1,385	687	747

The conclusion is that plasma gasification technologies do not have an energy efficiency advantage over the conventional gasification technologies. What makes plasma gasification technologies unique in the conversion of waste is their ability to cope with the large variability in particle size, moisture, energy content, and hazardous components of waste materials.

5.2. Tar and Methane Handling Technologies

One of the main challenges in gasification of biomass, particularly using gasification technologies that operate at lower temperatures than EFGs such as moving bed and fluidized bed gasifier, is the formation of tar and heavy hydrocarbon components that can cause issues in the down-stream unit operations. To investigate this challenge, we studied various tar handling options that potentially can be applied inside the gasifier or down-stream of a gasifier. To this end, we investigated a wide range of technologies including partial oxidation (in-situ and ex-situ), steam reforming, and scrubbing using various solvents. Here we present a summary of selected findings on this topic.

5.2.1. Kinetic-based Studies

In this work, we modeled and reported the performance of three frequently suggested secondary tar handling options – uncatalyzed partial oxidation, catalytic steam reforming and absorption. A few of the important results of this study, which are presented in this section, are taken from [47]. Please refer to Srinivas et al. [47] for a complete description of assumptions and the results of this case study.

Assumptions, Methodology and Results

For reasons of simplicity and kinetic data availability, the following four components were chosen as model tar compounds in our study - Phenol, Benzene, Toluene and Naphthalene. Suitable kinetic models were chosen from literature to model the reaction chemistry which consists of oxidation, cracking or thermal decomposition, and steam reforming reactions. Based on the components chosen, the syngas feed composition for the base case was specified as follows: H_2 – 5.93; CO – 5.37; CO_2 – 8.93; CH_4 – 4.64; N_2 – 6.7; H_2O – 64.7; Ar – 3.58; C_6H_6 – 0.15; C_7H_8 – 1.99e-5; C_6H_5OH – 3.92e-6; $C_{10}H_8$ – 1.59e-4 (all in mol%). 816 m^3/hr of syngas at 20.2 atm and 816°C completes the base case feed conditions, corresponding to run GT-11 from the Institute of Gas Technology (IGT) gasifier report by Evans et al. [48].

Results for Uncatalyzed Partial Oxidation and Catalytic Steam Reforming

Reactor simulations were performed using a plug flow kinetic reactor model for the base case feed at a pressure of 20 atm. For reforming, two cases were considered – Autothermal Reforming (ATR) and Steam Reforming (SR) using Ni and/or dolomite catalysts. The target tar concentration in the exit syngas was <5 mg/m3 which is reasonable for BTL applications. The results for the best cases are shown in Table 1. In addition to tar removal, the Partial Oxidation (POX) and reformer reactors also serve to covert methane to syngas. There is not a specific target conversion of methane required; a higher methane conversion is preferred for the process economics.

The choice of POX reactor temperature and residence time is driven more by the methane conversion than by tar conversion. To achieve high methane conversion, temperatures of 1400°C and above are needed based on the published works on the reaction kinetics. Soot formation is unavoidable in the POX reactor and the kinetics used in our model capture its formation. The reactor residence time is important to convert the soot (carbon) as well as reform methane into syngas (compare columns two and three in Table 5.3). The tar concentration in the exit syngas stream is ~2 mg/m^3 which is below the target value. Since part of the syngas is combusted to reach the desired POX reactor temperature, there is an energy penalty associated with the loss of this useful syngas. Further, oxygen demand increases with POX reactor temperature and is an additional parasitic load in terms of the energy required by the air separation unit.

Table 5.3 | Comparison of various methane and tar handling processes.

Parameter	POX-1	POX-2	ATR	SR
Reactor temperature (°C)	1400	1400	1043	900
Reactor residence time (s)	5	10	8	8
O_2 used (tonne/h)	~69	~68	~39	-
Tar conversion (%)	>99	>99	>99	>99
Tar concentration (mg/m^3)[b]	1.6	1.6	0.1	5.2
CH_4 conversion (%)	83.9	92.5	>99	>99
H_2/CO ratio	1.11	1.11	1.38	1.66
H_2+CO flow (tonne/h)	45.9	54.2	77.4	99.1
Soot formed (%)[a]	2.59	1.44	1.13	1.13

Notes: Assumed feed conditions: H_2/CO ratio: 1.1; H_2+CO flow: 43.3 tonne/h; methane mole fraction: 4.64%; Tar concentration: 26200 mg/m^3;
[a] As percent of incoming carbon
[b] Tar concentration at actual gas volume (conditions: stream temperature and 20 atm)

In the case of ATR, the reactor temperature is lower than the POX case owing to the use of a catalyst (Ni). The ATR also has energy penalties from the O_2 consumption and combustion of syngas to reach the desired reactor temperature, but to a lesser extent than for the POX. The exit tar concentration from the ATR is well below the target value. For the case of steam reforming (SR), it is assumed that an upstream reactor using dolomite catalyst converts some of the tars and methane in the syngas. The temperature of the SR using a Ni-catalyst is 900°C – which is typical of commercial catalytic steam reformers. The exit tar concentration is ~5 mg/m^3 (close to the target value). Soot formation is observed in both the reforming cases (ATR and SR), and is more problematic than the POX reactor since the soot can hamper catalyst performance.

The H_2/CO ratio and the combined flowrate of H_2 and CO increases as we go from POX to ATR to SR cases. This is as expected, owing to the reduction in the amount of syngas combusted to achieve the reactor temperature. It is important, however, to account for the energy input from an external fuel (natural gas or offgas) used in providing the heat for the steam reformer case.

Absorption

"Scrubbing or absorption by a liquid medium is one of the physical strategies to remove tar from syngas. While POX and reforming chemically transform the tars and methane into syngas, absorption does not. Using diesel, vegetable oil and biodiesel as the solvents, simulations were performed for the base case feed. The absorber has eight stages and operates at 20 atm. The simulation results showed that the performance order is diesel > vegetable oil > biodiesel [47]." Though scrubbing helps to lower the tar concentration, the solvent requirement is quite high to lower it to the extent needed for fuel synthesis applications. Further, methane slips through the scrubbing process with almost no absorption in the solvents. Since methane is an inert in BTL applications, it might lead to increased process complexity (additional reforming, purge, etc.) as discussed in the next section.

5.2.2. Scrubbing vs. Thermochemical Technologies for Tar handling

In another process study, we showcased the difference between two groups of tar handling technology options. In this study, we defined two cases: the first is a technology solution that only removes the tar components from the raw syngas but not the methane. An example of this solution is scrubbing the raw syngas using an organic solution. For the purpose of this study, we considered benzene as the wash solution (Organic Wash Case). The second technology option is one of the thermochemical technologies in which in addition of conversion tar components the methane in the syngas is at least partially converted to syngas. We considered a POX process as the representative of such technologies (POX case).

Figure 5.4 shows the distribution energy of the feedstock between the main components of the syngas after being treated using POX (left) and Organic Wash (right) units. Unlike the POX case, in the Organic Wash Case, the methane portion of syngas almost entirely passes through the wash unit without any change.

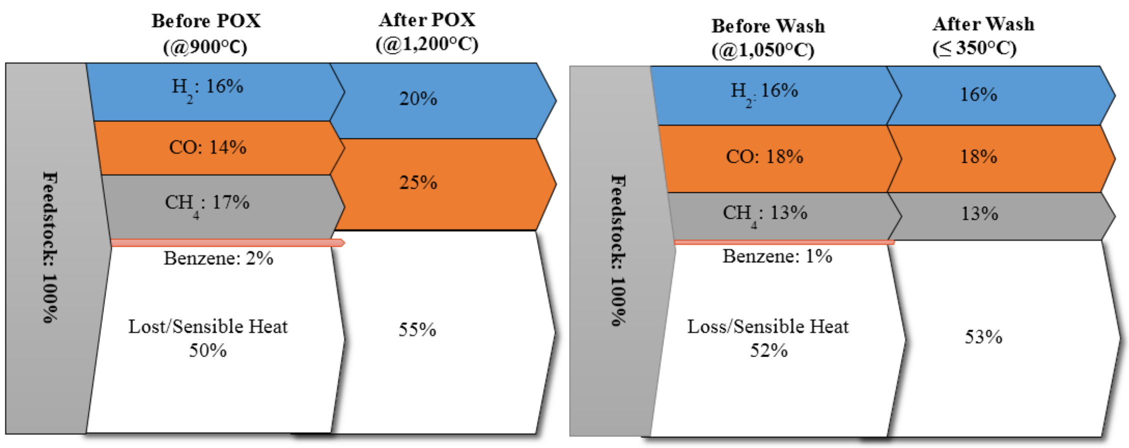

Figure 5.4 | Breakdown of syngas energy within different components before and after tar handling units – left: POX, right: organic wash; energy breakdown percentages are on a Lower Heating Value (LHV) basis.

Figure 5.5 represents the simplified process flow diagram of these two approaches in a typical BTL plant as well as the results from the process simulation model. The choice of tar handling technology affects the process design of the downstream sections of the BTL plant. In our design of the BTL plant, we assumed a fixed inert level in the feed to the FT reactor in all cases.

As can be seen in Figure 5.5, in the POX case, the HTW gasifier is assumed to operate at 900°C and the syngas temperature is increased to 1,200°C in the tar reformer to ensure destruction of most of the tar component and methane in the syngas. Due to the low methane content of the syngas product from the POX unit, there was no need for a reformer within the FT synthesis loop. The purpose of a reformer in the FT loop would be to reform the methane and higher hydrocarbons formed in the FT reactor to avoid the buildup of those inerts in the FT recycle loop which hinders FT reactor performance. As shown in the POX case, the inert content of the feed to the FT reactor could be maintained below the target threshold without the need for a reformer and with purging only a small fraction of the FT rector gas gaseous products.

For the Organic Wash Case, we assumed the HTW gasifier operates at higher temperature of 1050°C to reduce the amount of methane (and possibly tar) formed in the gasifier. The wash unit can only remove the tar components from the raw syngas; almost all methane in the syngas passes through the wash unit. Formation of the methane and other hydrocarbons in the FT reactor, in addition to methane from the gasifier, necessitates a reformer within the synthesis loop in order to keep the inert level of the FT feed stream below the target threshold. Since the added reformer converts most of the hydrocarbons to syngas, purging a very small fraction of FT gaseous product (to remove other inerts in the loop such as N_2 and Ar) is sufficient to keep the inerts below the target threshold.

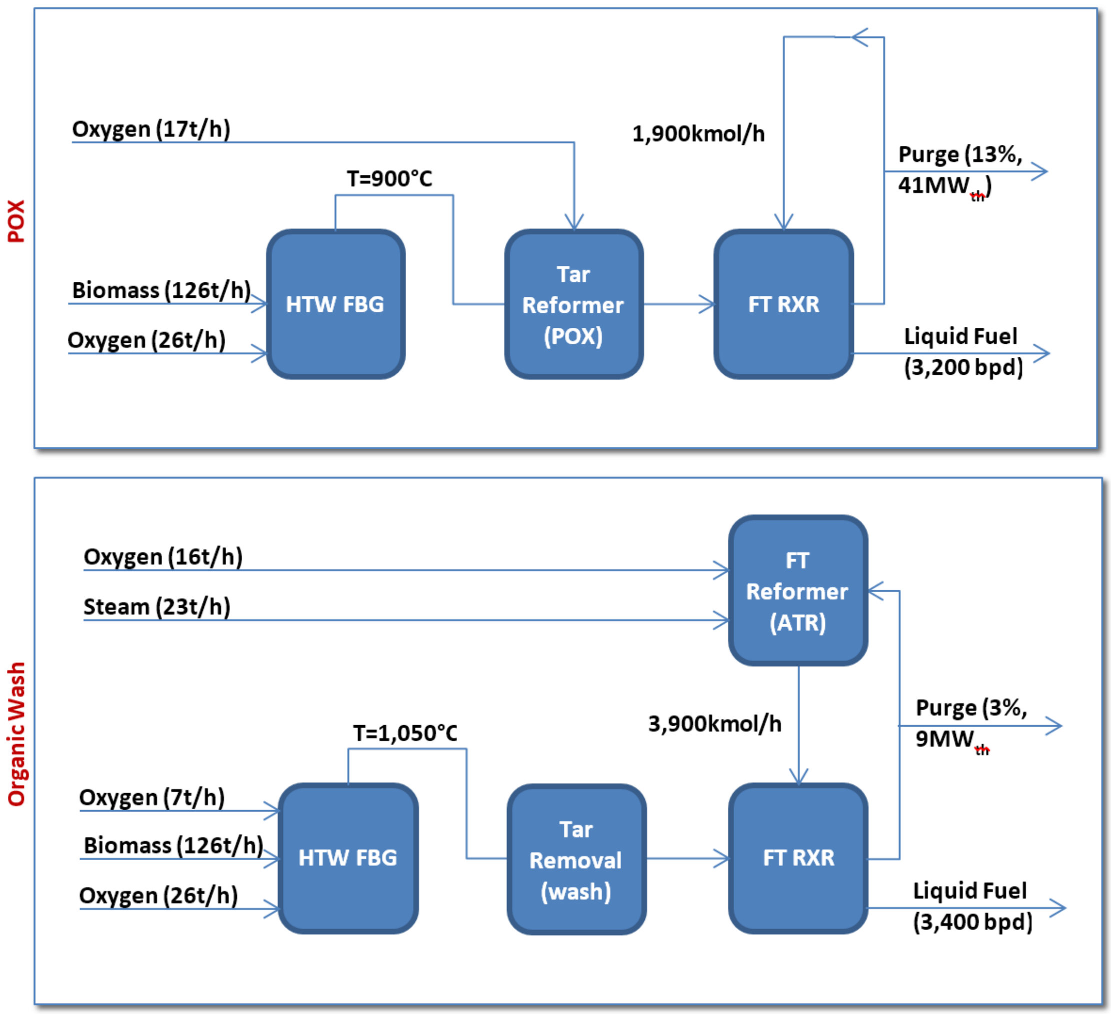

Figure 5.5 | Comparison of different process configurations for tar handling – partial oxidation *vs.* organic wash.

As shown in Figure 5.5, more fuel is produced in the Organic Wash Case at the cost of additional consumption of steam and oxygen in the gasifier and the reformer in the FT synthesis loop. In addition, the cost of the plant in the organic wash case is higher than that of the POX case due to the addition of both the wash and reformer units. The major challenge in using organic wash technologies for handling tar is that, in most cases, it does not removes tar components to the very low concentrations required for synthesis applications.

Although thermochemical technologies for removal of tar from syngas are more costly than their scrubbing counterparts, they present a better potential for removing tar components to the low levels required for fuel production and decreasing the overall technical and financial risks faced by BTL facilities due to formation of tar in the gasification of biomass. The results of comparing various thermochemical technologies for handling tar (and methane) in raw syngas are presented in the next section.

5.2.3. Comparison of different thermochemical technologies for tar handling

In another process study, the effect of various tar handling technologies on the liquid fuel production cost was investigated, the results of which are shown in Figure 5.6. In this study, three cases were considered: an ex-situ catalytic reformer downstream of an HTW gasifier that operates at 900°C (reformer case); an ex-situ partial oxidation reactor down-stream of a HTW gasifier that operates at 1,200°C (POX case); and a case in which the operating temperature of the HTW gasifier is increased by addition of oxygen to reach 1,200°C in the freeboard (UHTW case).

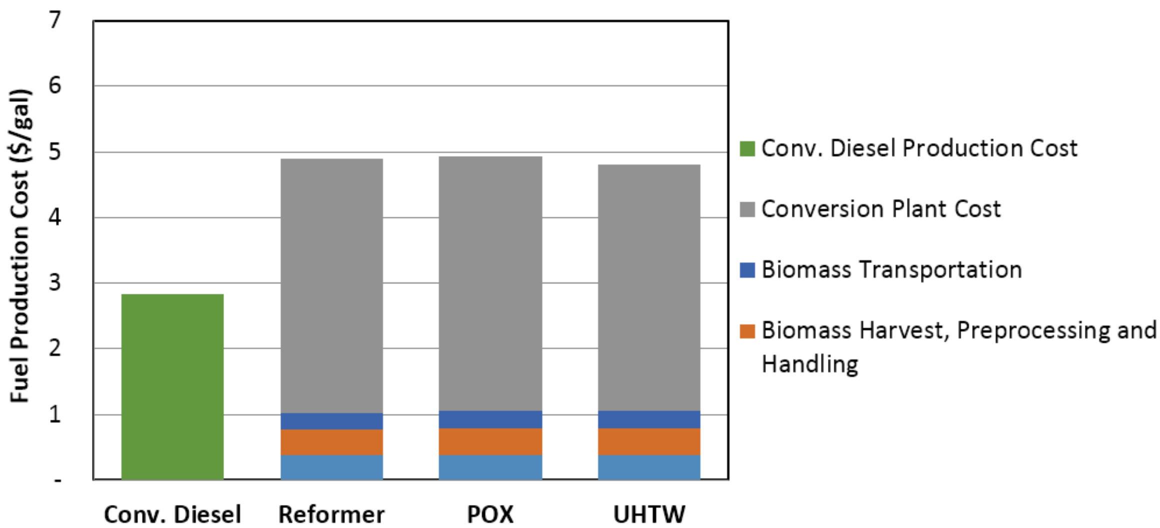

Figure 5.6 | Breakdown of the calculated cost of liquid fuel production using three different tar handling technologies and their comparison with the production cost of conventional diesel.

If demonstrated at scale, operating the freeboard of the FBG at higher temperatures (~1,200°C) could be the most cost-effective approach for dealing with methane and tar.

In this study, the capital cost for the UHTW gasifier was assumed to be the same as the HTW gasifier. This is a best case scenario since the incremental cost of the UHTW gasifier is currently unknown. Running the techno-economic tool under these assumptions revealed that the total production cost for the UHTW case is the lowest among the cases by $0.04/gal mainly due to lower plant capital cost.

Although the UHTW case demonstrates the lowest fuel production cost, it remains to be demostrated by Uhde (HTW gasifier's supplier) at large scale. The catalytic reforming has been in use for decades in various industries, but its application to biomass-derived syngas is in its early stages. A mature reforming technology should efficiently handle methane and tar components as well as be robust and reliable. Also, there is a long history of using POX in various applications. Its high operating temperatures ensure sufficient destruction of methane and tar components in the raw syngas and the absense of a catalyst in this process makes it reliable and robust. If increasing the freeboard operating temeprature (UHTW case) to levels similar to the POX reactor can have the same effect of methane and tar destruction (by having similar or longer residence time), it would result in lower capital cost of the total plant by avoiding the cost of the POX unit.

5.3. Effect of CO_2 Capture and Storage of BTL Plant Economics

CO_2 is removed (captured) from the syngas in a typical alternative fuel production plant that uses FT synthesis. The CO_2 is removed from the syngas to reduce the size and cost of the FT and to increase yield. Therefore, removal of CO_2 is a process requirement in such plants. In order to prepare the captured CO_2 for sequestration, it needs to be dried and compressed to the pressures needed for pipeline transportation. Although the addition of these units increases the capital cost of the plant, their incremental cost is very small compared to the total cost of the conversion plant and, therefore, does not have a considerable effect of the production cost of fuels in such plants.

We considered the different cases in Figure 5.7, to illustrate the effect of carbon capture and storage (CCS) on the economics of the reference case. In the reference case, we assume the captured CO_2 is released to the atmosphere (Vent). In the Storage case, we assumed that the plant pays \$20/tonne of CO_2 to a third party to store the captured CO_2. In the EOR case, we assumed that an Enhanced Oil Recovery (EOR) operator buys the captured CO_2 for \$20 per tonne.

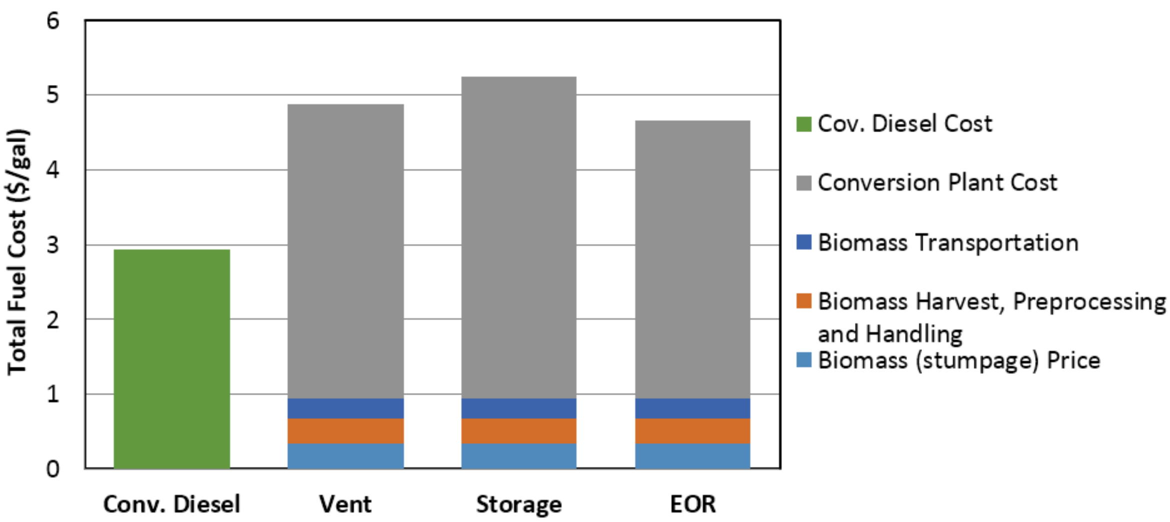

Figure 5.7 | Effect of CCS on fuel production cost of Reference (Vent) case.

As can be seen in Figure 5.7, the fuel production costs for the Storage and EOR cases are higher and lower than the Vent (reference) case, respectively. However the effect of addition of CCS (either Storage or EOR) does not have a major effect on plant economics.

5.4. Effect of the Economy of Scale

The term “economy of scale” refers to the cost advantage that can be obtained by increasing the size, throughput, or scale of a plant and thereby reducing the cost per unit of output. As in most industrial plants, economies of scale play a vital role in determining the optimum size of alternative fuel production plants. A BTL plant, as shown in Chapter 2, comprises various processing units. Each of these processing units has a maximum train size, which is limited by various factors such as the maximum size of pieces of equipment in that unit, reliability of train, and its relation with other processing trains within the plant.

In designing a BTL plant, like any other plant, specification and optimization of these train sizes plays a vital role in minimizing the capital cost of the plant per unit of product. This optimization exercise was out of scope for this project, but in defining various scenarios, we were mindful of the train sizes needed for the various trains, such as air separation unit, gasification island, and Fischer-Tropsch synthesis unit. Further details regarding the number of trains for different processing units in various scenarios investigated in this project are provided in Appendix A.

To demonstrate the effect of economy of scale on the capital cost of the BTL plant and the production cost of liquid fuel product, we ran the entire techno-economic model for different plant sizes. The results of this investigation are shown in Figure 5.8. The left and right axes show the breakdown of the liquid fuel production cost and Total As-Spent Cost (TASC) for different plant sizes, respectively.

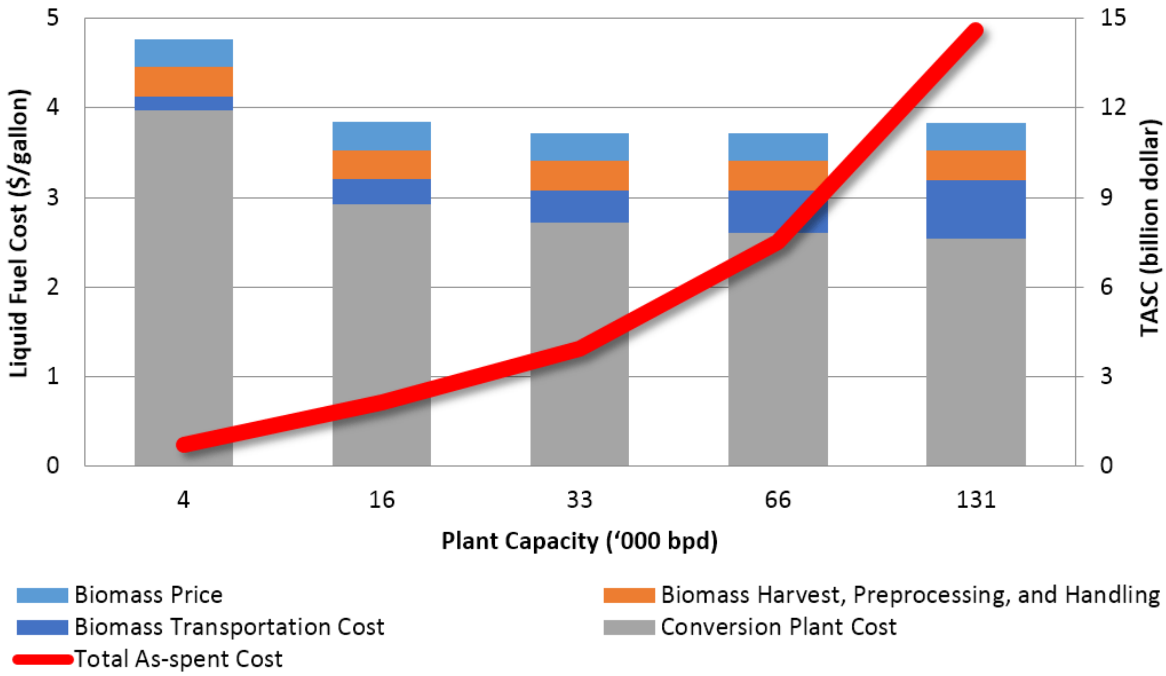

Figure 5.8 | Effect of economy of scale on liquid fuel production cost and total as-spent cost of BTL plants of different sizes.

As expected, the production cost, particularly the conversion plant capital cost component, decreases for larger plant sizes due to economy of scale. The interesting finding is that the advantages of scale plateau beyond ~20,000 bpd capacity due to the increased cost of biomass transportation from the source to the conversion plant. The cost increases because larger plants require more biomass as feedstock which necessitates the collection and transportation of biomass from farther distances. The feedstock considered for this exercise is loblolly pine woodchips. The gasification technology used for this analysis is the HTW gasifier.

Various sections of this report refer to a "Large Scale BTL plant" case, which is considered the maximum size of a BTL plant with reasonable plant capital cost as well as biomass transportation cost. For further assumptions regarding this case and other cases, please refer to Appendix A.

6. Natural Gas to Liquids

One way to achieve economies of scale without requiring large amounts of biomass is through a hybrid BTL and GTL plant (referred to as a BGTL plant). Given the mid-2014 prices of oil and natural gas in the United States, liquid fuel from GTL plants is competitive with conventional fuels.

The hybrid BGTL plant has higher capital costs when compared to the GTL plant, but lower costs than the BTL plants of similar sizes. BGTL plants also have reduced production costs compared to BTL plants, and can provide significant advantages in addressing the technical and financial risks associated with large-scale deployment of BTL technology.

This chapter investigates the co-processing of natural gas (NG) and biomass feedstocks for production of liquid fuels (BGTL). To examine and investigate the benefits of hybridization of natural gas and biomass to liquid fuels we first need to design a standalone GTL plant in order to find the best process configuration prior to hybridization of GTL and BTL plants. A similar process flow diagram was used for the BTL and GTL plants. The feed preparation unit was expanded to include natural gas feed treatment. Selexol process was used instead for Rectisol for acid gas removal for the GTL plant because sulfur is removed from the natural gas feedstock during pre-treatment. Using Selexol instead of Rectisol reduces the GTL plant's capital and operating costs. Because sulfur is present in biomass feedstocks, Rectisol is used for AGR in all BTL, BGTL, and WTL scenarios discussed in this report. The major unit operation needed for the GTL plant is the natural gas reforming unit, which is discussed in detail in the next section.

6.1. Comparison of Natural Gas reforming technologies

To select the best process design for the GTL plant, different natural gas reforming technologies were considered, including partial oxidation (POX), auto-thermal reforming (ATR), and steam methane reforming (SMR). The choice of natural gas reformer is affected by many factors, one of which is the scale of the plant. In this study, both the standalone GTL and hybrid BGTL plants were sized at ~18,000 bpd to maximize the train sizes for the air separation and FT synthesis units. In the envisioned hybrid design, natural gas is the predominant feedstock, because the economy of scale is enabled by abundant natural gas.

Reforming of NG using SMR produces a syngas product with a very high H_2 to CO ratio that greatly exceeds the 2:1 ratio needed for FT synthesis. Given the NG to biomass ratio for the hybrid plant, mixing SMR syngas with biomass-derived syngas would result in excess hydrogen and would significantly decrease the conversion yield of the hybrid plant. Because of these assumptions, SMR was not considered for the hybrid plant and was not further investigated. Table 6.1 summarizes the suitability of different NG reforming technologies for various GTL and hybrid BGTL conversion plants.

Table 6.1 | Suitability of NG reforming technologies for various plant types and configurations.

Reformer Technology	Small GTL	Large GTL	BGTL (with little biomass)	BGTL (with lots of biomass)
POX	Not suitable	Possible	Possible	Suitable
ATR	Possible	Suitable	Suitable	Suitable
SMR	Possible	Not suitable	Not suitable	Suitable

Two considered GTL plant configurations, based on ATR and POX reforming technologies, were designed and investigated using the developed techno-economic tools. Figure 6.1 and Figure 6.2 show the operating conditions and the process configuration for the ATR and POX cases, respectively.

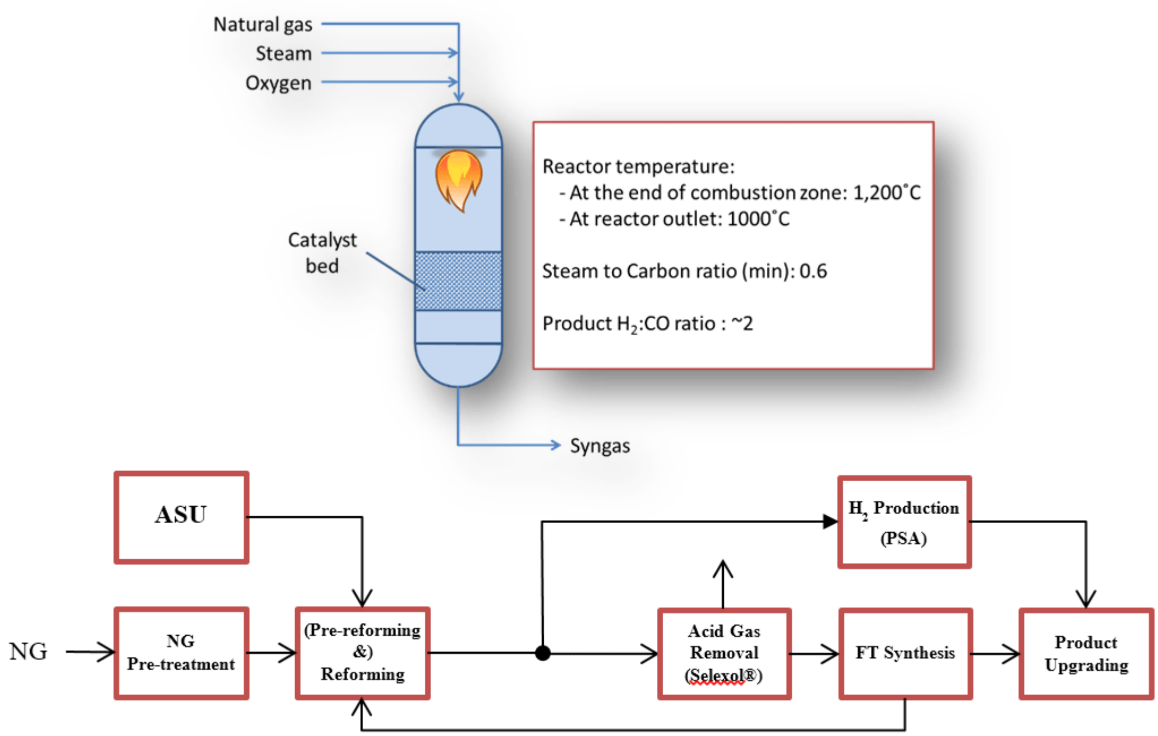

Figure 6.1 | Operating conditions (top) and process configuration (bottom) used for the ATR case.

Due to the lower operating temperature of the ATR reformer and the presence of catalyst, the H_2 to CO ratio of the syngas in this case is close to 2:1, the ratio needed for FT synthesis applications. Therefore, as shown in Figure 6.1, there is no need for a water-gas-shift unit to adjust this ratio. Given the operating conditions of the POX unit, including its higher operating temperature, the H_2:CO ratio of syngas from this unit is lower than the required ratio (2:1) and it needs to be adjusted using the water-gas-shift unit (Figure 6.2).

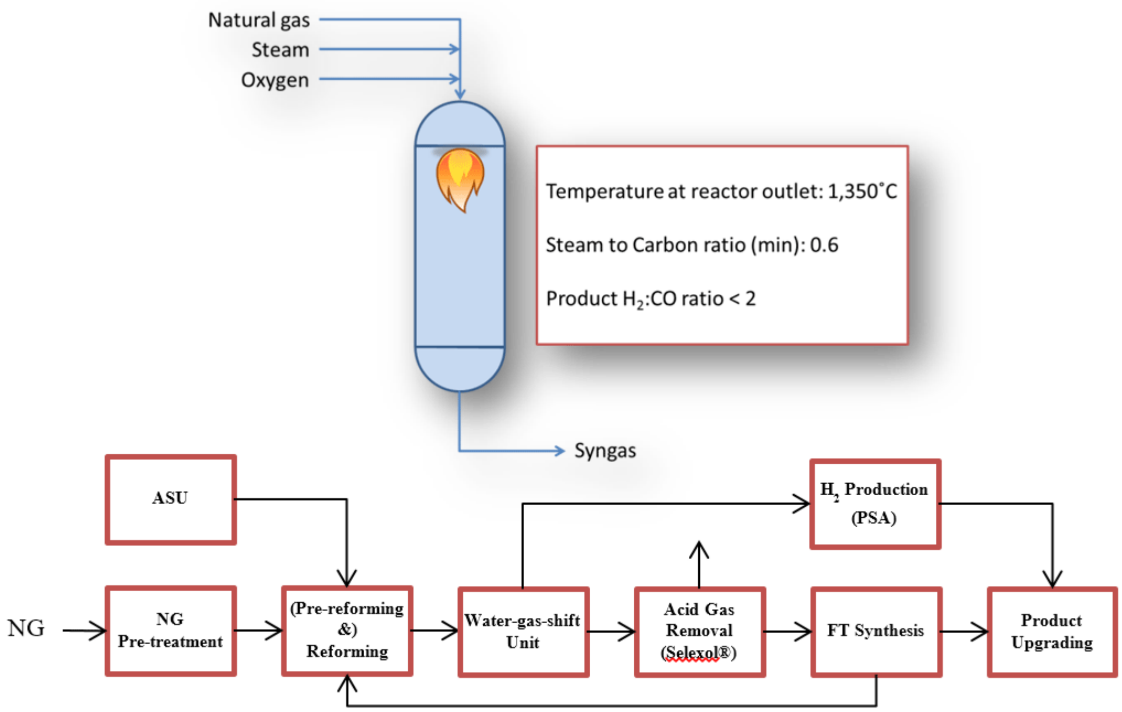

Figure 6.2 | Operating conditions (top) and process configuration (bottom) used for the POX case.

Figure 6.3 shows the breakdown of the production cost of liquid fuels for the two GTL cases and their comparison with the production cost of conventional diesel [8]. As shown, the production costs of liquid fuel in both cases are lower than that of conventional diesel at $2.8/gal [8], thanks to the low cost of NG feedstock. The assumed NG price for this study is $5/MMBtu [49].

Under the assumptions made, the total fuel cost of the GTL plants is lower than conventional diesel by up to $0.6/gal in the United States. This finding is consistent with the increased interest in the development of GTL plants in the United States by major players in the GTL industry. Also, as can be seen in Figure 6.3, the liquid fuel production cost of the ATR case is lower than the POX case due to two main reasons: 1) lower operating temperature of ATR means less NG is combusted in the reformer and more is converted to fuel product (lower cost of natural gas for the ATR case); 2) More oxygen is needed in the POX case to achieve its higher operating temperature (higher conversion plant cost due to larger air separation unit for the POX case) .

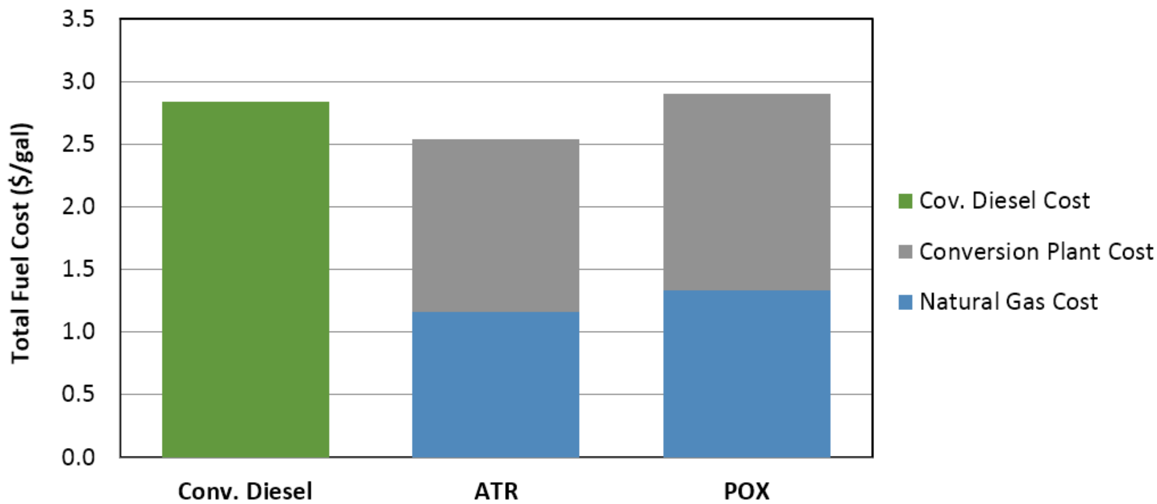

Figure 6.3 | Comparison of fuel production cost of different GTL plants – ATR *vs.* POX. Assumed natural gas price: $5/MMBtu [49].

Based on the results obtained from this case study, auto-thermal reforming was chosen as the reforming technology for the design of the hybrid natural gas and biomass to liquid fuels (BGTL) plant, discussed in the next section.

6.2. Hybridization of Natural Gas and Biomass to Liquid Fuels

Co-processing of biomass and natural gas has many benefits:

- In general, thermochemical pathways for production of fuels are most economic when deployed at large scale. This cannot be achieved for BTL plants due to the limitations in cost-effective supply of biomass feedstock within a reasonable range of the plant. The addition of NG, as another feedstock, will alleviate this limitation when the required infrastructure is in place for low cost natural gas supply.
- Life-cycle GHG emissions of fuels produced in GTL plants are usually higher than the conventional fuels; by the co-processing of biomass and NG, the lifecycle emissions of the produced fuel can be decreased. For further discussions regarding GHG emissions of BTL and hybrid plants, please refer to Chapter 7.
- There are technological synergies in co-processing of biomass and NG mostly because biomass-derived syngas is hydrogen lean while syngas produced by

reforming of natural gas can be hydrogen rich and the mixture of these syngas streams may be more suitable for fuel synthesis applications with respect to the required hydrogen to carbon monoxide ratio.

The hybridization also helps to reduce the technological and subsequent financial risks associated of biomass to liquids as a relatively new technology. Design and development of a multi-purpose (hybrid) plant can help reduce such risks since GTL is a proven technology, demonstrated at mega scales. For more information on this topic please refer to section 6.4.

Two hybridization strategies were considered in this study: a) Greenfield BGTL configuration in which a purpose-built BGTL plant is designed to take full advantage of the possible BTL and GTL synergies; b) Retrofit BGTL configuration in which an existing standalone GTL plant is retrofitted by the addition of a biomass gasification unit.

6.2.1. Greenfield Design of a Hybrid Biomass and Natural Gas to Fuels Plant

Biomass and Natural Gas to Liquids Hybridization Schemes

There are various possible integration schemes of BTL and GTL processes. Some of these integration schemes are processing technology specific (e.g., NG reforming) or valid only for a limited range of plant capacities. After investigating various hybridization schemes (not shown here), the process configuration shown in Figure 6.4 was considered for the design of the hybrid plant.

As shown in Figure 6.4, the biomass-derived syngas (bio-syngas) after treatment for tar and methane is mixed with NG-derived syngas. Depending on their composition and flowrates, one or both of the syngas streams are sent to the water-gas-shift (WGS) unit for H_2:CO ratio adjustment. The remaining unit operations downstream of the WGS unit are similar to either BTL or GTL processes described earlier.

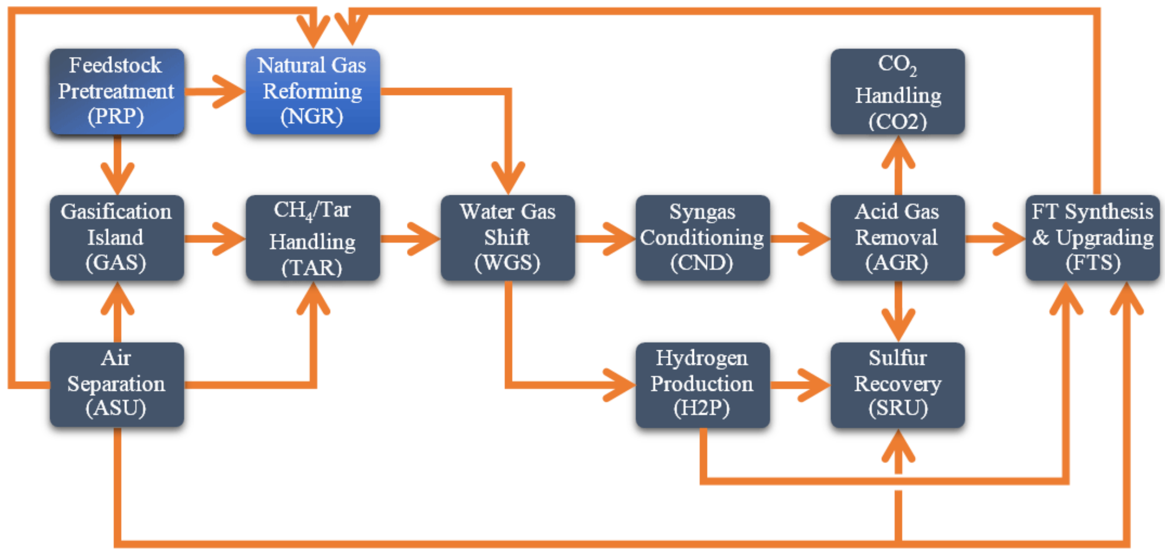

Figure 6.4 | Process configuration of the hybrid natural gas and biomass to liquid fuels plant.

Techno-economic Analysis of the Greenfield Hybrid Plant

In order to minimize the effect of economy of scale on the comparison of the installed cost of the BTL, GTL, and hybrid BGTL plants, the plant sizes considered for these cases are similar to each other in output at about 18,000 bpd. In the BGTL case, the biomass contribution to the plant capacity is roughly ~4,000 bpd and the NG contribution is roughly ~14,000 bpd. Figure 6.5 shows the breakdown of specific installed costs (thousand dollar per barrel per day capacity) for the BTL, GTL, and hybrid cases. Please note that the reported cost numbers are the installed (bare-erected) costs for the cases, not total plant cost.

As shown, the installed cost of the GTL case is significantly lower than that of the BTL case. The reduction in cost is due to significant reduction of the costs associated with feed preparation and gasification island of the BTL cost since treatment of NG for the GTL case is significantly less expensive. Although the cost of the NG reformer is included in the cost of the GTL case, it is still significantly lower than the BTL case.

The hybrid case includes cost components related to biomass feed preparation and gasification, but since the biomass feedstock rate of this case is significantly lower than that of the BTL case, these costs are much lower. Also, the hybrid plant still requires a large NG reformer unit. As expected, the specific installed cost of the hybrid plant is higher than GTL, but still lower than the BTL case. This means hybridization of biomass and NG to liquid fuels reduces the plant capital cost significantly when compared to the cost of a BTL plant of similar size.

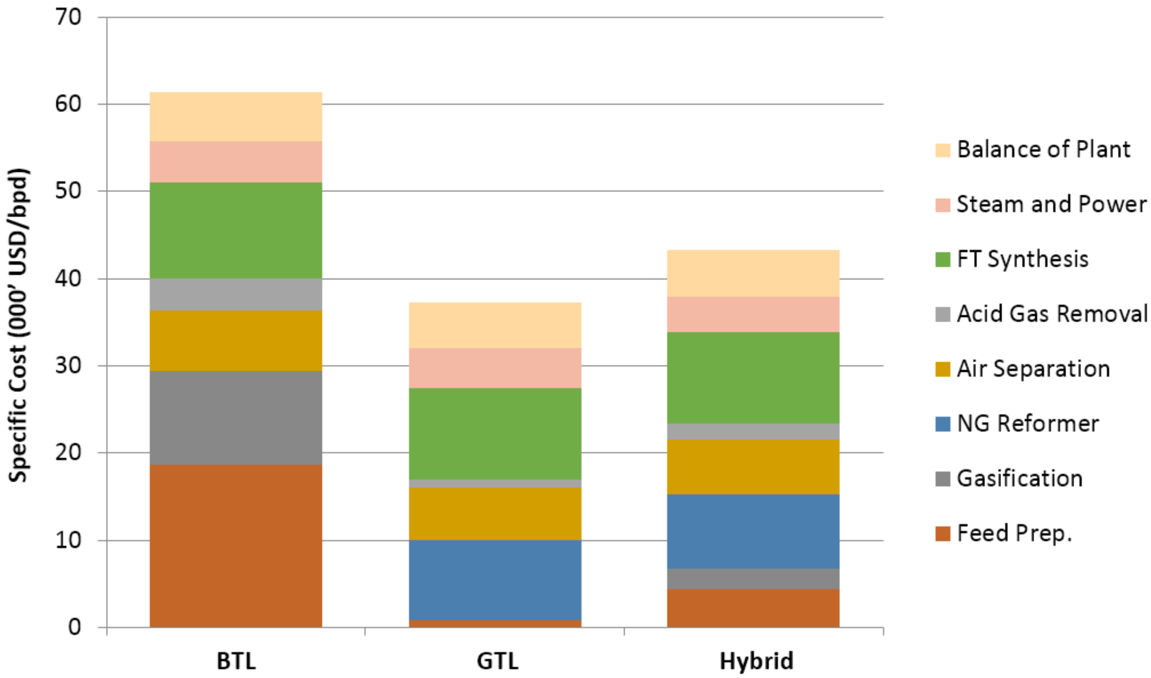

Figure 6.5 |Specific capital cost of different processing units for BTL, GTL, and hybrid plants.

Figure 6.5 also shows a substantial reduction of the cost of the air separation unit in the GTL and BGTL cases compared to the BTL case. The reduction in oxygen demand is due to higher energy content of NG compared with biomass as well as the more energy-efficient conversion of NG to syngas.

Figure 6.6 shows the breakdown of the fuel production cost of the defined GTL and greenfield BGTL hybrid) plant. The BGTL plant has higher capital costs compared to the GTL plant, but lower capital costs than BTL plants of similar size. Substituting 4,000 bbl/day capacity of an ~18,000 bpd GTL plant with BTL increases the average total fuel cost by more than $0.6/gal, but still keeps it below the cost of production of the conventional diesel at $2.9/gal [8].

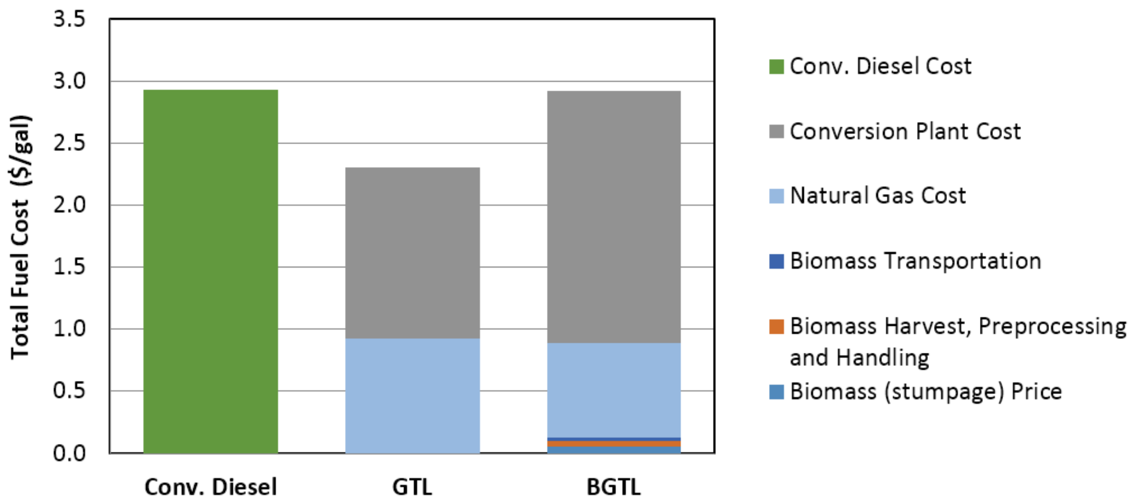

Figure 6.6 | Comparison of fuel production cost breakdown of GTL and hybrid BGTL plants.

6.2.2. Retrofitting a GTL Plant to a Hybrid Plant

In order to investigate the retrofit of a GTL plant to a hybrid BGTL plant (Retrofit plant), we assumed that the biomass gasification island, tar/methane handling and syngas cleanup and conditioning units are the only unit operations that will be added to the existing GTL facility. Furthermore, we assumed that the utility units, such as water management and steam island, will be modified to be able to satisfy the demands of the retrofitted plant. As mentioned earlier, the specific oxygen requirement (tonne of oxygen per barrel of liquid fuel product) of a BTL plant is higher than a GTL plant because biomass has a lower heating value than natural gas and its conversion to syngas is less efficient. This becomes an important fact when considering retrofitting an existing GTL plant because, within the major and most costly unit operations in the original GTL plant, the air separation unit becomes the production bottleneck of the Retrofit plant. Since the operation of the biomass gasification island will max out the capacity of the air separation unit, other major plant processing units need to operate below their name plant capacities. This will negatively affect the economics of the retrofitted plant as it cannot take full advantage of the existing processing capacities. As a matter of fact, retrofitting a GTL plant under the above assumptions will result in reduced production capacity.

Table 6.2 shows the utilization of the major (and most costly) processing units of a GTL facility before and after being retrofitted to a hybrid plant. As the table shows, all of the processing units are sized for the GTL mode of operation (original plant before retrofit) with 100% utilization. After retrofit, the air separation unit acts as the bottleneck of the hybrid plant and causes other units such as FT synthesis and natural gas reforming unit to be utilized below their nominal capacities.

Table 6.2 | Utilization of major processing units and production capacity of a GTL plant before and after being retrofitted to a hybrid plant.

Plant Processing Units	GTL Plant (before retrofit)	Hybrid Plant (after retrofit)
FT Synthesis and Upgrading	100%	95%
Air Separation Unit	100%	100%
Natural Gas Reformer	100%	87%
Plant Capacity (bbl/day)	17,960	17,000

Under this retrofitting scenario, the production capacity of the plant decreases after making the capital investment for the retrofit for the reasons mentioned above. Under current price assumptions for NG and biofuel credits, such a retrofit scenario is not economically viable. However, such a retrofit of a GTL plant may be economically viable when the cost of NG is considerably higher than that of the biomass or if there are large biofuel credits. The latter is discussed in details in Section 7.6.3.

This analysis serves as a simple investigation of retrofitting of GTL plants, but such decisions should be made on a case-by-case basis based on the actual costs of debottlenecking opportunities and other cost drivers. In the evaluation of a specific retrofitting opportunity, a careful analysis should be performed to understand the capacity utilization of the existing and new processing units (especially those with high cost) within the plant.

6.3. Design for Flexibility of Hybrid Plants with Respect to Feedstock

Figure 6.7 shows the effect of operating a BGTL hybrid plant in GTL mode on the plant's production capacity and the fuel production cost.

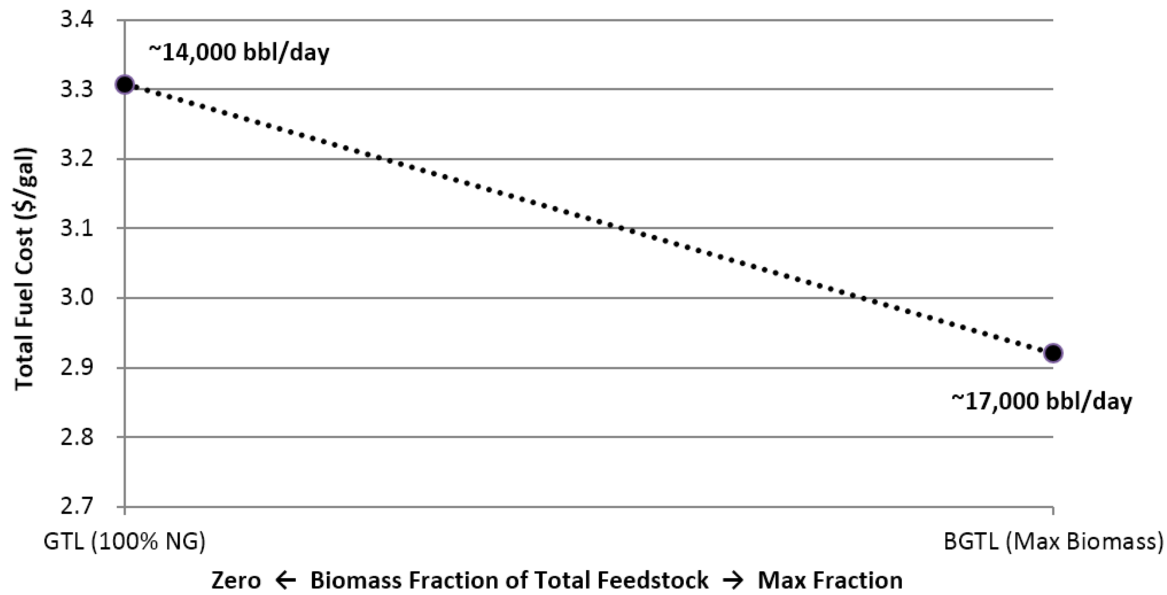

Figure 6.7 | Effect of operating a BGTL plant (with no provisions for flexibility) in GTL mode on the production capacity and fuel production cost.

As shown, operating a static design BGTL plant in GTL mode grossly underutilizes the asset and drives up the fuel production cost.

For this reason and those described in the previous section, the relative capacities of different processing units in a BGTL plant play a significant role in determining the economic viability of a hybrid plant. Such considerations can prove beneficial both during the design of a GTL plant (with plans for future retrofit to a hybrid plant) or during the design of a greenfield hybrid plant, where consideration of additional capacities can provide very valuable flexibility in changing the operation mode of a hybrid plant. For example, a hybrid plant can switch to GTL mode if there is a disruption to the biomass feedstock supply chain or a spike in the price of biomass feedstock. The design of such flexibility in operating a hybrid plant was also investigated in this project. The focus of this exercise was to identify the best allocation of investment between various processing units within the plant in the form of excess capacity. To this end, we considered two extreme operation modes: a) *BGTL mode:* when a hybrid BGTL plant is operated as its design mode with pre-defined flowrates of biomass and NG feedstocks; b) *GTL mode:* when the hybrid plant is operated in GTL mode with no biomass feedstock.

For this exercise, three design scenarios were considered. In each of these design scenarios, the capacity of a one of the major processing unit within the hybrid plant, including FT synthesis, air separation, and natural gas reforming units, was set to the maximum capacity needed for both the BGTL and GTL operation modes. The design of the other two processing units was set such that the production capacity of the hybrid plant in BGTL mode would be 17,000 bbl/day. The throughput of the major processing unit for these three design scenarios in BGTL and GTL operation modes are shown in Table 6.3.

The capacities of air separation and FTS unit are of significance since they provide oxygen (for biomass gasification and NG reforming) and synthesis capacity for production of liquid fuels from biomass and natural gas, respectively. The NG reforming unit reforms both the NG portion of the plant feedstock to syngas and the vapor fraction of the gaseous products of the FT reactor. Therefore, NG reformer capacity has to be large enough to provide capacity for both applications.

Table 6.3 | Capacity and utilization of major processing units in a greenfield hybrid plant for different operation modes.

	Design Scenario:	Fixed FTS Throughput		Fixed ASU Throughput		Fixed NGR Throughput	
	Operation Mode:	Fixed FTS Throughput	BGTL	GTL	BGTL	GTL	BGTL
Total oxygen demand	*tonne/day*	4,340	4,580	4,580	4,580	3,990	4,580
ASU utilization	*%*	95	100	100	100	87	100
NGR throughput	*tonne/day*	11,550	10,610	12,200	10,610	10,610	10,610
NGR unit utilization	*%*	92	100	100	87	100	100
Total fuel production rate	*bbl/day*	17,000	17,000	17,960	17,000	15,630	17,000
FTS unit utilization	*%*	100	100	100	95	92	100
Total overnight cost	***Million $(2013)***	**1,590**		**1,620**		**1,560**	

Also included in Table 6.3 is the estimated total overnight cost of the plant for the three design options. As shown, the Fixed NGR Throughput design has the lowest capital cost with a maximum production capacity of 17,000 bpd that drops to ~15,600 bpd if operated in GTL mode. The highest capital cost belongs to the Fixed ASU Throughput design with minimum production capacity of 17,000 bpd in BGTL mode (by design) that increases to just below 18,000 bpd if operated in GTL mode. The overall fuel production cost of these designs depend on how often and how long the plants are operated in BGTL or GTL modes and therefore cannot be calculated without assuming an operating schedule.

6.4. Staging of Large-scale BTL Deployment

Despite decades of research and development, large-scale deployment of biomass to liquid fuels has not been realized due to major technical risks and also risks associated with securing a long-term supply of biomass feedstock at an economically viable price.

Hybridization of biomass and natural gas for production of liquid fuel can, at least partially, mitigate such risks. If designed with operational flexibility in mind, the flexible hybrid plant can shift between operating in BGTL and GTL modes without any loss of production. This provides a major advantage when the operation of the biomass processing trains is upset, e.g., during biomass gasifier shutdown or during disruptions in the biomass supply chain or during periods of high cost of biomass feedstock.

Hybridization of biomass and natural gas for production of liquid fuels not only reduces the overall production cost of liquid fuels (compared with BTL), but also can have significant advantages in addressing the technical and financial risks associated with large-scale deployment of biomass-to-liquids technology if proper precautions are taken during the design of the hybrid plant.

7. Lifecycle GHG Emissions

A major driver of BTL technology is the lowering of the carbon footprint of liquid fuels. While BTL fuels are more expensive than conventional fuels, there are policies in place to incentivize BTL plants. Given mid-2014 prices, we found that with biofuel credits of \$0.60/gal$_{RIN}$, BGTL and large BTL plants are competitive with conventional diesel.

The choice of feedstock affects the carbon footprint. We found that BTL plants using switchgrass had higher GHG emissions compared to plants using loblolly pine. The nitrogen content of switchgrass is several times higher than pine, which results in a much higher nitrogen depletion rate which must be replenished with nitrogen fertilizer to maintain soil productivity. Another key consideration is whether there are any direct or indirect impacts from land-use change associated with the biomass feedstock.

Since BTL plants generate a high purity stream of CO_2, carbon dioxide capture and storage (CCS) can be added with no significant impact on the plant economics. CCS can significantly decrease the carbon footprint of the produced liquid fuels as well as lower the overall cost of avoided CO_2.

This chapter presents the results of the lifecycle GHG emissions estimation for the various conversion pathways. For information regarding the methodology used for calculation the GHG emissions, please refer to Chapters 2 and 3.

The lifecycle GHG emissions presented in this chapter are non-biogenic GHG emissions. Examples of biogenic emission includeCO_2 generated by combustion of biofuels or from biomass decomposition. These biogenic emissions are not included in the figures presented in this chapter unless otherwise noted as Total (biogenic and non-biogenic) GHG emissions.

7.1. GHG Emissions Related to the Production, Logistics, and Transportation of Biomass Feedstocks

This section presents the results of the estimation for the GHG emissions only related to the production, logistics (in-field operations), and transportation of biomass feedstocks. The lifecycle GHG emissions of the product liquid fuels are presented in the next section.

Farm and Forest Gate Life-cycle GHG Emissions

Figure 7.1 shows the breakdown of the GHG emissions associated with biomass production and in-field logistics operations, including harvest, collection, processing, and storage, for the four aforementioned biomass forms, loblolly pine whole-tree woodchip, loblolly pine clean woodchip, switchgrass square bale, and switchgrass round bale.

As can be seen from the figure, switchgrass square bale in-field operations has the lowest GHG emissions at 15 kgCO_2e/dry tonne. In-field operations for loblolly pine clean woodchip result in the highest GHG emissions at 27 kgCO_2e/dry tonne. The GHG emissions associated with biomass production have significant differences. The nitrogen content of switchgrass is several times higher than pine, which results in a much higher nitrogen depletion rate which must be replenished with nitrogen fertilizer to maintain soil productivity. Nitrogen fertilization contributes to GHG emissions from CO_2 emissions during the production of fertilizers and from N_2O emissions generated when fertilizers are used. Consequently, the high nitrogen fertilization rate results in about four time higher GHG emissions than that of loblolly pine. Soil organic carbon storage by switchgrass due to its deep root system could reduce the GHG emissions, but this aspect was not considered here. This topic is briefly discussed in Section 7.4.

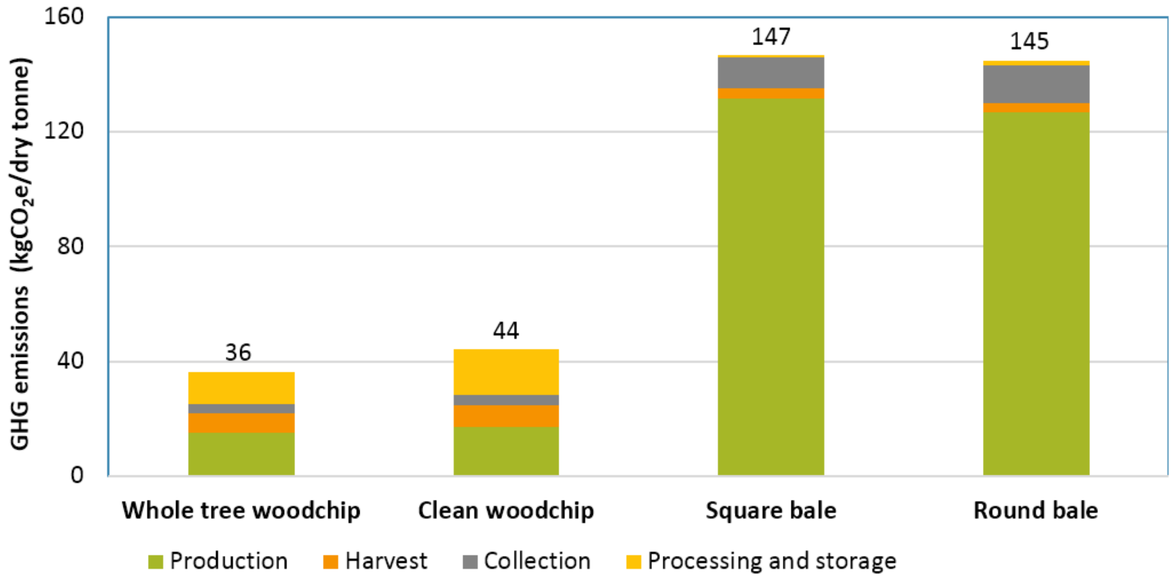

Figure 7.1 | Gate GHG emissions breakdown of loblolly pine woodchips and switchgrass bales.

Lifecycle GHG Emissions of Delivered Biomass Feedstock to Conversion Plant

Figure 7.2 presents the calculated GHG emissions for the different types and formats of biomass feedstock delivered to the conversion plant gate including the emissions associated with the transportation of these feedstocks. Although the transportation cost of different types and formats of biomass feedstocks are significantly different (see Chapter 3), the transportation is not a significant contributor to the total GHG emissions. In this analysis, we also considered in-field pelletization of woodchip as another scenario.

As shown in Figure 7.2, wood pellet has by far the highest GHG emissions among the biomass types and formats evaluated. This is due to the use of NG during the drying and pelletization processes. The GHG emissions associated with pelletization can be reduced if biomass (biomass waste or a fraction of biomass feedstock) is used as the source of heat during the drying and pelletization processes. Although this approach will reduce the GHG emissions of wood pellet to comparable levels with woodchips, it will significantly increase the delivered cost of wood pellets since biomass is more expensive than NG.

As mentioned previously, the higher collection emissions for herbaceous biomass reflect one of the major disadvantages of this type of biomass – the need for an annual harvest.

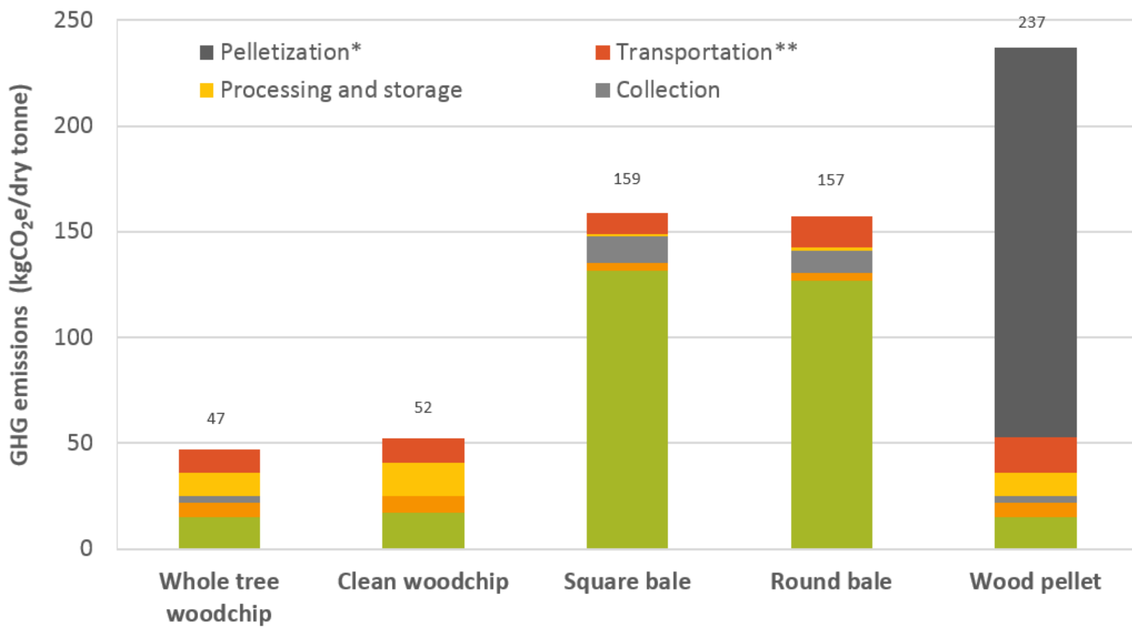

Figure 7.2 | GHG emissions of delivered feedstock to conversion plant for different types and formats of biomass.[1]

Site Sustainability

Site productivity and sustainability are always the major concerns for biomass production. However, the number of studies looking at productivity and sustainability is very limited, especially when biomass is managed as an energy crop. Productivity and sustainability are both highly dependent on the choice of feedstock and the management practices. In most cases, both loblolly pine and switchgrass can benefit from fertilization to maximize yields. However, due to the intensive management level and the higher nitrogen content of switchgrass, switchgrass requires more fertilizer input than loblolly pine. The high nitrogen fertilization rate can result in higher GHG emissions (as shown in Figure 7.1 and Figure 7.2). Further research on how fertilization interacts between environmental effects

[1] Figure notes: Assumed capacity: 2,600 dry tonne per day; *Source of energy for drying and pelletization: natural gas; ** Using trucks.

and biomass productivity is warranted. In general, switchgrass provides multiple environmental benefits compared to annual crop cultivation as deep-rooted perennials absorb excess nutrients, reduce soil erosion and runoff. However, these benefits generally appear to be similar to those of other perennial crops [14].

The clear-cutting of loblolly pine offers great economic benefit, however, the expanded removal of slash and live trees could affect forest structure and nutrient cycling. It is reported that intensive harvesting of managed forest does not universally reduce site productivity in general, but in some cases, it can cause substantial growth declines [50]. Biodiversity is another environmental issue associated with intensive tree removal. This is especially true in the southern United States where around 90% of forests are privately owned. Forest management should be regulated for a better sustainability and Best Management Practices (BMP) need to be carried out to mitigate potential environmental damages. Moreover, continued research is needed to identify specific forest and soil types where intensive biomass removal may exacerbate potential deficiencies.

7.2. Lifecycle GHG Emissions of Produced Liquid Fuels in BTL Plant

In Figure 7.3, the lifecycle GHG emissions of liquid fuel production from biomass feedstocks are presented in terms of gCO_2e equivalent per MJ of produced fuel. The GHG emissions of the loblolly pine and switchgrass cases are significantly lower than that of conventional diesel at 92 gCO_2e/MJ. As expected, GHG emissions for the switchgrass case are higher than loblolly pine due to higher emissions from production of switchgrass.

We also included GHG emissions credits for the conversion plant whenever the plant exports electricity, assuming the generated electricity displaces an equivalent amount of electricity from the grid. The total emissions values shown in Figure 7.3 are after accounting for the renewable electricity credits. The GHG emissions associated with the displaced electricity are calculated based on the mix of electricity generation for the region around the Decatur, Alabama location of the BTL plant.

7.3. Effect of Carbon Capture on Lifecycle GHG Emissions

In the Reference scenario, the assumption is that the captured CO_2 in the process is vented to the atmosphere. We investigated the lifecycle GHG emissions of the produced fuel if the captured CO_2 were to be sequestrated – either stored underground or used for Enhanced Oil Recovery (EOR) applications.

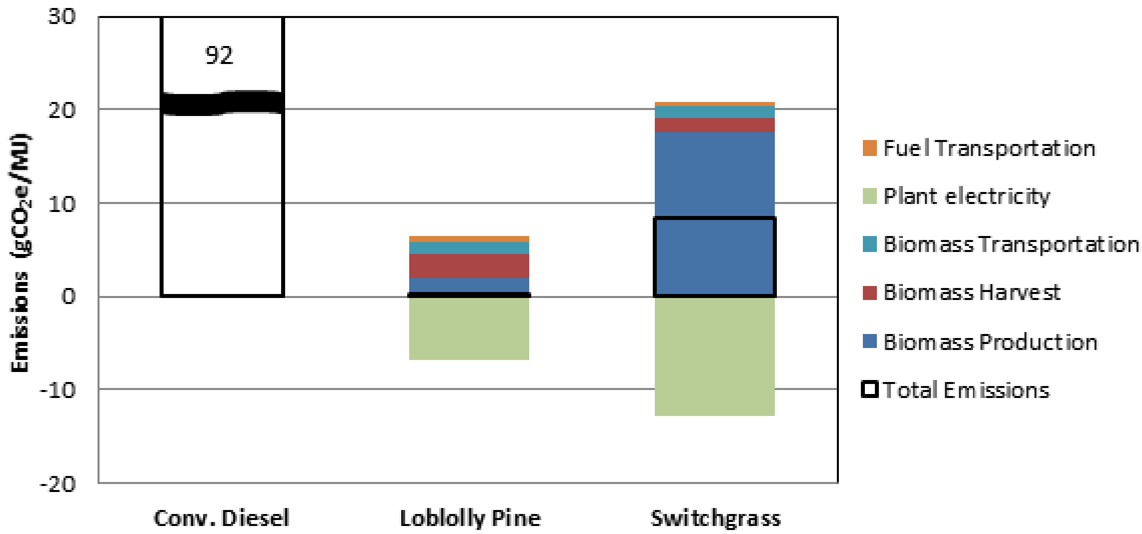

Figure 7.3 | Lifecycle GHG emissions for fuel production from loblolly pine and switchgrass.

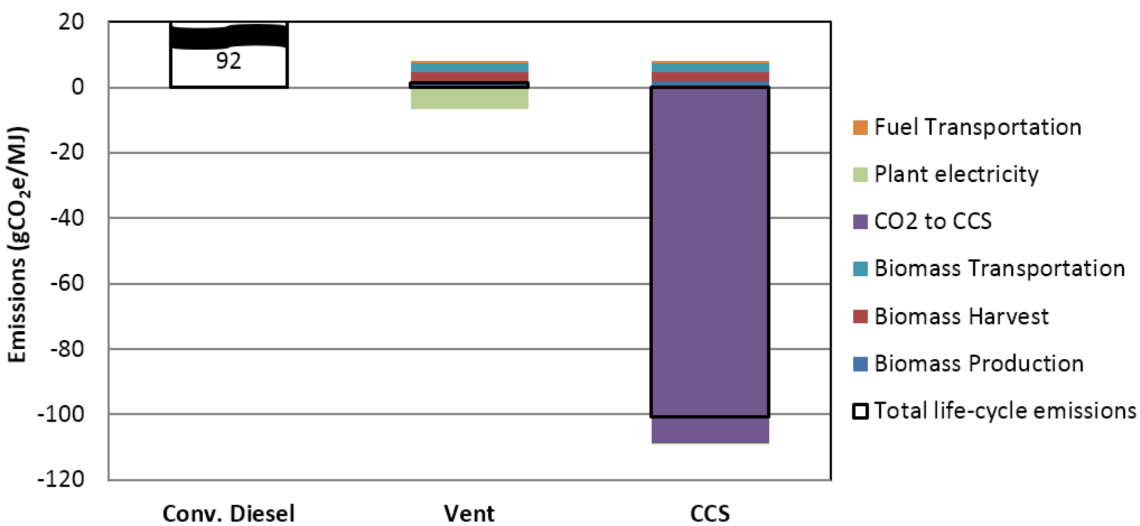

Figure 7.4 | Lifecycle GHG emissions of fuel production for the reference case if the captured CO_2 is vented and sequestrated.

The results of this investigation are shown in Figure 7.4. The Carbon Capture and Storage (CCS) case has significant negative GHG emissions; for every MJ of produced fuel almost 100 gCO_2e is *removed* from the carbon cycle while the lifecycle GHG emissions of the conventional diesel is +92 gCO_{2e}/MJ. This demonstrates the huge potential of BTL plants equipped with CCS to reduce global GHG emissions without significant (if any) cost disadvantage as shown in section 5.3.

Cost of Avoided CO_2

The cost of avoided CO_2 is the cost of CO_2 at which the production cost of an alternative fuel production pathway will be on par with that of the conventional fuel.

$$\text{Cost of Avoided } CO_2 = \frac{\text{Total Fuel Cost}_{\text{FT Diesel}} - \text{Total Fuel Cost}_{\text{Conventiona Diesel}}}{\text{GHG Emissions}_{\text{Conventional Diesel}} - \text{GHG Emissions}_{\text{FT Diesel}}}$$

Figure 7.5 shows the calculated cost of avoided CO_2 using the above formula assuming GHG emissions of 92 gCO_2e/MJ for conventional diesel. As shown, because CO_2 sequestration does not have a major impact on economics of the BTL plant (see section 5.3), it dramatically reduces the cost of avoided CO_2. An interesting observation is that the CO_2 price required to make BTL competitive with conventional diesel is much lower than what is needed to make a power plant equipped with CCS competitive with a traditional fossil-fuel power plant.

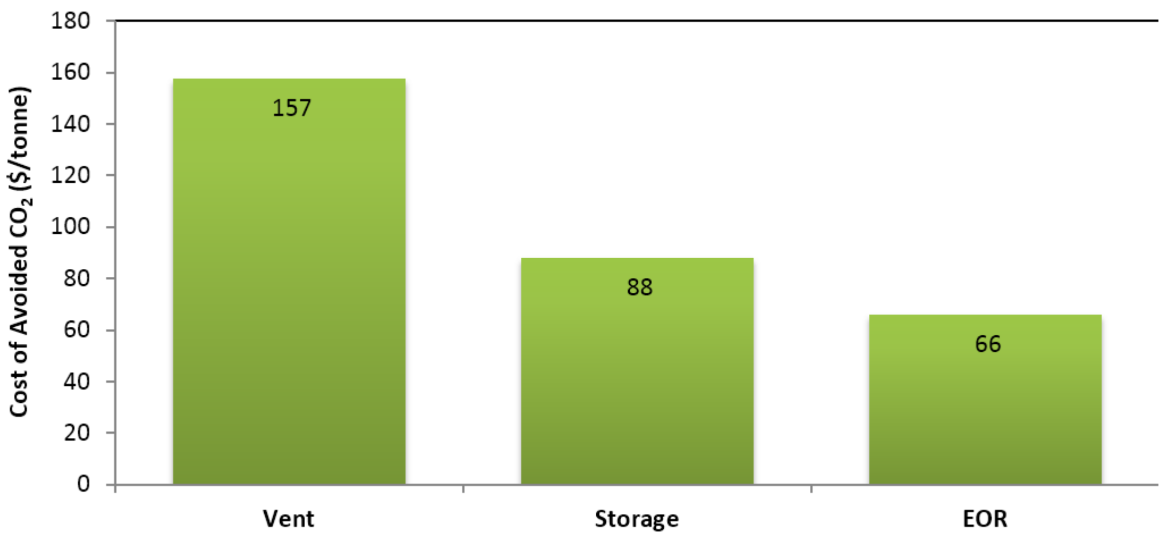

Figure 7.5 | Calculated cost of avoided carbon for the Reference case if the captured CO_2 stream in the conversion plant is vented, stored, or used for EOR application.

7.4. Tracking (Static) Lifecycle GHG Emissions

Total lifecycle GHG emissions are shown for the reference case in Figure 7.6, including all non-biogenic and biogenic carbon streams. CO_2 is removed from the atmosphere during biomass growth, then is emitted back to the atmosphere when carbon is released; for example, during degradation of lost dry matter, during processing in the conversion plant, or when the product fuel is combusted. The net GHG impact from the reference case is -0.4 gCO_{2e}/MJ, while applying CCS results in emissions of -100 gCO_{2e}/MJ.

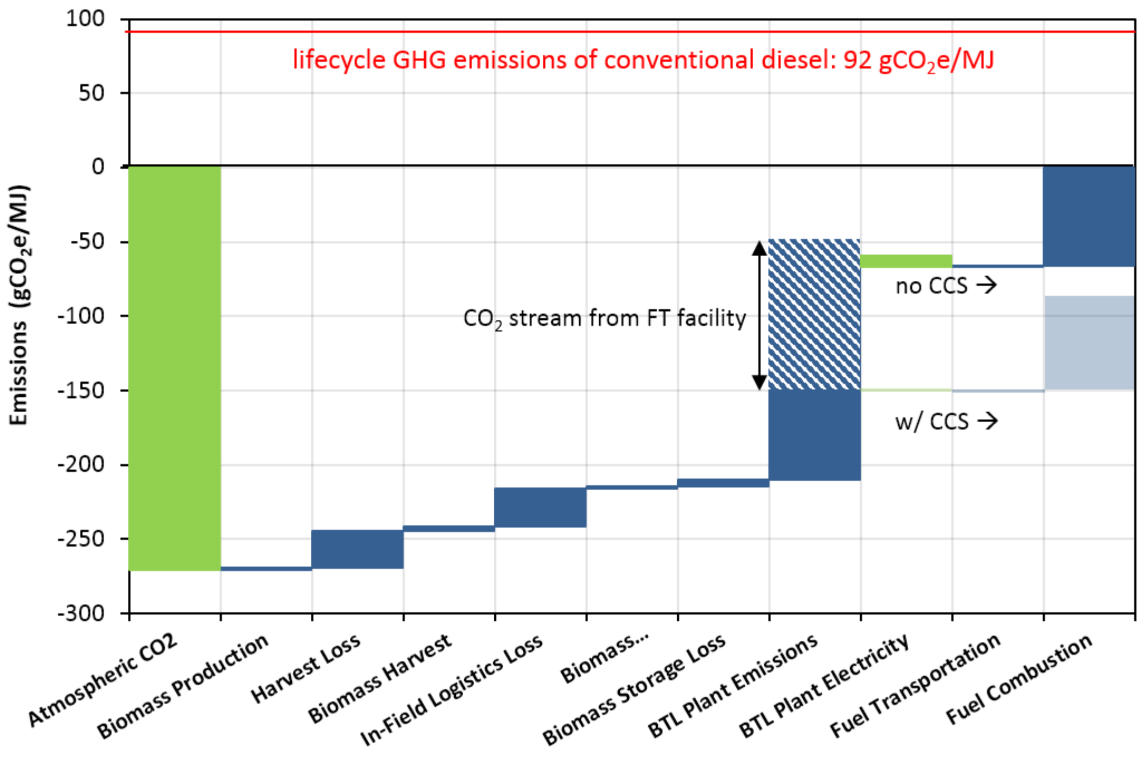

Figure 7.6 | Tracking of lifecycle GHG emissions of biomass conversion to liquid fuels with and without CO_2 sequestration (Reference case; feedstock loblolly pine).[2]

As indicated in Figure 7.6, the amount of carbon stored in the growing biomass is large compared to the amount emitted during combustion (about 4× greater). In the reference case (loblolly pine), this carbon is stored over a long period of biomass growth (the reference case uses a harvest age of 14 years). However, this carbon is emitted back to the atmosphere on much shorter timescales. In the following section, we investigate these transient effects on the lifecycle.

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[2] Green bars indicate a CO_2 credit. Blue bars indicate emissions. Diagonal shading shows the magnitude of CO_2 available for capture and storage.

7.5. Transient Carbon Analysis and Effect of CCS

In the previous sections of this chapter, we showcased the results of a *static* life-cycle GHG emissions analysis of biomass feedstocks and the liquid fuels produced from them. The intend of this section is to discuss how the various time-scales involved in the life-cycle of the biomass-derived liquid fuels affect the resulting *transient* GHG emissions. The results shown in this section are snapshots of the outcomes of a study on carbon, climate, and economic breakeven times for biofuels from woody biomass from managed forests. The complete and final results of this study were published in *Ecological Economics* [51].

Transient CO_2 emissions from biofuel production were estimated by comparing the total amount of stored carbon with a business-as-usual forestry scenario. Carbon pools in the managed forest were tracked with a carbon flow model adapted from Dewar [52], Dewar & Cannell [53], and Magnani et al. [54], who present an analytical model of stand growth, litter generation, and decomposition. More detailed carbon models can be found in the literature [55], but the selected model has been shown to agree with average values for mid-latitude tree plantations [53]. This model accounts for various carbon pools including live trees, forest litter, soil organic matter, and forestry products (such as lumber and paper).

The business-as-usual scenario approximates an average managed forest currently in a harvest rotation for forestry products. Trees are harvested when they have aged 30 years, with 35% of harvested material used for long-lived wood products (e.g. lumber) and 65% used for short-lived wood products (e.g. paper, wood fuel, etc.).

Two main effects were observed when the business-as-usual forest is converted to biofuel production: 1) if the harvest age is reduced (e.g. from 30 years to 14 years, as assumed in the reference case), the time-averaged mass of trees is reduced, causing the forest to store less carbon, and 2) when biofuels are produced instead of forestry products, CO_2 is released into the atmosphere more quickly (during processing in the conversion plant and product fuel combustion).

Figure 7.7 shows the cumulative CO_2 emissions from biofuel production compared to an equivalent amount (on an energy basis) of fossil fuel. The reference case (14-year harvest, no CCS) breaks even with fossil fuels after 179 years. When CCS is applied, this breakeven time drops to 45 years. The CO_2 breakeven time can be further reduced by keeping the harvest age consistent with the business-as-usual scenario. Since the time-averaged mass of live trees is unchanged, the only difference in stored carbon is a result of using biomass to make fuels instead of long-lived products. For a 30-year harvest, cumulative emissions break even with fossil fuels after 33 years. With CCS, emissions break even in just two years. Data labels indicate when parity with emissions from conventional fuel is achieved.

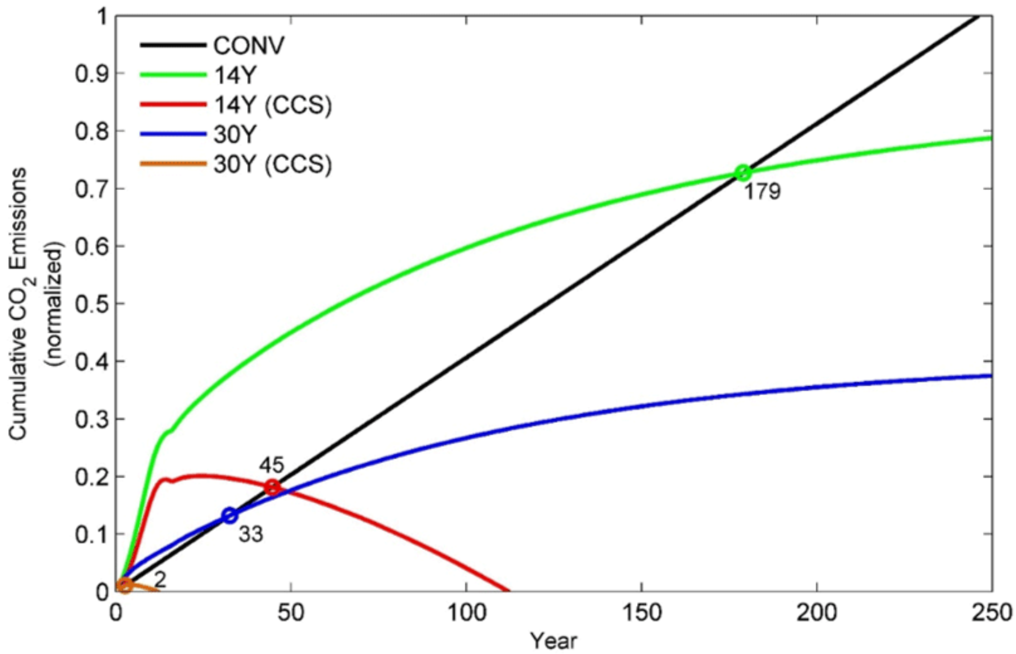

Figure 7.7 | Cumulative CO_2 emissions from conventional fossil fuel (CONV) compared with emissions from biofuel production on a 14-year rotation (14Y), with carbon capture and storage (14Y (CCS)), biofuel production on a 30-year rotation (30Y), and with carbon capture and storage (30Y (CCS)).

In this approach, we assumed that the market for forestry products is able to absorb the reduced supply of lumber and paper without consequence, which is unlikely. Reduced supply may cause an increase in the price of wood products, leading some forest owners to increase forestry operations, potentially involving the conversion of old-growth forests to managed forests. In turn, this could produce more CO_2 emissions due to land use change. The use of a global equilibrium model would be appropriate to determine the actual market-wide impacts of lost forestry products.

7.6. Renewable Fuel Standards and Credits

This section briefly discusses some aspects of the Renewable Fuel Standard (RFS) that was used in the evaluation of various pathways in this project.

7.6.1. Renewable Fuel Standard

There are different types of renewable fuels defined in the RFS based on the source of feedstock and the processing methods for production of such fuels. Figure 7.8 shows different types of biofuels included in RFS and their nested relationship. The figure also shows the total obligation volumes for different biofuel types proposed for year 2014.

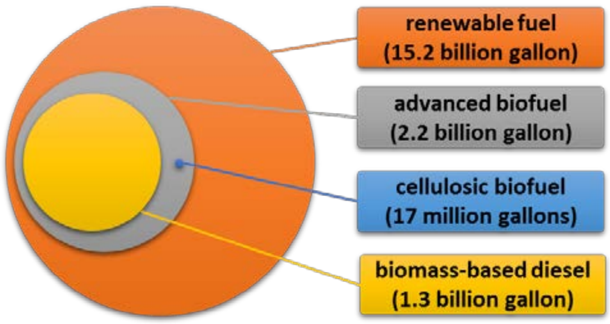

Figure 7.8 | Different biofuel types in RFS and the proposed obligation volumes for 2014.

Renewable Identification Numbers (RIN) are created as a means to track biofuel production, use, and trading. The number of RINs associated with biofuels depends on their Equivalence Value as shown in Table 7.1:

Table 7.1 | Equivalence value of different types of biofuels included in RFS.

Biofuel Type	Equivalence Value
Corn ethanol	1.0 (base)
Biodiesel (ester)	1.5
Renewable diesel (product of interest in this study)	1.7

For example, a gallon FT diesel produced from renewable biomass feedstock generates 1.7 RINs while a gallon of corn ethanol fuel generates 1 RIN. The equivalence values correspond to the energy content of various types of liquid fuels.

RINs for Municipal Solid Waste Feedstock

Under RSF, not all of the municipal solid waste is eligible for biofuel credits. The biofuel producers are required to quantify the fraction of the MSW that is “renewable.” The renewable fuel credit can be obtained only for the fraction of fuel product produced from the renewable fraction of the waste feedstock.

Calculating RINs for a Hybrid Plant

In RFS, a hybrid plant is a plant in which two or more feedstocks, of which at least one is renewable, are converted to liquid fuel products. RFS identifies two methods to determine the fraction of a hybrid plant product that is renewable and eligible for biofuel credits. *Method A* specifies the renewable portion of the product as the fraction of the energy input of the renewable feedstock(s) to total energy input of all feedstocks (renewable and non-renewable). *Method B*, which is an empirical method, measures the fraction of the carbon atoms in the fuel product that is C-14 isotope. The ratio of this fraction to the C-14 isotope fraction of the atmosphere is the renewable portion of the hybrid plant product. The reason behind this methodology is that carbon in biomass is derived from atmospheric CO_2 and therefore, a comparison of the C-14 fraction of the fuel product to that of the atmosphere shows the fraction of fuel product that is derived from biomass.

For more information regarding these methods and other topics related to the RFS, please refer to [56].

Method A: $biofuel\ fraction = \frac{EB}{\mathrm{EB+EF}}$

Method B: $biofuel\ fraction = \frac{\text{C−14 fraction of carbon in liquid fuel}}{\text{C−14 fraction of carbon in atmosphere}}$

Figure 7.9 | Accounting methods specified in RFS for determining the biofuel fraction of a hybrid plant product.

Table 7.2 shows the estimated fraction of product from the hybrid plan that would be eligible for biofuel credits. Using *Method A*, only 21% of the product is eligible for biofuel credits. Since *Method B* is an empirical method, the biofuel portion of the product cannot be predicted using this method. However, we took an analytical approach to estimate the biofuel fraction for this method. Due to the lack of data regarding the level of mixing and true kinetics of reactions in various reactors in the hybrid plant, we estimated the biofuel fraction of the hybrid plant to be in the range of 26% to 30%. According to RFS, producers can use the method of their choice to determine the biofuel portion of their products. This study shows that using Method B (carbon-based) results in a higher eligible portion, which is expected since biomass is more carbon intensive than NG on an energy basis.

Table 7.2 | Comparison of different accounting methods to determine the portion of a hybrid plant fuel product eligible for biofuel credits.

Implemented Methods	Fraction of product eligible for biofuel credits
EPA Method A (energy based)	21%
EPA Method B (carbon dating)	Max. isotope exchange: 30%
	Min. isotope exchange: 26%

7.6.2. Impact of Biofuels Credit on Cost of Alternative Fuels

The objective of RIN generation is to credit the producer, importers, and blenders of biofuels for the renewable portion of their products. RINs can be traded between various entities involved with production, import and blending of liquid fuels to cover their biofuel obligations set forth in the renewable fuel standard. For the purpose of this analysis, we assumed a RIN price of \$0.60/gal_{RIN}. gal_{RIN} is a gallon of renewable ethanol fuel since its equivalence value is 1.0.

Figure 7.10 shows the net production cost of liquid fuels from the different BTL, GTL, and hybrid plants considered in this study, before and after applying biofuel credits.

The plant capacity for small BTL is assumed to be <4,000 bbl/day and for large BTL, GTL, and hybrid cases to be >17,000 bbl/day.

The conventional diesel and fuel product from GTL plant are not eligible for biofuel credit since they are not produced from renewable feedstocks. Biofuel credits can improve the economic viability of renewable fuel production plants to some extent. After application of biofuel credits of \$0.60/gal_{RIN}, large BTL and hybrid plants are competitive with conventional diesel based on mid-2014 fuel prices.

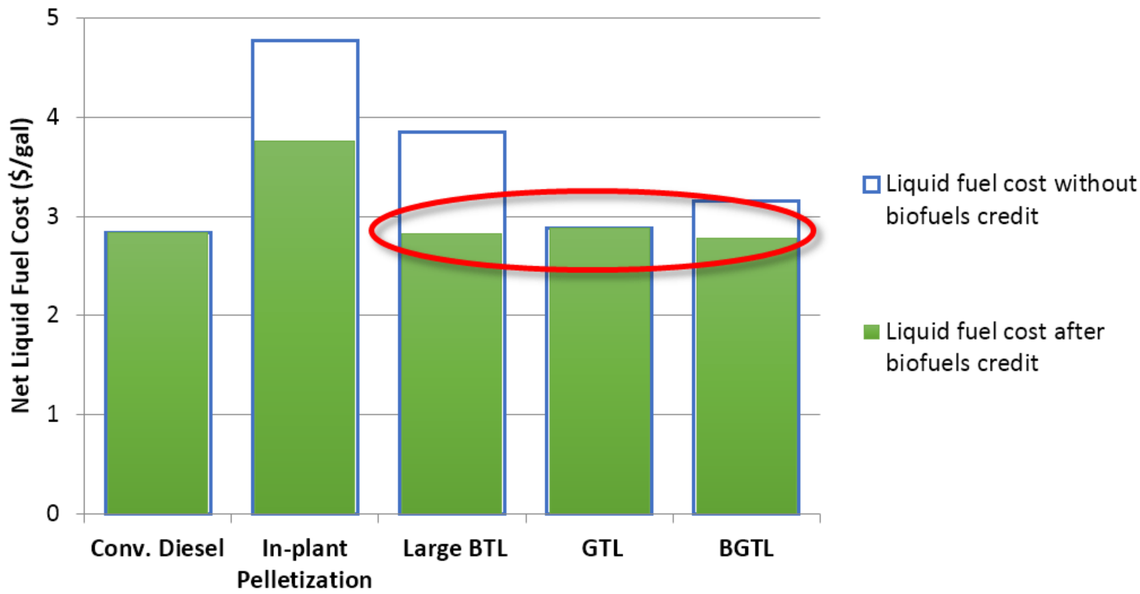

Figure 7.10 | Effect of biofuels credit on the net production cost of liquid fuels from different BTL, GTL, and hybrid plants. Assumed RIN price: $\$0.60/\text{gal}_{RIN}$.

7.6.3. Implication of Biofuel Credits for Flexible Hybrid Plants

In section 6.3, we introduced the concept of flexible hybrid plant that includes the extra capacities needed in different processing units within the plant to switch from one mode of operation to another. We also defined two operation modes. The *BGTL mode* is the mode in which the hybrid plant operates in normal conditions with predefined flowrates of two feedstocks (biomass and NG). In the *GTL mode*, the hybrid plant operates as a GTL plant with no biomass feed. In section 6.3, we defined three flexible designs in which the throughput of one of the three major unit operations of the plant, air separation (ASU), Fischer-Tropsch synthesis (FTS), and natural gas reforming (NGR) was kept constant when switched from BGTL to GTL mode. The other two processing units were sized for nominal capacity when operated at BGTL mode.

The decision about switching the operation modes is sometimes obvious. For example, if the supply of biomass feedstock is interrupted or the biomass gasifier(s) is down, the operator switches the operation mode from BGTL to GTL to avoid production loss. There are times when making this decision is not so clear. Many external factors affect the profitability of a hybrid plant including price of feedstocks and products, and biofuel product credit (RIN prices). To illustrate this concept, we focus on the effect of change in the prices of NG, liquid fuel products, and RINs.

Figure 7.11 shows the operating mode in which each of the hybrid plants would operate when faced with different NG, product fuel, and RIN prices. The green zones on the charts indicate conditions where operating in BGTL mode is more economic. The red zones indicate conditions where the GTL mode is preferred. Please note that in this illustration, operation between the two defined modes was not allowed. The plant operates either at BGTL or pure GTL mode with no other operation modes in between.

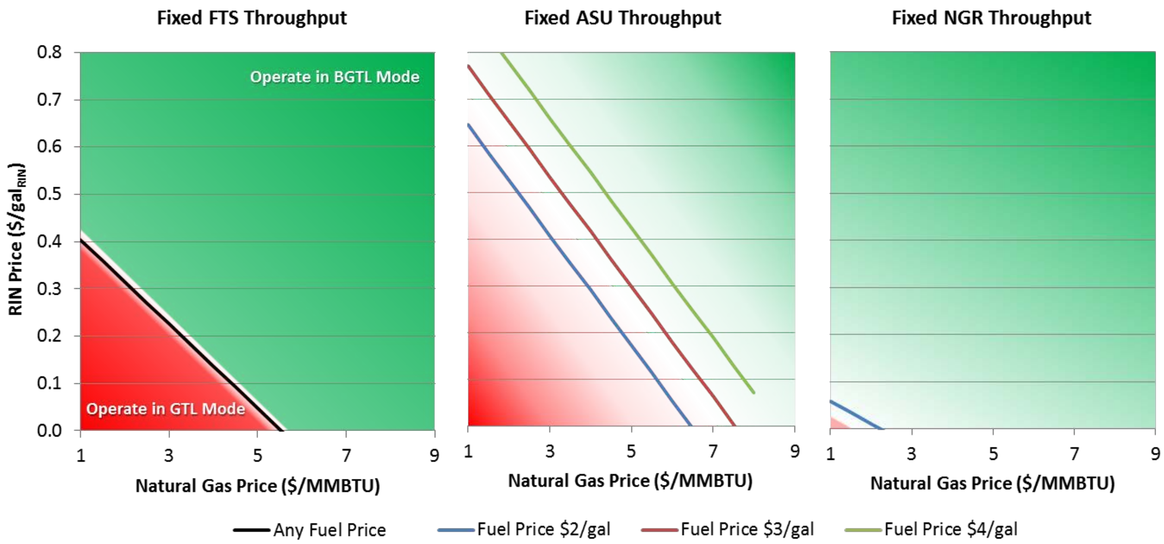

Figure 7.11 | Effect of price of natural gas and RIN on the optimum operation mode of three flexible design hybrid plants.

In the Fixed FT Throughput design, switching operation modes does not change the production capacity (see section 6.3), therefore, the decision of switching operation modes is independent of product fuel price. At any given NG price, there is a RIN price (corresponding to the black line) at which the operation modes should be changed to improve the economics of the plant). As shown in section 6.3, the production capacity of the hybrid plant with Fixed ASU Throughput design increases in GTL mode. Therefore, higher RIN prices (in comparison with Fixed FTS Throughput design) are required to justify operation in BGTL mode. Also, due to changes in production capacity, the “switchover” line changes with change in the product fuel price. In the Fixed NGR Throughput design, the production capacity is lower in GTL mode than in BGTL mode and therefore it is more economical to operate in BGTL mode unless the prices of the fuel product, NG, and RIN are all very low.

Careful design of hybrid plants, including the inclusion of operation flexibility, is key in addressing the technological risks and other uncertainties (such as change in supporting policies and disruptions to the biomass supply chain) associated with the production of fuels from biomass.

8. Outlook

Given current energy prices, the climate policy situation, and the state of conversion technologies, large BTL projects are extremely challenging from an economic viewpoint. When this study was conducted, crude oil prices were in the $100/bbl range. The corresponding production cost for conventional diesel, used in many charts in this report, was $2.84/gal. At this price, we concluded that of all the pathways studied for producing “drop-in” liquid fuels, only three could compete with conventional diesel:

- Gas to liquids (GTL), with gas at $5/MMBtu and a plant capacity of about 18,000 bpd.
- Hybrid biomass and gas to liquids (BGTL) with biomass being responsible for about 4,000 bpd of product and gas about 14,000 bpd. Also, biofuel credits of $0.60/galRIN ($1.02/gal diesel) are required.
- Large scale BTL (about 17,000 bpd) with biofuel credits as above. Note that this is about optimum size to capture economies of scale without adding excessive biomass transportation costs.

While our simulations show these projects could compete, they would nonetheless be considered very financially risky today because of volatility of energy prices, uncertainty about biomass supply, uncertainty about long-term carbon policies, and technology risks. This assessment is reinforced by the fact that these types of plants are not being built today. During the period of low US natural gas prices and high oil prices, Sasol announced plans to build two GTL plants in the southeastern US, but the current status of those projects is unknown. Most commercial biofuel plants produce ethanol through fermentation processes on a fairly small scale. Enerkem has built a Waste-to-Liquids plant in Edmonton Canada to convert MSW into methanol at a small scale (10 million gallons/year or 650 bbl/day). However, we are unaware of any commercial BTL plant producing drop-in fuels via a thermochemical process.

The key question is what needs to change in order to make thermochemical conversion of biomass to a drop-in liquid fuel a reality. The challenge is even greater in 2015 than when the simulations were conducted, as the current (January, 2015) production cost of diesel has dropped to $1.50/gal, about half of the diesel benchmark cost used in this report. Below we look at several key items and explore how changes in them can impact the outlook for BTL. The items which have the biggest direct impact on cost and competitiveness of BTL technology are oil price, climate policy, and biomass price. There are a two other areas, the maturing of thermochemical conversion technology for biomass feeds and development of commodity markets for biomass supply, that will not necessarily directly reduce prices, but can remove significant risks. The practical effect of this is to limit first mover costs and cost overruns that plague many emerging technologies.

Oil Prices. The drop in oil prices to about $50/bbl has made thermochemical BTL plants very unattractive. However, oil prices are volatile and they will eventually rise again. The biggest impact of petroleum prices is on the cost of conventional diesel, which sets the target price that BTL fuels have to beat. Petroleum prices will also impact the cost of BTL fuels because diesel is consumed during the production, harvesting, and transport of the biomass. However, this impact is much smaller than the impact on conventional diesel. There may also be an impact on biomass price due to market feedback. Higher petroleum prices may drive up demand for biomass as a substitute fuel, resulting in higher biomass prices. This later impact is beyond the scope of this study. Based on our results (refer to Figure 7.10), petroleum prices would need to be in the range of $200/bbl for small-scale BTL (4,100 bpd with in-plant pelletization) to compete with conventional diesel in the absence of any subsidies.

Climate Policy. Climate policy can take many forms. Current US policy affecting BTL is the Renewable Fuel Standard. This manifests itself as a subsidy per gallon of renewable fuel produced. In this report, we used credits of \$0.60/gal_{RIN}, which translates to $1.02/gal diesel. Referring to Figure 7.10, these subsidies must double for small-scale BTL to compete with conventional diesel when oil is $100/bbl. Using today’s oil price of $50/bbl, the subsidies must triple for small-scale BTL to be competitive.

Climate policy may take the form of a carbon price in the future. Very roughly, a carbon price of \$100/metric ton CO_2 would raise the price of diesel about \$1/gal. So, without other biomass subsidies, a carbon price of about \$200/tCO_2 is needed for small-scale BTL to compete with conventional diesel when oil is $100/bbl. Unless there is a drastic shift in the political landscape, carbon prices on this level are decades in the future.

Biomass Price. Based on Figure 8.1, the biomass price delivered to a conversion facility contributes about $0.70/gal to the product cost. This includes all harvesting and transport costs. So even in the unlikely case of the price being cut in half, the savings is only about $0.35/gal. The impact would be equivalent to a 35% increase in RINS price or an increase of $13/bbl of oil.

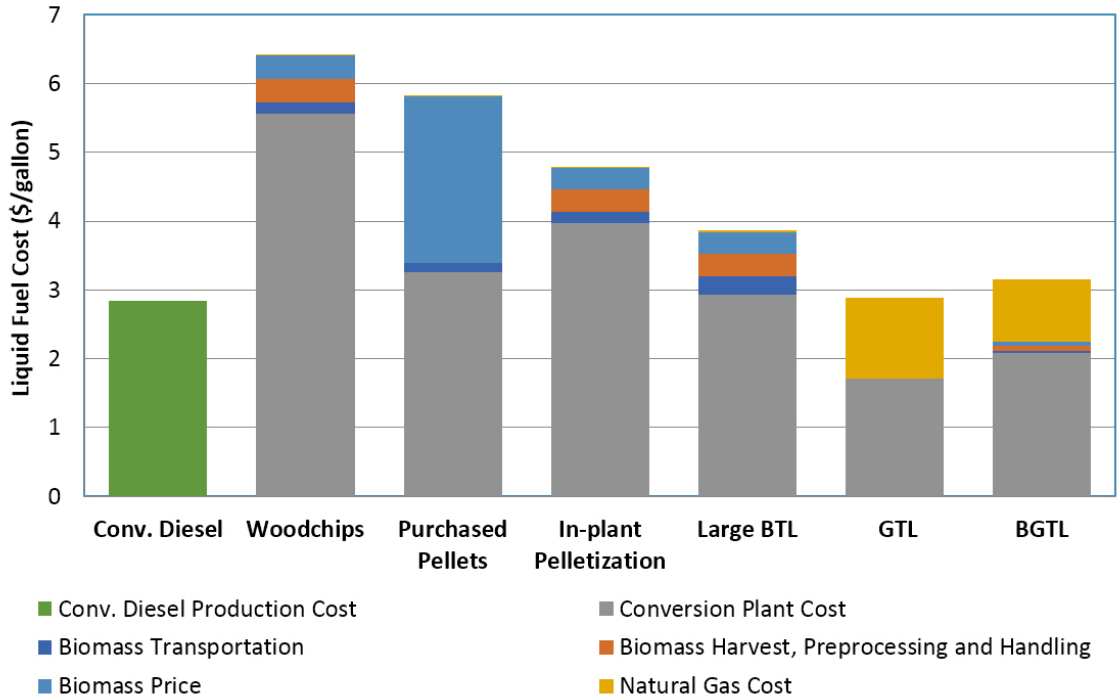

Figure 8.1 | Comparison of the fuel production cost breakdown for a range of scenarios investigated in this study. Assumed biomass feedstock: loblolly pine. Assumed purchase pellet price: $150/tonne$_{dry}$. Assumed natural gas price: $5/MMBtu). Assumed crude oil price: $100/BBL; Plant capacities: Woodchips: 3,700; Purchased Pellets and In-plant Pelletization: 4,100; Large BTL: 16,400; GTL: 18,900; and BGTL: 18,600 (all in bbl/day).

Using MSW is a way to change the feedstock cost in a more drastic manner. Instead of paying for biomass, a credit in the form of a tipping fee can be taken. This credit can translate into as much as $1/gal of product. However, the MSW feedstock supplies are limited, so plant sizes will be small (<3,000 bpd). Based on the results shown in Figure 4.6, MSW can do better than our reference BTL plant, but not as well as our large BTL plant.

Thermochemical Conversion Processes. The BTL processes examined in this study all involve biomass gasification. Although there are hundreds of commercial gasifiers operating today, few have biomass feeds and even these biomass gasifiers do not meet the requirements for BTL because they are generally air-fed, low-pressure and/or small scale. Referring to Figure 8.1, the conversion process is the overwhelming cost component. Going to large scale and pellet feeds, the conversion cost can almost be cut in half compared to the reference case. Otherwise, we do not see dramatic cost reductions for the conversion process in the near-term. As with most emerging technologies, first of a kind plants may cost significantly more than projected. The important objective in the near-term is to reach a maturity level where we can reliably predict price and performance.

Biomass Supply. In this study, we have assumed biomass is available and that it can be considered carbon neutral. This is not necessarily the case today. Therefore, this adds risks to any BTL project. Once again, these risks and associated costs were not included in our simulations. If biomass can become more of a commodity, these risks and costs can be eliminated.

In conclusion, the outlook for thermochemical BTL plants is very challenging. To have a robust market for this technology will require:

- Conversion technology with established costs and performance.
- Commodity markets for biomass feedstocks that are certified as carbon neutral.
- A combination of oil price and climate policy that will provide the needed economic incentive.

Only then can thermochemical BTL be considered commercial.

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Appendices

Appendix A - Case Definitions

This appendix summarizes the main assumptions for each pathway case in this report for which a full techno-economic-environmental evaluation was performed. Additional cases evaluated specifically for process and/or economic performance without a full techno-economic-environmental analysis are not included in this appendix. Due to the long execution duration of the Project and the continuous improvements made to the models and tools during this time, the case definitions may not be entirely consistent.

Parameters	Scenario Names			
	Reference (BTL, Reference BTL)	EFG	FBG	Loblolly Pine
Plant Production Capacity (bbl/day)	3,700	2,600	2,900	3,000
Train Design Philosophy	4× HTW	(2+1)× 200MWth Siemens	(4+1)× HTW	3× HTW
Biomass Feedstock Type	Loblolly pine	Willow	Willow	Loblolly pine
Biomass In-field Storage Method	N.A.	N.A.	N.A.	N.A.
Biomass Feedstock Format	Whole-tree woodchip	Woodchip	Woodchip	Whole-tree woodchip
In-plant Pelletization	No	No	No	No
Natural Gas Feedstock	No	No	No	No
Biomass Transportation mode	Truck	N.A.	N.A.	Truck
Gasification Technology	Fluidized-bed (HTW)	Entrained-flow	Fluidized-bed (HTW)	Fluidized-bed (HTW)
Tar and Methane Handling Technology	POX	N.A.	POX	POX
NG Reforming Technology	N.A.	N.A.	N.A.	N.A.
AGR Technology	Rectisol	Rectisol	Rectisol	Rectisol
CCS	Vent	Vent	Vent	Vent
Results Generated in/before	Oct-13	Sep-12	Sep-12	Oct-13
Operational Flexibility	No	No	No	No

Parameters	Scenario Names			
	Switchgrass	Vent	STORAGE (CCS)	EOR (CCS)
Plant Production Capacity (bbl/day)	3,000	17,000	17,000	17,000
Train Design Philosophy	3× HTW	1× Fixed-bed FT RXR	1× Fixed-bed FT RXR	1× Fixed-bed FT RXR
Biomass Feedstock Type	Switchgrass	Loblolly pine	Loblolly pine	Loblolly pine
Biomass In-field Storage Method	Tarping	N.A.	N.A.	N.A.
Biomass Feedstock Format	Large bale	Whole-tree woodchip	Whole-tree woodchip	Whole-tree woodchip
In-plant Pelletization	No	No	No	No
Natural Gas Feedstock	No	No	No	No
Biomass Transportation mode	Truck	Truck	Truck	Truck
Gasification Technology	Fluidized-bed (HTW)	Fluidized-bed (HTW)	Fluidized-bed (HTW)	Fluidized-bed (HTW)
Tar and Methane Handling Technology	POX	POX	POX	POX
NG Reforming Technology	N.A.	N.A.	N.A.	N.A.
AGR Technology	Rectisol	Rectisol	Rectisol	Rectisol
CCS	Vent	Vent	Storage	EOR
Results Generated in/before	Oct-13	Oct-13	Oct-13	Oct-13
Operational Flexibility	No	No	No	No

Parameters	**Scenario Names**			
	POX	ATR	Fixed FTS Throughput	Fixed ASU Throughput
Plant Production Capacity (bbl/day)	17,000	17,000	BGTL: 17,000 GTL: 17,000	BGTL: 17,000 GTL: 17,960
Train Design Philosophy	1× Fixed-bed FT RXR	1× Fixed-bed FT RXR	1× HTW 1× Fixed-bed FT RXR	1× HTW 1× Fixed-bed FT RXR
Biomass Feedstock Type	N.A.	N.A.	Loblolly pine	Loblolly pine
Biomass In-field Storage Method	N.A.	N.A.	N.A.	N.A.
Biomass Feedstock Format	N.A.	N.A.	Whole-tree woodchip	Whole-tree woodchip
In-plant Pelletization	N.A.	N.A.	Yes	Yes
Natural Gas Feedstock	Yes	Yes	Yes	Yes
Biomass Transportation mode	N.A.	N.A.	Truck	Truck
Gasification Technology	N.A.	N.A.	Fluidized-bed (HTW)	Fluidized-bed (HTW)
Tar and Methane Handling Technology	N.A.	N.A.	NG reformer	NG reformer
NG Reforming Technology	POX	ATR	ATR	ATR
AGR Technology	Selexol	Selexol	Rectisol	Rectisol
CCS	Vent	Vent	Vent	Vent
Results Generated in/before	Oct-13	Oct-13	Nov-13	Nov-13
Operational Flexibility	No	No	Yes	Yes

Parameters	Scenario Names			
	Fixed NGR Throughput	Reformer	POX(TAR)	UHTW
Plant Production Capacity (bbl/day)	BGTL: 15,630 GTL: 17,000	3,800	3,800	3,800
Train Design Philosophy	1× HTW 1× Fixed-bed FT RXR	1× HTW	1× HTW	1× HTW
Biomass Feedstock Type	Loblolly pine	Loblolly pine	Loblolly pine	Loblolly pine
Biomass In-field Storage Method	N.A.	N.A.	N.A.	N.A.
Biomass Feedstock Format	Whole-tree woodchip	Whole-tree woodchip	Whole-tree woodchip	Whole-tree woodchip
In-plant Pelletization	Yes	Yes	Yes	Yes
Natural Gas Feedstock	Yes	No	No	No
Biomass Transportation mode	Truck	Truck	Truck	Truck
Gasification Technology	Fluidized-bed (HTW)	Fluidized-bed (HTW)	Fluidized-bed (HTW)	Fluidized-bed (HTW) with freeboard oxygen injection
Tar and Methane Handling Technology	NG reformer	Catalytic reforming	POX	Oxygen injection to gasifier freeboard
NG Reforming Technology	ATR	N.A.	N.A.	N.A.
AGR Technology	Rectisol	Rectisol	Rectisol	Rectisol
CCS	Vent	Vent	Vent	Vent
Results Generated in/before	Nov-13	May-14	May-14	May-14
Operational Flexibility	Yes	No	No	No

Parameters	Scenario Names			
	Woodchips	Purchased Pellets	In-plant pelletization	"4"
Plant Production Capacity (bbl/day)	3,700	4,100	4,100	4,100
Train Design Philosophy	4× HTW	1× HTW	1× HTW	1× HTW
Biomass Feedstock Type	Loblolly pine	Loblolly pine	Loblolly pine	Loblolly pine
Biomass In-field Storage Method	N.A.	N.A.	N.A.	N.A.
Biomass Feedstock Format	Whole-tree woodchip	Wood pellet ($150/tonne$_{dry}$)	Whole-tree woodchip	Whole-tree woodchip
In-plant Pelletization	No	No	Yes	Yes
Natural Gas Feedstock	No	No	No	No
Biomass Transportation mode	Truck	Truck	Truck	Truck
Gasification Technology	Fluidized-bed (HTW)	Fluidized-bed (HTW)	Fluidized-bed (HTW)	Fluidized-bed (HTW)
Tar and Methane Handling Technology	POX	POX	POX	POX
NG Reforming Technology	N.A.	N.A.	N.A.	N.A.
AGR Technology	Rectisol	Rectisol	Rectisol	Rectisol
CCS	Vent	Vent	Vent	Vent
Results Generated in/before	Jun-14	Jun-14	Jun-14	Jun-14
Operational Flexibility	No	No	No	No

Parameters	Scenario Names			
	"16"	"33"	"66"	"131"
Plant Production Capacity (bbl/day)	16,400	32,800	65,600	131,200
Train Design Philosophy	4× HTW	8× HTW	16× HTW	32× HTW
Biomass Feedstock Type	Loblolly pine	Loblolly pine	Loblolly pine	Loblolly pine
Biomass In-field Storage Method	N.A.	N.A.	N.A.	N.A.
Biomass Feedstock Format	Whole-tree woodchip	Whole-tree woodchip	Whole-tree woodchip	Whole-tree woodchip
In-plant Pelletization	Yes	Yes	Yes	Yes
Natural Gas Feedstock	No	No	No	No
Biomass Transportation mode	Truck	Truck	Truck	Truck
Gasification Technology	Fluidized-bed (HTW)	Fluidized-bed (HTW)	Fluidized-bed (HTW)	Fluidized-bed (HTW)
Tar and Methane Handling Technology	POX	POX	POX	POX
NG Reforming Technology	N.A.	N.A.	N.A.	N.A.
AGR Technology	Rectisol	Rectisol	Rectisol	Rectisol
CCS	Vent	Vent	Vent	Vent
Results Generated in/before	Jun-14	Jun-14	Jun-14	Jun-14
Operational Flexibility	No	No	No	No

Parameters	Scenario Names			
	Large BTL	GTL	BGTL (hybrid)	Small BTL
Plant Production Capacity (bbl/day)	16,400	18,900	18,600	400
Train Design Philosophy	4× HTW 1× Max. Size ASU	1× Max. Size ASU	1× HTW 1× Max. Size ASU	1× HTW
Biomass Feedstock Type	Loblolly pine	N.A.	Loblolly pine	Loblolly pine
Biomass In-field Storage Method	N.A.	N.A.	N.A.	N.A.
Biomass Feedstock Format	Whole-tree woodchip	N.A.	Whole-tree woodchip	Whole-tree woodchip
In-plant Pelletization	Yes	N.A.	Yes	No
Natural Gas Feedstock	No	Yes	Yes	No
Biomass Transportation mode	Truck	N.A.	Truck	Truck
Gasification Technology	Fluidized-bed (HTW)	N.A.	Fluidized-bed (HTW)	Fluidized-bed (HTW)
Tar and Methane Handling Technology	POX	N.A.	NG reformer	POX
NG Reforming Technology	N.A.	ATR	ATR	N.A.
AGR Technology	Rectisol	Selexol	Rectisol	Rectisol
CCS	Vent	Vent	Vent	Vent
Results Generated in/before	Jun-14	Jun-14	Jun-14	Sep-14
Operational Flexibility	No	No	No	No

Parameters	Scenario Names	
	Small WTL	Large WTL
Plant Production Capacity (bbl/day)	400	1,440
Train Design Philosophy	1× HTW	2× HTW
Biomass Feedstock Type	MSW	MSW
Biomass In-field Storage Method	N.A.	N.A.
Biomass Feedstock Format	Fluff	Fluff
In-plant Pelletization	No	No
Natural Gas Feedstock	No	No
Biomass Transportation mode	Truck	Truck
Gasification Technology	Fluidized-bed (HTW)	Fluidized-bed (HTW)
Tar and Methane Handling Technology	POX	POX
NG Reforming Technology	N.A.	N.A.
AGR Technology	Rectisol	Rectisol
CCS	Vent	Vent
Results Generated in/before	Sep-14	Sep-14
Operational Flexibility	No	No