



High-Octane Gasoline from Lignocellulosic Biomass via Syngas and Methanol/Dimethyl Ether Intermediates: 2018 State of Technology and Future Research

Eric C.D. Tan,¹ Dan Ruddy,¹ Connor Nash,¹ Dan Dupuis,¹ Abhijit Dutta,¹ Damon Hartley,² and Hao Cai³

¹ *National Renewable Energy Laboratory*

² *Idaho National Laboratory*

³ *Argonne National Laboratory*

**NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC**

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-5100-71957
November 2018



High-Octane Gasoline from Lignocellulosic Biomass via Syngas and Methanol/Dimethyl Ether Intermediates: 2018 State of Technology and Future Research

Eric C.D. Tan,¹ Dan Ruddy,¹ Connor Nash,¹ Dan Dupuis,¹ Abhijit Dutta,¹ Damon Hartley,² and Hao Cai³

¹ *National Renewable Energy Laboratory*

² *Idaho National Laboratory*

³ *Argonne National Laboratory*

Suggested Citation

Eric C.D. Tan, Dan Ruddy, Connor Nash, Dan Dupuis, Abhijit Dutta, Damon Hartley, and Hao Cai. 2018. *High-Octane Gasoline from Lignocellulosic Biomass via Syngas and Methanol/Dimethyl Ether Intermediates: 2018 State of Technology and Future Research*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5100-71957. <https://www.nrel.gov/docs/fy19osti/71957.pdf>.

**NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC**

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-5100-71957
November 2018

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

NOTICE

This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308; Idaho National Laboratory, operated for DOE by Battelle Energy Alliance under contract DE-AC07-05ID14517; and Argonne National Laboratory, managed by UChicago Argonne, LLC, under DOE Contract No. DE-AC02-06CH11357. Funding provided by U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Bioenergy Technologies Office. The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government.

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

U.S. Department of Energy (DOE) reports produced after 1991 and a growing number of pre-1991 documents are available free via www.OSTI.gov.

Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

NREL prints on paper that contains recycled content.

Acknowledgments

The authors wish to thank the following contributors from the National Renewable Energy Laboratory: Jesse Hensley for some preliminary experimental design discussion; Josh Schaidle and Mary Bidy for reviewing this report and providing valuable comments; and Kathy Cisar for technical editing.

Nomenclature

ANL	Argonne National Laboratory
BETO	Bioenergy Technologies Office
Btu	British thermal unit
DME	dimethyl ether
GGE	gallon of gasoline equivalent
GHG	greenhouse gas
GREET	Greenhouse gases, Regulated Emissions, and Energy use in Transportation
HHV	higher heating value
HMB	hexamethylbenzene
HOG	high-octane gasoline
INL	Idaho National Laboratory
IRR	internal rate of return
LHV	lower heating value
MFSP	minimum fuel selling price
MM	million
MYPP	Multi-Year Program Plan
NREL	National Renewable Energy Laboratory
ODT	oven dry ton
R&D	research and development
SCSA	supply chain sustainability analysis
SOT	state of technology
TCI	total capital investment
TEA	techno-economic analysis

Executive Summary

This report was developed as part of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy Bioenergy Technologies Office's (BETO's) efforts to enable the development of technologies for the production of infrastructure-compatible, cost-competitive liquid hydrocarbon fuels from lignocellulosic biomass feedstocks. The research funded by BETO is designed to advance the state of technology of biomass feedstock supply and logistics, conversion, and overall system sustainability. Current projections include research improvements deemed feasible within the 2022 timeframe. As part of their involvement in this research and development effort, the National Renewable Energy Laboratory, Idaho National Laboratory, and Argonne National Laboratory investigate the economics of conversion pathways through the development of conceptual biorefinery process models and techno-economic analysis models, delivered feedstock quality and cost, and supply chain sustainability assessment, respectively.

This report covers the 2018 state of technology (SOT) assessment and a revision of previous 2022 projections. The 2018 SOT assesses research progress made since 2014 toward the 2022 goal of developing technologies to produce cost-competitive, high-octane gasoline from woody biomass. It captures current research results as well as projected future technical improvements necessary to achieve the projected 2022 minimum fuel selling price (MFSP). Previous 2022 cost projections published in the BETO Multi-Year Program Plan have been revised based on current understanding of the research trajectory. The techno-economic analysis (TEA) model revisions include changes in the feedstock composition, delivered feedstock cost, the income tax rate, and the cost year basis. Additionally, to improve the model predictions, the model compounds used for modeling the process and bulk properties of the gasoline product have been updated to reflect the actual isomers from experiments. The process and economic models for the revised 2022 projection will serve as the framework for developing future annual SOT assessments. The National Renewable Energy Laboratory research and analysis teams will continue to work together to incorporate demonstrated experimental research results into the process and economic models to assess progress toward the 2022 goals. Table ES-1 summarizes the performance metrics for the 2018 SOT and the 2022 projection. The summary of the TEA results for the 2018 SOT and the 2022 projection are presented in Table ES-2 and Table ES-3, respectively. The modeled MFSP for the 2018 SOT is \$3.79 per gallon of gasoline equivalent (GGE) in 2016 dollars, compared to the 2022 projection of \$3.30/GGE.

Experimental research efforts to achieve the 2022 MFSP projection are ongoing. As seen in Table ES-1, a significant increase in the overall C5+ C-selectivity and a corresponding decrease in aromatics C-selectivity are required. To achieve this shift in C-selectivity away from aromatics and toward the desired C5+ products, catalyst development research is underway to control hydrogenation activity to reduce aromatic formation, with a complementary effort to control the chemistry to convert the resulting intermediates to C5+ products. These research improvements directly address the fuel synthesis cost, representing a \$0.16 reduction in capital and operating costs in that area; combined with yield increases this will allow a total \$0.49/GGE reduction in the MFSP. Research through 2022 and beyond will focus on process intensification and increasing the overall carbon efficiency as the primary avenues to address further cost reduction. Toward that goal, process analysis research is underway to identify the most impactful opportunities to recycle lost carbon back into the process. For example, carbon dioxide from

syngas cleanup could potentially be recycled back to the methanol synthesis reactor to recover this otherwise lost carbon. Similarly, carbon lost to char could be recovered. Based on the findings of this analysis, complementary experimental research will be performed to explore the viability of these opportunities to increase carbon efficiency and reduce the overall cost.

Table ES-1. Performance Metrics for the 2018 SOT and 2022 Projection

Performance Metrics	2018 SOT	Revised 2022 Projection
DME Conversion (%)	38.9 ^a	40 ^a
C5+ C-Selectivity (%)	72.3 ^b	86.7 ^b
Aromatics C-Selectivity (%)	8.0	0.5
C4 Recycle Conversion (%)	22 ^a	40 ^a
HOG Hydrocarbon Productivity (kg/kg-cat/h)	0.073	0.1
HOG Product Yield (GGE/dry U.S. ton)	49.6	54.7
MFSP (\$/GGE; 2016\$)	3.79	3.30
Fuel Synthesis Cost (¢/GGE; 2016\$)	64	48

^a Single-pass conversion. ^b Overall selectivity.

Table ES-2. Economic Summary for 2018 State of Technology

Process Engineering Analysis for High Octane Gasoline via Indirect Gasification and Methanol Intermediate

2,000 Dry Metric Tonnes Biomass per Day

Indirect Gasifier, Tar Reformer, Sulfur Removal, Methanol Synthesis, Hydrocarbon Synthesis on Cu-Beta-Zeolite Catalyst, Fuel Purification, Steam-Power Cycle

All Values in 2016 US\$

Minimum Fuel Selling Price

(MFSP, Gasoline-Equivalent Basis) \$3.79 per GGE

Feedstock & In-Plant Handling Costs	1.236 per GGE
Operating Costs & Credits	0.734 per GGE
Capital Charges & Taxes	1.825 per GGE

Fuel Production at Operating Capacity	35.91 MM GGE per Year
Fuel Product Yield	49.59 GGE per Dry US Ton Feedstock
LPG Production at Operating Capacity	0.0 MM GGE per Year
LPG Product Yield	0.0 GGE per Dry US Ton Feedstock

Delivered Feedstock Cost \$60.58 per Dry US Ton

Capital Costs		Annual Operating Costs		
Feed Handling & Drying	\$200,000	Feedstock	\$43,900,000	
Gasification	\$44,600,000	Natural Gas	\$0	
Gas Cleanup	\$53,700,000	Catalysts	\$14,600,000	
Methanol Synthesis	\$33,500,000	Olivine	\$600,000	
Methanol Conditioning	\$2,400,000	Other Raw Matl. Costs	\$1,600,000	
DME & Hydrocarbons Conversion	\$53,900,000	Waste Disposal	\$1,600,000	
Gasoline Separations	\$5,100,000	Electricity Transfer Charge	\$0	
Steam System & Power Generation	\$35,700,000	Electricity	\$0	
Cooling Water & Other Utilities	\$7,400,000	Fixed Costs	\$20,100,000	
Total Installed Equipment Cost (TIC)	\$236,500,000	Coproduct credits	-\$20,000	
		Capital Depreciation	\$13,000,000	
ISBL (Areas A100 to A500, A1400, A1500)	\$193,400,000	Average Income Tax	\$4,000,000	
OSBL (Areas A600, A700)	\$43,100,000	Average Return on Investment	\$48,600,000	
Other Direct Costs	7,700,000	Operating Costs per Product	(c/MMBtu)	(c/GGE)
(% of ISBL)	4.0%	Feedstock	1052.3	122.2
Total Direct Costs (TDC)	244,300,000	Natural Gas	0.0	0.0
		Catalysts	73.1	8.5
Indirect Costs	146,600,000	Olivine	13.3	1.5
(% of TDC)	60.0%	Other Raw Materials	37.6	4.4
Land Purchase Cost	1,600,000	Waste Disposal	38.4	4.5
Working Capital	19,500,000	Electricity Transfer	0.0	0.0
		Electricity	0.0	0.0
Total Capital Investment (TCI)	412,000,000	Fixed Costs	481.1	55.8
		Coproduct credits	-0.4	0.0
Installed Equipment Cost per Annual Gallon	\$6.35	Capital Depreciation	311.8	36.2
Total Capital Investment per Annual Gallon	\$11.07	Average Income Tax	96.9	11.3
		<u>Average Return on Investment</u>	<u>1164.8</u>	<u>135.2</u>
Debt Financing (% of Investment)	60.0%	Total (Plant Gate Price)	3268.9	379.5
Loan Interest Rate	8.0%	Power Balance	(KW)	(hp)
Loan Term (years)	10.0	Total Plant Power Consumption (KW)	38,058	51,036
		Power Generated Onsite (KW)	38,051	51,027
Equity Financing (% of Investment)	40.0%	Power Imported from Grid (KW)	7	9
Internal Rate of Return (After-Tax)	10.0%	Power Exported to Grid (KW)	0	0
Plant Operating Hours per year	7,884	Power Generation	(KW)	(hp)
On-Stream Percentage	90.0%	Steam Turbine Generators	36,500	48,948
		Process Gas Turboexpander(s)	1,551	2,079
Process Efficiency		Sustainability Metrics		
Gasifier Efficiency - HHV %	72.3	Plant Electricity Consumption (KWh/ GGE)	8.4	
Gasifier Efficiency - LHV %	71.9	Gasification & Reforming Steam (lb / GGE)	24.4	
Efficiency to Gasoline - HHV %	36.9	Water Consumption (Gal Water / GGE)	3.3	
Efficiency to Gasoline - LHV %	36.6	Carbon Conversion Efficiency (C in Fuel/C in Feedstock)	25.47%	
Overall Plant Efficiency - HHV %	36.9	Fossil GHG Emissions (g CO _{2,e} /MJ Fuel)	2.9	
Overall Plant Efficiency - LHV %	36.6	Fossil Energy Consumption (MJ Fossil Energy/MJ Fuel)	0.035	
		Feedstock Rate and Cost		
		Feed Rate	Dry Tonnes / Day	2,000
			Dry US Tons / Day	2,205
		Feedstock Cost	\$/ Dry Ton	\$60.58
			\$/ Moisture & Ash Free Ton	\$62.45

Table ES-3. Economic Summary for 2022 Projection

Process Engineering Analysis for High Octane Gasoline via Indirect Gasification and Methanol Intermediate

2,000 Dry Metric Tonnes Biomass per Day

Indirect Gasifier, Tar Reformer, Sulfur Removal, Methanol Synthesis, Hydrocarbon Synthesis on Cu-Beta-Zeolite Catalyst, Fuel Purification, Steam-Power Cycle

All Values in 2016 US\$

Minimum Fuel Selling Price

(MFSP, Gasoline-Equivalent Basis) \$3.30 per GGE

Feedstock & In-Plant Handling Costs	1.121 per GGE
Operating Costs & Credits	0.644 per GGE
Capital Charges & Taxes	1.537 per GGE

Fuel Production at Operating Capacity	39.59 MM GGE per Year
Fuel Product Yield	54.66 GGE per Dry US Ton Feedstock
LPG Production at Operating Capacity	0.0 MM GGE per Year
LPG Product Yield	0.0 GGE per Dry US Ton Feedstock

Delivered Feedstock Cost \$60.58 per Dry US Ton

Capital Costs		Annual Operating Costs		
Feed Handling & Drying	\$200,000	Feedstock	\$43,900,000	
Gasification	\$44,600,000	Natural Gas	\$0	
Gas Cleanup	\$52,800,000	Catalysts	\$11,700,000	
Methanol Synthesis	\$33,700,000	Olivine	\$600,000	
Methanol Conditioning	\$2,300,000	Other Raw Matl. Costs	\$1,500,000	
DME & Hydrocarbons Conversion	\$47,300,000	Waste Disposal	\$1,600,000	
Gasoline Separations	\$5,000,000	Electricity Transfer Charge	\$0	
Steam System & Power Generation	\$34,700,000	Electricity	\$0	
Cooling Water & Other Utilities	\$7,200,000	Fixed Costs	\$19,500,000	
Total Installed Equipment Cost (TIC)	\$227,800,000	Coproduct credits	\$0	
		Capital Depreciation	\$12,500,000	
ISBL (Areas A100 to A500, A1400, A1500)	\$185,900,000	Average Income Tax	\$3,900,000	
OSBL (Areas A600, A700)	\$41,900,000	Average Return on Investment	\$44,500,000	
Other Direct Costs	7,400,000	Operating Costs per Product	(c/MMBtu)	(c/GGE)
(% of ISBL)	4.0%	Feedstock	954.7	110.8
		Natural Gas	0.0	0.0
Total Direct Costs (TDC)	235,300,000	Catalysts	59.6	6.9
		Olivine	12.1	1.4
Indirect Costs	141,200,000	Other Raw Materials	33.1	3.8
(% of TDC)	60.0%	Waste Disposal	34.7	4.0
		Electricity Transfer	0.0	0.0
Land Purchase Cost	1,600,000	Electricity	0.0	0.0
Working Capital	18,800,000	Fixed Costs	424.8	49.3
		Coproduct credits	0.0	0.0
Total Capital Investment (TCI)	396,900,000	Capital Depreciation	272.0	31.6
		Average Income Tax	84.4	9.8
Installed Equipment Cost per Annual Gallon	\$5.62	<u>Average Return on Investment</u>	<u>968.6</u>	<u>112.4</u>
Total Capital Investment per Annual Gallon	\$9.79	Total (Plant Gate Price)	2844.0	330.2
Debt Financing (% of Investment)	60.0%	Power Balance	(KW)	(hp)
Loan Interest Rate	8.0%	Total Plant Power Consumption (KW)	36,084	48,389
Loan Term (years)	10.0	Power Generated Onsite (KW)	36,049	48,342
		Power Imported from Grid (KW)	35	47
Equity Financing (% of Investment)	40.0%	Power Exported to Grid (KW)	0	0
Internal Rate of Return (After-Tax)	10.0%			
		Power Generation	(KW)	(hp)
Plant Operating Hours per year	7,884	Steam Turbine Generators	34,419	46,157
On-Stream Percentage	90.0%	Process Gas Turboexpander(s)	1,630	2,186
Process Efficiency		Sustainability Metrics		
Gasifier Efficiency - HHV %	72.3	Plant Electricity Consumption (KWh/ GGE)	7.2	
Gasifier Efficiency - LHV %	71.9	Gasification & Reforming Steam (lb / GGE)	20.5	
Efficiency to Gasoline - HHV %	40.7	Water Consumption (Gal Water / GGE)	2.8	
Efficiency to Gasoline - LHV %	40.4	Carbon Conversion Efficiency (C in Fuel/C in Feedstock)	27.95%	
Overall Plant Efficiency - HHV %	40.7	Fossil GHG Emissions (g CO _{2,e} /MJ Fuel)	2.4	
Overall Plant Efficiency - LHV %	40.4	Fossil Energy Consumption (MJ Fossil Energy/MJ Fuel)	0.029	
		Feedstock Rate and Cost		
		Feed Rate	Dry Tonnes / Day	2,000
			Dry US Tons / Day	2,205
		Feedstock Cost	\$ / Dry Ton	\$60.58
			\$ / Moisture & Ash Free Ton	\$62.45

Table of Contents

1	Introduction	1
2	Process Description and Assumptions	2
3	Feedstock Specifications and Costs	3
4	nth-Plant Financial Assumptions for Techno-Economic Analysis	5
5	2018 State of Technology	7
5.1	Experimental and Results.....	7
5.1.1	Isobutane Recycle Study	7
5.1.2	Key Catalyst Performance Metrics.....	8
5.2	Heat Integration and Pinch Analysis.....	10
5.3	Energy Balance	11
5.4	Techno-Economic Analysis	12
5.5	2018 SOT Sensitivity Case	14
6	Revised 2022 Projection	16
6.1	Heat Integration and Pinch Analysis.....	16
6.2	Energy Balance	17
6.3	Techno-Economic Analysis	17
6.4	Sensitivity Analyses	18
7	Sustainability Assessment	21
8	Conclusions and Future Work	24
9	References	26
	Appendix A: Supplemental Information for SOT and Projection Cases	28

List of Figures

Figure 1. Simplified process flow diagram.....	2
Figure 2. Sensitivity of key preprocessing parameters on delivered cost of logging residue (\$/dry U.S. ton).....	4
Figure 3. Total hydrocarbon gravimetric productivity over Cu/BEA catalyst during the three reaction conditions performed in these experiments. The data at 220°C included co-fed isobutane.....	8
Figure 4. Carbon selectivity for the 2018 SOT case.....	9
Figure 5. Pinch analysis hot and cold composite curves for the 2018 SOT model.....	11
Figure 6. Overall energy analysis (dry biomass LHV basis) for the 2018 SOT model.....	12
Figure 7. Cost breakdown for the 2018 SOT model.....	13
Figure 8. Process flow diagram for the syngas conversion pathway to HOG blendstock followed by dehydrogenation of mixed butane and catalytic coupling of C4+ olefins to jet-/diesel-range hydrocarbons.....	14
Figure 9. Comparison of 2018 SOT base case and sensitivity case.....	15
Figure 10. Pinch analysis hot and cold composite curves for the 2022 projection model.....	16
Figure 11. Overall energy analysis (dry biomass LHV basis) for the 2022 projection model.....	17
Figure 12. Cost breakdown for the 2022 projection model.....	18
Figure 13. Results of sensitivity analyses for the 2022 projection.....	19
Figure A-1. SOT/waterfall for syngas conversion high-octane gasoline pathway (excluding feedstock costs) in 2016\$.....	30
Figure A-2. SOT/waterfall for syngas conversion high-octane gasoline pathway in 2016\$.....	31

List of Tables

Table ES-1. Performance Metrics for the 2018 SOT and 2022 Projection.....	vi
Table ES-2. Economic Summary for 2018 State of Technology.....	vii
Table ES-3. Economic Summary for 2022 Projection.....	viii
Table 1. Woody Feedstock Specifications Used in Process Model.....	3
Table 2. Summary of n th -Plant Assumptions for Techno-Economic Analysis.....	6
Table 3. Summary of 2018 Experimental Performance Relative to 2022 Projections.....	9
Table 4. 2018 SOT Experimental DME-to-Hydrocarbons on Cu/BEA Catalyst Product Selectivity.....	10
Table 5. Summary of Process Performance and Economic Results.....	13
Table 6. Material and Energy Flows for the High-Octane Gasoline Conversion Process (Gate-to-Gate)..	21
Table 7. Summary of Sustainability Metric Indicators for 2018 SOT and 2022 Projection Cases.....	23
Table A-1. Detailed Cost Breakdown of SOT/Projection for Syngas Conversion High-Octane Gasoline Pathway.....	28

1 Introduction

This report covers the 2018 state of technology (SOT) assessment and a revised 2022 projection for the conversion of woody biomass to high-octane gasoline. The 2018 SOT assesses research progress since 2014 toward the 2022 goal of demonstrating technologies that can enable future production of cost competitive high-octane gasoline from woody biomass. It captures current research results as well as projected future improvements necessary to achieve reductions in the minimum fuel selling price (MFSP) by 2022.

The National Renewable Energy Laboratory (NREL) research and analysis teams on this project had previously published a 2022 projection for this pathway in the design report, *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons via Indirect Liquefaction: Thermochemical Research Pathways to High-Octane Gasoline Blendstock through Methanol/Dimethyl Ether Intermediates* [1]. A revised 2022 projection is presented here based on learnings from the research since 2014; the process design remains unchanged. The techno-economic analysis (TEA) model revisions include the following changes:

- The feedstock composition has been updated to reflect logging residues: from 1 wt% ash and 10 wt% moisture content to 3 wt% ash and 30 wt% moisture content, and with the updated corresponding delivered feedstock cost of \$60.58/dry U.S. ton.
- The financial assumptions were updated to reflect the current income tax rate of 21% (versus 35% previously) and the costs are reported in 2016 dollars (versus 2011 dollars in the design report).
- To improve the model predictions, the model compounds used for modeling the process and bulk properties of the gasoline product have been updated to reflect the actual isomers from experiments.

The process and techno-economic models from the revised 2022 projections will serve as the framework for developing future annual SOT assessments. The research and analysis teams will continue to work together to incorporate demonstrated experimental research results into the TEA models to assess progress toward the 2022 goals.

This report summarizes the analysis results from NREL for conversion, Idaho National Laboratory (INL) for feedstocks, and Argonne National Laboratory (ANL) for sustainability, in support of the biomass-derived syngas conversion pathway to high-octane gasoline.

2 Process Description and Assumptions

A simplified flow diagram for the process is shown in Figure 1. The diagram depicts the major processing steps for the conversion of woody biomass to syngas via indirect steam gasification, syngas cleanup, and sequential synthesis of methanol, dimethyl ether (DME), and high-octane hydrocarbons. No change was made to the process design and configuration from the design report [1]. The biomass to clean syngas conversion steps (including indirect gasification and syngas cleanup via reforming) leverage technologies previously researched under Bioenergy Technologies Office (BETO) funding [2,3]. Commercial technologies were adopted for the methanol synthesis and the subsequent methanol dehydration to DME. The current research efforts focus on the DME-to-high-octane gasoline step where DME undergoes homologation to primarily form branched paraffin hydrocarbons. A detailed description of each process area, including design basis and operating conditions, can be found in the design report [1] and will not be repeated here.

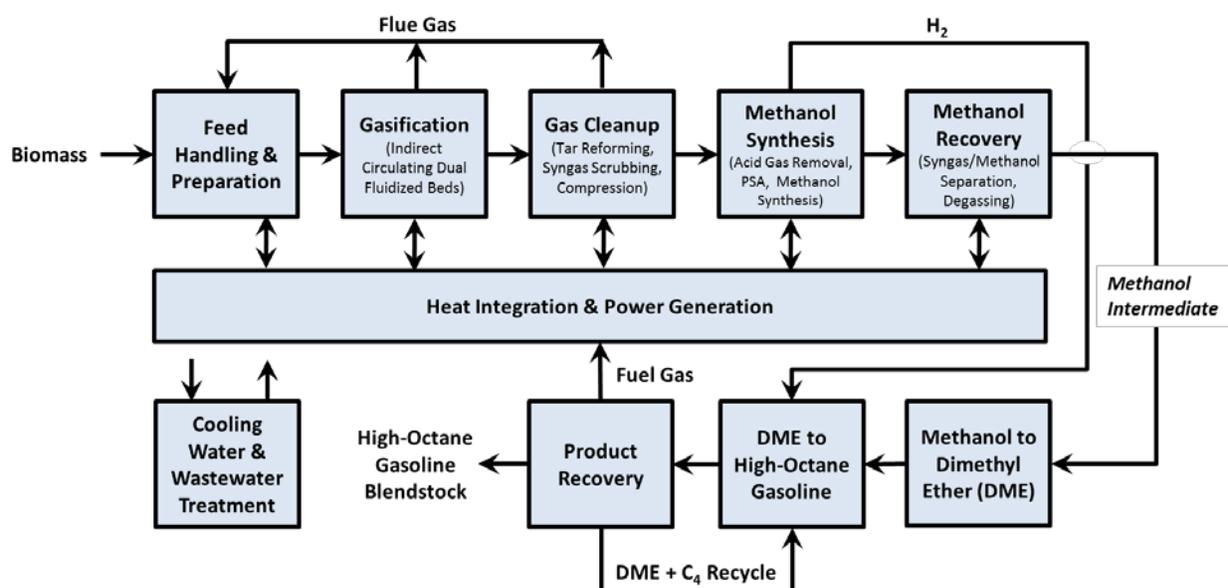


Figure 1. Simplified process flow diagram

3 Feedstock Specifications and Costs

The feedstock composition and delivered cost have been updated for this report. The modeled feedstock assumptions for the 2018 SOT and the 2022 projection were maintained to be consistent with the feedstock specifications shown in Table 1, which represents higher-ash material derived from logging residues. The updated dry basis elemental composition of the feedstock is different from that in the NREL design report, which used woody material with <1 wt% ash [1]. INL has recently updated the feedstock specification and cost for the forest residues-based material [4]. The current feedstock contains 3 wt% ash (i.e., mineral matter contained in the biomass feedstock) as opposed to 0.92 wt% in the previous study. Furthermore, the current feedstock moisture specification is 30 wt%, unlike the study in the design report [1] where moisture of 10 wt.% was assumed at the plant gate. The feedstock is subsequently dried from 30 wt% to 10 wt% using biorefinery waste heat prior to being fed to the gasification reactor.

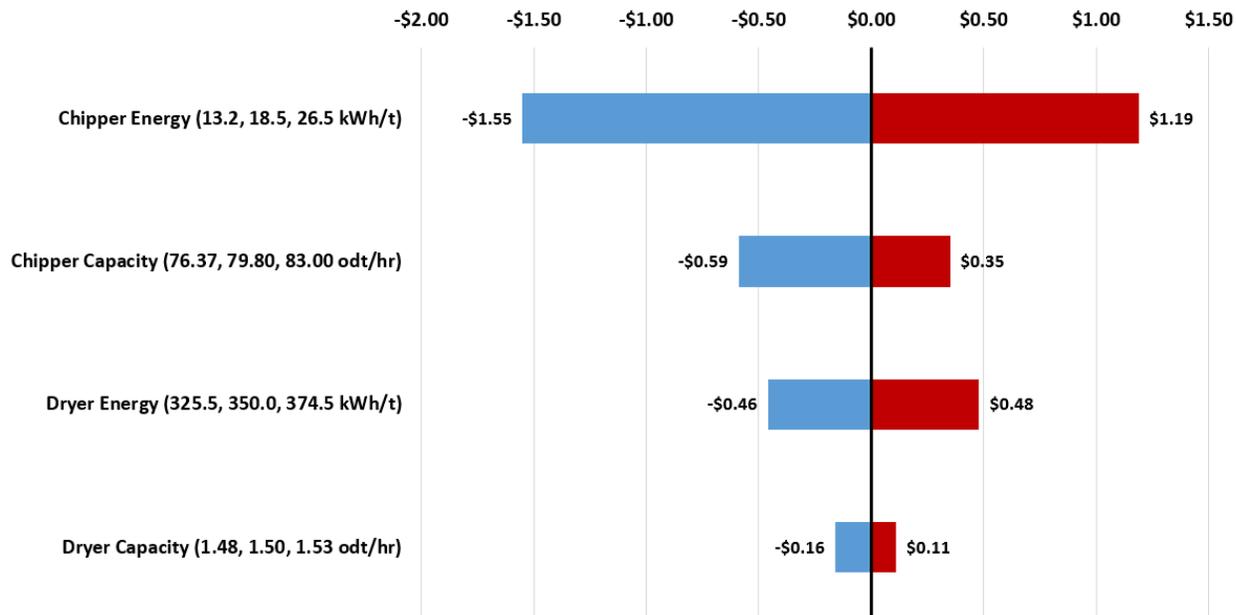
Table 1. Woody Feedstock Specifications Used in Process Model

Component	Weight % (Dry Basis)
Carbon	49.81
Hydrogen	5.91
Nitrogen	0.17
Sulfur	0.09
Oxygen	41.02
Ash	3.00
Heating Value ^a (Btu/lb)	8,449 HHV 7,856 LHV

^a Calculated using the Aspen Plus Boie correlation. HHV = higher heating value; LHV lower heating value.

The delivered feedstock cost was estimated by INL and was determined to be \$60.58/dry U.S. ton (2016\$). This modeled feedstock cost is expected to remain the same from 2014 through 2018 and beyond. The feedstock cost encompasses all feedstock logistics and the feedstock drying equipment at the biorefinery. The feedstock specifications and costs are expected to be met via research, development, and optimization at INL.

It is prudent to perform the uncertainty analysis for the delivered feedstock baseline cost. The uncertainty can be attributed to those associated with the feedstock logistics, particularly the preprocessing steps. The parameters associated with the feedstock preprocessing steps, namely chipper energy consumption, chipper capacity, dryer energy, and dryer capacity, can have an impact on the overall feedstock delivery cost. Figure 2 illustrates the impact of the sensitivities for these parameters. The lower bound (minimum) and upper bound (maximum) for the parameters were obtained based on literature survey and are deemed practical. Chipper energy consumption exhibits the highest impact among the four parameters evaluated here. Lowering the chipper energy consumption from the baseline of 18.5 to 13.2 kWh/dry U.S. ton can improve the delivered feedstock cost by \$1.55/dry U.S. ton (or about 2.6% improvement). Conversely, increasing the chipper energy consumption from 18.5 to 26.5 kWh/dry U.S. ton will add an additional \$1.19/dry U.S. ton (or 2.0% increase).



odt = over dry ton

Figure 2. Sensitivity of key preprocessing parameters on delivered cost of logging residue (\$/dry U.S. ton)

The current design capacity remains at 2,000 dry tonnes per day (2,205 dry U.S. tons per day). With an expected 7,884 operating hours per year (90% on-stream factor/availability), the annual feedstock requirement is approximately 657,000 dry tonnes per year (724,000 dry U.S. tons per year). The assumed on-stream factor allows approximately 36 days of planned and unplanned downtime per year. Impacts of plant size and feedstock cost on the MFSP for the 2022 projection are included in the sensitivity analysis in Section 6.4.

4 n^{th} -Plant Financial Assumptions for Techno-Economic Analysis

The TEA reported here uses n^{th} -plant economic assumptions. The key aspect associated with n^{th} -plant economics is that a successful industry has been established with many operating plants using similar process technologies. The TEA model encompasses a process model and an economic model. For a given set of conversion parameters, the process model solves mass and energy balances for each unit operation. This data is used to size and cost process equipment and compute raw material and other operating costs. The capital and operating costs are then used for a discounted cash flow rate of return analysis. An MFSP required to obtain a net present value of zero for a 10% internal rate of return (IRR) on the equity (also known as discount rate) is determined. Further discussion about the TEA model is available in the previous design report [1].

To be consistent with the latest financial assumptions used for other recent economic analyses done for BETO, the income tax rate was updated from 35% to 21%, and the cost year basis for analysis was updated to 2016 dollars (versus 2014 dollars in BETO's previous Multi-Year Program Plan [MYPP]) published in 2016 [5]. A summary of the updated n^{th} -plant assumptions applied in this report are listed in Table 2.

Table 2. Summary of nth-Plant Assumptions for Techno-Economic Analysis

Description of Assumption	Assumed Value
Cost year	2016 US dollars
IRR on equity	10%
Plant financing by equity/debt	40%/60% of total capital investment
Plant life	30 years
Income tax rate	21%
Interest rate for debt financing	8.0% annually
Term for debt financing	10 years
Working capital cost	5.0% of fixed capital investment (excluding land purchase cost)
Depreciation schedule	7-year MACRS schedule ^a
Construction period (spending schedule)	3 years (8% Y1, 60% Y2, 32% Y3)
Plant salvage value	No value
Startup time	6 months
Revenue and costs during startup	Revenue = 50% of normal Variable costs = 75% of normal Fixed costs = 100% of normal
On-stream percentage after startup	90% (7,884 operating hours per year)

^aCapital depreciation is computed according to the United States Internal Revenue Service modified accelerated cost recovery system (MACRS). Because the plant described here is not a net exporter of electricity, the steam plant and power generation equipment are not depreciated over a 20-year recovery period, according to the Internal Revenue Service. The whole plant capital is depreciated over a 7-year recovery period.

5 2018 State of Technology

5.1 Experimental and Results

The current research efforts focus on the DME-to-high-octane gasoline step where DME undergoes homologation to primarily form branched paraffin hydrocarbons. The direct homologation of DME into alkanes and water is hydrogen-deficient, resulting in the formation of unsaturated alkylated aromatic residues, which reduce yield and can contribute to catalyst deactivation. NREL researchers have overcome this challenge by developing a Cu-modified H-BEA catalyst (Cu/BEA) that is able to incorporate hydrogen, from gas-phase hydrogen co-fed with DME, into the desired branched alkane products while maintaining the high C4 and C7 carbon selectivity of the parent H-BEA [6]. The Cu/BEA catalyst is a multifunctional catalyst. It activates co-fed hydrogen and incorporates it into the hydrocarbon products, increasing paraffin selectivity and decreasing aromatics selectivity. Additionally, the Cu/BEA catalyst exhibits C4 or isobutane reactivation capability. C4 hydrocarbons can be recycled back to the DME-to-hydrocarbons reactor, significantly increasing the overall C5+ hydrocarbons product selectivity. Noticeable process economic benefits can be realized by incorporating these catalyst performance improvements into the process design. The combination of increased productivity and decreased aromatics selectivity suggests a corresponding increase in overall carbon efficiency to desired products, which is a key driver in biomass-to-fuels process economics. Similarly, the reduction in aromatic products suggests that the catalyst may also exhibit a longer lifetime than the parent H-BEA catalyst that requires frequent regeneration. The NREL research team continues to improve the Cu/BEA catalyst performance, including the C4 or isobutane recycle conversion, to help achieve the 2022 cost goal. The catalyst performance metrics are shown in Table 3 and the results are derived from the bench-scale experiments described below.

5.1.1 Isobutane Recycle Study

Isobutane recycle and re-incorporation in the hydrocarbon product for the production of larger molecules can help improve the economics of this process. The 2018 SOT Cu/BEA catalyst was tested in simulated isobutane recycle experiments to quantify its effectiveness in this regard. A corresponding control experiment for the catalyst was run without co-fed C4. Catalysts were first subjected to an induction period at 200°C, 3 psig, 1:1 mol_{DME}/mol_{H₂}, and a DME weight hourly space velocity of approximately 0.6 h⁻¹. Following the induction period, catalysts were tested at 220°C and 3 psig, and finally 220°C and 25 psig. For simulated C4 recycle conditions, a 1% isobutane/He mixture was used in place of inert He gas. The resulting isobutane concentration was 0.4 mol%, corresponding to a weight hourly space velocity with respect to C4 = 0.01 h⁻¹. The data from these experiments with co-fed isobutane are presented in Figure 3.

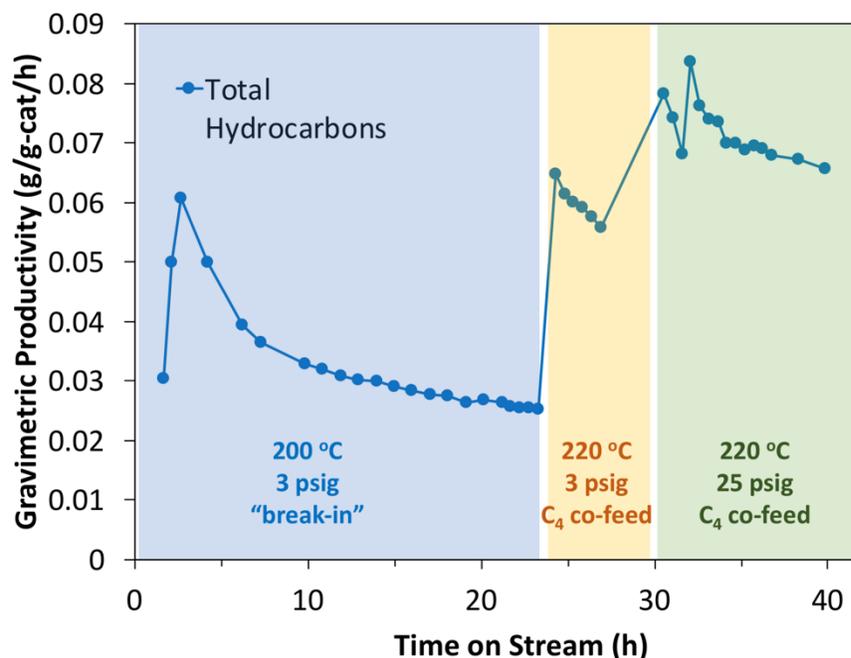


Figure 3. Total hydrocarbon gravimetric productivity over Cu/BEA catalyst during the three reaction conditions performed in these experiments. The data at 220°C included co-fed isobutane.

5.1.2 Key Catalyst Performance Metrics

The research focus for this pathway is the conversion of DME to hydrocarbons. The key Cu/BEA catalyst performance metrics or parameters for assessing overall performance of the DME to hydrocarbon conversion step are (1) single-pass conversion of DME, (2) hydrocarbon productivity of the catalyst, (3) selectivity to desired products (C5+ hydrocarbons), and (4) carbon selectivity to aromatics. The NREL thermochemical research team generated experimental data for the 2018 SOT performance. The 2018 experimental results for the SOT base case for the key technical performance metrics are highlighted in Table 3. The demonstrated DME single-pass conversion obtained from NREL’s Cu-modified beta zeolite catalyst is 38.9% at 220°C, which is about 97% of the 2022 projection (40% at 225°C). Single-pass DME conversion is expected to be higher at higher operating temperature. Earlier experimental data also revealed that an increased operating pressure at 20 psig resulted in a moderate increase in the C5+ selectivity, and also a notable increase in the C7 product along with a corresponding decrease in C4- species (non-gasoline-range light gases) during the DME-to-hydrocarbons reaction. While the current process model includes higher pressure (95 psia) operation and includes additional compression costs, the experimental data was at a lower pressure, and leaves room for future improvements by adjusting the operating conditions. Thus, the current simulated results can be considered conservative in the context of the improved product selectivity trend at higher pressures compared to experimental pressures of 3–40 psig.

Table 3. Summary of 2018 Experimental Performance Relative to 2022 Projections

Process Parameters	2018 SOT ^a	2022 Projection
Hydrocarbon Synthesis Reactor Temperature	220°C	225°C
Single-Pass DME Conversion	38.9%	40.0%
Productivity of Hydrocarbon Synthesis Catalyst (kg/kg-cat/h)	0.073 (total)	0.10 (total)
Carbon Selectivity to C5+ Product	56.4% (72.3% overall)	58% (86.7% overall)
Carbon Selectivity to Aromatics	8% Aromatics (4% HMB)	0.5% Aromatics (0.5% HMB)
H ₂ Addition to Hydrocarbon Synthesis	Yes	Yes
Mixed Butane (C4s) Handling	Recycled to hydrocarbon synthesis reactor: 22% single-pass conversion ^b	Recycled to hydrocarbon synthesis reactor: 40% single-pass conversion ^b

^aNREL's Cu/BEA zeolite catalyst (220°C, 25 psig, and averaged data with simulated C4 recycle from on-stream time of 31.1 to 33.7 h). ^bIso-butane single-pass conversion.

Further, the Cu/BEA catalyst is able to reactivate C4 alkanes, thus increasing the overall C5+ product yield. The overall C5+ selectivity for the 2018 SOT was found to be at 72.3%, compared to 86.7% for the 2022 projection. The lower overall C5+ selectivity in the 2018 SOT case is due to both the lower single-pass C5+ selectivity (not including the recycle) and the lower C4 reactivation (22% for the 2018 SOT compared to 40% for the 2022 projection). The observed DME homologation hydrocarbon product distribution and selectivity under these conditions were updated for the 2018 SOT process model, as shown in Figure 4 and Table 4.

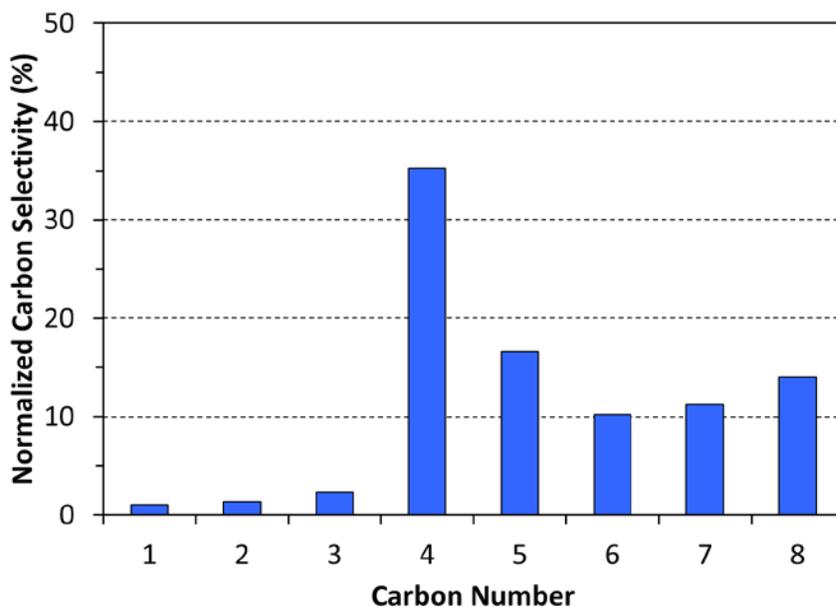


Figure 4. Carbon selectivity for the 2018 SOT case

The demonstrated hydrocarbon productivity is determined to be 0.073 kg/kg-cat/h, which is about 27% lower than the 2022 projection (0.10 kg/kg-cat/h). Note that catalyst productivity is affected by the interplay of multiple factors including DME conversion, carbon selectivity, and space velocity.

The carbon selectivity to aromatics for the 2018 SOT is 8%; half of those are heavy aromatic deposits on the catalyst and is represented with hexamethylbenzene (HMB). HMB is removed from the catalyst surface during the catalyst regeneration under a mild oxidation condition. The selectivity for the aromatics for the 2022 projection is 0.5%.

Table 4. 2018 SOT Experimental DME-to-Hydrocarbons on Cu/BEA Catalyst Product Selectivity

Carbon Number	Carbon Selectivity	Species	Species Selectivity per Carbon Number
C1	1.0%	Methane (CH ₄)	100%
C2	1.4%	Ethane (C ₂ H ₆)	46.4%
		Ethene (C ₂ H ₄)	53.6%
C3	2.3%	Propane (C ₃ H ₈)	31.2%
		Propene (C ₃ H ₆)	68.8%
C4	35.3%	Methylpropane (C ₄ H ₁₀)	93.1%
		N-butane (C ₄ H ₁₀)	1.8%
		2-methylpropene (C ₄ H ₈)	1.8%
		But-1-ene (C ₄ H ₈)	3.3%
C5	16.6%	2-methylbutane (C ₅ H ₁₂)	95.9%
		2-methyl-1-butene (C ₅ H ₁₀)	4.1%
C6	10.2%	2-methyl-pentane (C ₆ H ₁₄)	68.1%
		2,3-dimethylbutane (C ₆ H ₁₄)	27.5%
		2,3-methyl-1-butene (C ₆ H ₁₂)	4.4%
C7	11.2%	2,2,3-trimethylbutane (C ₇ H ₁₆)	73.3%
		2,4-dimethyl-pentane (C ₇ H ₁₆)	25.1%
		2,3,3-trimethyl-1-butene (C ₇ H ₁₄)	1.6%
C8	14.0%	2,5-dimethylhexane (C ₈ H ₁₈)	100%
Aromatics (HMB)	4.0%	Hexamethylbenzene (C ₆ (CH ₃) ₆)	100%
Aromatics (Others)	4.0%	Methylbenzene (C ₇ H ₈)	100%
Total	100%		

5.2 Heat Integration and Pinch Analysis

The importance of performing the heat integration of a process is to improve its overall energy efficiency. Additionally, it is important to make sure that there are no temperature crossovers and that a feasible heat exchanger network can be designed based on process heat exchange in the modeled system. This can be accomplished via the heat integration and pinch analysis. The concept

of pinch technology offers a systematic approach for optimizing energy integration in process design. Temperature and heat flow (Q) data were gathered for the hot process streams (streams cooled in the process), cold process streams (streams heated in the process), and utility streams like steam. Figure 5 shows the cumulative hot and cold pinch curves for the 2018 SOT case. The minimum vertical distance between the curves is ΔT_{\min} , which is theoretically the smallest approach temperature in the exchanger network. For this design, the pinch occurs at $\sim Q = 18.5$ MMBtu/h where the upper and lower pinch temperatures are 181.4°F (83.0°C) and 147.5°F (64.2°C), respectively. The resulting ΔT_{\min} is 33.9°F (18.8°C) which is feasible for a heat exchange network design. The heat exchanger costs were derived by scaling the costs from the detailed heat exchange network in the design report [1] using total process heat exchange duties.

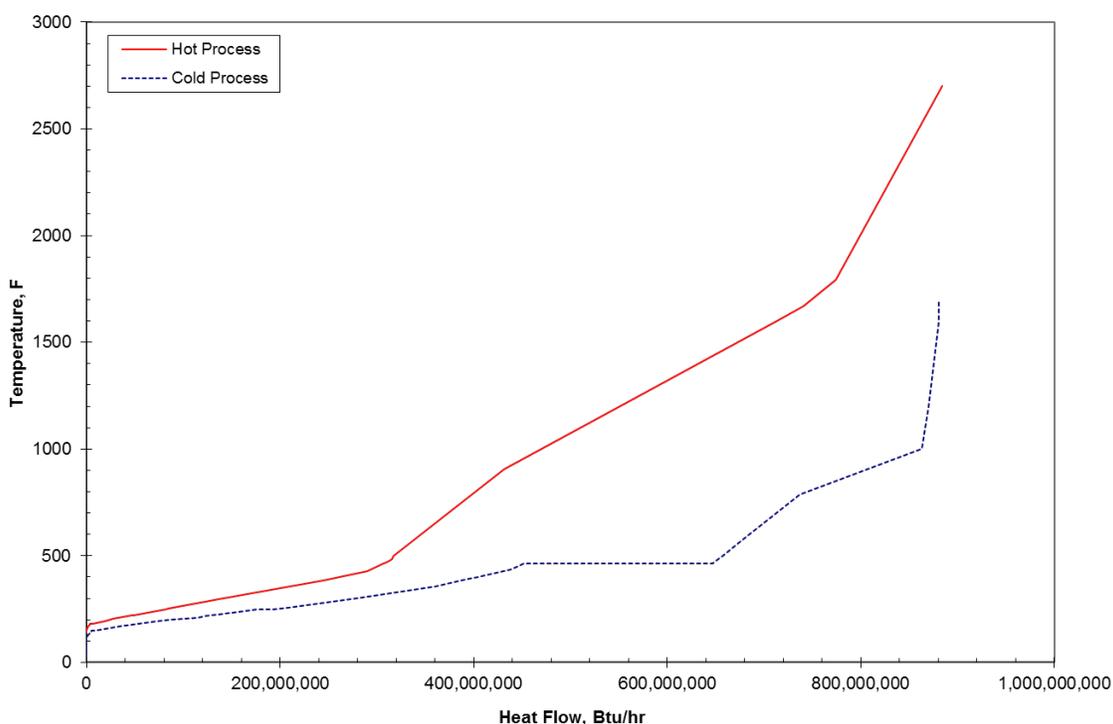


Figure 5. Pinch analysis hot and cold composite curves for the 2018 SOT model

5.3 Energy Balance

Detailed energy balances around the major process areas were derived using data from the Aspen Plus simulation. Comparing the process energy inputs and outputs allows the energy efficiency of the process to be quantified. Tracing energy transfer between process areas also makes it possible to identify potential improvements to the energy efficiency. The output distribution of the total energy content of dry biomass (LHV basis) is shown in Figure 6. The total energy in the dry portion of the biomass feed (0% moisture) is 1,443 MMBtu/h. Approximately 36% of the LHV is recovered in gasoline-range product. A significant amount (30%) is lost through air-cooled exchangers, and the rest (34%) is lost because of moisture in the feed and other water input to the process, as well as electrical and thermal losses.

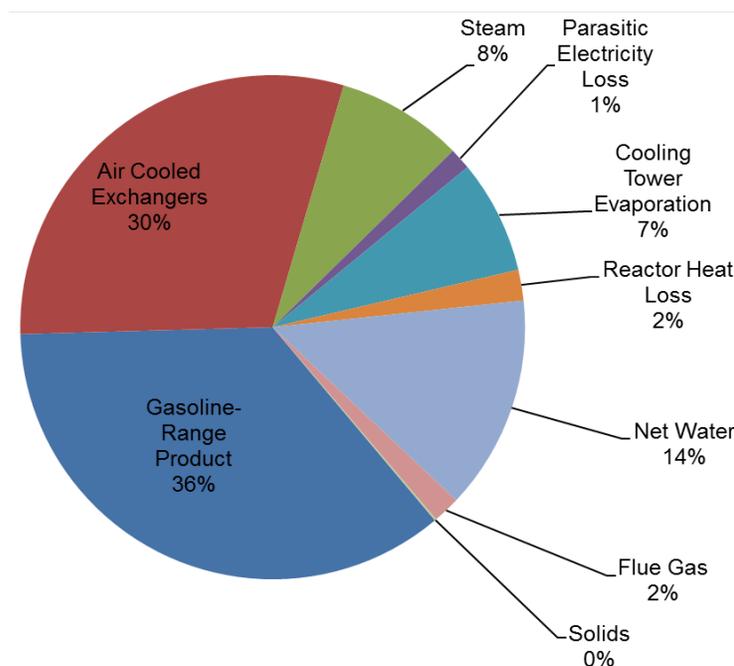


Figure 6. Overall energy analysis (dry biomass LHV basis) for the 2018 SOT model

5.4 Techno-Economic Analysis

Table 5 provides the summary of yields, rates, and conversion costs for both the 2018 SOT case and the revised 2022 projection (presented in Section 6). The production rates for the high-octane gasoline (HOG) blendstock is 35.9 million gallon of gasoline equivalent (GGE) per year, corresponding to 49.6 GGE per dry U.S. ton of feedstock. About 36% of the energy content of the feedstock is recovered in the HOG (as depicted in Figure 6). The resulting MFSP for the 2018 SOT for high-octane gasoline was determined to be \$3.79/GGE in 2016 U.S. dollars. Note that the baseline used in the GGE calculation is obtained from Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model, 116,090 Btu/gal (LHV) for gasoline blendstock [7]; the LHV for the high-octane gasoline produced in the 2018 SOT model is 112,026 Btu/gal (LHV).

A summary of the costs contributing to the total high-octane gasoline selling price is presented in Figure 7. This cost contribution chart shows coproduct credits for electricity (1) from the methanol synthesis area for electricity from the syngas expansion and (2) for electricity from the steam system and power generation area. However, the process was adjusted so that the electricity generation balances the plant's electricity requirements and no excess electricity is sold to the grid. The production cost associated with the DME-to-HOG synthesis is about \$0.64/GGE, or about 17% of the MFSP. The biggest contributor is the feedstock, about \$1.24/GGE or 33% of the MFSP.

Table 5. Summary of Process Performance and Economic Results

	2018 SOT	2022 Projection
Feedstock rate	2,205 dry U.S. ton/day	
Online time	7,884 h/yr (90% online factor)	
Total fuel yield	49.6 GGE/dry U.S. ton feedstock	54.7 GGE/dry U.S. ton feedstock
Total fuel production rate	35.9 MM GGE/yr	39.6 MM GGE/yr
Total annual operation cost and credits	\$82 MM	\$79 MM
Total installed equipment cost	\$237 MM	\$228 MM
Total capital investment (TCI)	\$412 MM	\$397 MM
TCI per annual gallon	\$11.47/GGE	\$10.03/GGE
Minimum fuel selling price	\$3.79/GGE	\$3.30/GGE
Feedstock costs	\$1.22/GGE	\$1.11/GGE
Operating costs and credits	\$0.75/GGE	\$0.66/GGE
Capital charges and taxes	\$1.83/GGE	\$1.54/GGE

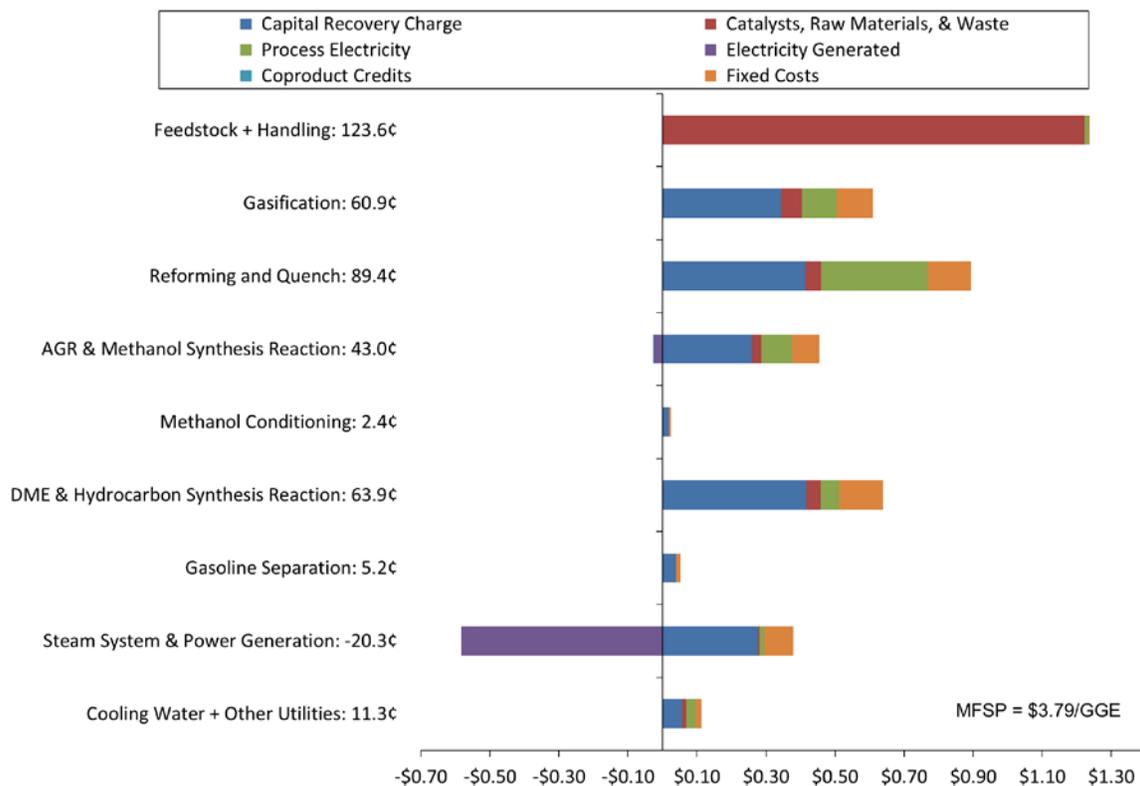


Figure 7. Cost breakdown for the 2018 SOT model

5.5 2018 SOT Sensitivity Case

Figure 8 shows the process flow diagram for a sensitivity case for the 2018 SOT. As a sensitivity study, mixed butane is sent to a dehydrogenation reactor in which isobutane to isobutene conversion takes place on a commercial $\text{CrO}_x/\text{ZrO}_2$ catalyst at 550°C and 137 psia, and with the isobutane conversion and isobutene selectivity set at 53% and 89%, respectively [8]. Subsequently, the C4 olefins together with the C5+ olefins present in the crude gasoline-range hydrocarbon stream are allowed to undergo coupling to make jet- and diesel-range hydrocarbons, using an Amberlyst-35 catalyst to produce distillate-range hydrocarbons (C10–C20) using reaction conditions and product distributions specified in the literature [9]; the C10+ productivity of the Amberlyst-35 catalyst of $0.172 \text{ kg/kg-cat/h}$ at 100°C was used in the model.

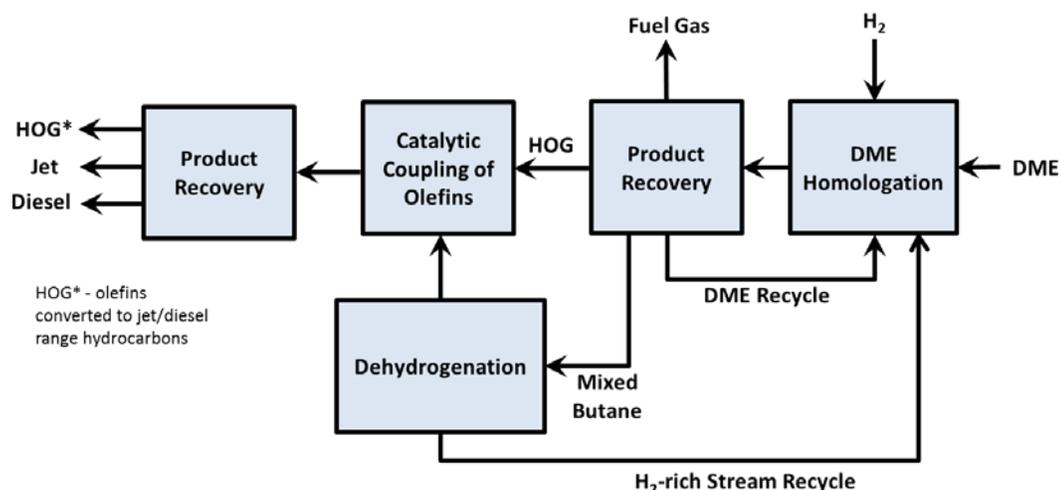


Figure 8. Process flow diagram for the syngas conversion pathway to HOG blendstock followed by dehydrogenation of mixed butane and catalytic coupling of C4+ olefins to jet-/diesel-range hydrocarbons

For the sensitivity case, the addition of the mixed C4 dehydrogenation step and the coupling of C4+ olefins to jet-/diesel-range hydrocarbons offers an additional product stream from this process. As shown in Figure 9, the product slate includes, on an energy basis, about 57% HOG-, 38% jet-, and 6% diesel-range hydrocarbons. Furthermore, the total fuel yield for the sensitivity case is also higher ($51.8 \text{ GGE/dry U.S. ton}$) compared to the base case ($49.6 \text{ GGE/dry U.S. ton}$). The higher overall hydrocarbon yield due to the production of jet/diesel is largely attributed to the high selectivity of isobutane (approximately 33%, derived from Table 4), which holds the key to high distillate yields.

Higher overall fuel yield does not completely compensate for the additional capital and operating costs associated with the dehydrogenation and coupling steps, and consequently, the resulting MFSP for the sensitivity case is nearly 2% higher, $\$3.86/\text{GGE}$ compared to $\$3.79/\text{GGE}$ for the base case. Overall, this alternative design can expand the product slate and potentially help improve the overall product yield, and this comes with a relatively small increase ($< 5\%$) in the production cost. Note that this sensitivity case is based on prior year experimental results and that future research and development (R&D) is focused on improving yields to the HOG product.

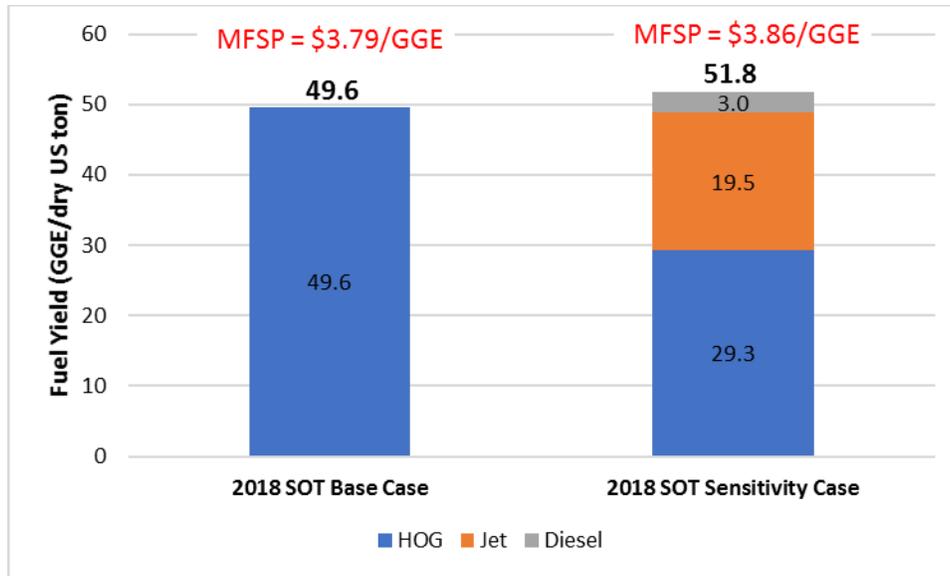


Figure 9. Comparison of 2018 SOT base case and sensitivity case

6 Revised 2022 Projection

The 2022 projection presented previously in the design report [1] and the 2016 MYPP [5] was updated. The overall process design and configuration remained unchanged (shown in Figure 1). The TEA model revisions included the following: (1) the feedstock composition was updated to reflect the use of logging residues (3 wt% ash and 30 wt% moisture content) (Table 1), with a corresponding delivered feedstock cost of \$60.58/dry U.S. ton; (2) revised financial assumptions included a 21% income tax rate and 2016 cost year basis, as presented in Table 2; and additionally, (3) the model compounds listed in Table 17 of the design report [1] were updated here to reflect the actual isomers from the 2018 SOT experiments and to better align the process model with current experiments (shown in Table 4). Results from these revisions are presented below.

6.1 Heat Integration and Pinch Analysis

Figure 10 shows the cumulative hot and cold pinch curves for the updated 2022 projection. For this design, the pinch occurs at $\sim Q = 72.7$ MMBtu/h where the upper and lower pinch temperatures are 184.7°F (84.8°C) and 150.8°F (66°C), respectively. The resulting ΔT_{\min} is 33.9°F (18.8°C), which is feasible for a heat exchange network design. Note that decreasing the approach temperature (ΔT_{\min}) may potentially improve the efficiency. However, this will increase the heat transfer area in an exchanger network design, resulting in a higher associated capital cost.

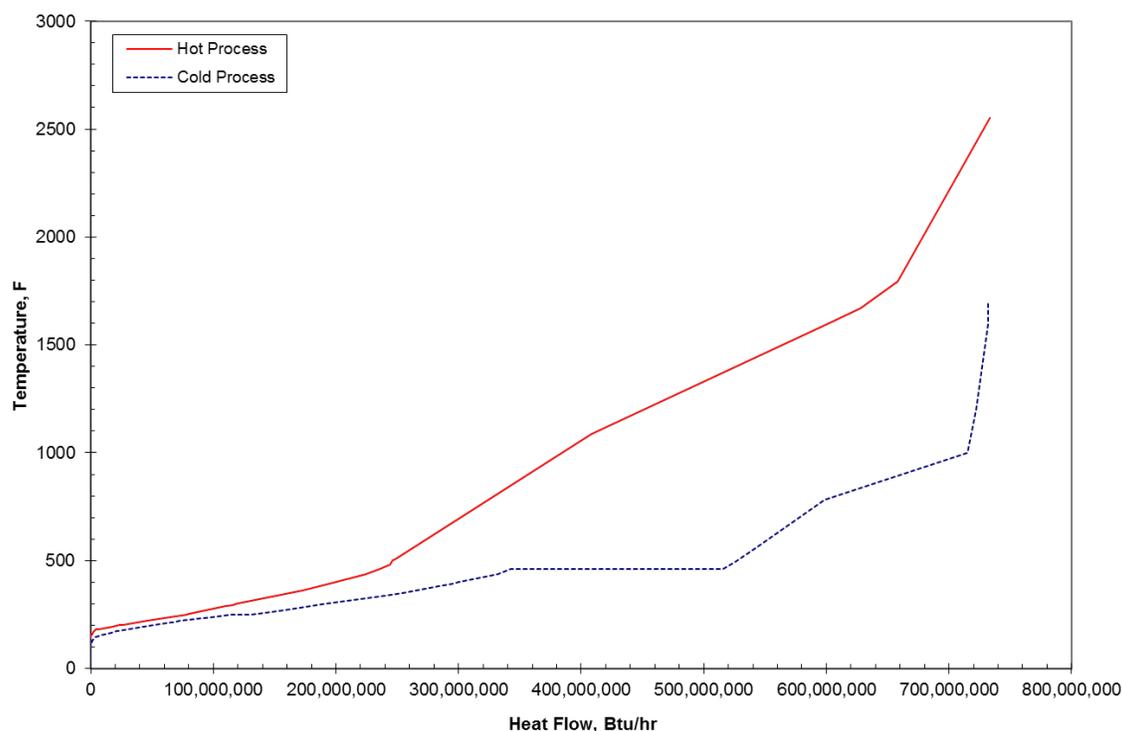


Figure 10. Pinch analysis hot and cold composite curves for the 2022 projection model

6.2 Energy Balance

Figure 11 shows a detailed energy balance for the 2022 projection model. The total energy in the dry biomass feed (0% moisture) is 1,443 MMBtu/h. Approximately 40% of the LHV is recovered in gasoline-range product. A significant amount (29%) is lost through air-cooled exchangers, and the rest (31%) is lost because of moisture in the feed and other water inputs to the process, as well as electrical and thermal losses.

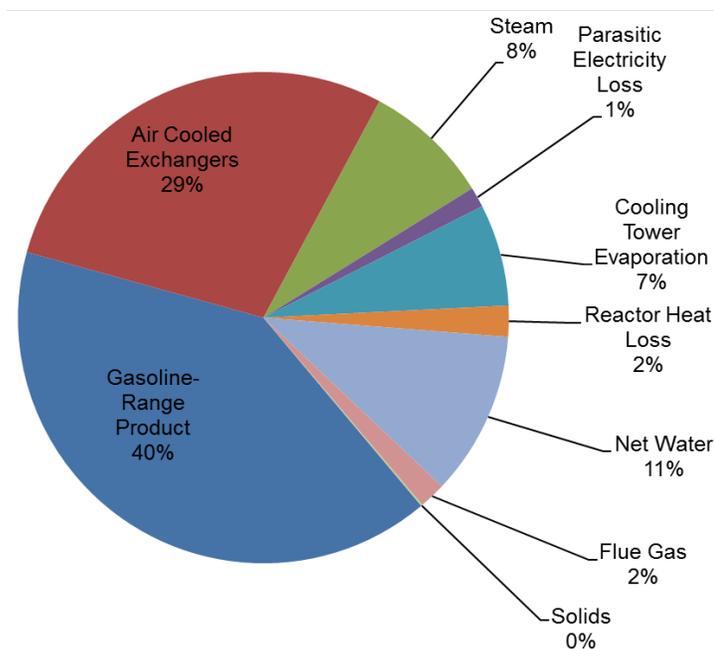


Figure 11. Overall energy analysis (dry biomass LHV basis) for the 2022 projection model

6.3 Techno-Economic Analysis

The combination of all process and financial targets, as well as other assumptions presented in this report, result in a minimum fuel selling price of \$3.30/GGE in 2016 U.S. dollars (Table 5). The production rates for the high-octane gasoline blendstock is 39.6 million GGE per year, corresponding to 54.7 GGE per dry U.S. ton of feedstock. About 40% of the energy content of the feedstock is recovered in the HOG (as depicted in Figure 11). Again, the baseline used in the GGE calculation is obtained from GREET, 116,090 Btu/gal (LHV) for gasoline blendstock [7]; the LHV for the high-octane gasoline produced in the 2022 projection model is 113,309 Btu/gal (LHV).

A summary of the costs contributing to the total high-octane selling price is presented in Figure 12. The production cost associated with the DME-to-HOG synthesis is about \$0.48/GGE, or about 15% of the MFSP. The biggest contributor is the feedstock, about \$1.12/GGE or 34% of the MFSP.

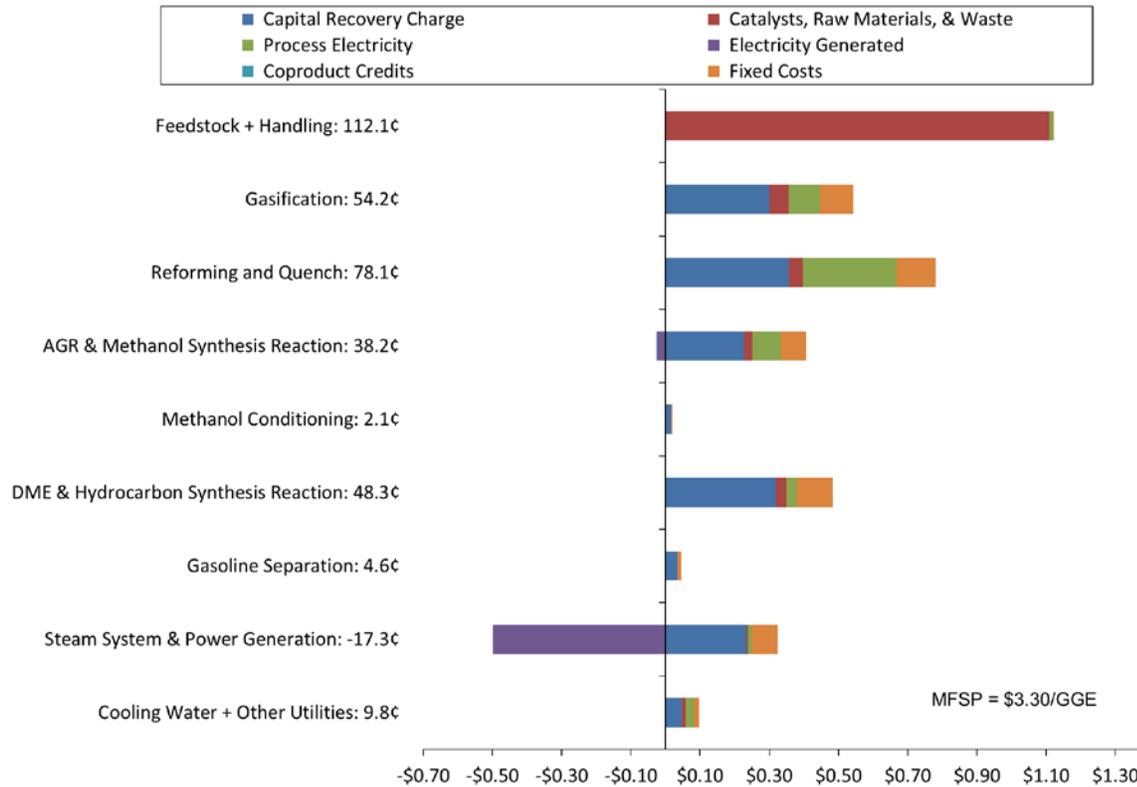


Figure 12. Cost breakdown for the 2022 projection model

6.4 Sensitivity Analyses

The total cost of high-octane gasoline production, as indicated by the MFSP, is determined based on a combination of various assumptions, both technical and financial. Financial and market assumptions include financing criteria like IRR for equity investment and the interest on debt. In addition, potential variability in equipment design, installation, and construction costs may impact the economics. Although the assumptions and estimated plant capital costs are reasonable, it is important to consider the impact of deviations from the base case 2022 projection. Sensitivity analysis results for key parameters identified as important factors affecting the MFSP are discussed here. The results for the sensitivity analysis are summarized in Figure 13. The results are ordered by potential impacts on MFSP value (highest to lowest). The sensitivity scenarios represent a deviation in a single parameter with all other uncorrelated parameters remaining constant at base case values. Note that each sensitivity scenario in Figure 13 has an associated deviation value from the base case. If a deviation bar is not visible, then the impact on MFSP is negligible. The case numbers in the following discussion refer to the numbers shown in the labels of Figure 13.

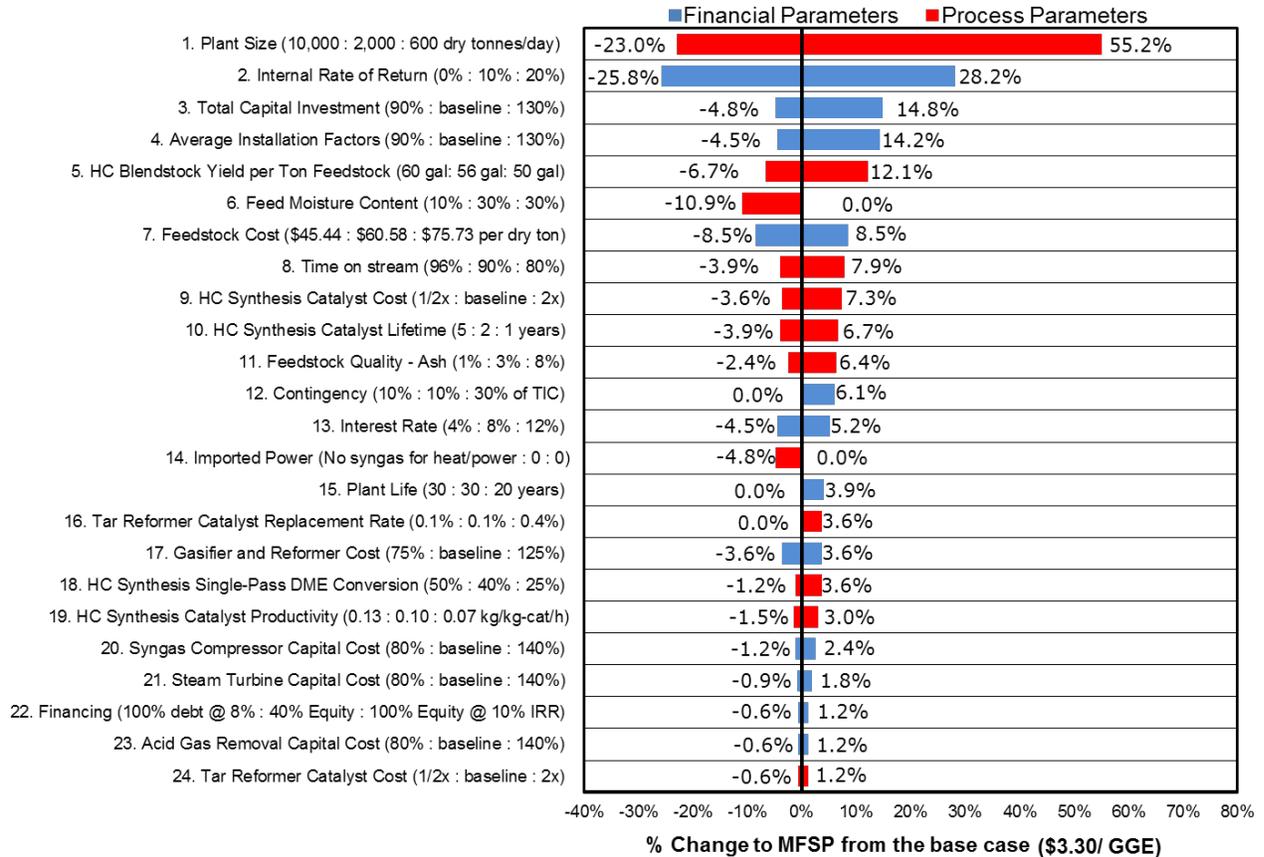


Figure 13. Results of sensitivity analyses for the 2022 projection

Deviation from base case financial parameters can have significant impacts on the MFSP. The base case financial assumptions are shown in Table 2. Case 1 in Figure 13 shows the possible savings realized by economies of scale from changes to the plant size. It is assumed in the plant size sensitivity scenario that the same technology is utilized for all plant sizes. A major constraint to larger plant sizes will potentially be significantly higher feedstock logistics costs. An increase in required IRR for the project from 10% to 20% (Case 2) would increase the MFSP from \$3.30 to \$4.23 per GGE (an increase of 28.2%). Variability in the total capital investment (TCI) can also have a major impact on MFSP. Applying a variability range of -10% to +30% to a TCI sensitivity (Case 3) results in an MFSP range of \$3.14 to \$3.79 per GGE (-4.8% to +14.8%). The impact of changes to the capital costs of the gasifier and reformer is shown in Case 17.

Although the current plant design basis specifies logging residues-based feedstock, there is a potential for other feedstocks to be used, such as from pulpwood or blended biomass, based on future biomass availability. The composition of the feedstock (such as ash and moisture contents) and delivered feedstock cost, as well as the resulting yield, are likely to be different than the current base case. The yield of the high-octane gasoline blendstock exhibits a direct impact on MFSP, as shown in Case 5. An increase in the yield from the baseline (56 gallons or 55 GGE/dry U.S. ton) to 60 gallons leads to a 6.7% decrease in MFSP. Likewise, decreasing the yield from 56 gallons to 50 gallons per dry U.S. ton results in an increase of 12.1% in the MFSP. As shown in Case 7, changing the feedstock cost 25% above or below the baseline of \$60.58/dry U.S. ton results in an 8.5% increase or decrease in the MFSP. The impacts of moisture and ash and contents are quantified in

Cases 6 and 11, respectively. Product yields increase for lower moisture feedstocks because less energy is used for drying, resulting in lower MFSP (Case 6); a decrease in moisture content from the base case of 30% to 10% results in 11% improvement in the MFSP. Increasing the ash content from the base case to 8% will increase the MFSP by 6.4%; decreasing the ash content to 1% will improve the MFSP by 2.4% (Case 11).

Because the heat and power requirements of the process cannot be met through char and off-gas combustion alone, some raw syngas from indirect gasifier is diverted for heat and power production. Although this option makes the design energy self-sufficient, it also lowers the overall product yield. Case 14 is a sensitivity case without utilizing raw syngas for plant heat and power; electricity import is required. Importing electricity in lieu of combusting syngas improves both fuel yield and carbon-to-fuel efficiency by 7%, leading to a lower MFSP of \$3.14/GGE, or 4.8% lower than the base case. It is noteworthy that importing electricity will impact the supply chain greenhouse gas (GHG) emission. The carbon intensity associated with the import electricity was determined to be about 5.9 g CO_{2e}/MJ.

7 Sustainability Assessment

This section presents the conversion process-related sustainability metrics based on the 2018 SOT and 2022 projection models. Direct air emissions from the biorefinery (i.e., CO₂, NO₂, and SO₂), water consumption, and other process-related metrics were taken from the Aspen Plus conversion process models described above. The material and energy flows of the conversion step capture the impacts of input raw materials, and outputs, such as fuel yields, waste, and coproducts as predicted by the process model, and are shown in Table 6.

The input/output inventories in Table 6 also provide the necessary information required for performing life cycle and supply chain sustainability modeling to quantify GHG emissions and fossil energy consumption. The biorefinery GHGs and fossil energy consumption are quantified separately under supply chain sustainability analysis efforts by ANL. A complete well-to-wheel or supply chain life cycle assessment evaluation is required to fully understand the sustainability implications for the full supply chain based on this technology pathway, such as how the overall integrated biorefinery GHG emissions profiles compare with petroleum-derived liquid fuels.

Table 6. Material and Energy Flows for the High-Octane Gasoline Conversion Process (Gate-to-Gate)

Cases --->	2018 SOT	2022 Projection
	Production Rate	Production Rate
Products		
High Octane Gasoline (HOG), lb/hr	28,015	30,768
gal, hr	4,720	5,144
MM Btu/hr	529	583
HOG properties: LHV (Btu/gal)	112,026	113,309
Density (g/gal)	2,692	2,713
Biogenic C in HOG, %	100.00%	100.00%
C Content in HOG, wt%	83.21%	83.11%
By-products		
Sulfur, lb/hr	118	114
Excess electricity, kWh	(7)	(36)
Resource Consumption	Flow Rate, lb/hr	Flow Rate, lb/hr
Blended woody biomass (wet)	262,455	262,455
Blended woody biomass (dry)	183,718	183,718
Magnesium oxide (MgO)	23	23
Fresh olivine	527	527
Tar reformer catalyst	10	9
Natural gas for reformer	0	0
Methanol synthesis catalyst	5	5

DME catalyst	7	6
Beta zeolite catalyst	45	34
Zinc oxide catalyst	2.5	2.5
Cooling tower water makeup	36,995	31,213
Boiler feedwater makeup	89,723	86,887
Dimethyl disulfide (DMDS)	2.1	2.1
Amine (MDEA) makeup	3.8	3.7
LO-CAT chemicals	118	114
Boiler feedwater chemicals	2.9	2.7
Cooling tower chemicals	1.1	1.0
No. 2 diesel fuel	69	69
Waste Streams	lb/hr	lb/hr
Sand and ash purge	6,679	6,679
Tar reformer catalyst	8.7	8.7
Scrubber solids	7.8	8.8
Wastewater	16,369	14,845
Air Emissions	lb/hr	lb/hr
CO ₂ (biogenic)	250,142	241,844
CO ₂ (fossil)	0	0
CH ₄	0	0
CO	0	0
NO ₂	117	142
SO ₂	43	51
H ₂ O	76,498	73,422
H ₂ S	0	0
Heating Values of Fuel to Combustors	MM Btu/hr	MM Btu/hr
<i>Char combustor</i>		
LHV to char combustor	528	528
HHV to char combustor	553	553
Char combustor % biogenic C	100%	100%
<i>Fuel combustor</i>		
LHV to fuel combustor	267	235
HHV to fuel combustor	290	254
Fuel combustor % biogenic C	100%	100%

Table 7 summarizes the key sustainability metrics for the 2018 SOT and 2022 projection conversion processes evaluated here. The supply chain sustainability assessment (SCSA) of the syngas conversion pathway was conducted using ANL’s 2018 version of the GREET model [10]. The SCSA incorporated the 2018 SOT feedstock (100% logging residues) and the 2022 feedstock design (100% logging residues) that INL has modeled [4] for the syngas conversion pathway. For the conversion step, fossil energy consumption is about 0.035 and 0.029 MJ/MJ for the 2018 SOT and 2022 projection cases, respectively, and GHG emission intensities are about 2.9 and 2.4 g CO_{2e}/MJ for the 2018 SOT and 2022 projection cases, respectively. Almost 100% energy self-sufficient conversion processes contribute to the low fossil energy consumption and low GHG emission intensities of the syngas conversion technology. The overall GHG reduction relative to the petroleum-derived fuels are greater than 60% for both 2018 SOT and 2022 projection cases [11].

Table 7. Summary of Sustainability Metric Indicators for 2018 SOT and 2022 Projection Cases

Sustainability Metrics	Units	2018 SOT	2022 Projection
Greenhouse gas emissions ^a	g CO _{2e} /MJ	2.9	2.4
Fossil energy consumption ^a	MJ/MJ	0.035	0.029
Fuel yield by weight of biomass	GGE per dry U.S. ton biomass	49.6	54.7
Carbon efficiency to fuels	% C in feedstock	25.5	28.0
Electricity import	kWh/GGE	-- ^b	-- ^b
Natural gas import	MJ/GGE	-- ^c	-- ^c
Water consumption	gal/GGE	3.3	2.8
Water consumption	m ³ /day	1380	1286

^aCalculated by ANL using GREET v. 2018 [10] for the conversion step only (i.e., at the biorefinery or "gate-to-gate"), excluding upstream and downstream processes in the supply chain. The full SCSA results are reported separately [11]. ^bNegligible. ^cNo natural gas import.

The respective fuel yield for the 2018 SOT and the 2022 projection are 49.6 and 54.7 GGE/dry U.S. ton. The carbon efficiency for the 2018 SOT and 2022 projection are roughly 26% and 28%, respectively. Because the current design option is to make the process energy self-sufficient, the heat and power requirements of the process can be met through the combustion of char, available fuel gas and process off-gases, as well as make-up fuel from the raw syngas. Thus, electricity imported from the grid and supplemental natural gas for heating are not required. On an energy basis, the conversion process water consumption for the 2018 SOT and the 2022 projection are 3.3 gal/GGE (1,380 m³/day) and 2.8 gal/GGE (1,286 m³/day), respectively. Biorefinery net water consumption includes, but is not limited to, water that is incorporated into products and other output streams, and cooling tower evaporative losses.

8 Conclusions and Future Work

Annual SOT updates are conducted to track R&D progress for the syngas -HOG conversion pathway. TEA helps quantify research progress toward 2022 goals. This report documents the 2018 SOT assessment and the revised 2022 projections. The 2018 SOT experiments and the associated TEA model document the progress made with the improved performance of the Cu-modified beta-zeolite catalyst for the conversion of DME to high-octane gasoline blendstock. The 2018 SOT assessment for this pathway also includes one scenario for the coproduction of jet- and diesel-range blendstocks through dehydrogenation of mixed butane and olefins coupling. This scenario enables the biorefinery to diversify the product slate at an extra production cost. This sensitivity case is based on prior year experimental results; ongoing R&D is focused toward improving HOG yields, and not the sensitivity case yields of distillates. Future research efforts will continue to focus on improving the catalyst performance, reflected by hydrocarbon productivity, which in turn is a function of DME conversion, C5+ hydrocarbon selectivity, and space velocity.

This report also summarizes results of pinch analysis, energy balance, economic analysis, and environmental sustainability analysis for the 2018 SOT and revised 2022 projection. For the 2018 SOT, the modeled gasoline equivalent price by lower heating value is \$3.79 per gallon based on bench-scale experimental results and TEA assumptions described in this report. The MFSP for the 2022 projection is \$3.30/GGE using the underlying assumptions and catalyst performance goals outlined in this report. Further improvements and cost reductions for the 2022 projection of \$3.30/GGE are possible, as shown in the sensitivity analysis. Significant impacts identified in the sensitivity cases include economies of larger scales, lower feedstock costs, and higher product yields.

Experimental research efforts to achieve the 2022 MFSP projection are on-going. As seen in Table ES-1, a significant increase in the overall C5+ C-selectivity and a corresponding decrease in aromatics C-selectivity are required. To achieve this shift in C-selectivity away from aromatics and toward the desired C5+ products, catalyst development research is underway to control hydrogenation activity to reduce aromatic formation, with a complementary effort to control the chemistry to convert the resulting intermediates to C5+ products. These research improvements directly address the fuel synthesis cost, representing \$0.16 reduction in capital and operating costs in that area; combined with yield increases, this will allow a total \$0.49/GGE reduction in the MFSP. Research through 2022 and beyond will focus on process intensification and increasing the overall carbon efficiency as the primary avenues to address further cost reduction. Toward that goal, process analysis research is underway to identify the most impactful opportunities to recycle lost carbon back into the process. For example, carbon dioxide from syngas cleanup could potentially be recycled back to the methanol synthesis reactor to recover this otherwise lost carbon. Similarly, carbon lost to char could be recovered. Based on the findings of this analysis, complementary experimental research will be performed to explore the viability of these opportunities to increase carbon efficiency and reduce the overall cost.

The full life cycle and supply chain sustainability assessment (from feedstock production to vehicle operation) showed that the overall life cycle GHG emissions reduction for both the 2018 SOT and 2022 projection exceeds the 60% reduction criteria relative to the 2005 petroleum gasoline baseline. The analysis team(s) will continue to support BETO's pathway development goals through (1) state of technology assessments to quantify progress toward 2022, (2) alternate scenario models and

research variations for the achievement of 2022 goals, (3) integration of sustainability metrics into analyses, (4) sharing goals and results publicly through NREL technical reports, (5) the BETO MYPP, (6) journal publications, and (7) continued improvement of modeling information and techniques.

9 References

1. Tan, E.C.D., M. Talmadge, A. Dutta, J. Hensley, J. Schaidle, M. Bidy, and D. Humbird et al. 2105. *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons via Indirect Liquefaction: Thermochemical Research Pathway to High-Octane Gasoline Blendstock Through Methanol/Dimethyl Ether Intermediates*. NREL/TP-5100-62402; PNNL-23822. Golden, CO: National Renewable Energy Laboratory.
2. Dutta, A., M. Talmadge, J. Hensley, M. Worley, D. Dudgeon, D. Barton, and P. Groendijk et al. 2011. *Process Design and Economics for Conversion of Lignocellulosic Biomass to Ethanol: Thermochemical Pathway by Indirect Gasification and Mixed Alcohol Synthesis*. NREL/TP-5100-51400. Golden, CO: National Renewable Energy Laboratory.
3. Dutta, A., J. Hensley, R. Bain, K. Magrini, E.C.D. Tan, G. Apanel, and D. Barton et al. 2014. “Technoeconomic Analysis for the Production of Mixed Alcohols via Indirect Gasification of Biomass Based on Demonstration Experiments.” *Ind Eng Chem Res* 53, no. 30: 12149–12159. <http://dx.doi.org/10.1021/ie402045q>.
4. Hartley, D.S., D.N. Thompson, H. Hu, and H. Cai. 2018. *Woody Feedstock 2018 State of Technology Report*. INL/EXT-18-51655. Idaho Falls, ID: Idaho National Laboratory.
5. U.S. Department of Energy. 2016. *Bioenergy Technologies Office Multi-Year Program Plan*. Washington, DC: U.S. Department of Energy.
6. Schaidle, J.A., D.A. Ruddy, S. Habas, M. Pan, G. Zhang, J.T. Miller, and J.E. Hensley. 2015. “Conversion of Dimethyl Ether to 2,2,3-Trimethylbutane over a Cu/BEA Catalyst: Role of Cu Sites in Hydrogen Incorporation.” *ACS Catal* 5: 1794-1803. <http://dx.doi.org/10.1021/cs501876w>.
7. Argonne National Laboratory. 2016. *Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) Model*. Lemont, IL: Argonne National Laboratory.
8. Sattler, J.J.H.B., J. Ruiz-Martinez, E. Santillan-Jimenez, and B.M. Weckhuysen. 2014. “Catalytic Dehydrogenation of Light Alkanes on Metals and Metal Oxides.” *Chem Rev* 114, no. 20: 10613–53. <http://dx.doi.org/10.1021/cr5002436>.
9. Behl, M., J.A. Schaidle, E. Christensen, and J.E. Hensley. 2015. “Synthetic Middle-Distillate-Range Hydrocarbons via Catalytic Dimerization of Branched C₆–C₈ Olefins Derived from Renewable Dimethyl Ether.” *Energy Fuels* 29, no. 9: 6078–87. <http://dx.doi.org/10.1021/acs.energyfuels.5b01175>.
10. Wang, M., A. Elgowainy, P.T. Benavides, A. Burnham, H. Cai, Q. Dai, and T.R. Hawkins et al. 2018. *Summary of Expansions and Updates in GREET 2018*. ANL-18/38. Lemont, IL: Argonne National Laboratory.

11. Cai, H., T. Benavides, U. Lee, M. Wang, E.C.D. Tan, R. Davis, and A. Dutta et al. 2018. *Supply Chain Sustainability Analysis of Renewable Hydrocarbon Fuels via Indirect Liquefaction, Ex Situ Catalytic Fast Pyrolysis, Hydrothermal Liquefaction, and Biochemical Conversion: Update of the 2018 State-of-Technology Cases and Design Cases*. ANL/ESD-18/13. Lemont, IL: Argonne National Laboratory.

Appendix A: Supplemental Information for SOT and Projection Cases

Table A-1. Detailed Cost Breakdown of SOT/Projection for Syngas Conversion High-Octane Gasoline Pathway

Conversion of Lignocellulosic Biomass to High Octane Gasoline via Indirect Gasification and Methanol/DME Intermediates (2016\$)							
2018 State of Technology and Out-Year Target Assessment for DOE-BETO Multi-Year Program Plan Update (October 2018)							
Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT †	2015 SOT †	2016 SOT †	2017 SOT †	2018 SOT †	2022 Projection
Process Concept: Gasification, Syngas Cleanup, Methanol / DME Synthesis & Conversion to HCs		Woody Feedstock					
C ₅ + Minimum Fuel Selling Price (per Actual Product Volume) ▲	\$ / Gallon	\$4.31	\$4.17	\$3.85	\$3.74	\$3.66	\$3.22
Mixed C ₄ Minimum Fuel Selling Price (per Actual Product Volume) ▲	\$ / Gallon	\$3.98	\$3.91	N/A	N/A	N/A	N/A
Minimum Fuel Selling Price (per Gallon of Gasoline Equivalent) ▲	\$ / Gal GE	\$4.33	\$4.24	\$3.99	\$3.93	\$3.79	\$3.30
Conversion Contribution (per Gallon of Gasoline Equivalent) ▲	\$ / Gal GE	\$3.13	\$3.03	\$2.76	\$2.64	\$2.56	\$2.18
Year for USD (\$) Basis		2016	2016	2016	2016	2016	2016
Total Capital Investment per Annual Gallon	\$	\$15.80	\$15.94	\$11.01	\$11.54	\$11.07	\$9.79
Plant Capacity (Dry Feedstock Basis)	Tonnes / Day	2,000	2,000	2,000	2,000	2,000	2,000
High-Octane Gasoline Blendstock (C ₅ +) Yield	Gallons / Dry Ton	36.2	36.4	51.4	50.0	51.4	56.0
Mixed C ₄ Co-Product Yield	Gallons / Dry Ton	16.3	16.2	0.0	0.0	0.0	0.0
Feedstock							
Total Cost Contribution	\$ / Gallon GE	\$1.20	\$1.21	\$1.24	\$1.29	\$1.24	\$1.12
Capital Cost Contribution	\$ / Gallon GE	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Operating Cost Contribution	\$ / Gallon GE	\$1.20	\$1.21	\$1.24	\$1.29	\$1.23	\$1.12
Feedstock Cost	\$ / Dry US Ton	\$60.58	\$60.58	\$60.58	\$60.58	\$60.58	\$60.58
Feedstock Moisture at Plant Gate	Wt % H ₂ O	30%	30%	30%	30%	30%	30%
In-Plant Handling and Drying / Preheating	\$ / Dry US Ton	\$0.72	\$0.70	\$0.70	\$0.69	\$0.69	\$0.69
Cost Contribution	\$ / Gallon	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01
Feed Moisture Content to Gasifier	wt % H ₂ O	10%	10%	10%	10%	10%	10%
Energy Content (LHV, Dry Basis)	BTU / lb	7,856	7,856	7,856	7,856	7,856	7,856
Gasification							
Total Cost Contribution	\$ / Gallon GE	\$0.69	\$0.67	\$0.65	\$0.62	\$0.61	\$0.54
Capital Cost Contribution	\$ / Gallon GE	\$0.43	\$0.41	\$0.38	\$0.35	\$0.34	\$0.30
Operating Cost Contribution	\$ / Gallon GE	\$0.26	\$0.26	\$0.27	\$0.28	\$0.26	\$0.24
Raw Dry Syngas Yield	lb / lb Dry Feed	0.76	0.76	0.76	0.76	0.76	0.76
Raw Syngas Methane (Dry Basis)	Mole %	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%
Gasifier Efficiency (LHV)	% LHV	71.9%	71.9%	71.9%	71.9%	71.9%	71.9%
Synthesis Gas Clean-up (Reforming and Quench)							
Total Cost Contribution	\$ / Gallon GE	\$0.96	\$0.93	\$0.94	\$0.94	\$0.89	\$0.78
Capital Cost Contribution	\$ / Gallon GE	\$0.51	\$0.49	\$0.46	\$0.43	\$0.41	\$0.36
Operating Cost Contribution	\$ / Gallon GE	\$0.45	\$0.45	\$0.48	\$0.51	\$0.48	\$0.42
Tar Reformer (TR) Exit CH ₄ (Dry Basis)	Mole %	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
TR CH ₄ Conversion	%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
TR Benzene Conversion	%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
TR Tars Conversion	%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%
Catalyst Replacement	% of Inventory / Day	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%

(continued next page)

(continued from previous page)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT †	2015 SOT †	2016 SOT †	2017 SOT †	2018 SOT †	2022 Projection
Acid Gas Removal, Methanol Synthesis and Methanol Conditioning							
Total Cost Contribution	\$ / Gallon GE	\$0.52	\$0.50	\$0.47	\$0.47	\$0.45	\$0.40
Capital Cost Contribution	\$ / Gallon GE	\$0.35	\$0.33	\$0.30	\$0.28	\$0.28	\$0.24
Operating Cost Contribution	\$ / Gallon GE	\$0.17	\$0.17	\$0.17	\$0.19	\$0.18	\$0.16
Methanol Synthesis Reactor Pressure	psia	730	730	730	730	730	730
Methanol Productivity	kg / kg-cat / hr	0.7	0.8	0.8	0.8	0.8	0.7
Methanol Intermediate Yield	Gallons / Dry Ton	143	142	138	144	141	134
Hydrocarbon Synthesis							
Total Cost Contribution	\$ / Gallon GE	\$0.91	\$0.91	\$0.70	\$0.68	\$0.64	\$0.48
Capital Cost Contribution	\$ / Gallon GE	\$0.56	\$0.56	\$0.46	\$0.44	\$0.42	\$0.32
Operating Cost Contribution	\$ / Gallon GE	\$0.35	\$0.35	\$0.24	\$0.23	\$0.22	\$0.16
Methanol to DME Reactor Pressure	psia	145	145	145	145	145	145
Hydrocarbon Synthesis Reactor Pressure	psia	129	129	129	129	129	129
Hydrocarbon Synthesis Catalyst		Commercial Beta-Zeolite		NREL modified Beta-Zeolite with copper (Cu) as active metals for activity and performance improvement			
Hydrogen Addition to Hydrocarbon Synthesis		No H ₂ Addition	Supplemental H ₂ added to hydrocarbon synthesis reactor inlet to improve selectivity to branched paraffins relative to aromatics				
Utilization of C ₄ Reactor Products		Co-Product	Co-Product	Recycle	Recycle	Recycle	Recycle
Single-Pass DME Conversion	%	15.0%	15.0%	19.2%	27.6%	38.9%	40.0%
Overall DME Conversion	%	83%	85%	83%	88%	92%	90%
Hydrocarbon Synthesis Catalyst Productivity	kg / kg-cat / hr	0.02	0.03	0.04	0.09	0.07	0.10
Carbon Selectivity to C ₅ + Product	% C in Reactor Feed	46.2%	48.3%	81.8%	74.8%	72.3%	86.7%
Carbon Selectivity to Total Aromatics (Including Hexamethylbenzene)	% C in Reactor Feed	25.0%	20.0%	4.0%	4.0%	8.0%	0.5%
Carbon Selectivity to Coke and Pre-Cursors (Hexamethylbenzene Proxy)	% C in Reactor Feed	10.0%	9.3%	4.0%	4.0%	4.0%	0.5%
Hydrocarbon Product Separation							
Total Cost Contribution	\$ / Gallon GE	\$0.04	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05
Capital Cost Contribution	\$ / Gallon GE	\$0.03	\$0.03	\$0.04	\$0.04	\$0.04	\$0.03
Operating Cost Contribution	\$ / Gallon GE	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01
Balance of Plant							
Total Cost Contribution	\$ / Gallon GE	\$0.01	(\$0.02)	(\$0.05)	(\$0.11)	(\$0.09)	(\$0.07)
Capital Cost Contribution	\$ / Gallon GE	\$0.42	\$0.40	\$0.36	\$0.34	\$0.33	\$0.28
Operating Cost Contribution	\$ / Gallon GE	(\$0.41)	(\$0.42)	(\$0.42)	(\$0.45)	(\$0.42)	(\$0.36)
Sustainability and Process Efficiency Metrics							
Carbon Efficiency to C ₅ + Product	% C in Feedstock	19.3%	19.4%	25.2%	24.3%	25.5%	27.9%
Carbon Efficiency to Mixed C ₄ Co-Product	% C in Feedstock	7.0%	6.9%	0.0%	0.0%	0.0%	0.0%
Overall Carbon Efficiency to Hydrocarbon Products	% C in Feedstock	26.3%	26.3%	25.2%	24.3%	25.5%	27.9%
Overall Energy Efficiency to Hydrocarbon Products	% LHV of Feedstock	37.7%	37.7%	36.6%	35.1%	36.6%	40.4%
Electricity Production	kWh / Gallon C ₅ +	11.7	11.8	7.9	8.4	8.1	7.0
Electricity Consumption	kWh / Gallon C ₅ +	11.7	11.8	7.9	8.5	8.1	7.0
Water Consumption	Gal H ₂ O / Gal C ₅ +	12.9	10.1	3.1	3.3	3.2	2.8
TEA Reference File		2014 SOT Rev4a 2016\$ (high ash)_1.xlsm	2015 SOT Rev6 Comm-HBEA 2016\$ FR Rev2_1.xlsm	2016 SOT Base Rev6 Rev2 2016\$ FR_1.xlsm	2017 SOT Base Rev1 2016\$ FR_1.xlsm	2018SOT_2018-07-20data Rev3_2.xlsm	2022 Design FR Rev6a_2.xlsm

▲ Conceptual design result. † SOT: State of Technology.

Conversion Cost Breakdown (\$ / Gallon of Gasoline Equivalent)	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2022 Projection
Gasification	\$ 0.69	\$ 0.67	\$ 0.65	\$ 0.62	\$ 0.61	\$ 0.54
Synthesis Gas Clean-up (Reforming and Quench)	\$ 0.96	\$ 0.93	\$ 0.94	\$ 0.94	\$ 0.89	\$ 0.78
Acid Gas Removal, Methanol Synthesis and Methanol Conditioning	\$ 0.52	\$ 0.50	\$ 0.47	\$ 0.47	\$ 0.45	\$ 0.40
Hydrocarbon Synthesis	\$ 0.91	\$ 0.91	\$ 0.70	\$ 0.68	\$ 0.64	\$ 0.48
Hydrocarbon Product Separation	\$ 0.04	\$ 0.05	\$ 0.05	\$ 0.05	\$ 0.05	\$ 0.05
Balance of Plant	\$ 0.01	\$ (0.02)	\$ (0.05)	\$ (0.11)	\$ (0.09)	\$ (0.07)
Minimum Fuel Selling Price (MFSP)	\$ 3.13	\$ 3.03	\$ 2.76	\$ 2.64	\$ 2.56	\$ 2.18

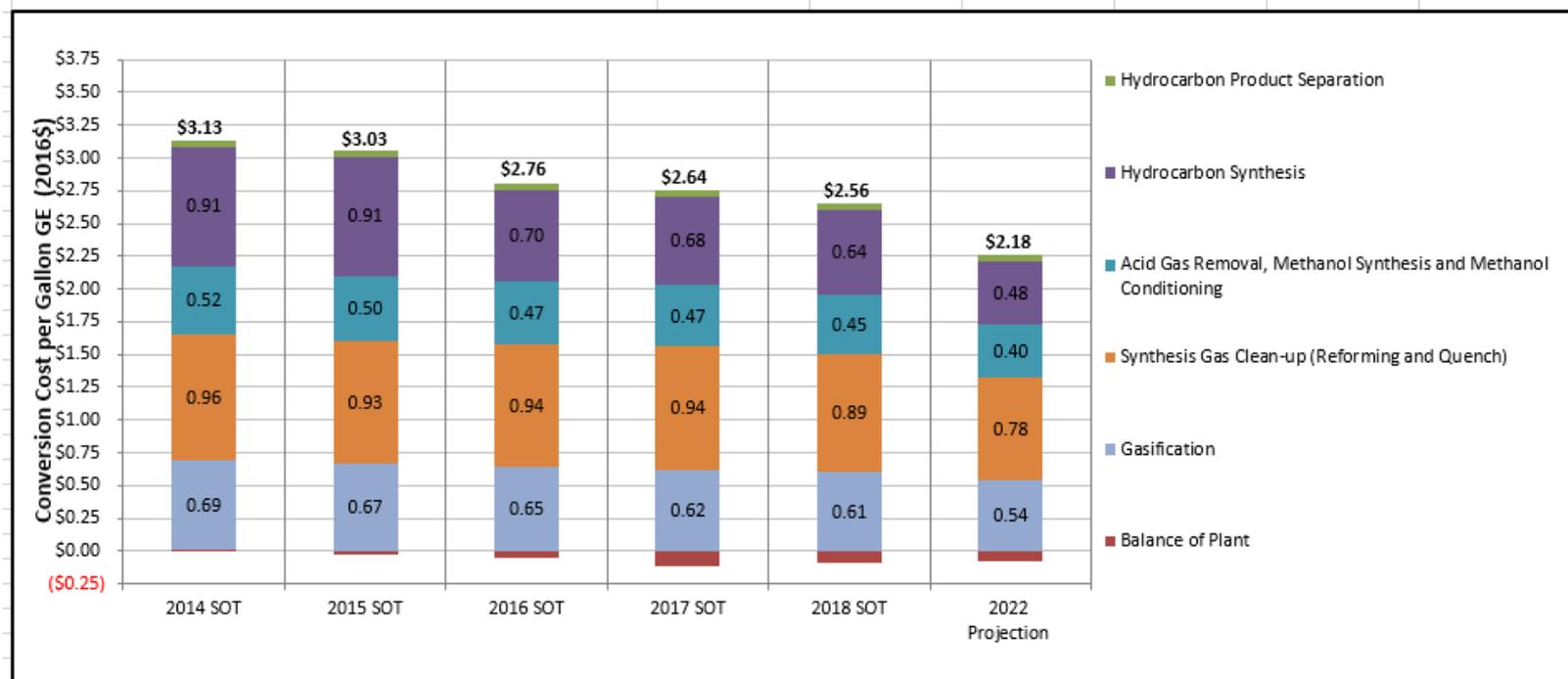


Figure A-1. SOT/waterfall for syngas conversion high-octane gasoline pathway (excluding feedstock costs) in 2016\$

Minimum Fuel Selling Price (MFSP) Breakdown (\$ / Gallon of Gasoline Equivalent)	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2022 Projection
Feedstock	\$ 1.20	\$ 1.21	\$ 1.24	\$ 1.29	\$ 1.24	\$ 1.12
Gasification	\$ 0.69	\$ 0.67	\$ 0.65	\$ 0.62	\$ 0.61	\$ 0.54
Synthesis Gas Clean-up (Reforming and Quench)	\$ 0.96	\$ 0.93	\$ 0.94	\$ 0.94	\$ 0.89	\$ 0.78
Acid Gas Removal, Methanol Synthesis and Methanol Conditioning	\$ 0.52	\$ 0.50	\$ 0.47	\$ 0.47	\$ 0.45	\$ 0.40
Hydrocarbon Synthesis	\$ 0.91	\$ 0.91	\$ 0.70	\$ 0.68	\$ 0.64	\$ 0.48
Hydrocarbon Product Separation	\$ 0.04	\$ 0.05	\$ 0.05	\$ 0.05	\$ 0.05	\$ 0.05
Balance of Plant	\$ 0.01	\$ (0.02)	\$ (0.05)	\$ (0.11)	\$ (0.09)	\$ (0.07)
Minimum Fuel Selling Price (MFSP)	\$ 4.33	\$ 4.24	\$ 3.99	\$ 3.93	\$ 3.79	\$ 3.30

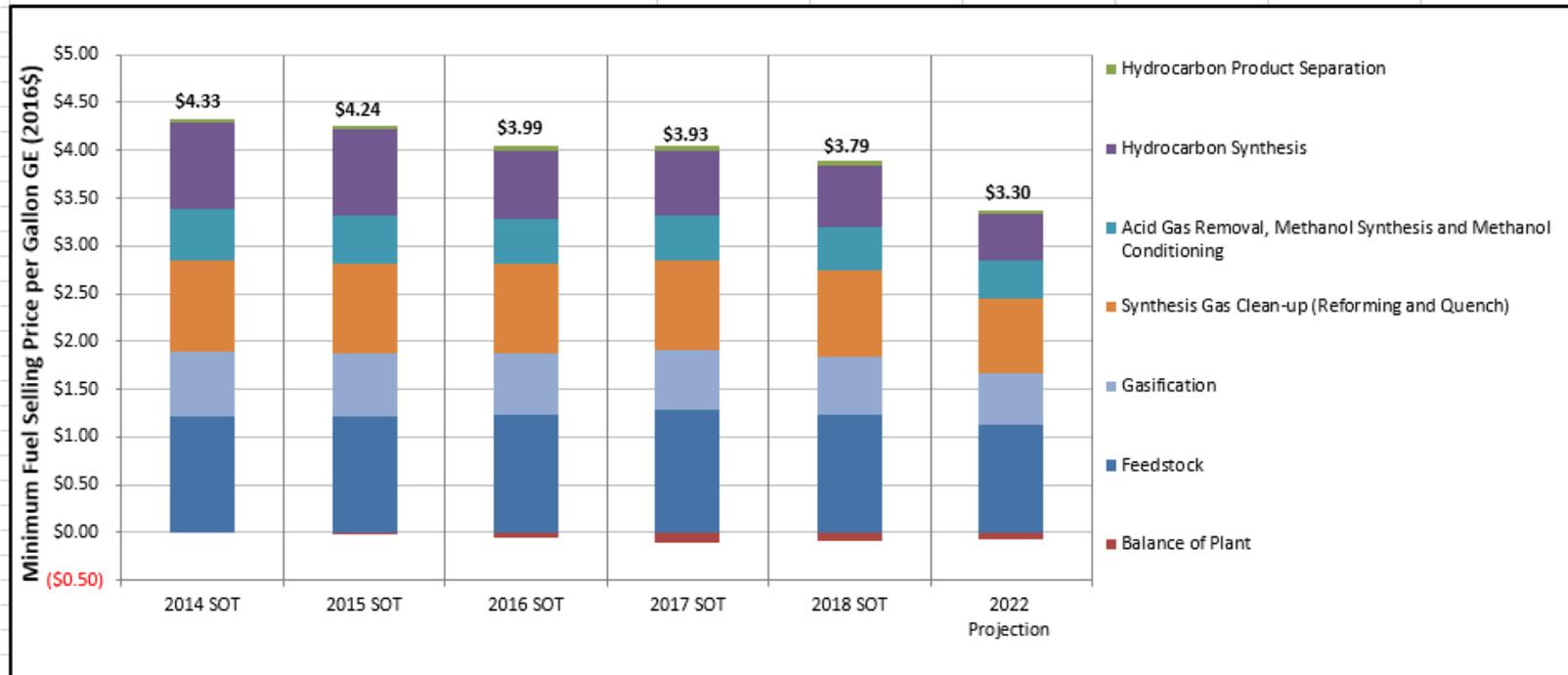


Figure A-2. SOT/waterfall for syngas conversion high-octane gasoline pathway in 2016\$