High-Octane Gasoline from Lignocellulosic Biomass via Syngas and Methanol/Dimethyl Ether Intermediates: 2019 State of Technology

Eric C.D. Tan,[1] Dan Ruddy,[1] Connor Nash,[1] Dan Dupuis,[1] Kylee Harris,[1] Abhijit Dutta,[1] Damon Hartley,[2] and Hao Cai[3]

1 National Renewable Energy Laboratory
2 Idaho National Laboratory
3 Argonne National Laboratory

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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
LPG	liquid petroleum gas
MFSP	minimum fuel selling price
MM	million
NREL	National Renewable Energy Laboratory
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 conversion of lignocellulosic biomass to infrastructure-compatible, cost-competitive liquid hydrocarbon fuels. The conversion pathway presented in this report includes the gasification of biomass, steam reforming, and cleanup of the syngas, followed by the conversion of the syngas to high-octane gasoline (HOG) via methanol and dimethyl-ether (DME) intermediates. The HOG product has superior anti-knock properties, highlighted by a Research Octane Number (RON) range of 105–110. Current research at the National Renewable Energy Laboratory (NREL) focuses on the DME-to-HOG conversion step. Results from bench-scale experiments for DME to HOG were used to assess the 2019 State of Technology (SOT) and improvement in the modeled minimum fuel selling price (MFSP). Methods used for techno-economic analysis (TEA) were detailed in a design report.[i] The TEA presented here maintains previous[ii] cost basis and assumptions for all the conversion operations; steps other than DME to HOG conversion are relatively mature (commercial or near commercial) and are not areas of current research. Feedstock supply, logistics, and costs were modeled by the Idaho National Laboratory (INL) and presented in a separate report.[iii] Sustainability metrics for feedstock logistics from INL and conversion steps from NREL were integrated into a supply chain sustainability assessment (SCSA) by the Argonne National Laboratory (ANL); details will be included in a separate SCSA report published by ANL.[iv]

The report focuses on 2019 SOT updates; a 2018 SOT report[ii] presented research and TEA updates since the detailed 2015 design report,[i] along with sensitivity analysis showing the effect of key assumptions and parameters. Relevant developments in 2019 are presented here without repeating the bulk of the material included in the previous reports. A portion of the developments and potential commercial application of this technology were discussed in a *Nature Catalysis* article.[v] A comprehensive summary table for metrics since 2014–2019 and projected improvements for 2020–2022 is included in the Appendix.

Key achievements in 2019 for the DME-to-HOG conversion step include increased DME conversion, while maintaining selectivity toward desirable C5+ hydrocarbon products, reduced aromatics formation, and an increased conversion of cofed C4 to C5+ (in experiments conducted to simulate the recycle of C4 products). Because the experimental C4 cofeed utilization was less than the C4 produced, a C4 coproduct stream (sold at the price of liquid petroleum gas or LPG) was included in the 2019 SOT to account for excess C4 (after an extrapolation to estimate conversion of some of the excess C4 recycle in the model); future experiments will target a higher C4 cofeed conversion to match the C4 production, thus testing whether the C4 intermediate can be recycled to extinction within the process (and removing the LPG coproduct assumption in future SOT assessments). Table ES-1 summarizes performance metrics for the 2018 and 2019 SOTs, and the 2022 projection. The summary of the TEA results for the 2019

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[i] NREL/TP-5100-62402, PNNL-23822. Available at https://www.nrel.gov/docs/fy15osti/62402.pdf.
[ii] NRELTP-5100-71957. Available at https://www.nrel.gov/docs/fy19osti/71957.pdf.
[iii] INL/EXT-20-57181. Accessed April 12, 2020 at https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_21882.pdf.
[iv] ANL/ESD-20/2. SCSA SOT Update 2019. Cai et al. To be published April 2019.
[v] Ruddy et al., *Nature Catalysis* 2, 632–640, 2019.

SOT and the 2022 projection is presented in Table ES-2 and Table ES-3, respectively. The modeled MFSP for the 2019 SOT is $3.53 per gallon of gasoline equivalent (GGE) in 2016 dollars, compared to the 2018 SOT of $3.79/GGE and a 2022 projection of $3.30/GGE. The 2019 SOT of $3.53/GGE was better than the projected 2019 goal of $3.62/GGE.[vi] Based on previous sensitivity analysis[ii] the most significant research impact on the MFSP is from the product yield. An HOG yield range of ±7% is expected to adequately cover uncertainties in the current experimental setup, and accordingly, we report a corresponding MFSP range of $3.42/GGE to $3.74/GGE around the base model MFSP of $3.53/GGE.

Experimental research efforts to achieve the 2022 MFSP projection are ongoing. As shown in Table ES-1, a significant increase in the overall C5+ C-selectivity, with a corresponding decrease in aromatics C-selectivity and the conversion of a majority of the C4 intermediate to C5+ liquid fuels, is 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 address the reduction in the modeled MFSP goal by 2022 primarily through an increased yield of the saleable HOG product. In addition to yield improvements, research through 2022 and beyond will also focus on process intensification and increasing the overall carbon efficiency as the primary avenues to address further cost reduction.

Table ES-1. Performance Metrics for the 2018 and 2019 SOTs and 2022 Projection

Performance Metrics	2018 SOT	2019 SOT	2022 Projection
DME Conversion (%)	38.9[a]	44.7[a]	40[a]
C5+ C-Selectivity (%)	72.3[b]	73.6[b]	86.7[b]
Aromatics C-Selectivity (%)	8.0	5.8	0.5
HOG Hydrocarbon Productivity (kg/kg-cat/h)	0.07	0.07	0.1
HOG Product Yield (GGE/dry U.S. ton)	49.6	49	54.7
LPG Coproduct (GGE/dry U.S. ton)	-	5.6	-
MFSP ($/GGE; 2016$)	3.79	3.53	3.30
Fuel Synthesis Cost (¢/GGE; 2016$)	64	49	48

[a] Single-pass conversion. [b] Overall selectivity.

[vi] Dutta, A. 2019 BETO Peer Review Presentation for WBS 2.1.0.302. Accessed April 12, 2020. https://www.energy.gov/sites/prod/files/2019/03/f61/Thermochemical%20Platform%20Analysis%20%E2%80%93NREL_NL0008191.pdf.

Table ES-2. Economic Summary for 2019 SOT

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)	**$3.53 per GGE**
Feedstock & In-Plant Handling Costs	1.306 **per GGE**
Operating Costs & Credits	0.575 **per GGE**
Capital Charges & Taxes	1.652 **per GGE**
Fuel Production at Operating Capacity	35.46 MM GGE per Year
Fuel Product Yield	48.96 GGE per Dry US Ton Feedstock
LPG Production at Operating Capacity	4.0 MM GGE per Year
LPG Product Yield	5.6 GGE per Dry US Ton Feedstock
Delivered Feedstock Cost	$63.23 per Dry US Ton

Capital Costs	
Feed Handling & Drying	$200,000
Gasification	$44,600,000
Gas Cleanup	$53,600,000
Methanol Synthesis	$34,000,000
Methanol Conditioning	$2,300,000
DME & Hydrocarbons Conversion	$46,000,000
Gasoline Separations	$4,600,000
Steam System & Power Generation	$33,000,000
Cooling Water & Other Utilities	$6,900,000
Total Installed Equipment Cost (TIC)	$225,200,000
ISBL (Areas A100 to A500, A1400, A1500)	$185,300,000
OSBL (Areas A600, A700)	$39,900,000
Other Direct Costs	7,400,000
(% of ISBL)	4.0%
Total Direct Costs (TDC)	232,641,059
Indirect Costs	139,600,000
(% of TDC)	60.0%
Land Purchase Cost	1,600,000
Working Capital	18,600,000
Total Capital Investment (TCI)	392,400,000
Installed Equipment Cost per Annual Gallon	$6.35
Total Capital Investment per Annual Gallon	$11.07
Debt Financing (% of Investment)	60.0%
Loan Interest Rate	8.0%
Loan Term (years)	10.0
Equity Financing (% of Investment)	40.0%
Internal Rate of Return (After-Tax)	10.0%
Plant Operating Hours per year	7,884
On-Stream Percentage	90.0%

Process Efficiency	
Gasifier Efficiency - HHV %	72.6
Gasifier Efficiency - LHV %	72.3
Efficiency to Gasoline - HHV %	36.1
Efficiency to Gasoline - LHV %	35.8
Overall Plant Efficiency - HHV %	39.6
Overall Plant Efficiency - LHV %	39.6

Annual Operating Costs	
Feedstock	$45,800,000
Natural Gas	$0
Catalysts	$9,900,000
Olivine	$600,000
Other Raw Matl. Costs	$1,500,000
Waste Disposal	$1,000,000
Electricity Transfer Charge	$0
Electricity	$0
Fixed Costs	$19,400,000
Coproduct credits	-$4,140,000
Capital Depreciation	$12,400,000
Average Income Tax	$3,800,000
Average Return on Investment	$42,400,000

Operating Costs per Product	(¢/MMBtu)	(¢/GGE)
Feedstock	1112.5	129.1
Natural Gas	0.0	0.0
Catalysts	61.2	7.1
Olivine	13.7	1.6
Other Raw Materials	36.3	4.2
Waste Disposal	24.8	2.9
Electricity Transfer	0.0	0.0
Electricity	0.0	0.0
Fixed Costs	470.5	54.6
Coproduct credits	-100.5	-11.7
Capital Depreciation	301.2	35.0
Average Income Tax	93.1	10.8
Average Return on Investment	1030.1	119.6
Total (Plant Gate Price)	3043.0	353.3

Power Balance	(KW)	(hp)
Total Plant Power Consumption (KW)	36,024	48,309
Power Generated Onsite (KW)	36,045	48,337
Power Imported from Grid (KW)	0	0
Power Exported to Grid (KW)	21	27

Power Generation	(KW)	(hp)
Steam Turbine Generators	34,321	46,025
Process Gas Turboexpander(s)	1,724	2,312

Sustainability Metrics	
Plant Electricity Consumption (KWh/ GGE)	8.0
Gasification & Reforming Steam (lb / GGE)	29.9
Water Consumption (Gal Water / GGE)	3.1
Carbon Conversion Efficiency (C in Fuel/C in Feedstock)	27.07%
Fossil GHG Emissions (g CO_{2-e}/MJ Fuel)	2.13
Fossil Enegy Consumption (MJ Fossil Energy/MJ Fuel)	0.034

Feedstock Rate and Cost		
Feed Rate	Dry Tonnes / Day	2,000
	Dry US Tons / Day	2,205
Feedstock Cost	$ / Dry Ton	$63.23
	$ / Moisture & Ash Free Ton	$64.36

Excel File: 2019 SOT Oct Update Rev02 - (C4-DME-1_LPG) Rev0_b.xlsm

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**
Contributions: Feedstock Costs	1.108	**per GGE**
Operating Costs & Credits	0.655	**per GGE**
Capital Charges & Taxes	1.538	**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	$60.54	per Dry US Ton

Capital Costs	
Feed Handling & Drying	$200,000
Gasification	$44,600,000
Gas Cleanup	$52,800,000
Methanol Synthesis	$33,700,000
Methanol Conditioning	$2,300,000
DME & Hydrocarbons Conversion	$47,300,000
Gasoline Separations	$5,000,000
Steam System & Power Generation	$34,700,000
Cooling Water & Other Utilities	$7,200,000
Total Installed Equipment Cost (TIC)	$227,800,000
ISBL (Areas A100 to A500, A1400, A1500)	$185,900,000
OSBL (Areas A600, A700)	$41,900,000
Other Direct Costs	7,400,000
(% of ISBL)	4.0%
Total Direct Costs (TDC)	235,265,659
Indirect Costs	141,200,000
(% of TDC)	60.0%
Land Purchase Cost	1,600,000
Working Capital	18,800,000
Total Capital Investment (TCI)	396,900,000
Installed Equipment Cost per Annual Gallon	$5.62
Total Capital Investment per Annual Gallon	$9.79
Debt Financing (% of Investment)	60.0%
Loan Interest Rate	8.0%
Loan Term (years)	10.0
Equity Financing (% of Investment)	40.0%
Internal Rate of Return (After-Tax)	10.0%
Plant Operating Hours per year	7,884
On-Stream Percentage	90.0%

Process Efficiency	
Gasifier Efficiency - HHV %	72.3
Gasifier Efficiency - LHV %	71.9
Efficiency to Gasoline - HHV %	40.7
Efficiency to Gasoline - LHV %	40.4
Overall Plant Efficiency - HHV %	40.7
Overall Plant Efficiency - LHV %	40.4

Annual Operating Costs	
Feedstock	$43,800,000
Natural Gas	$0
Catalysts	$11,700,000
Olivine	$600,000
Other Raw Matl. Costs	$1,500,000
Waste Disposal	$1,600,000
Electricity Transfer Charge	$0
Electricity	$0
Fixed Costs	$19,500,000
Coproduct credits	$0
Capital Depreciation	$12,500,000
Average Income Tax	$3,900,000
Average Return on Investment	$44,500,000

Operating Costs per Product	(¢/MMBtu)	(¢/GGE)
Feedstock	954.0	110.8
Natural Gas	0.0	0.0
Catalysts	59.6	6.9
Olivine	12.1	1.4
Other Raw Materials	33.1	3.8
Waste Disposal	34.7	4.0
Electricity Transfer	0.0	0.0
Electricity	0.0	0.0
Fixed Costs	424.8	49.3
Coproduct credits	0.0	0.0
Capital Depreciation	272.0	31.6
Average Income Tax	84.4	9.8
Average Return on Investment	968.6	112.4
Total (Plant Gate Price)	2843.3	330.1

Power Balance	(KW)	(hp)
Total Plant Power Consumption (KW)	36,084	48,389
Power Generated Onsite (KW)	36,049	48,342
Power Imported from Grid (KW)	35	47
Power Exported to Grid (KW)	0	0

Power Generation	(KW)	(hp)
Steam Turbine Generators	34,419	46,157
Process Gas Turboexpander(s)	1,630	2,186

Sustainability Metrics	
Plant Electricity Consumption (KWh/ GGE)	7.2
Gasification & Reforming Steam (lb / GGE)	20.5
Water Consumption (Gal Water / GGE)	2.8
Carbon Conversion Efficiency (C in Fuel/C in Feedstock)	27.95%
Fossil GHG Emissions (g $CO_{2\text{-}e}$/MJ Fuel)	2.06
Fossil Enegy Consumption (MJ Fossil Energy/MJ Fuel)	0.032

Feedstock Rate and Cost		
Feed Rate	Dry Tonnes / Day	2,000
	Dry US Tons / Day	2,205
Feedstock Cost	$ / Dry Ton	$60.54
	$ / Moisture & Ash Free Ton	$62.41

Excel File: 2022 Design FR Rev5a_2 KH (Feedstock Cost).xlsm

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1 Introduction

This report covers the 2019 State of Technology (SOT) assessment for the conversion of woody biomass to high-octane gasoline via gasification and syngas conversion (also called indirect liquefaction or IDL). Research improvements in 2019 are presented, with further improvements proposed for achieving the performance improvements and cost reduction goals by 2022.

The underlying conceptual design was detailed in a 2015 design report [1] and a revised 2022 projection was presented in a 2018 SOT report [2]. This report focuses on updates since the 2018 SOT publication. The process design assumptions for the techno-economic analysis (TEA) are generally consistent with the 2018 report; there was a change in the modeled feedstock assumption in 2019 with a lower ash (1.75% in 2019 versus 3% in 2018) blended feedstock in the process model; the feedstock blend information provided by the Idaho National Laboratory (INL) [3] is discussed further in a following section.

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 [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 [4,5]. Information from 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 (HOG) 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.

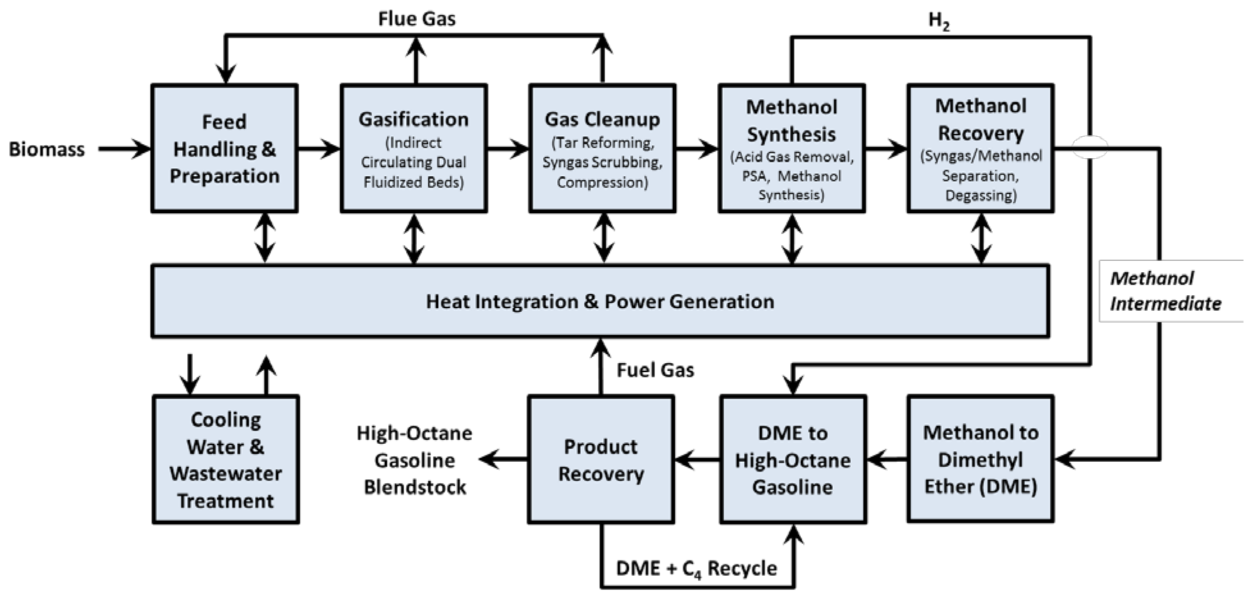

Figure 1. Process flow diagram for the production of high-octane gasoline blendstock via syngas conversion pathway and methanol/dimethyl ether intermediates

3 Feedstock Specifications and Costs

The modeled feedstock composition and delivered cost were updated for the 2019 SOT case and shown in Table 1; this information was based on INL models [3]. The updated dry basis elemental composition of the feedstock is different from that in the 2018 SOT and 2022 target cases, which used woody material with 3 wt.% ash [2]. The current modeled feedstock contains 1.75 wt.% ash (i.e., mineral matter contained in the biomass feedstock). The feedstock moisture specification is still assumed to be 30 wt.% 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. The delivered feedstock cost was estimated by INL at $63.23/dry U.S. ton (2016$). The feedstock cost includes 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.

Table 1. Woody Feedstock Specifications Used in the 2019 SOT Process Model

Component	Weight % (Dry Basis)
Carbon	50.45
Hydrogen	5.99
Nitrogen	0.17
Chlorine	0.00
Sulfur	0.09
Oxygen	41.55
Ash	1.75
Heating Value[a] (Btu/lb)	8,533 HHV 7,933 LHV

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

4 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. A minimum fuel selling price (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]. A summary of the assumptions applied in this report is listed in Table 2.

Table 2. Summary of n^{th}-Plant Assumptions for Techno-Economic Analysis

Description of Assumption	Assumed Value
Cost year	2016 U.S. 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)

[a]Capital depreciation is computed according to the U.S. 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 2019 SOT

5.1 Experiment and Results

The current research efforts focus on the DME-to-HOG 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 reactivation, to help achieve the 2022 cost goal. The catalyst performance metrics are shown in Table 4; the results are derived from the bench-scale experiments described below. A portion of the developments and potential commercial application of this technology were discussed in a 2019 *Nature Catalysis* publication [7].

5.1.1 Key Catalyst Performance Metrics and Model Assumptions

The key Cu/BEA catalyst performance metrics or parameters for assessing the overall performance of the DME to hydrocarbon conversion step are: (1) single-pass conversion of DME, (2) hydrocarbon productivity of the catalyst, (3) C4 alkane recycle utilization efficiency, (4) selectivity to desired products (C5+ hydrocarbons), and (5) carbon selectivity to aromatics. The NREL catalytic conversion research team generated experimental data for the 2019 SOT performance evaluation. The 2019 experimental results and process model inputs for the SOT base case for the key technical performance metrics are highlighted in Tables 3 and 4, and compared against the 2022 projection values. At 220°C the demonstrated DME single-pass conversion obtained from NREL's Cu-modified beta zeolite catalyst was 33.0% without C4 cofeed and 40.9% with C4 cofeed, which are comparable to the 2022 projection (40% at 225°C). Single-pass DME conversion was demonstrated to increase at higher operating temperature, but lower operating temperatures were shown to increase C_{5+} selectivity [2]. Thus, there is a trade-off between single-pass DME conversion and C5+ selectivity. Earlier experimental data also revealed that an increased operating pressure of 20-40 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 employs higher pressure (95 psia) operation and includes additional compression costs, the experimental data was at a lower pressure due to operational limitations of delivering DME (i.e., max delivery pressure *ca.* 40 psig), 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. 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 Cu/BEA catalyst can reactivate C4 alkanes, thus increasing the overall C5+ product yield. Isobutane recycle and re-incorporation in the hydrocarbon product to produce larger molecules improves the economics of this process. The 2019 SOT Cu/BEA catalyst was tested with simulated isobutane (i.e., iC_4) recycle experiments to quantify its effectiveness in this regard. The Cu/BEA catalyst was tested with and without isobutane cofeed at 220 °C, 323 kPa absolute (35 psig), 1:1 mol_{DME}/mol_{H2} (each at *ca.* 27 mol%), and a DME weight-hourly space velocity of 0.57 h^{-1}. When isobutane (iC_4) was co-fed, the partial pressure of isobutane in the feed was *ca.* 90 kPa absolute, corresponding to *ca.* 1:1:1 of DME:H_2:iC_4, respectively. To aid in quantifying the effect of co-fed isobutane on catalytic performance, the catalyst was tested without co-fed isobutane (0 kPa iC_4). At this condition, helium was used as the balance gas to establish the equivalent DME and H_2 partial pressures (*ca.* 90 kPa absolute) as in the co-fed isobutane condition. The data from these experiments with co-fed isobutane are presented in Figure 2. The overall product distribution with C4 recycle is shown in Table 5. Co-fed isobutane conversion is difficult to directly measure due to concurrent isobutane production from DME; however, the overall production of isobutane was determined, and this was found to decrease when isobutane was co-fed at 90 kPa. A 47% C4 utilization was observed with a C4 cofeed of 90 kPa, which exceeds the 2022 projection of 40% [2]. Under these conditions, a notable decrease in C_4 selectivity was observed, with a corresponding increase in C_{5+} product selectivity. Similarly, the productivity of C_{5+} hydrocarbons was found to increase by 19% with co-fed C_4 alkanes, increasing from 0.062 μmol/g_{cat}/s without cofeed to 0.074 μmol/g_{cat}/s with co-fed C_4 at 90 kPa.

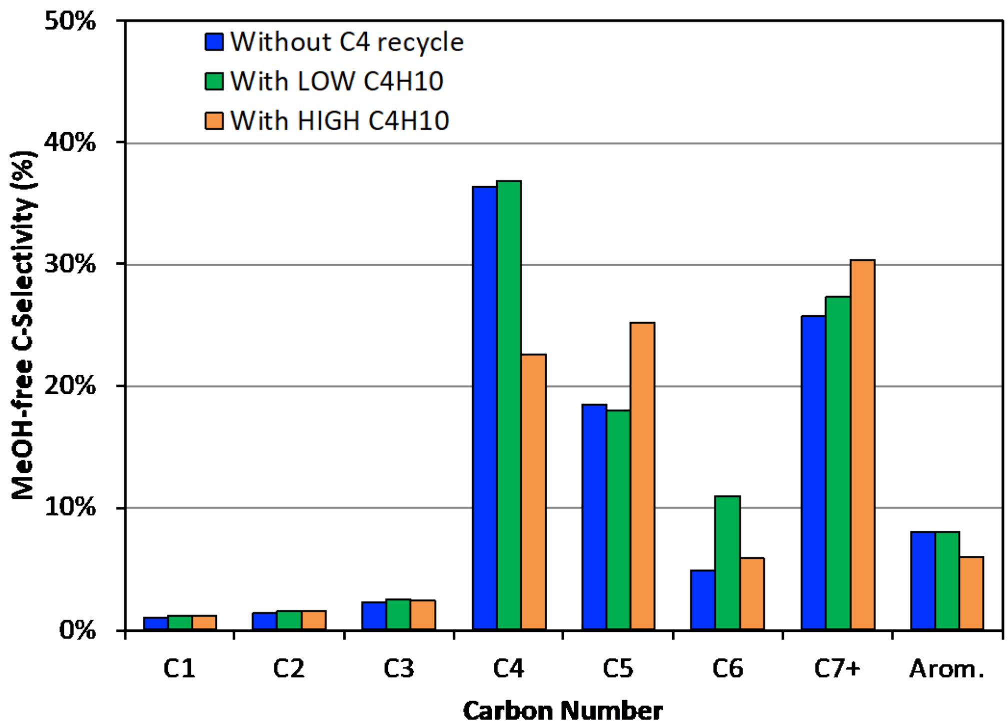

Figure 2. Carbon selectivity for the 2019 SOT case comparing the experiments without *i*C4H10, with low C4H10 cofeed (DME:*i*C4H10 of 55:1) and high C4H10 cofeed (DME:*i*C4H10 of 1:1)

In the process model, both the unconverted DME and C_4 are recycled back to the DME-to-hydrocarbons reactor, as depicted in Figure 1. The resulting reactor feed composition, for this case the iC_4/DME molar ratio, will vary from 0 to 1.9 depending on these recycle streams, which in turn are dictated by the catalyst performance, namely, the extent of the DME single-pass conversion and C_4 activation. Model inputs were obtained from the extrapolation from the experimental results, at iC_4/DME ratios of 0 and 1 (Table 3). The extrapolation was performed as a means of modeling the effect of catalyst performance as net iC4 co-feed conversion is approached at the ratio of 1.9. To avoid introducing excessive uncertainty into the process model at the iC_4/DME ratio furthest from the experimental conditions, an intermediate iC_4/DME ratio of 1.49 was used in the model. A 15.2% selectivity to C_4 hydrocarbons was modeled at this ratio, thus representing a significant decrease in the reactor C_4 effluent, but with sub-complete conversion of C_4 hydrocarbon products. As such, a C_4 product stream was included in the model to handle the unreacted C_4 in the reactor effluent as an LPG commodity. Experimental data at higher iC_4/DME (i.e., >1.5) will be collected in the future to extend the modeled ratio to complete C_4 conversion.

Sensitivity analysis to understand the impact of the recycle assumption showed: (a) an increase in MFSP to $3.74/gallon of gasoline equivalent (GGE) at a iC_4/DME ratio of 1.0, and (b) a decrease in the MFSP to $3.42/GGE at a iC_4/DME ratio of 1.9 (100% recycle). It is worth noting that the extrapolation of the iC_4/DME ratio to 1.49 represents one option to capture experimentally observed selectivity improvements in the process model. Another option would be to extrapolate pressure effects, where higher C5+ selectivity is typically observed at higher pressures. We did not include or extrapolate selectivity improvements at the higher modeled reactor pressure, nor did we reduce the added compression costs already included in the process model.

Table 3. Summary of Model Inputs Extrapolated from the Experimental Results

	Experimental Results		Model Inputs*
iC_4/DME Ratio	0.00	1.00	1.49
Single-Pass DME Conversion	33.0%	40.9%	44.7%
Carbon Selectivity			
C1	0.9%	1.1%	1.2%
C2	1.2%	1.4%	1.4%
C3	2.1%	2.3%	2.4%
C4	33.4%	21.1%	15.2%
C5	17.0%	23.6%	26.8%
C6	4.4%	5.6%	6.1%
C7	16.8%	20.0%	21.5%
C8	6.9%	8.4%	9.2%
C8+cyc	7.8%	8.4%	8.7%
C9	1.1%	1.3%	1.4%
Aromatics (HMB)	4.0%	3.25%	2.89%
Aromatics (Others)	4.0%	3.25%	2.89%
Catalyst Productivity (kg/kg-cat/h)	0.092	0.079	0.073

*Obtained from extrapolation of the experimental data

Table 4. Summary of 2019 Model Parameters Relative to 2022 Projections

Process Parameters	2019 SOT[a]	2022 Projection
Hydrocarbon Synthesis Reactor Temperature	220°C	225°C
Single-Pass DME Conversion	44.7%	40.0%
Productivity of Hydrocarbon Synthesis Catalyst (kg/kg-cat/h)	0.073 (total)	0.10 (total)
Carbon Selectivity to C5+ Product	56.4% (73.6% overall)	58% (86.7% overall)
Carbon Selectivity to Aromatics	5.8% Aromatics (2.9% HMB)	0.5% Aromatics (0.5% HMB)
H_2 Addition to Hydrocarbon Synthesis	Yes	Yes

[a]NREL's Cu/BEA zeolite catalyst (220°C, 35 psig, and averaged data with simulated C4 recycle from on-stream time of 47 - 52 h).

The overall C_{5+} selectivity determined from the process model for the 2019 SOT was found to be 73.6%, a modest increase over the 2018 SOT value of 72.3%, toward achieving the 86.7% for the 2022 projection [2]. The carbon selectivity to aromatics for the 2019 SOT is 5.9%; 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 5. 2019 SOT Experimental DME-to-Hydrocarbons on Cu/BEA Catalyst Product Selectivity

Carbon Number	Carbon Selectivity	Species	Species Selectivity per Carbon Number
C1	1.6%	Methane (CH4)	100.0%
C2	1.4%	Ethane (C2H6)	43.2%
		Ethene (C2H4)	56.8%
C3	2.4%	Propane (C3H8)	39.5%
		Propene (C3H6)	60.5%
C4	15.2%	Methylpropane/isobutane (C4H10)	89.8%
		N-Butane (C4H10)	3.6%
		2-Methylpropene (C4H8)	3.0%
		But-1-ene (C4H8)	3.6%
C5	26.8%	2-Methylbutane (C5H12)	97.6%
		2-Methylbutene (C5H10)	2.4%
C6	6.1%	3-Methylpentane (C6H14)	28.9%
		2,3-Dimethylbutane (C6H14)	63.1%
		2,3-Dimethylbutene (C6H12)	8.0%
C7	21.5%	2,2,3-Trimethylbutane (C7H16)	48.1%
		2,4-Timethylpentane (C7H16)	25.5%
		2-Methylhexane (C7H16)	21.5%
		2,2,3-Trimethylbutene (C7H14)	0.1%
		2-Methyl-1-Hexene (C7H14)	4.8%
C8	9.2%	2,2,4-Trimethylpentane (C8H18)	94.8%
		2,4,4-Trimethyl-1-pentene (C8H16)	5.2%
C8+cyc	8.7%	Dimethylcyclohexane (C8H16)	9.4%
		Trimethylcyclohexane (C9H18)	90.6%
C9+	1.4%	Trimethylpentane (C9H20)	100%
Aromatics (HMB)	2.9%	Hexamethylbenzene (C6(CH3)6)	100%
Aromatics (Others)	2.9%	Methylbenzene (C7H8)	100%
Total	**100%**		

5.2 Techno-Economic Analysis Results

Table 6 provides the summary of yields, rates, and conversion costs for both the 2019 SOT case and the 2022 projection [2]. The production rates for the HOG blendstock is 35.5 million GGE per year with a 4 million GGE/year of LPG coproduct, corresponding to 49 GGE HOG per dry U.S. ton of feedstock with 5.6 GGE LPG/dry U.S. ton coproduct. The resulting MFSP for the 2019 SOT for high-octane gasoline was determined to be $3.53/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 [8]; the LHV for the high-octane gasoline produced in the 2019 SOT model is 110,205 Btu/gal (LHV).

A summary of the costs contributing to the total high-octane gasoline selling price is presented in Figure 3. 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. An LPG coproduct credit of $0.11/GGE is included. The production cost associated with the DME-to-HOG synthesis is about $0.49/GGE, or about 14% of the MFSP. The biggest contributor is the feedstock, about $1.31/GGE or 37% of the MFSP.

Table 6. Summary of Process Performance and Economic Results

	2019 SOT	2022 Projection
Feedstock rate	2,205 dry U.S. ton/day	
Online time	7,884 h/yr (90% online factor)	
Total C5+ fuel yield	49 GGE/dry U.S. ton feedstock	54.7 GGE/dry U.S. ton feedstock
LPG Coproduct	5.6 GGE/dry U.S. ton feedstock	-
Total fuel production rate C5+ [LPG]	35.5 [4] MM GGE/yr	39.6 [0] MM GGE/yr
Total annual operation cost and credits	$74 MM	$79 MM
Total installed equipment cost	$225 MM	$228 MM
Total capital investment (TCI)	$392 MM	$397 MM
TCI per annual gallon	$11.07/GGE	$10.03/GGE
Minimum fuel selling price	**$3.53/GGE**	**$3.30/GGE**
Feedstock costs	$1.31/GGE	$1.11/GGE
Operating costs and credits	$0.58/GGE	$0.66/GGE
Capital charges and taxes	$1.65/GGE	$1.54/GGE

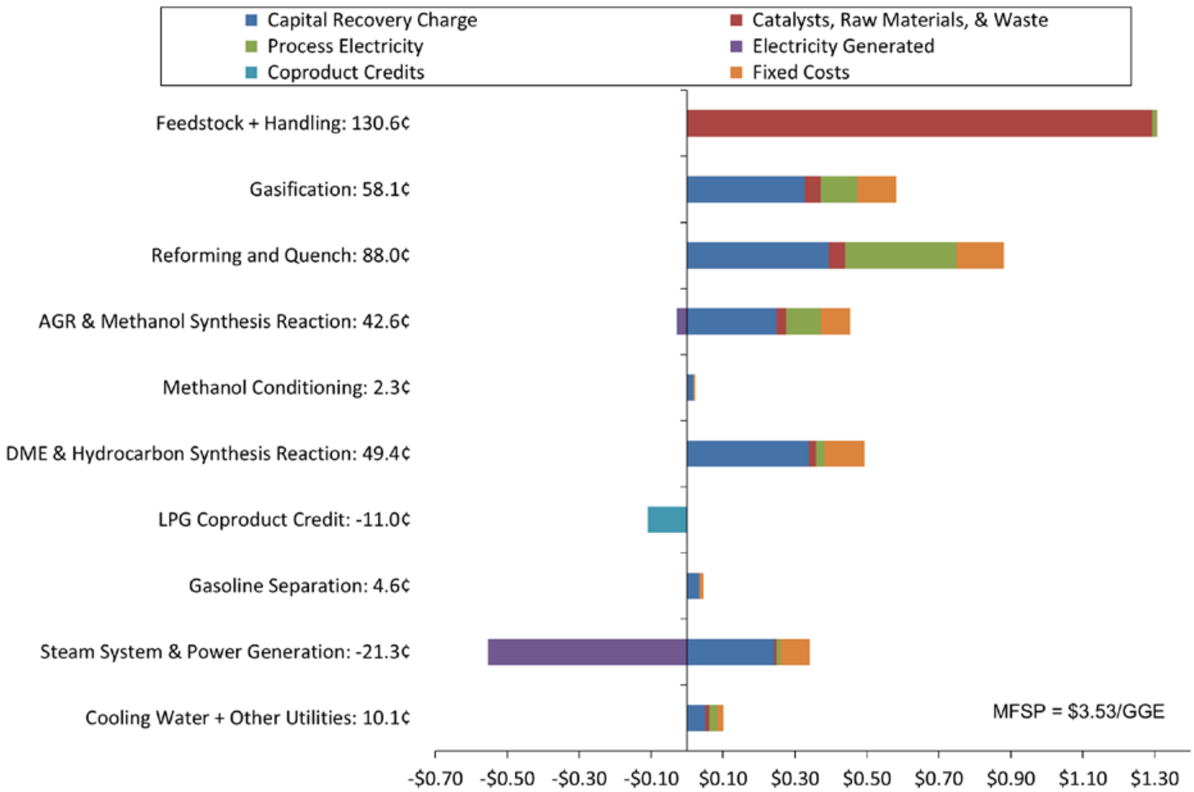

Figure 3. Cost breakdown for the 2019 SOT model

6 Sustainability Assessment

This section presents the conversion process-related sustainability metrics based on the 2019 SOT and 2022 projection models. Direct air emissions from the biorefinery (i.e., CO_2, NO_2, and SO_2), 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 7.

The input/output inventories in Table 7 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 7. Material and Energy Flows for the High-Octane Gasoline Conversion Process (Gate-to-Gate)

Cases		2019 SOT	2022 Projection
		Production Rate	**Production Rate**
Products			
HOG	lb/hr	27,727	30,768
	gal, hr	4,737	5,144
	MM Btu/hr	522	583
HOG properties:	LHV (Btu/gal)	110,205	113,309
	Density (g/gal)	2,655	2,713
	Biogenic C in HOG, %	100.00%	100.00%
	C Content in HOG, wt%	82.89%	83.11%
By-products			
Mixed Butanes (LPG),	lb/hr	2,572	-
	gal, hr	512	-
	MM Btu/hr	54	-
LPG properties:	LHV (Btu/gal)	105,977	-
	Density (g/gal)	2,280	-
	Biogenic C in HOG, %	100.00%	-
	C Content in HOG, wt%	82.17%	-
Sulfur,	lb/hr	114	114
Excess electricity,	kWh	(21)	(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)		13	23
Fresh olivine		537	527
Tar reformer catalyst		10	9
Natural gas for reformer		0	0
Methanol synthesis catalyst		6	5
DME catalyst		8	6
Beta zeolite catalyst		44	34
Zinc oxide catalyst		2.5	2.5
Cooling tower water makeup		3,160	31,213
Boiler feedwater makeup		112,383	86,887

Cases	2019 SOT	2022 Projection
Dimethyl disulfide (DMDS)	2.1	2.1
Amine (MDEA) makeup	3.8	3.7
LO-CAT chemicals	114	114
Boiler feedwater chemicals	2.8	2.7
Cooling tower chemicals	0.6	1.0
No. 2 diesel fuel	69	69
Waste Streams	lb/hr	lb/hr
Sand and ash purge	4,128	6,679
Tar reformer catalyst	8.8	8.7
Scrubber solids	10.6	8.8
Wastewater	19,040	14,845
Air Emissions	lb/hr	lb/hr
CO_2 (biogenic)	247,880	241,844
CO_2 (fossil)	0	0
CH_4	0	0
CO	0	0
NO_2	150	142
SO_2	54	51
H2O	81,304	73,422
H2S	0	0
Heating Values of Fuel to Combustors	MM Btu/hr	MM Btu/hr
Char combustor		
LHV to char combustor	532	528
HHV to char combustor	557	553
Char combustor % biogenic C	100%	100%
Fuel combustor		
LHV to fuel combustor	240	235
HHV to fuel combustor	265	254
Fuel combustor % biogenic C	100%	100%

Table 8 summarizes the key sustainability metrics for the 2019 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 [9]. The SCSA incorporated the 2019 SOT feedstock (50% clean pine and 50% logging residues) and the 2022 feedstock design (100% logging residues) that INL has modeled [3] for the syngas conversion pathway. For the conversion step, fossil energy consumption is about 0.034 and 0.029 MJ/MJ for the

2019 SOT and 2022 projection cases, respectively, and GHG emission intensities are about 2.6 and 2.4 g CO2e/MJ for the 2019 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 2019 SOT and 2022 projection cases [10].

Table 8. Summary of Sustainability Metric Indicators for 2019 SOT and 2022 Projection Cases

Sustainability Metrics	Units	2019 SOT	2022 Projection
Greenhouse gas emissions[a]	g CO_{2e}/MJ	2.6	2.4
Fossil energy consumption[a]	MJ/MJ	0.034	0.029
HOG fuel yield by weight of biomass	GGE per dry U.S. ton biomass	49	54.7
LPG fuel yield by weight of biomass	GGE per dry U.S. ton biomass	5.6	-
Carbon efficiency to HOG + LPG	% C in feedstock	24.8 + 2.3	28 + 0
Electricity import	kWh/GGE	--[b]	--[b]
Natural gas import	MJ/GGE	--[c]	--[c]
Water consumption	gal/GGE	2.9	2.8
Water consumption	m^3/day	1258	1286

[a]Calculated by ANL using GREET v. 2018 [9] 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 [10]. [b]Negligible. [c]No natural gas import.

The fuel yields in GGE/dry U.S. ton are 49 HOG + 5.6 LPG for the 2019 SOT and 54.7 HOG for the 2022 projection. The carbon efficiency for the 2019 SOT and 2022 projection are roughly 27.1% 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 2019 SOT and the 2022 projection are 2.9 gal/GGE (1,258 m^3/day) and 2.8 gal/GGE (1,286 m^3/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.

7 Conclusions and Future Work

Annual SOT updates are conducted to track R&D progress for the syngas-to-HOG conversion pathway. TEA helps quantify research progress toward 2022 goals. This report documents the 2019 SOT assessment and the revised 2022 projections. The 2019 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; significant single-pass conversion improvements were made for the DME-to-HOG step, while maintaining selectivity toward HOG products. Aromatics production was also reduced. C4 products were recycled to the DME reactor in the process model with estimated yields derived using data from simulated recycle experiments. A small LPG coproduct was included in the process model because experiments at this time did not include a larger recycle of C4 to support model assumptions (future experiments are planned with higher C4 recycle). These advances helped achieve a reduction in the 2019 SOT modeled MFSP to $3.53/GGE, versus a 2019 projected goal of $3.62/GGE.

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. 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 (including recycled C4) to C5+ products. Research through 2022 and beyond will also 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 2019 SOT and 2022 projection exceeds the 60% reduction criteria relative to the petroleum gasoline baseline.

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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

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 Projection	2021 Projection	2022 Projection (Design Case)
Process Concept: Gasification, Syngas Cleanup, Methanol / DME Synthesis & Conversion to HCs		Forest Residues	Forest Residues	Forest Residues	Forest Residues	Forest Residues	50/50 Blend Forest Residues+ Clean Pine	Forest Residues	Forest Residues	Forest Residues
Year for USD ($) Basis		2016	2016	2016	2016	2016	2016	2016	2016	2016
C_5+ Minimum Fuel Selling Price (per Actual Product Volume) ▲	$ / Gallon	$4.31	$4.17	$3.85	$3.67	$3.66	$3.35	$3.39	$3.30	$3.22
Mixed C_4 Minimum Fuel Selling Price (per Actual Product Volume) ▲	$ / Gallon	$3.98	$3.91	N/A	N/A	N/A	$1.02	N/A	N/A	N/A
Minimum Fuel Selling Price (per Gallon of Gasoline Equivalent) ▲	$ / Gal GE	$4.33	$4.24	$3.99	$3.86	$3.79	$3.53	$3.49	$3.40	$3.30
Conversion Contribution (per Gallon of Gasoline Equivalent) ▲	$ / Gal GE	$3.13	$3.03	$2.76	$2.64	$2.56	$2.23	$2.33	$2.25	$2.18
Total Capital Investment per Annual Gallon	$	$15.80	$15.94	$11.01	$11.54	$11.07	$11.07	$10.28	$10.03	$9.79
Plant Capacity (Dry Feedstock Basis)	Tonnes / Day	2,000	2,000	2,000	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	51.6	54.1	55.1	56.0
Mixed C_4 Co-Product Yield	Gallons / Dry Ton	16.3	16.2	0.0	0.0	0.0	5.6	0.0	0.0	0.0
Feedstock										
Total Cost Contribution	$ / Gallon GE	$1.20	$1.21	$1.24	$1.22	$1.23	$1.31	$1.17	$1.14	$1.12
Capital Cost Contribution	$ / Gallon GE	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Operating Cost Contribution	$ / Gallon GE	$1.20	$1.21	$1.24	$1.22	$1.23	$1.30	$1.16	$1.14	$1.12
Feedstock Cost to Preheater	$ / Dry US Ton	$60.58	$60.58	$60.58	$57.28	$60.54	$63.23	$60.54	$60.54	$60.54
Additional Charge for Preheating	$ / Dry US Ton	$0.72	$0.70	$0.70	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69
Total Feedstock Cost to Gasifier	$ / Dry US Ton	$61.30	$61.28	$61.28	$57.97	$61.23	$63.92	$61.23	$61.23	$61.23
Feedstock Moisture at Plant Gate	wt % H_2O	30%	30%	30%	30%	30%	30%	30%	30%	30%
Feed Moisture Content to Gasifier	wt % H_2O	10%	10%	10%	10%	10%	10%	10%	10%	10%
Feedstock Ash Content to Gasifier	wt % Ash	3.00%	3.00%	3.00%	3.00%	3.00%	1.75%	3.00%	3.00%	3.00%
Energy Content (LHV, Dry Basis) to Gasifier	BTU / lb	7,856	7,856	7,856	7,856	7,856	7,933	7,856	7,856	7,856
Gasification										
Total Cost Contribution	$ / Gallon GE	$0.69	$0.67	$0.65	$0.62	$0.61	$0.58	$0.57	$0.56	$0.54
Capital Cost Contribution	$ / Gallon GE	$0.43	$0.41	$0.38	$0.35	$0.34	$0.33	$0.32	$0.31	$0.30
Operating Cost Contribution	$ / Gallon GE	$0.26	$0.26	$0.27	$0.28	$0.26	$0.25	$0.25	$0.25	$0.24
Raw Dry Syngas Yield	lb / lb Dry Feed	0.76	0.76	0.76	0.76	0.76	0.77	0.76	0.76	0.76
Raw Syngas Methane (Dry Basis)	Mole %	15.4%	15.4%	15.4%	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%	72.3%	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	$0.88	$0.83	$0.80	$0.78
Capital Cost Contribution	$ / Gallon GE	$0.51	$0.49	$0.46	$0.43	$0.41	$0.39	$0.38	$0.37	$0.36
Operating Cost Contribution	$ / Gallon GE	$0.45	$0.45	$0.48	$0.51	$0.48	$0.49	$0.45	$0.44	$0.42
Tar Reformer (TR) Exit CH_4 (Dry Basis)	Mole %	1.7%	1.7%	1.7%	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%	80.0%	80.0%	80.0%
TR Benzene Conversion	%	99.0%	99.0%	99.0%	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%	99.9%	99.9%	99.9%
Catalyst Replacement	% of Inventory / Day	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%

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Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 Projection	2021 Projection	2022 Projection (Design Case)
Acid Gas Removal, Methanol Synthesis and Methanol Conditioning										
Total Cost Contribution	$ / Gallon GE	$0.52	$0.50	$0.47	$0.47	$0.45	$0.45	$0.42	$0.41	$0.40
Capital Cost Contribution	$ / Gallon GE	$0.35	$0.33	$0.30	$0.28	$0.28	$0.27	$0.26	$0.25	$0.24
Operating Cost Contribution	$ / Gallon GE	$0.17	$0.17	$0.17	$0.19	$0.18	$0.18	$0.17	$0.16	$0.16
Methanol Synthesis Reactor Pressure	psia	730	730	730	730	730	730	730	730	730
Methanol Productivity	kg / kg-cat / hr	0.7	0.7	0.8	0.8	0.8	0.7	0.8	0.7	0.7
Methanol Intermediate Yield	Gallons / Dry Ton	143	142	138	144	141	137	137	136	134
Hydrocarbon Synthesis										
Total Cost Contribution	$ / Gallon GE	$0.91	$0.91	$0.70	$0.67	$0.64	$0.49	$0.54	$0.51	$0.48
Capital Cost Contribution	$ / Gallon GE	$0.56	$0.56	$0.46	$0.44	$0.42	$0.34	$0.36	$0.34	$0.32
Operating Cost Contribution	$ / Gallon GE	$0.35	$0.35	$0.24	$0.23	$0.22	$0.16	$0.19	$0.17	$0.16
Methanol to DME Reactor Pressure	psia	145	145	145	145	145	145	145	145	145
Hydrocarbon Synthesis Reactor Pressure	psia	129	129	129	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 relativete to aromatics							
Utilization of C_4 in Reactor Outlet via Recycle		0%	0%	100%	100%	100%	90%	Recycle	Recycle	100%
Single-Pass DME Conversion	%	15.0%	15.0%	19.2%	27.6%	38.9%	44.7%	39.5%	39.7%	40.0%
Overall DME Conversion	%	83%	85%	83%	88%	92%	88%	89%	90%	90%
Hydrocarbon Synthesis Catalyst Productivity	kg / kg-cat / hr	0.02	0.03	0.04	0.09	0.07	0.07	0.09	0.09	0.10
Carbon Selectivity to C_5+ Product	% C in Reactor Feed	46.2%	48.3%	81.8%	74.8%	72.3%	73.6%	80.1%	83.4%	86.7%
Carbon Selectivity to Total Aromatics (Including Hexamethylbenzene)	% C in Reactor Feed	25.0%	20.0%	4.0%	4.0%	8.0%	5.8%	4.2%	2.4%	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%	2.9%	2.2%	1.4%	0.5%
Hydrocarbon Product Separation										
Total Cost Contribution	$ / Gallon GE	$0.04	$0.05	$0.05	$0.05	$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	$0.04	$0.03	$0.03
Operating Cost Contribution	$ / Gallon GE	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
LPG Coproduct Credit										
Total Cost Contribution	$ / Gallon GE	$0.00	$0.00	$0.00	$0.00	$0.00	($0.11)	$0.00	$0.00	$0.00
Capital Cost Contribution	$ / Gallon GE	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Operating Cost Contribution	$ / Gallon GE	$0.00	$0.00	$0.00	$0.00	$0.00	($0.11)	$0.00	$0.00	$0.00
Balance of Plant										
Total Cost Contribution	$ / Gallon GE	$0.01	($0.02)	($0.05)	($0.11)	($0.09)	($0.11)	($0.08)	($0.08)	($0.07)
Capital Cost Contribution	$ / Gallon GE	$0.42	$0.40	$0.36	$0.34	$0.33	$0.29	$0.30	$0.29	$0.28
Operating Cost Contribution	$ / Gallon GE	($0.41)	($0.42)	($0.42)	($0.45)	($0.42)	($0.41)	($0.38)	($0.37)	($0.36)
Sustainability and Process Efficiency Metrics										
Carbon Efficiency to C_5+ Product	% C in Feedstock	19.3%	19.4%	25.2%	24.3%	25.5%	24.8%	26.9%	27.4%	27.9%
Carbon Efficiency to Mixed C_4 Co-Product	% C in Feedstock	7.0%	6.9%	0.0%	0.0%	0.0%	2.3%	0.0%	0.0%	0.0%
Overall Carbon Efficiency to Hydrocarbon Products	% C in Feedstock	26.3%	26.3%	25.2%	24.3%	25.5%	27.1%	26.9%	27.4%	27.9%
Overall Energy Efficiency to Hydrocarbon Products	% LHV of Feedstock	37.7%	37.7%	36.6%	35.1%	36.6%	39.6%	38.8%	39.6%	40.4%
Electricity Production	kWh / Gallon C_5+	11.7	11.8	7.9	8.4	8.1	7.6	7.4	7.2	7.0
Electricity Consumption	kWh / Gallon C_5+	11.7	11.8	7.9	8.5	8.1	7.6	7.4	7.2	7.0
Water Consumption	Gal H_2O / Gal C_5+	12.9	10.1	3.1	3.3	3.2	2.9	2.9	2.8	2.8
TEA Reference File		2014 SOT Rev4a 2016$ (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 KH (Feedstock Cost).xlsm	2018SOT_2018-07-20data Rev3_2 KH (Feedstock Cost).xlsm	2019 SOT Oct Update Rev02 - (C4-DME-1_LPG) Rev0_b.xlsm	2020 Target Rev0 KH (Feedstock Cost).xlsm	2021 Target Rev0 KH (Feedstock Cost).xlsm	2022 Design FR Rev5a_2 KH (Feedstock Cost).xlsm

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

Minimum Fuel Selling Price (MFSP) Breakdown **($ / Gallon of Gasoline Equivalent)**	**2014 State of Technology**	**2015 State of Technology**	**2016 State of Technology**	**2017 State of Technology**	**2018 State of Technology**	**2019 State of Technology**	**2020 Projection**	**2021 Projection**	**2022 Projection (Design Case)**
Gasification	$ 0.69	$ 0.67	$ 0.65	$ 0.62	$ 0.61	$ 0.58	$ 0.57	$ 0.56	$ 0.54
Synthesis Gas Clean-up (Reforming and Quench)	$ 0.96	$ 0.93	$ 0.94	$ 0.94	$ 0.89	$ 0.88	$ 0.83	$ 0.80	$ 0.78
Acid Gas Removal, Methanol Synthesis and Methanol Conditioning	$ 0.52	$ 0.50	$ 0.47	$ 0.47	$ 0.45	$ 0.45	$ 0.42	$ 0.41	$ 0.40
Hydrocarbon Synthesis	$ 0.91	$ 0.91	$ 0.70	$ 0.67	$ 0.64	$ 0.49	$ 0.54	$ 0.51	$ 0.48
Hydrocarbon Product Separation	$ 0.04	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05
LPG Coproduct Credit	$ -	$ -	$ -	$ -	$ -	$ (0.11)	$ -	$ -	$ -
Balance of Plant	$ 0.01	$ (0.02)	$ (0.05)	$ (0.11)	$ (0.09)	$ (0.11)	$ (0.08)	$ (0.08)	$ (0.07)
Minimum Fuel Selling Price (MFSP)	**$ 3.13**	**$ 3.03**	**$ 2.76**	**$ 2.64**	**$ 2.56**	**$ 2.23**	**$ 2.33**	**$ 2.25**	**$ 2.18**

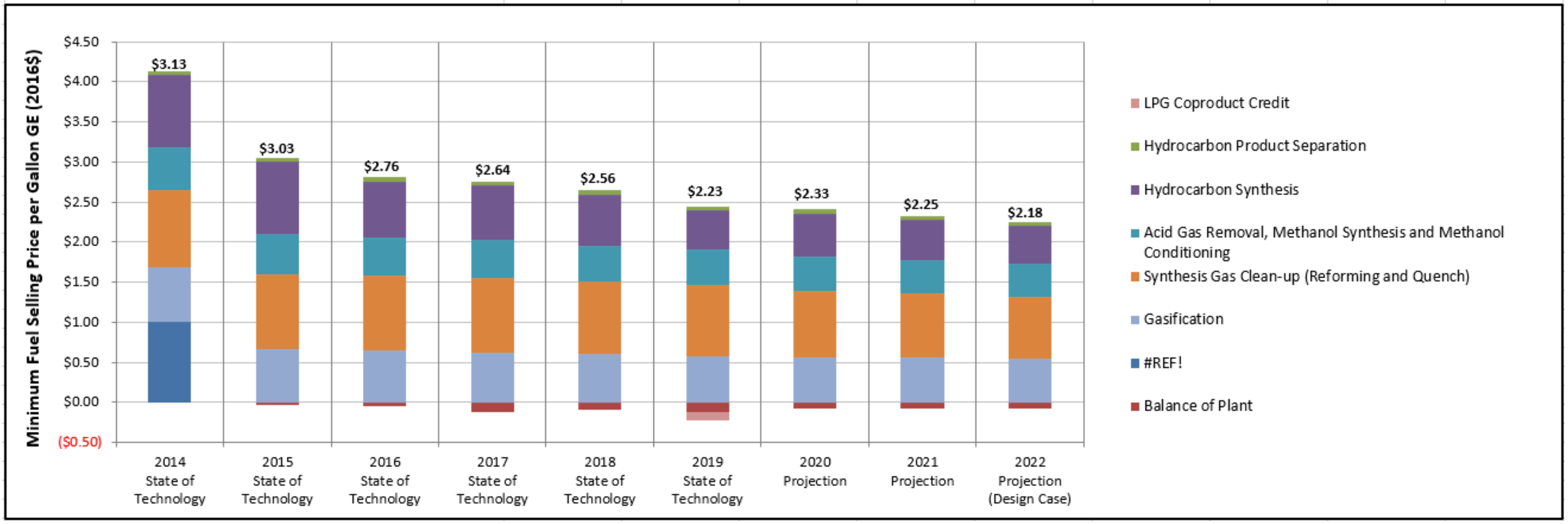

Figure A-1. SOT/waterfall for syngas conversion high-octane gasoline pathway (excluding feedstock costs) in 2016$

Minimum Fuel Selling Price (MFSP) Breakdown **($ / Gallon of Gasoline Equivalent)**	**2014 State of Technology**	**2015 State of Technology**	**2016 State of Technology**	**2017 State of Technology**	**2018 State of Technology**	**2019 State of Technology**	**2020 Projection**	**2021 Projection**	**2022 Projection (Design Case)**
Feedstock	$ 1.20	$ 1.21	$ 1.24	$ 1.22	$ 1.23	$ 1.31	$ 1.17	$ 1.14	$ 1.12
Gasification	$ 0.69	$ 0.67	$ 0.65	$ 0.62	$ 0.61	$ 0.58	$ 0.57	$ 0.56	$ 0.54
Synthesis Gas Clean-up (Reforming and Quench)	$ 0.96	$ 0.93	$ 0.94	$ 0.94	$ 0.89	$ 0.88	$ 0.83	$ 0.80	$ 0.78
Acid Gas Removal, Methanol Synthesis and Methanol Conditioning	$ 0.52	$ 0.50	$ 0.47	$ 0.47	$ 0.45	$ 0.45	$ 0.42	$ 0.41	$ 0.40
Hydrocarbon Synthesis	$ 0.91	$ 0.91	$ 0.70	$ 0.67	$ 0.64	$ 0.49	$ 0.54	$ 0.51	$ 0.48
Hydrocarbon Product Separation	$ 0.04	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05
LPG Coproduct Credit	$ -	$ -	$ -	$ -	$ -	$ (0.11)	$ -	$ -	$ -
Balance of Plant	$ 0.01	$ (0.02)	$ (0.05)	$ (0.11)	$ (0.09)	$ (0.11)	$ (0.08)	$ (0.08)	$ (0.07)
Minimum Fuel Selling Price (MFSP)	**$ 4.33**	**$ 4.24**	**$ 3.99**	**$ 3.86**	**$ 3.79**	**$ 3.53**	**$ 3.49**	**$ 3.40**	**$ 3.30**

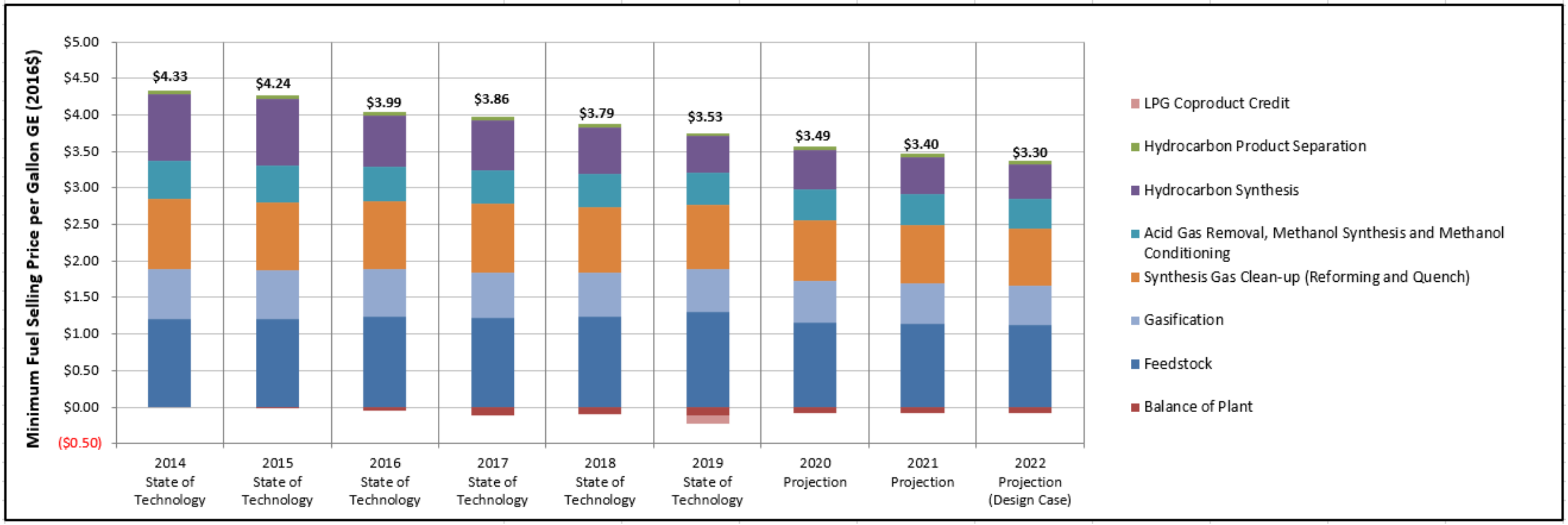

Figure A-2. SOT/waterfall for syngas conversion high-octane gasoline pathway in 2016$