

BIOENERGY TECHNOLOGIES OFFICE 2019 R&D State of Technology

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Acronyms and Abbreviations

ABY1	Algal Biofuel Yield Funding Opportunity	HDO	hydrodeoxygenation
AD	anaerobic digestion	HHV	higher heating value
AFDW	ash-free dry weight	HLSD	high-lipid <i>Scenedesmus</i>
AHTL	algal hydrothermal liquefaction	HOG	high-octane gasoline
APL	alkaline pretreated liquor	HPSD	high-protein <i>Scenedesmus</i>
ATP ³	Algae Testbed Public-Private Partnership	HTL	hydrothermal liquefaction
BCD	base-catalyzed depolymerization	HX	heat exchanger
BDO	butanediol	IDL	indirect liquefaction
BEA	beta-zeolite	IRR	internal rate of return
BETO	Bioenergy Technologies Office	IS	insoluble solids
Btu	British thermal unit	kWh	kilowatt hour
CA	carboxylic acids	LHV	lower heating value
CAP	combined algae processing	LPG	liquefied petroleum gas
CAPEX	capital expenditures	MBSF	minimum biomass selling price
CCPC	Consortium for Computational Physics and Chemistry	MEK	methyl ethyl ketone
CEH	continuous enzymatic hydrolysis	MFSP	minimum fuel selling price
CFP	catalytic fast pyrolysis	MJ	megajoule
ChemCatBio	Chemical Catalysis for Bioenergy Consortium	MM	million
CHG	catalytic hydrothermal gasification	NG	natural gas
CHN	carbon-hydrogen-nitrogen	NH ₃	ammonia
CHP	combined heat and power	NO _x	oxides of nitrogen
CO ₂	carbon dioxide	OPEX	operating expenses
CSTR	continuous stirred tank reactor	ppm	parts per million
DCFROR	discounted cash flow rate of return	PSA	pressure swing adsorption
DM	dry matter	psia	pounds per square inch absolute
DME	dimethyl ether	PU	polyurethane
DMR	deacetylation and mechanical refining	R&D	research and development
dt	dry ton	RD	renewable diesel
EVAP	evaporation	scf	standard cubic feet
EH	enzymatic hydrolysis	SCSA	supply chain sustainability analysis
FA	Florida algae	S/L	solid/liquid
FAME	fatty acid methyl ester	SOT	state of technology
FCIC	Feedstock-Conversion Interface Consortium	t	ton
FSL	Feedstock Supply and Logistics	TEA	techno-economic analysis
FY	fiscal year	TCI	total capital investment
GGE	gasoline gallon equivalent	TIC	total indirect cost
GHG	greenhouse gas	TR	tar reformer
H ₂ O	water	VGO	vacuum gas oil
HC	hydrocarbon	WHSV	weight hourly space velocity
HCSD	high-carbohydrate <i>Scenedesmus</i>	wt	weight
		WWT	wastewater treatment
		WWTP	wastewater treatment plant

Bioenergy Technologies Office State of Technology – 2019 Research and Development Status

The U.S. Department of Energy's Bioenergy Technologies Office (BETO) funds research and development (R&D) on technologies necessary for the deployment and production of cost-competitive bioenergy, primarily biofuels. Results of experimental efforts are periodically compiled and compared with benchmark technology designs to assess overall progress. This report provides a status of those R&D efforts at the end of 2019.

This report first describes the approach for assessing progress followed by specific technology pathway configurations within which progress is charted. Each pathway configuration is described separately and the state of technology progress is presented for the combined pathway as well as for pathway components. Detailed component descriptions reference technology barriers and challenges that are detailed in the appendix.

BETO develops and maintains example conceptual design cases with analysis for feedstock production, feedstocks logistics, and conversion to a specific fuel and, where economical, a coproduct or coproducts and biopower. Design cases provide engineering-based goal-year (2022 or 2030) projections and R&D technical targets based on techno-economic analysis (TEA) across the supply chain accompanied by a whole supply chain sustainability analysis (SCSA) of that configuration. Design cases provide the benchmark against which the current state of technology (SOT) is assessed to understand the technology breakthroughs needed to reach ultimate design-case-based technical targets. Interim projections between the latest SOT results and goal-year projections anchor interim R&D technical targets.

Each design case is based on specific design reports for feedstock supply and logistics and conversion components of the pathway. These design reports include sensitivity analyses that highlight factors having the greatest impact on cost of production and those most able to be addressed through R&D investments. SOT progress is monitored annually based on actual experimental results, translated to relevant metrics, and presented for each illustrative pathway. Periodically, BETO adjusts R&D priorities based on technology development progress, which may also result in refinements to design cases.

Techno-economic analyses calculate mature modeled minimum fuel selling price (MFSP) for a set of technical design parameters and R&D technical targets for key operations using standard financial assumptions¹ to calculate goal-year and interim price projections, as well as annual SOT progress. Mature means that capital and operating costs are assumed to be for an “nth-plant,” where several plants have been built and are operating successfully at design capacities, so additional costs for risk financing, longer startups, underperformance, over-engineering, and other costs associated with first-of-a-kind or early-implementation plants are not included.

Design cases for technology pathways are process specific and include specific feedstock requirements with corresponding costs for feedstock supply, logistics, and conversion. These process-specific designs are configured to reach a net present value of zero at a target rate of return (i.e., operating costs and return on capital investment are met). As such, the calculated mature modeled MFSP assumes a minimum acceptable rate of return on investment has been reached. MFSP is comparable to the wholesale rack price of current fuel products with downstream costs, subsidies, and tax incentives excluded. All dollar projections are presented in 2016 dollars and on a gasoline gallon equivalent (GGE) lower heating value basis (LHV).

In addition to TEAs that annually translate technical progress into cost impact, pathway SCSAs monitor progress against environmental and other metrics. SCSAs are used to monitor progress against BETO goals of developing pathways with increased net energy efficiency and improved environmental performance. Life cycle greenhouse gas (GHG) emissions of design and SOT cases are evaluated using the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model.² Pathway-specific SCSA results do not address all aspects of environmental sustainability, but are critical to understanding the key drivers of energy use, GHG and NO_x emissions, and water consumption, and how these attributes change in relation to process design changes and cost improvements.

The example pathway configurations shown in Figure 1 are currently used to assess progress toward achieving BETO goals³:

By 2022, verify integrated systems research for hydrocarbon biofuel technologies that achieve a mature modeled MFSP of \$3/GGE with a minimum 60% reduction in emissions relative to currently predominant fuels.

¹ These financial assumptions are standardized across BETO design cases.

² For more information, see <http://greet.es.anl.gov/>.

³ U.S. Department of Energy, *Bioenergy Technologies Office 2020 Multi-Year Plan* (forthcoming).

By 2030, verify integrated systems research for hydrocarbon biofuel technologies that achieve a mature modeled MFSP of \$2.5/GGE with a minimum 60% reduction in emissions relative to currently predominant fuels.

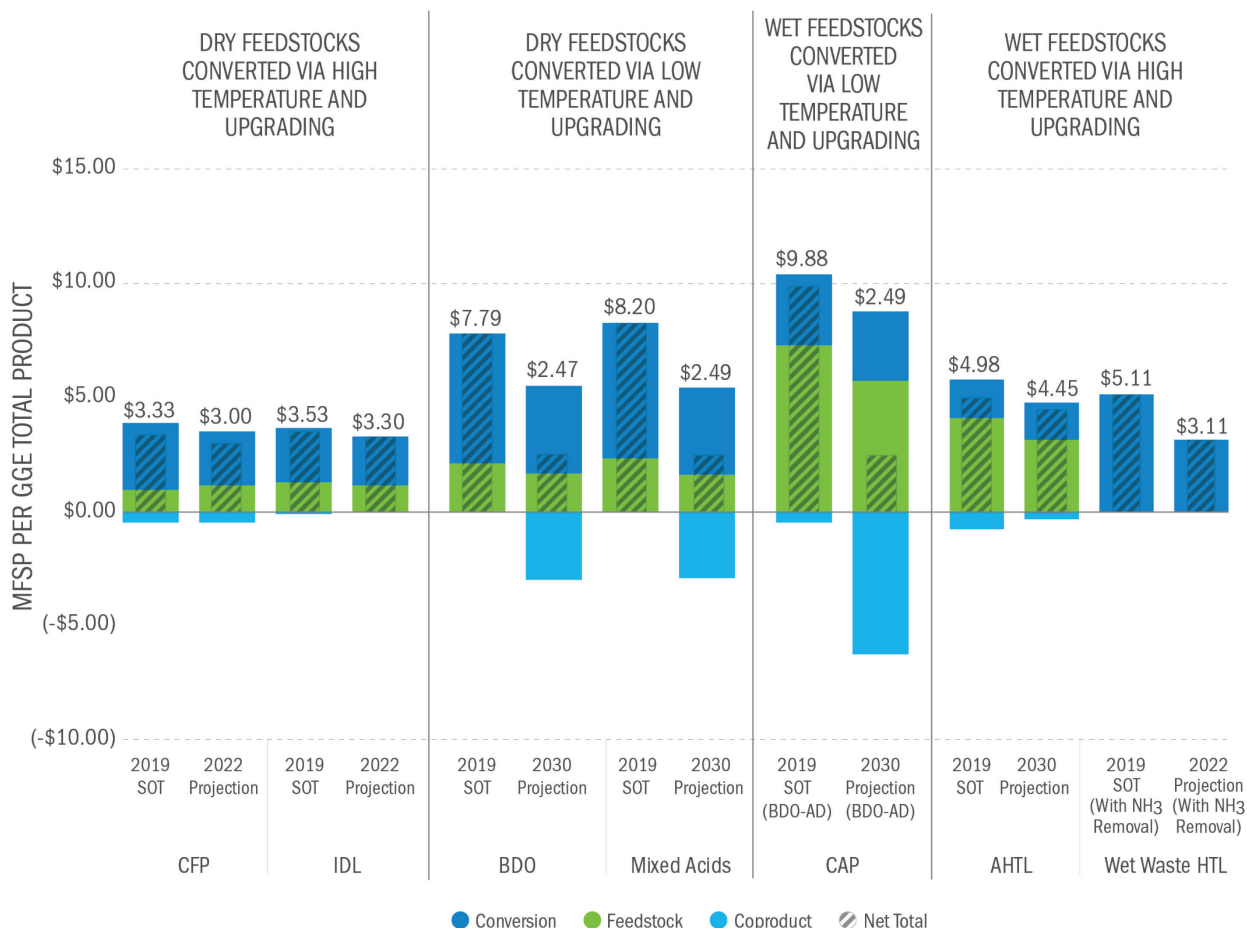


Figure 1: 2019 state of technology and goal-year projection for illustrative pathways used to assess technology progress

These illustrative technology pathways are periodically assessed for economic viability and, when appropriate, replaced with more robust pathway designs. Technology pathway designs may be selected as candidates for process integration and, possibly, for experimental verification at engineering and/or pilot scale after component technologies are deemed sufficiently developed. As noted in the Figure 1, these example technology pathways are organized by the primary category of feedstock used by R&D efforts—dry or wet—and by the type of conversion process employed, either high or low temperature. This state of technology report is organized in the same manner as the seven pathways in Figure 1, i.e., design cases using:

1. Dry feedstocks converted via high temperature and upgrading
 - a. Dry feedstocks converted via direct liquefaction and upgrading (catalytic fast pyrolysis [CFP])
 - b. Dry feedstocks converted via indirect liquefaction and upgrading (IDL)
2. Dry feedstocks converted via low temperature and upgrading
 - a. Dry feedstocks converted via 2,3-butanediol (BDO) intermediate
 - b. Dry feedstock converted via mixed-acids intermediate
3. Wet feedstocks converted via low temperature and upgrading
 - a. Combined algae processing (CAP) via 2,3-BDO or carboxylic acid intermediate
4. Wet feedstocks converted via high temperature and upgrading
 - a. Algal hydrothermal liquefaction (AHTL)
 - b. Wet waste hydrothermal liquefaction (HTL)

Dry feedstocks can economically meet a conversion specification of 50 wt % or less moisture content (e.g., herbaceous, woody, or municipal solid waste feedstocks). Wet feedstocks can be accepted into a conversion process at higher than 50 wt % moisture content (e.g., algal and wet waste/biosolids feedstocks).⁴ BETO is also developing TEAs and life cycle analyses for conversion of gaseous feedstocks, i.e., those that enter the conversion process as a gas stream (e.g., waste carbon dioxide [CO₂], waste flue gas, and biogas).

In addition to production of hydrocarbon fuels, most of these pathways are based on design cases which include coproducts with various market sizes and price ranges. Table 1 presents recent market information on potential coproducts.

Table 1: Potential Coproducts with Historical Market Information⁵

Product	World Production (MMtons/year)	Price Range 2011-2017 (\$/ton)	Projected Growth Rate	Major Uses
Methyl Ethyl Ketone	~1	1,300–2,400	~2%	Adhesives, paints, coatings, inks, dewaxing
1,4-Butanediol	~2	1,500–3,400	~3%	Tetrahydrofuran, specialty chemicals
Adipic Acid	~3	1,000–1,600	~2%	Nylon-6,6, polyurethanes, plasticizers
Acetone	~7	600–1,000	~3%	Solvent, methyl methacrylate, bisphenol A
Phenol	~11	840–1,500	~3%	Bisphenol A, resin
1,3-Butadiene	~12	680–2,600	~2%	Synthetic rubber
Terephthalic Acid	~66	640–1,100	~4%	Polyethylene terephthalate

⁴ The distinction of “dry” versus “wet” feedstock is used to roughly classify broad types of preprocessed feedstocks based on conversion process specifications. While a particular type of raw biomass may be harvested at greater than the 50 wt % basis, the biomass will be processed into a feedstock that can meet lower moisture specifications.

⁵ IHS Markit, *Chemical Economics Reports*, accessed March 2020.

Technology Pathways Using Dry Feedstocks

BETO tracks progress for technologies used in pathways using dry feedstocks. Dry feedstocks are defined as those that can economically meet a conversion specification of 50% or less moisture content after preprocessing raw biomass into conversion-ready feedstocks. Dry feedstocks are categorized as woody (e.g., logging residues, forest thinnings, and purpose-grown woody energy crops such as pine, eucalyptus, poplar, and willow), herbaceous (e.g., agricultural crop residues, primarily corn stover, and dedicated energy crops such as switchgrass, biomass sorghum, miscanthus, and energy cane), and dry waste (the organic fraction of sorted municipal solid waste).

For dry feedstocks, the Feedstock Supply and Logistics (FSL) R&D program focuses on delivering feedstocks that meet the required conversion specifications at a nearer-term targeted feedstock cost of \$86 or less per dry ton to a biorefinery throat. FSL cost targets include grower payment and logistics costs. Grower payment is based on supply curves from the *2016 Billion-Ton Report*⁶ and represents the cost of production, compensation for soil nutrient removal, and grower profit. Logistics costs include harvest and collection, storage, transportation, and preprocessing (primarily reduction of organic species and drying) from the point of harvest or collection to the conversion reactor throat in-feed. Longer term, FSL focuses on delivering conversion-ready industrially relevant, economically advantaged feedstocks and waste streams at a targeted per dry ton feedstock cost of \$71 or less. Individual technology configurations discuss design-case-specific feedstock specifications and assumptions.

Dry Feedstocks Converted via High Temperature and Upgrading

Dry Feedstocks Converted via Direct Liquefaction and Upgrading Design Case

Research on dry feedstocks converted via the direct liquefaction and upgrading pathway helps BETO understand challenges related to coupling high-temperature deconstruction processes with downstream upgrading, including catalyst contamination and deactivation, separation of desired intermediates, and various opportunities for deoxygenation and finishing. The design case configuration used to assess progress for technologies relevant to this pathway is the CFP with *ex situ* vapor phase upgrading and subsequent additional upgrading into hydrocarbon fuel

⁶ U.S. Department of Energy, edited by M. H. Langholtz, B. J. Stokes, and L. M. Eaton, *2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy, Volume 1: Economic Availability of Feedstocks* (Oak Ridge, TN: Oak Ridge National Laboratory, ORNL/TM-2016/160, 2016), https://www.energy.gov/sites/prod/files/2016/12/f34/2016_billion_ton_report_12.2.16_0.pdf.

blendstocks, as illustrated in Figure 2.⁷ Figure 3 outlines the modeled cost projections of the CFP design case with SOT contributions from feedstocks and conversion from 2014 to 2019 and interim projections up to the goal-year of 2022, and a preliminary projection for 2030.^{8,9}

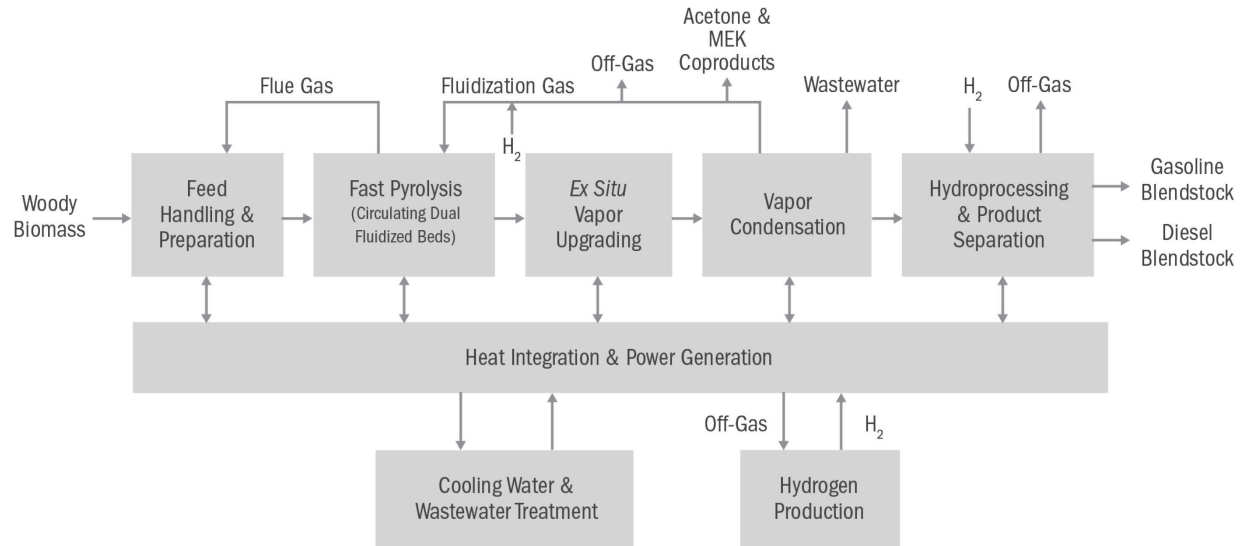


Figure 2: Process flow diagram for the conversion of dry feedstocks to hydrocarbon fuel via direct liquefaction

⁷ A. Dutta, A. H. Sahir, E. Tan, D. Humbird, L. J. Snowden-Swan, P. A. Meyer, J. Ross, D. Sexton, R. Yap, and J. Lukas, *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels: Thermochemical Research Pathways with In Situ and Ex Situ Upgrading of Fast Pyrolysis Vapors* (Golden, CO: National Renewable Energy Laboratory; Richland, WA: Pacific Northwest National Laboratory, NREL/TP-5100-62455; PNNL-23823, 2015), <https://www.nrel.gov/docs/fy15osti/62455.pdf>.

⁸ A. Dutta, K. Iisa, M. Talmadge, C. Mukarakate, M. Griffin, E. C. D. Tan, and N. Wilson et al., *Ex Situ Catalytic Fast Pyrolysis of Lignocellulosic Biomass to Hydrocarbon Fuels: 2019 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76269, 2020), <https://www.nrel.gov/docs/fy20osti/76269.pdf>.

⁹ A. Dutta, K. Iisa, C. Mukarakate, M. Griffin, E. C. D. Tan, J. Schaidle, and D. Humbird et al., *Ex Situ Catalytic Fast Pyrolysis of Lignocellulosic Biomass to Hydrocarbon Fuels: 2018 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-71954, 2018), <https://www.nrel.gov/docs/fy19osti/71954.pdf>.

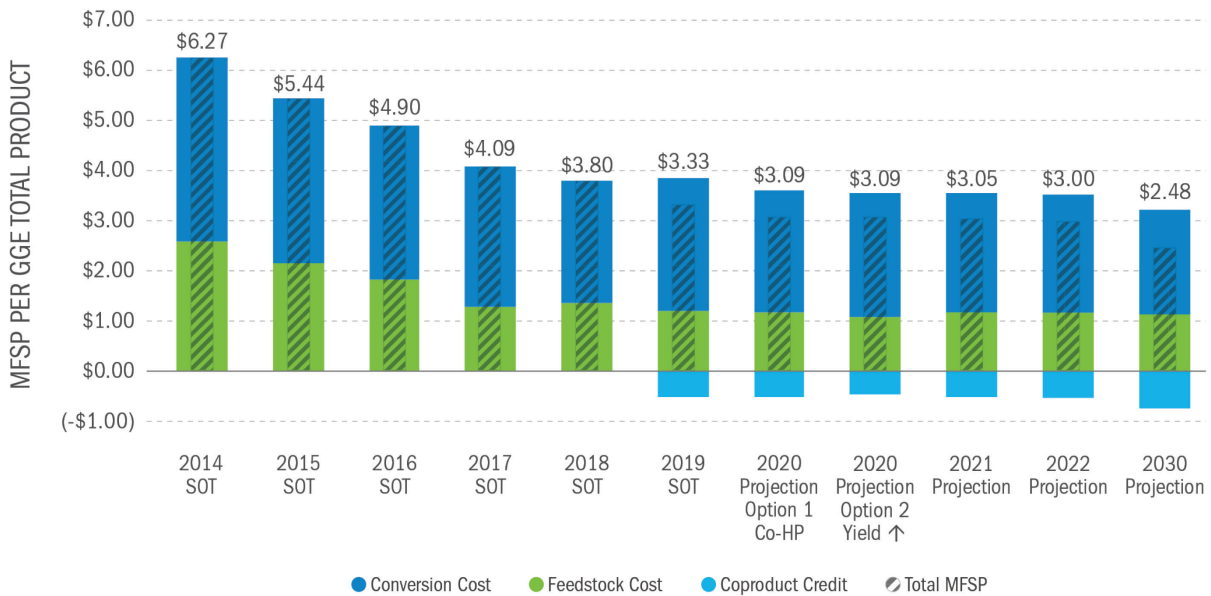


Figure 3: Cost projections with feedstock and conversion breakouts for the CFP design case

Feedstocks

Feedstock composition is a key factor in conversion process performance. MFSP projections for the CFP design assume that low concentrations of inorganic species (i.e., ash) and high-quality feedstock can be provided at compositional specifications summarized in Table 2 and at the targeted feedstock cost.¹⁰

FSL R&D efforts focus on understanding the fundamental drivers of feedstock quality while developing and improving preprocessing operations, such as air classification, advanced fractionation, mechanical and chemical preprocessing, and densification, to transform low-cost, more abundant woody biomass and forest residues into feedstocks that meet or exceed conversion quality specifications that can currently only be met with less available, more expensive clean pine feedstocks. Other R&D strategies include understanding how blending and formulation can utilize low-quality and low-cost biomass such as forest residues and developing preprocessing technologies capable of reducing the physical and chemical variability of raw biomass for more reliable, predictable, and efficient performance in conversion processes.

¹⁰ D. S. Hartley, D. N. Thompson, and H. Cai, *Woody Feedstocks 2019 State of Technology Report* (Idaho Falls, ID: Idaho National Laboratory, INL/EXT-20-57181, 2019), https://indigitallibrary.inl.gov/sites/sti/sti/Sort_21882.pdf.

Table 2: Feedstock Composition and Processing Assumptions for the CFP 2019 SOT Case

Component	Composition (dry wt %)
Carbon	50.94
Hydrogen	6.04
Nitrogen	0.17
Sulfur	0.03
Oxygen	41.90
Inorganic Species*	≤1.75
Heating Value (Btu/lb)	8,601 HHV
	7,996 LHV
Moisture (bulk wt %)	10.0
Particle Size (inches)	≤0.08

*Specs for inorganic species such as alkali and alkaline earth metals (1,300 ppm) are included in the 2022 projection, not in the SOT cases.

The 2019 SOT achieved a lower cost of \$70.15/dry ton by focusing on the blend of clean pine and pine logging residue, which assumed that the pine logging residues brought to the landing are part of the primary harvest operation with all cost attributed to the main product; the application of field-side preprocessing operations resulted in the further decrease of transportation cost. The 2022 projections are based on a blend of clean pine and pine logging residues as one possible option, and assume technology advancements in advanced fractionation and other preprocessing technologies to improve the quality of pine logging residues to formulate a blend that meets or exceeds quality conversion specifications (based on clean pine) at a

Figure 4 and Table 3 show the projected reduction in the delivered feedstock cost from 2013 through 2022 for woody biomass provided as input to the CFP process.^{11,12,13,14,15} The 2015 and 2016 SOTs reflect feedstock blends that combine multiple types of biomass to deliver a feedstock that conforms to CFP conversion specifications and cost targets. The 2017 and 2018 SOTs, which were based on clean pine feedstock that is not projected to be available in adequate quantities or at a price point required to meet the annual supply requirement for a biorefinery¹⁶ using a single clean pine feedstock, resulted in 2017 and 2018 SOT costs of \$87.82/dry ton, exceeding the \$86/dry ton threshold. In comparison, the

¹¹ P. Jernigan, T. Gallagher, D. Mitchell, M. Smidt, and L. Teeter, "High tonnage harvesting and skidding for loblolly pine energy plantations," *Forest Products Journal* 66, nos. 3–4 (2016): 185–191, <https://doi.org/10.13073/FPJ-D-14-00055>.

¹² P. Jernigan, T. Gallagher, J. Aulakh, R. Tufts, and T. McDonald, "Implementing Residue Chippers on Harvesting Operations in the Southeastern US for Biomass Recovery," *International Journal of Forest Engineering* 24, no. 2 (2013): 129–136, <https://doi.org/10.1080/14942119.2013.798130>.

¹³ D. S. Hartley, D. N. Thompson, H. Hu, and H. Cai, *Woody Feedstock 2018 State of Technology Report* (Idaho Falls, ID: Idaho National Laboratory, INL/EXT-18-51655, 2018), https://indigitallibrary.inl.gov/sites/sti/sti/Sort_7464.pdf.

¹⁴ M. H. Eisenbies, T. A. Volk, J. Posselius, C. Foster, S. Shi, and S. Karapetyan, "Evaluation of a Single-pass, Cut and Chip Harvest System on Commercial-scale, Short-rotation Shrub Willow Biomass Crops," *Bioenergy Research* 7, no. 4 (2014): 1506–1518, <https://doi.org/10.1007/s12155-014-9482-0>.

¹⁵ D. S. Hartley, D. N. Thompson, H. Hu, and H. Cai, *Woody Feedstock 2017 State of Technology Report* (Idaho Falls, ID: Idaho National Laboratory, INL/EXT-17-43459, 2017). This reference contains proprietary information, please contact Damon Hartley at damon.hartley@inl.gov for additional details.

¹⁶ The 2017 SOT assumes an annual supply of 800,000 dry tons and the 2018 and 2019 SOTs assume an annual supply of 725,000 dry tons with 90% on-stream time using locations tied to high availability of resources.

delivered feedstock cost of less than \$70.31/dry ton. The final selection of feedstock for the 2022 verification will be determined through continuing R&D with feedstock critical quality attributes and critical process parameters to be defined through the Feedstock-Conversion Interface Consortium (FCIC). Out-year cost projections will be updated going forward as new research is completed.

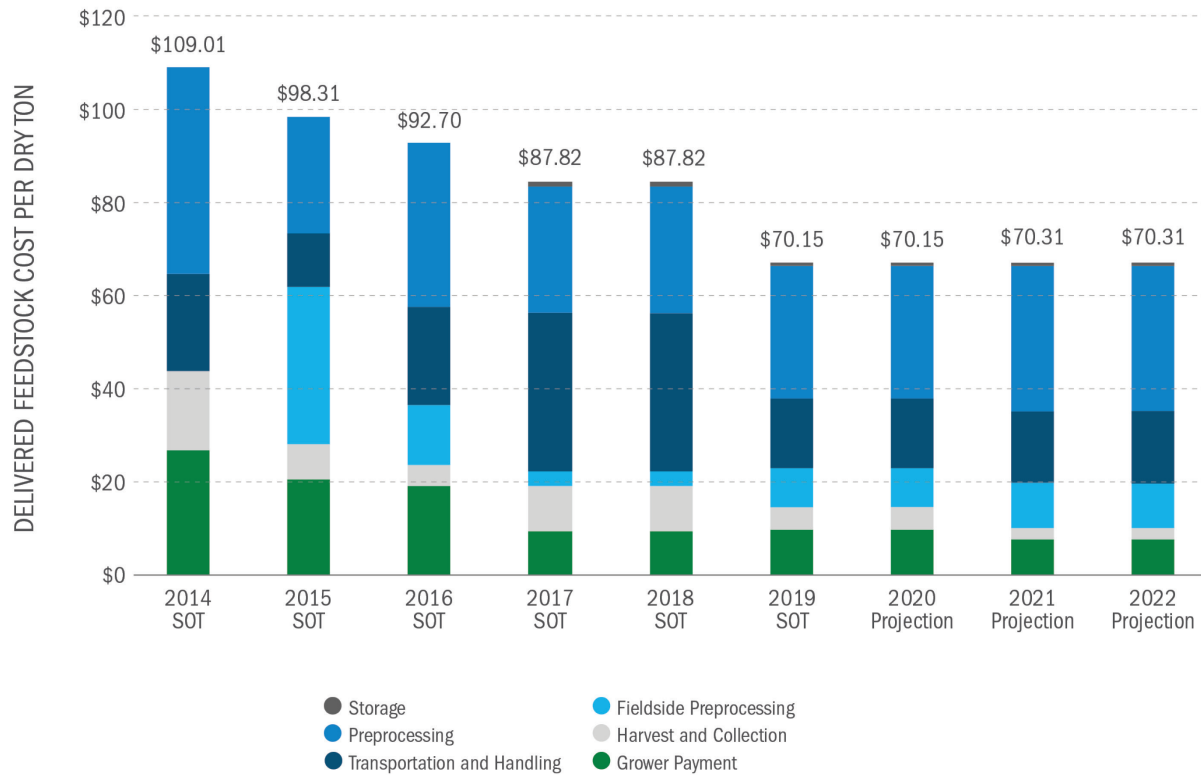


Figure 4: Dry feedstock cost delivered to the reactor throat, modeled for the CFP design case

Table 3: Dry Feedstock Costs Delivered to Reactor Throat for the CFP Design Case

Cost per Dry Ton	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 Projection ^a	2021 Projection ^a	2022 Projection ^a
Feedstock Type	Clean Pine ^b	Blend ^c	Blend ^d	Clean Pine ^b	Clean Pine ^b	Blend ^e	Blend ^e	Blend ^f	Blend ^f
Grower Payment	\$26.71	\$20.49	\$19.30	\$9.48	\$9.48	\$9.74	\$9.74	\$7.64	\$7.64
Harvest and Collection	\$17.11	\$7.68	\$4.37	\$9.87	\$9.87	\$4.94	\$4.94	\$2.47	\$2.47
Fieldside Preprocessing	\$0.00	\$33.84	\$12.81	\$2.82	\$2.82	\$8.41	\$8.41	\$9.81	\$9.81
Transportation and Handling	\$20.71	\$11.19	\$21.25	\$34.18	\$34.18	\$14.87	\$14.87	\$15.41	\$15.41
Preprocessing	\$44.48	\$25.11	\$34.97	\$27.14	\$27.14	\$28.55	\$28.55	\$31.12	\$31.12
Storage	\$0.00	\$0.00	\$0.00	\$0.86	\$0.86	\$0.68	\$0.68	\$0.58	\$0.58
Preprocessing Construction	-	-	-	\$3.47	\$3.47	\$2.96	\$2.96	\$3.28	\$3.28
Delivered Feedstock Price	\$109.01	\$98.31	\$92.70	\$87.82	\$87.82	\$70.15	\$70.15	\$70.31	\$70.31

^a The 2020 projection is assumed to be same as the 2019 SOT cost that already met the cost target, while the 2021 projection is assumed to be the same as the 2022 projection cost.

^b Clean, debarked pine chips.

^c The overall blend composition (after preprocessing) was targeted to match the elemental analysis of clean pine. Modeled costs shown reflect the use of 45% clean pine chips (pulp wood), 35% pine logging residues, and 20% construction and demolition waste with subsequent preprocessing to meet the clean pine elemental analysis specified in the 2015 CFP design report¹⁷. The 2015 SOT conversion experiments were conducted using clean pine.

^d The overall blend composition (after preprocessing) was targeted to match the elemental analysis of clean pine. Modeled costs shown reflect the use of 30% clean pine chips (pulp wood), 60% air-classified pine logging residue, and 10% hybrid poplar with subsequent preprocessing to meet the clean pine elemental analysis specified in the 2015 CFP design report. The 2016 SOT conversion experiments were conducted using clean pine.

^e 50% clean pine chips (pulp wood), 50% pine logging residues.

^f 25% clean pine chips (pulp wood) and 75% air-classified and preprocessed pine logging residues. This is a potential feedstock option for 2022 verification and final selection will be determined through continuing R&D.

¹⁷ A. Dutta, A. H. Sahir, E. Tan, D. Humbird, L. J. Snowden-Swan, P. A. Meyer, J. Ross, D. Sexton, R. Yap, and J. Lukas, *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels: Thermochemical Research Pathways with In Situ and Ex Situ Upgrading of Fast Pyrolysis Vapors* (Golden, CO: National Renewable Energy Laboratory; Richland, WA: Pacific Northwest National Laboratory, NREL/TP-5100-62455; PNNL-23823, 2015), <https://www.nrel.gov/docs/fy15osti/62455.pdf>.

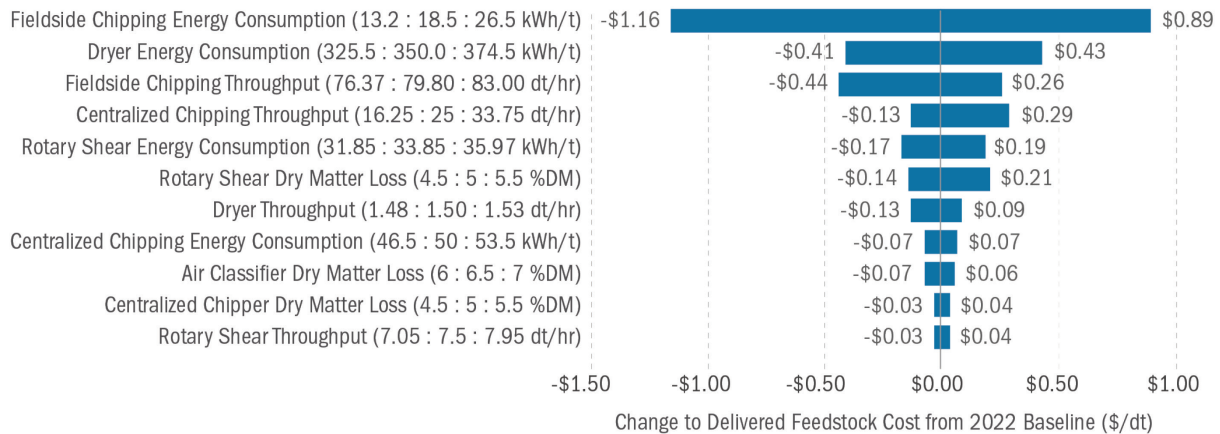


Figure 5: Sensitivity analysis of the delivered feedstock cost in the CFP design case

Figure 5 shows the impact on total delivered cost of varying energy consumption and throughput of key feedstock preprocessing operations, based on actual process experience and from literature.^{18,19,20,21} The 2022 cost of the blended feedstock is most sensitive to the energy consumption of the fieldside chipper, followed by the dryer energy consumption, and the fieldside and centralized chipping throughput.

The physical, chemical, and mechanical properties of feedstocks can have significant impacts on the equipment operations and downstream conversion performance (for reference, see the appendix, barriers Ft-E and Ft-J). The FCIC’s objective is to quantify, understand, and manage feedstock variability from field to conversion. The FCIC focuses on developing first-principles based knowledge and tools to understand the interactions between feedstock quality properties, preprocessing equipment performance (e.g., energy consumption, throughput, and wear), and conversion performance and yield. FCIC also focuses on identifying underlying factors, critical quality attributes, and critical process parameters to enable development of technologies that can reduce the delivered feedstock cost and provide well-defined,

¹⁸ D. S. Hartley, D. N. Thompson, and H. Cai, *Woody Feedstocks 2019 State of Technology Report* (Idaho Falls, ID: Idaho National Laboratory. INL/EXT-20-57181, 2019), https://indigitalibrary.inl.gov/sites/sti/sti/Sort_21882.pdf.

¹⁹ P.Jernigan, T. Gallagher, J. Aulakh, R. Tufts, and T. McDonald, “Implementing residue chippers on harvesting operations in the southeastern US for biomass recovery,” *International Journal of Forest Engineering* 24, no. 2 (2013): 129–136, <https://doi.org/10.1080/14942119.2013.798130>.

²⁰ R. Spinelli, E. Cavallo, A. Facello, N. Magagnotti, C. Nati, and G. Paletto, “Performance and energy efficiency of alternative comminution principles: chipping versus grinding,” *Scandinavian Journal of Forest Research* 27, no. 4 (2012): 393–400, <https://doi.org/10.1080/02827581.2011.644577>.

²¹ J. S. Tumuluru, “Specific energy consumption and quality of wood pellets produced using high-moisture lodgepole pine grind in a flat die pellet mill,” *Chemical Engineering Research and Design* 110 (2016): 82–97, <https://doi.org/10.1016/j.cherd.2016.04.007>.

homogeneous, and quality-controlled feedstock for efficient conversion performance with 90% on-stream time and design-rated throughput.

Conversion

In the CFP design case, on-spec dry feedstocks are fed into a non-catalytic fast pyrolysis reactor and the resulting vapors are catalytically upgraded in a fixed bed reactor through deoxygenation, hydrogenation, and the coupling of smaller molecules. The resulting vapors are condensed and separated into component streams with the majority of the non-condensable gases recycled to the fast pyrolysis reactor for fluidization and the remaining gases used for hydrogen production. Light oxygenated coproducts, acetone, and methyl ethyl ketone (MEK), are also recovered from the gases. The resulting pyrolysis oil is subsequently hydrotreated for deoxygenation and saturation of a portion of the products to reduce aromatic content to produce a gasoline- or diesel-range blendstock and the aqueous liquid fraction that is sent to wastewater treatment. CFP oil from this process may also be co-processed in a petroleum refinery.

BETO currently works to decrease overall modeled conversion costs for the direct liquefaction of dry feedstocks pathway by addressing a number of research barriers, including improving overall yield, increasing catalyst lifetime, and decreasing process severity (for reference, see the appendix, barriers Ct-E, Ct-F, Ct-G, and Ct-N). Figure 6 shows the impact that improvements in each of these areas may have on the 2022 projected MFSP for the CFP design.

Figure 6 shows that increasing overall carbon efficiency is key to achieving future cost and performance goals. Research in this area focuses on improving catalyst and reactor performance to provide cheaper catalysts that have a longer lifetime and that can generate targeted products in high yields. Higher yields have the added benefit of potentially reducing heat recovery and electricity generation expenses. This work is supported through the Chemical Catalysis for Bioenergy Consortium (ChemCatBio) and the Consortium for Computational Physics and Chemistry (CCPC). Additional benefits from coproduct recovery and refinery coprocessing of the CFP oil are further discussed in the 2019 SOT report.²²

²² A. Dutta, K. Iisa, M. Talmadge, C. Mukarakate, M. Griffin, E. C. D. Tan, and N. Wilson et al., *Ex Situ Catalytic Fast Pyrolysis of Lignocellulosic Biomass to Hydrocarbon Fuels: 2019 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76269, 2020), <https://www.nrel.gov/docs/fy20osti/76269.pdf>.

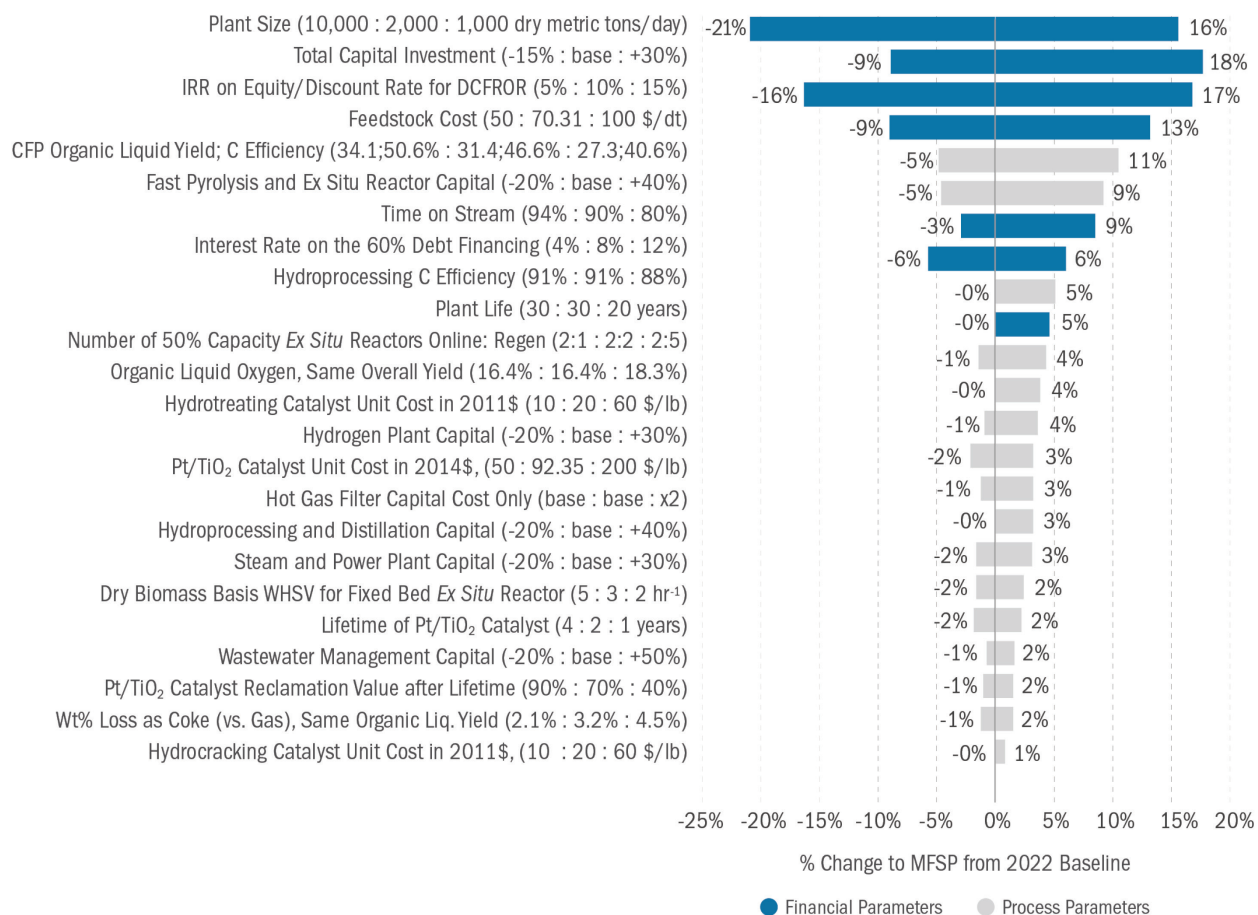


Figure 6: Factors influencing conversion costs relative to the CFP design case 2022 projection²³

In addition to improving overall yields, BETO also invests in other methods for reducing costs from the vapor upgrading step, including improving online time for reactors, increasing space velocity, designing catalysts with reduced precious metal content, and more efficient catalyst regeneration. The current SOT model assumes that half of the fixed bed upgrading reactors would need to be dedicated to catalyst regeneration at any one time; a significant decrease in redundancy has been achieved since 2017 with catalyst development allowing increased experimental on-stream times before requiring regeneration. Further increases in on-stream times are being pursued to increase cycle times during future commercial operations. Experimental work in this area also currently utilizes a platinum or titanium dioxide catalyst, but research on the viability of using either lower platinum loadings or alternate catalysts with no

²³ Baseline may not reflect exact 2022 design case values. Ranges chosen based on potential representative values for each parameter.

noble metals (such as molybdenum carbide) is ongoing. Use of lower-cost materials depends on a number of factors, including performance and regenerability.

Costs for the FY19 SOT have decreased compared with FY17 and FY18 based on experimentally showing shorter regeneration times while using a catalyst with lower platinum loading. Upstream deoxygenation during the catalytic upgrading process can be beneficial because downstream hydroprocessing steps require relatively higher hydrogen purity (and significantly higher hydrogen partial pressures) compared to vapor phase upgrading. Achieving future cost goals may be accomplished by further increasing carbon efficiency by lowering conversion to light gases and enabling the use of lower cost and lower quality feedstocks.

In FY19, enhanced analytical capabilities allowed for near 100% mass and carbon balance closures for the CFP process, which revealed that about 10% of the biomass carbon was being converted to light oxygenates. Hydrotreating these compounds yields light hydrocarbon gases instead of liquid-range fuels, which results in a lower carbon efficiency to liquid fuel blendstocks than previously assumed and leads to an increase in the MFSP compared to previous projections. As a result, new process steps were added in FY19 to recover the light oxygenates and separate them for the recovery of chemical products (such as acetone and MEK) and/or additional upgrading to fuels and coproducts. Future research will help determine the optimal treatment of these light oxygenates. For the 2019 SOT, only acetone was recovered and sold as an additional coproduct from the light oxygenate stream.

In 2019, BETO also considered the impact of co-processing the CFP oil in petroleum refineries to avoid some of the high capital costs associated with upgrading pyrolysis oils. This work will continue to analyze potential impacts to a traditional refinery due to the highly oxygenated nature of CFP oils and investigate the potential for meeting other targets including cost and GHG reduction metrics. The potential impact of co-processing is shown as Option 1 for 2020 in Table 4. If co-processing is not used, current analysis suggests that fuel yields will need to increase through better catalyst performance and reactor online time in 2020 in order to meet cost targets. This scenario is shown in Table 4 as Option 2 for 2020. Research in the next year will focus on the viability of these two options.

BETO also considers a number of other factors that may contribute to meeting longer-term cost targets. The Bioprocessing Separations Consortium is considering how catalytic hot gas filtration can enable additional chemistry to improve product quality and yield of desirable liquid-range molecules in the product stream via removal of contaminants and reactions that are synergistic

with the *ex situ* upgrading; this can prolong catalyst on-stream time and increase the lifetime of the *ex situ* reactor catalyst.

Additionally, BETO is assessing catalyst and reactor tolerance to cheaper feedstocks containing more impurities (for reference, see the appendix, barriers Ct-A, Ct-J, Ct-K, and Ct-P). The 2030 projections in Figure 7 and Table 4 show the potential impact some of these areas may have on modeled costs, depending on future investment and results.

Many of the additional research areas in the 2030 modeled projection are in the preliminary stage as part of a broader BETO strategy to assess options for reaching future cost and performance goals. Therefore, the 2030 modeled projection in Figure 7 represents only one potential path forward and is not directly comparable to modeled costs from prior years, which are based on more rigorous analysis.

Table 5 presents the process efficiency metrics for the CFP design. Table 6 includes the detailed cost and technical projections for the CFP design.



Figure 7: Cost projections for the conversion portion of the CFP design case

Table 4: Cost Projections for the CFP Design Case

Conversion Cost Breakdown (\$/GGE)	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 Projection Option 1 Co HP*	2020 Projection Option 2 Yield ↑	2021 Projection	2022 Projection (Design Case)	2030 Projection
Pyrolysis and Vapor Upgrading	\$2.34	\$2.03	\$1.84	\$1.46	\$1.10	\$1.14	\$1.14	\$1.06	\$1.13	\$1.12	\$1.14
Vapor Quench, Coproduct Recovery + Contingency	\$0.35	\$0.33	\$0.28	\$0.20	\$0.22	\$0.34	\$0.42	\$0.30	\$0.40	\$0.40	\$0.23
Hydroprocessing and Separation/Refinery Coprocessing	\$0.33	\$0.31	\$0.34	\$0.35	\$0.38	\$0.30	\$0.21	\$0.30	\$0.21	\$0.21	\$0.04
Hydrogen Production	\$0.61	\$0.56	\$0.60	\$0.62	\$0.51	\$0.61	\$0.44	\$0.60	\$0.44	\$0.44	\$0.46
Balance of Plant	\$0.04	\$0.07	\$0.03	\$0.20	\$0.23	\$0.27	\$0.20	\$0.21	\$0.20	\$0.19	\$0.22
Coproduct Credit	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$0.52)	(\$0.52)	(\$0.47)	(\$0.52)	(\$0.53)	(\$0.74)
Net Conversion Contribution to MFSP	\$3.66	\$3.30	\$3.08	\$2.82	\$2.44	\$2.14	\$1.90	\$2.02	\$1.87	\$1.83	\$1.34

*Note: Co-HP = co-hydroprocessing.

Table 5: Process Efficiency Metrics for the CFP Design Case

Sustainability and Process Efficiency Metrics	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT ^a	2018 SOT	2019 SOT	2020 Projection Option 1 Co HP*	2020 Projection Option 2 Yield ↑	2021 Projection	2022 Projection (Design Case)	2030 Projection
Fuel and Coproducts Yield by Weight of Biomass	% w/w of dry biomass	13.7%	15.0%	16.5%	22.2%	20.9%	22.5%	22.5%	24.4%	22.7%	22.8%	24.8%
Carbon Efficiency of Biomass to Fuels and Coproducts	% C in feedstock	23.5%	25.9%	28.3%	38.1%	35.9%	37.2%	37.2%	40.5%	37.2%	37.3%	42.4%
Overall Carbon Efficiency to Liquid Hydrocarbon Fuels	% C in feedstock	23.5%	25.9%	28.3%	38.1%	35.9%	33.0%	33.0%	36.3%	33.0%	33.0%	33.9%
Overall Energy Efficiency to Liquid Hydrocarbon Fuels	% LHV of feedstock	30.5%	33.4%	37.1%	50.3%	47.2%	43.6%	43.6%	48.0%	43.6%	43.6%	44.9%
Electricity Production	kWh/GGE	21.0	18.0	14.7	8.0	8.7	7.8	10.8	6.3	10.8	10.7	7.9
Electricity Consumption (Entire Process)	kWh/GGE	12.7	11.0	9.6	6.4	7.5	7.4	7.1	6.7	7.1	7.0	7.4

*Note: Co-HP = co-hydroprocessing at a petroleum refinery. ^a For the 2017 SOT, the unquantified portion of CFP yields were prorated to solids, liquids, and gases using measured yields.

Table 6: Unit Operation Cost Estimates and Technical Projections for Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels via Catalytic Fast Pyrolysis with Further Hydroprocessing of CFP Oil

Sustainability and Process Efficiency Metrics	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT ^a	2018 SOT	2019 SOT	2020 Projection Option 1 Co HP*	2020 Projection Option 2 Yield ↑	2021 Projection	2022 Projection (Design Case)	2030 Projection ^b
Process Concept: Hydrocarbon Fuel Production via <i>Ex Situ</i> Upgrading of Fast Pyrolysis Vapors		Clean Pine	Clean Pine	Clean Pine	Clean Pine	Clean Pine	50% Residues/50% Pine ^c	50% Residues/50% Pine ^c	50% Residues/50% Pine ^c	75% Residues/25% Pine	75% Residues/25% Pine	75% Residues/25% Pine
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
Projected MFSP	\$/GGE	\$6.27	\$5.44	\$4.90	\$4.09	\$3.80	\$3.33	\$3.09	\$3.09	\$3.05	\$3.00	\$2.48
Conversion Contribution	\$/GGE	\$3.66	\$3.30	\$3.08	\$2.82	\$2.44	\$2.14	\$1.90	\$2.02	\$1.87	\$1.83	\$1.34
Total Project Investment per Annual GGE	\$/GGE-yr	\$18.50	\$16.46	\$14.94	\$12.17	\$12.47	\$13.53	\$12.32	\$12.27	\$12.19	\$12.07	\$11.13
Plant Capacity (Dry Feedstock Basis)	metric tons/day	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Total Gasoline Equivalent Yield	GGE/dry ton	42	46	51	69	65	59	59	65	60	61	62
Diesel-Range Product Proportion (GGE Basis)	% of fuel product	15%	15%	15%	52%	52%	48%	48%	48%	48%	48%	52%
Feedstock												
Total Cost Contribution ^d	\$/GGE	\$2.60	\$2.14	\$1.82	\$1.27	\$1.36	\$1.18	\$1.19	\$1.08	\$1.18	\$1.17	\$1.14
Capital Cost Contribution ^d	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Operating Cost Contribution ^d	\$/GGE	\$2.60	\$2.14	\$1.81	\$1.27	\$1.35	\$1.18	\$1.18	\$1.07	\$1.18	\$1.16	\$1.13
Feedstock Cost ^e	\$/dry ton	\$109.01	\$98.31	\$92.70	\$87.82	\$87.82	\$70.15	\$70.15	\$70.15	\$70.31	\$70.31	\$70.31
Feedstock Moisture at Plant Gate	wt % H ₂ O	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Feed Moisture Content to Pyrolyzer	wt % H ₂ O	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Energy Content (LHV, Dry Basis)	Btu/lb	8,000	8,000	8,000	8,000	8,000	7,900	7,900	7,900	8,000	8,000	8,000
Pyrolysis and Vapor Upgrading												
Total Cost Contribution ^d	\$/GGE	\$2.60	\$2.14	\$1.82	\$1.27	\$1.36	\$1.18	\$1.19	\$1.08	\$1.18	\$1.17	\$1.14
Capital Cost Contribution ^d	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

Sustainability and Process Efficiency Metrics	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT ^a	2018 SOT	2019 SOT	2020 Projection Option 1 Co HP*	2020 Projection Option 2 Yield ↑	2021 Projection	2022 Projection (Design Case)	2030 Projection ^b
Operating Cost Contribution ^d	\$/GGE	\$2.60	\$2.14	\$1.81	\$1.27	\$1.35	\$1.18	\$1.18	\$1.07	\$1.18	\$1.16	\$1.13
Ex Situ Reactor Configuration	reactor type	fluidized bed	fluidized bed	fluidized bed	fixed bed	fixed bed	fixed bed	fixed bed	fixed bed	fixed bed	fixed bed	fixed bed
Ratio of Online: Regenerating Fixed Bed Reactors	ratio	N/A	N/A	N/A	2:5	2:3	2:2	2:2	2:2	2:2	2:2	2:2
Gas Phase	wt % of dry biomass	35%	36%	34%	31%	35%	38%	38%	34%	38%	38%	31%
Aqueous Phase	wt % of dry biomass	25%	25%	24%	27%	22%	24%	24%	26%	24%	24%	23%
Carbon Loss	% of C in biomass	2.9%	2.9%	3.4%	2.9%	5.0%	4.4%	4.4%	4.3%	4.4%	4.4%	3.0%
Organic Phase	wt % of dry biomass	17.5%	18.6%	21.8%	28.3%	27.9%	23.2%	23.2%	25.6%	23.4%	23.4%	31.4%
H/C Molar Ratio	ratio	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Oxygen	wt % of organic phase	15.0%	13.3%	16.8%	16.5%	18.6%	15.1%	15.1%	15.2%	15.1%	15.1%	16.4%
Carbon Efficiency	% of C in biomass	27%	29%	33%	42%	40%	35%	35%	39%	35%	35%	47%
Solid Losses (Char + Coke)	wt % of dry biomass	23%	21%	20%	14%	15%	14%	14%	14%	14%	14%	15%
Char	wt % of dry biomass	12.0%	11.0%	12.0%	10.4%	11.7%	11.6%	11.6%	11.6%	11.7%	11.7%	11.7%
Coke	wt % of dry biomass	11.0%	9.5%	8.3%	3.3%	3.7%	2.3%	2.3%	2.2%	2.3%	2.3%	3.2%
Vapor Quench, Coproduct Recovery + Contingency												
Total Cost Contribution	\$/GGE	\$0.35	\$0.33	\$0.28	\$0.20	\$0.22	\$0.34	\$0.42	\$0.30	\$0.40	\$0.40	\$0.23
Capital Cost Contribution	\$/GGE	\$0.20	\$0.19	\$0.16	\$0.12	\$0.13	\$0.22	\$0.26	\$0.19	\$0.24	\$0.24	\$0.13

Sustainability and Process Efficiency Metrics	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT ^a	2018 SOT	2019 SOT	2020 Projection Option 1 Co HP*	2020 Projection Option 2 Yield ↑	2021 Projection	2022 Projection (Design Case)	2030 Projection ^b
Operating Cost Contribution	\$/GGE	\$0.15	\$0.14	\$0.12	\$0.08	\$0.09	\$0.12	\$0.16	\$0.11	\$0.16	\$0.16	\$0.10
Hydroprocessing and Separation/Refinery Co-Processing												
Total Cost Contribution	\$/GGE	\$0.33	\$0.31	\$0.34	\$0.35	\$0.38	\$0.30	\$0.21	\$0.30	\$0.21	\$0.21	\$0.04
Capital Cost Contribution	\$/GGE	\$0.17	\$0.16	\$0.18	\$0.19	\$0.20	\$0.16	\$0.00	\$0.16	\$0.00	\$0.00	\$0.00
Operating Cost Contribution	\$/GGE	\$0.15	\$0.14	\$0.16	\$0.16	\$0.18	\$0.14	\$0.21	\$0.14	\$0.21	\$0.21	\$0.04
Carbon Efficiency of Organic Liquid Feed to Fuels	%	88.4%	89.5%	87.2%	91.0%	89.0%	93.5%	93.5%	93.5%	93.5%	93.5%	91.0%
Hydrotreating Pressure	psia	2,000	2,000	2,000	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
Oxygen Content in Cumulative Fuel Product	wt %	0.8%	0.8%	0.8%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.6%
Hydrogen Production												
Total Cost Contribution	\$/GGE	\$0.61	\$0.56	\$0.60	\$0.62	\$0.51	\$0.61	\$0.44	\$0.60	\$0.44	\$0.44	\$0.46
Capital Cost Contribution	\$/GGE	\$0.39	\$0.36	\$0.38	\$0.41	\$0.33	\$0.39	\$0.28	\$0.37	\$0.28	\$0.28	\$0.28
Operating Cost Contribution	\$/GGE	\$0.22	\$0.20	\$0.22	\$0.21	\$0.18	\$0.22	\$0.16	\$0.24	\$0.16	\$0.16	\$0.17
Additional Natural Gas at the Biorefinery ^f	% of biomass LHV	0.3%	0.1%	0.2%	0.1%	0.3%	0.1%	0.5%	1.3%	0.6%	0.6%	0.2%
Coproducts												
Total Cost Contribution	\$/GGE						(\$0.52)	(\$0.52)	(\$0.47)	(\$0.52)	(\$0.53)	(\$0.74)
Capital Cost Contribution ^g	\$/GGE											\$0.06
Operating Cost Contribution ^g	\$/GGE											(\$0.81)
Coproduct Credit	\$/GGE						(\$0.52)	(\$0.52)	(\$0.47)	(\$0.52)	(\$0.53)	(\$0.83)
Balance of Plant												
Total Cost Contribution	\$/GGE	\$0.04	\$0.07	\$0.03	\$0.20	\$0.23	\$0.27	\$0.20	\$0.21	\$0.20	\$0.19	\$0.22

Sustainability and Process Efficiency Metrics	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT ^a	2018 SOT	2019 SOT	2020 Projection Option 1 Co HP*	2020 Projection Option 2 Yield ↑	2021 Projection	2022 Projection (Design Case)	2030 Projection ^b
Capital Cost Contribution	\$/GGE	\$0.80	\$0.71	\$0.56	\$0.43	\$0.46	\$0.45	\$0.52	\$0.38	\$0.52	\$0.51	\$0.41
Operating Cost Contribution ^g	\$/GGE	(\$0.76)	(\$0.64)	(\$0.54)	(\$0.23)	(\$0.23)	(\$0.18)	(\$0.32)	(\$0.17)	(\$0.32)	(\$0.32)	(\$0.20)
Electricity Production from Steam Turbine (Credit Included in Operational Cost Above)	\$/GGE	(\$1.12)	(\$0.96)	(\$0.78)	(\$0.42)	(\$0.45)	(\$0.40)	(\$0.57)	(\$0.37)	(\$0.57)	(\$0.57)	(\$0.41)

*Note: Co-HP = co-hydroprocessing.

^a For the 2017 SOT, the unquantified portion of CFP yields were prorated to solids, liquids, and gases using measured yields.

^b 2030 projections are based on high-level estimates and will be modeled in detail in future years. It is proposed that co-hydroprocessing of CFP oil will occur at a petroleum refinery. Capital for hydrogen production is included, while natural gas feed for hydrogen production is not included because credit is not taken for an equivalent amount of fuel gas from the CFP biorefinery. Coproduct credit is based on a preliminary estimate of diverting 20% CFP oil to produce coproducts, including from the organic liquid phase.

^c Modeled ash is 1.75% for 2019 and 2020, and less than 1% for all other years.

^d An additional biomass heater is included as a small additional in-plant cost, as shown in the 2015 process design report: <https://www.nrel.gov/docs/fy15osti/62455.pdf>.

^e Small adjustments made to previously published feedstock cost estimates for 2014–2016.

^f Natural gas stream was negligible in most of the biorefinery models. This was included to maintain model flexibility to allow natural gas use as an option.

^g Capital and operating costs for coproduct recovery in the 2019–2022 models are included in the “Vapor Quench, Coproduct Recovery + Contingency” section.

Integration and Scale-Up (Conversion and Advanced Development and Optimization)

Once the technical targets are reached through R&D, unit operations or process steps developed at lab-scale R&D will require integration at engineering scale, along with testing to ensure technical targets can be reached when run as an integrated process. Key integration challenges for dry feedstocks converted via the direct liquefaction and upgrading pathway may include:

- Reliable and robust operations of feed handling systems, including feeding woody biomass into a pressurized conversion reactor (for reference, see the appendix, barrier ADO-A)
- Addressing the buildup of impurities in process recycle systems and their impact on catalyst performance and regeneration requirements for converting pyrolysis vapor to hydrocarbon fuels (for reference, see the appendix, barrier ADO-F)
- The influence of inorganic species present in feedstocks on conversion efficiency to desired products (for reference, see the appendix, barrier ADO-F)
- Developing efficient product separation and purification schemes
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barrier ADO-D)
- Minimizing abrasion and corrosion of plant equipment due to external contaminants present in the feedstock (for reference, see the appendix, barrier ADO-H).

To further decrease modeled fuel costs, BETO researches opportunities for co-processing catalytic fast pyrolysis oils with petroleum-derived vacuum gas oil (VGO) through fluid catalytic cracking. Co-processing the pyrolysis oil in the refinery is expected to reduce capital and operating costs for upgrading to stable oil, fuel finishing to gasoline and diesel, and balance of plant. To be accepted for co-processing, petroleum refiners need to understand how bio-oil or bio-intermediates will perform when integrated into existing operations (for reference, see the appendix, barriers ADO-C and ADO-G). Integrated system research includes understanding how the characteristics and components of bio-oil and bio-oil intermediates differ from those found in petroleum feedstocks, developing equipment operating conditions for blending bio-intermediates with petroleum feedstocks to meet existing product specifications, and extending current refinery practices and procedures to include characteristics of biomass and bio-intermediates.

Supply Chain Sustainability Analysis

Table 7 summarizes the supply chain sustainability metrics, including fossil energy consumption, net energy balance, GHG emissions, water consumption, and NO_x emissions of renewable gasoline and renewable diesel from CFP for the 2015–2019 SOT and the 2022 design case.²⁴ The CFP design consumes little net fossil energy after accounting for fossil energy displacement credits from coproduced electricity. The net energy balance of renewable gasoline/renewable diesel (RD) from the CFP design could achieve about 0.58 MJ/MJ, indicating a 58% fossil energy saving potential in the 2022 design. Utilizing energy-intensive air-classified logging residues as part of the feedstock blend in the 2022 design case leads to trade-offs of better fuel yields, lower costs, and reduced net energy balance, as shown in Tables 4 and 7.

²⁴ H. Cai, L. Ou, M. Wang, E. Tan, R. Davis, A. Dutta, and L. Tao et al., *Supply Chain Sustainability Analysis of Renewable Hydrocarbon Fuels via Indirect Liquefaction, Ex Situ Catalytic Fast Pyrolysis, Hydrothermal Liquefaction, Combined Algal Processing, and Biochemical Conversion: Update of the 2019 State-of-Technology Cases* (Lemont, IL: Argonne National Laboratory, ANL/ESD-20/2, 2020), https://greet.es.anl.gov/publication-renewable_hc_2019.

Table 7: Supply Chain Sustainability Metrics for the CFP Design Case

	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2022 Design Case	Petroleum Gasoline
Biofuel Yield^a							
MMBtu/dry ton	5.3	5.9	8.0	8.3	6.9	9.0	
Fossil Energy Consumption^b							
MJ/MJ	0.4 (-97%)	0.11 (-91%)	0.19 (-85%)	0.33 (-74%)	0.19 (-85%)	0.42 (-66%)	1.25
Net Energy Balance^c							
MJ/MJ	0.6	0.89	0.81	0.67	0.81	0.58	
GHG Emissions							
g CO ₂ e/MJ	6.0 (-94%)	11.4 (-88%)	17.7 (-81%)	26.4 (-72%)	16.2(-83%)	29.5 (-69%)	95
g CO ₂ e/GGE	738	1,402	2,171	3,234	1,985	3,619	11,671
Water Consumption							
gal/MJ	0.006	0.013	0.025	0.030	0.029	0.030	0.03
gal/GGE	0.8	1.6	3.0	3.7	3.6	3.7	3.1
Total NO_x Emissions							
g NO _x /MJ	0.11	0.10	0.07	0.13	0.33	0.16	0.06
g NO _x /GGE	13.1	11.7	8.7	15.6	40.6	19.2	7.1
Urban NO_x Emissions^d							
g NO _x /MJ	0.018	0.019	0.021	0.021	0.020	0.020	0.024
g NO _x /GGE	2.3	2.4	2.5	2.5	2.4	2.5	2.9

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values.

^a Includes both renewable gasoline and renewable diesel.

^b This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

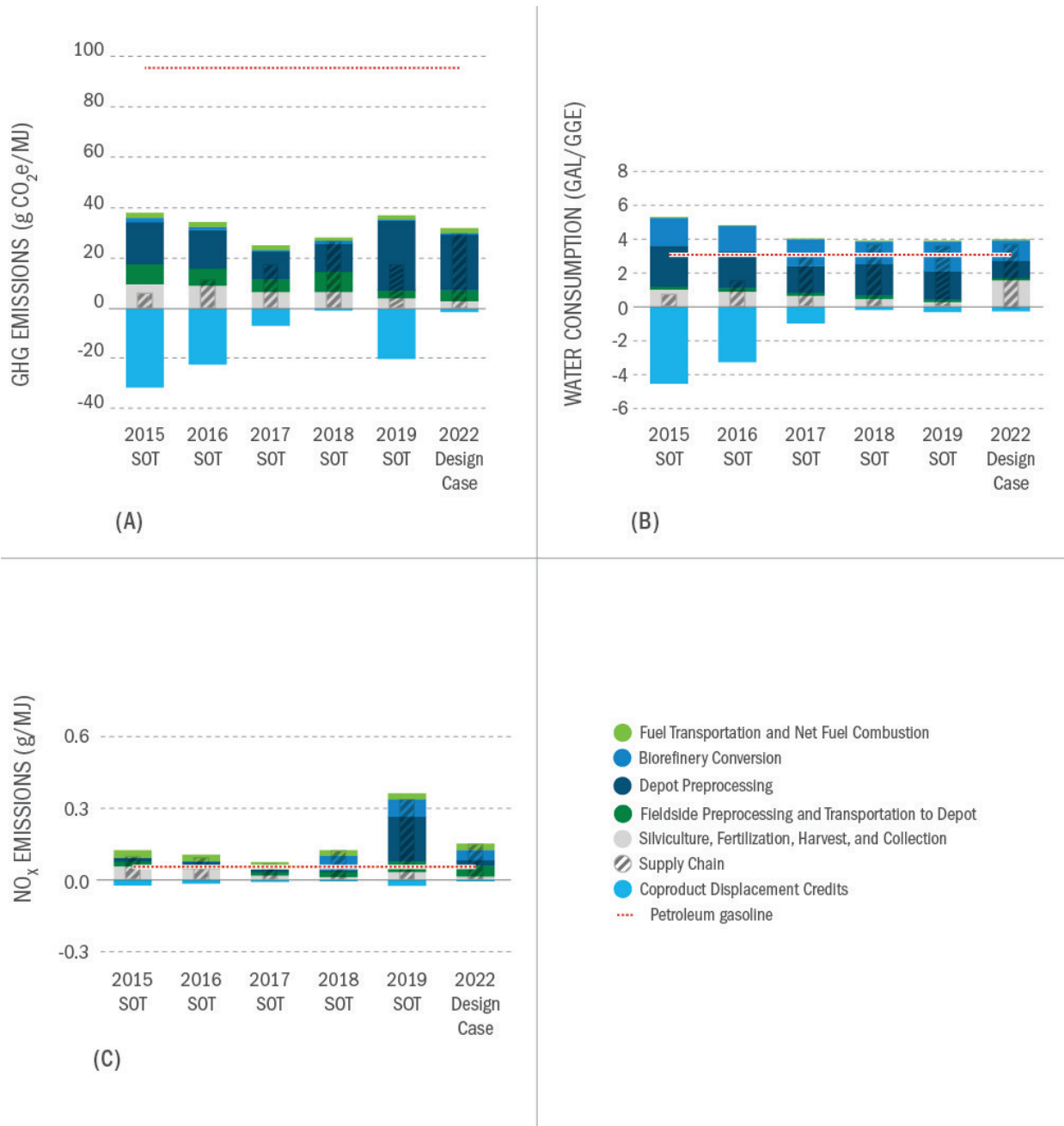
^c Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

^d Urban NO_x emissions account for emissions that occur in municipal statistical areas.

Figure 8A shows the supply chain GHG emissions and their key contributing supply chain processes, in g CO₂e/MJ, compared to a life cycle carbon intensity for petroleum gasoline of 95 g CO₂e/MJ. Table 7 shows that a total GHG reduction of 69% compared to petroleum gasoline can be achieved by 2022 through improvement in biofuel yields and by reducing energy consumption during conversion. The GHG emissions increase from the 2019 SOT case to the 2022 design case is due to switching to 75% air-classified and preprocessed pine logging residues in the 2022 design case. Preprocessing air-classified and leached pine logging residues is much more energy-intensive and thus emission-intensive than preprocessing clean pine in the 2018 SOT case. The net GHG emissions increase from the 2015 SOT to the 2018 SOT is due to the reduction in coproduced electricity generation (and an elimination of coproduct displacement credits). Improved conversion yields along with reduced emissions from feedstock production and logistics and from CFP conversion result, on a total biofuel output basis, in a significant emissions reduction compared with fossil-derived fuels. The 2019 SOT case has lower GHG emissions than the 2018 SOT case primarily because the displacement credit of coproducts including electricity, acetone, and MEK, which more than offset increased GHG emissions associated with more energy-intensive feedstock preprocessing in the 2019 SOT case due to the adoption of a feedstock blend with 50% clean pine and 50% pine logging residues.

Figure 8B shows that water consumption decreases from 3.7 gal/GGE in the 2018 SOT case to 3.6 gal/GGE in the 2019 SOT case. Reducing the supply chain water consumption to 1.3 gal/GGE in the 2022 design case can be achieved through less water consumption associated with energy consumption at depot preprocessing, less direct process water consumption in the CFP conversion processes (e.g., through water-free air cooling technologies), and higher biofuel yields.

Figure 8C shows that total supply chain NO_x emissions increase from the 2018 SOT case to the 2019 SOT case due to more energy-intensive preprocessing that is also more NO_x emission-intensive. This presents a trade-off between cost and environmental performance of this pathway in the 2019 SOT case. Developing a means to integrate heat from the downstream conversion process into feedstock drying could help address this trade-off.



Figures 8A–8C: Supply chain for the CFP design case for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions²⁵

²⁵ 2019 SOT data assumes a feedstock of 50% clean pine and 50% forest residues. 2022 projects assume a feedstock of 25% clean pine and 75% forest residues. The 2019 SOT also included updates to the carbon balance and the addition of coproducts. These changes impacted many of the SCSA metrics compared to 2018 and earlier. Additional details are available in the SOT reports referenced earlier.

Dry Feedstocks Converted via Indirect Liquefaction and Upgrading Design Case

Research on dry feedstocks converted via the IDL and upgrading to hydrocarbon fuels pathway helps BETO address multiple challenges in upgrading biomass-derived syngas and other shorter carbon chain intermediates. Progress for technologies relevant to this pathway is assessed using the woody biomass converted via gasification with catalytic upgrading of cleaned syngas to high-octane gasoline.²⁶ This is illustrated in Figure 9. Figure 10 shows the modeled costs of this configuration, with feedstocks and conversion contributions specified.²⁷

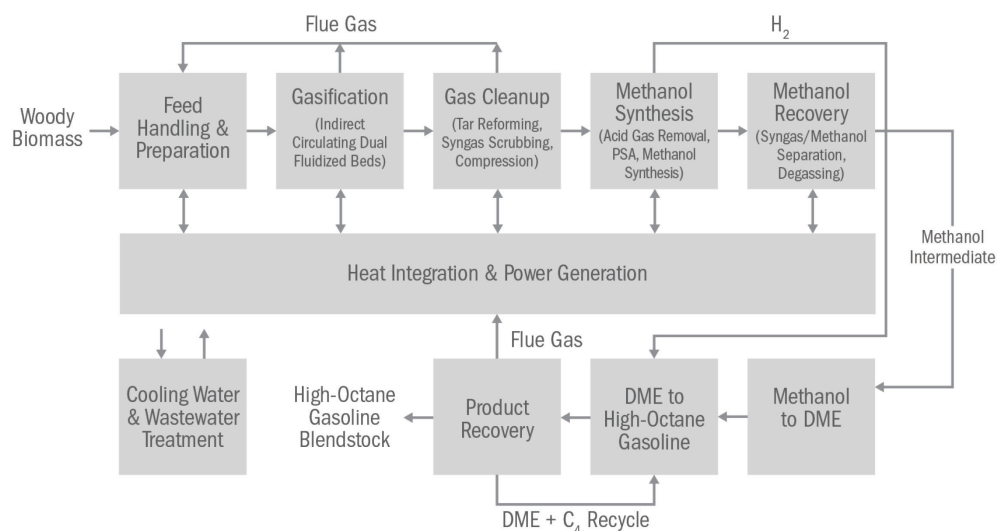


Figure 9: Process flow diagram for the conversion of dry feedstocks to hydrocarbon fuel via indirect liquefaction

²⁶ E. C. D. Tan, M. Talmadge, A. Dutta, J. Hensley, J. Schaidle, M. Bidy, and D. Humbird et al., *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* (Golden, CO: National Renewable Energy Laboratory; Richland, WA: Pacific Northwest National Laboratory, NREL/TP-5100-62402; PNNL-23822, 2015), <https://www.nrel.gov/docs/fy15osti/62402.pdf>.

²⁷ E. C. D. Tan, D. Ruddy, C. Nash, D. Dupuis, K. Harris, A. Dutta, D. Hartley, and H. Cai, *High-Octane Gasoline from Lignocellulosic Biomass via Syngas and Methanol/Dimethyl Ether Intermediates: 2019 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76619, 2020), <https://www.nrel.gov/docs/fy20osti/76619.pdf>.

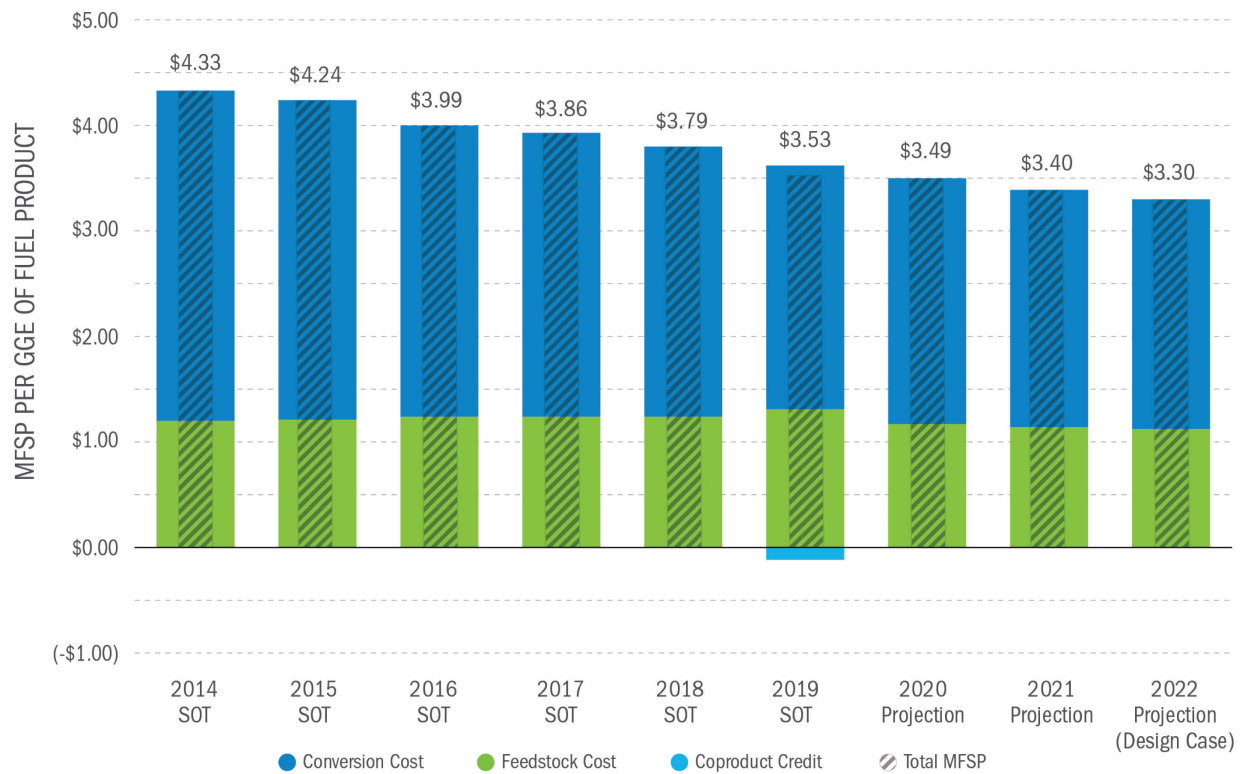


Figure 10: Feedstock and conversion cost contributions for the IDL design case

Feedstocks

As shown in Table 8, the IDL pathway has less stringent feedstock quality and physical composition requirements than the direct liquefaction pathway. The feedstock design for the IDL pathway utilizes a conventional system that delivers un-preprocessed wood chips from logging residue directly to the biorefinery. The ability to accommodate feedstocks derived from lower quality biomass along with less required preprocessing result in lower overall delivered feedstock costs for the IDL pathway.

Table 8: Delivered Feedstock Composition Specifications for the IDL Design Case

Component	Composition (dry wt %)
Carbon	49.81
Hydrogen	5.91
Nitrogen	0.17
Sulfur	0.09
Oxygen	41.02
Inorganic Species	≤3.00
Heating Value (Btu/lb)	8,449 HHV 7,856 LHV
Moisture (bulk wt %)	10.0
Particle Size	≤2" chips

Figure 11 and Table 9 show the projected feedstock costs delivered to the reactor throat for this design.²⁸ The 2018 woody SOT and 2020–2022 cases project a modeled delivered feedstock cost of \$60.54/dry ton. The cost of logging residue delivered to the reactor throat in the 2018 SOT increased by \$3.26/dry ton over the 2017 SOT due to projected reductions in material availability, necessitating greater travel distances and higher transportation costs.^{29,30,31,32} The 2019 SOT updates the 2018 SOT to utilize a blend of 50% pine logging residues and 50% clean pine, delivering 725,000 dry tons, with the location (Southeast region)

fed to the high availability of resources. The cost of the delivered feedstock for IDL increased by \$2.69/dry ton from the 2018 Woody SOT for IDL due to the incorporation of clean pine, which was partially offset by shrinking of the required draw radius. Logistics costs include harvest, collection, storage, transportation, and preprocessing costs from the point of harvest to the conversion reactor throat in-feed. The introduction of clean pine in the blend reduced the ash content to 1.75% to the benefit of conversion performance and yield.

The IDL design case currently includes the minimum process steps required to deliver feedstock that meets conversion quality specifications. However, these specifications and feedstock quality parameters may change as they are informed by future research to consider downstream impacts (e.g., feeding disruption, equipment wear, and pollution emissions) that can be caused by the large particle size and relatively high levels of inorganic species

²⁸ D. S. Hartley, D. N. Thompson, and H. Cai, *Woody Feedstocks 2019 State of Technology Report* (Idaho Falls, ID: Idaho National Laboratory, INL/EXT-20-57181, 2019), https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_21882.pdf.

²⁹ U.S. Department of Energy, edited by M. H. Langholtz, B. J. Stokes, and L. M. Eaton, *2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy, Volume 1: Economic Availability of Feedstocks* (Oak Ridge, TN: Oak Ridge National Laboratory, ORNL/TM-2016/160, 2016), https://www.energy.gov/sites/prod/files/2016/12/f34/2016_billion_ton_report_12.2.16_0.pdf.

³⁰ A. Dutta, K. Lisa, C. Mukarakate, M. Griffin, E. C. D. Tan, J. Schaidle, and D. Humbird et al., *Ex Situ Catalytic Fast Pyrolysis of Lignocellulosic Biomass to Hydrocarbon Fuels: 2018 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-71954, 2018), <https://www.nrel.gov/docs/fy19osti/71954.pdf>.

³¹ D. S. Hartley, D. N. Thompson, H. Hu, and H. Cai, *Woody Feedstock 2018 State of Technology* (Idaho Falls, ID: Idaho National Laboratory, INL/EXT-18-51655, 2018), https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_7464.pdf.

³² D. S. Hartley, D. N. Thompson, H. Hu, and H. Cai, *Woody Feedstock 2017 State of Technology* (Idaho Falls, ID: Idaho National Laboratory, INL/EXT-17-43459, 2017). This reference contains proprietary information, please contact Damon Hartley at damon.hartley@inl.gov for additional details.

for the feedstock composition shown in Table 8. The critical feedstock quality attributes of pine logging residues combined with clean pine and their impacts on the performance of unit operations and conversion yields need to be investigated and understood through the FCIC. The FCIC, as well as other FSL fundamental R&D, will quantify trade-offs between cost and yield improvement.

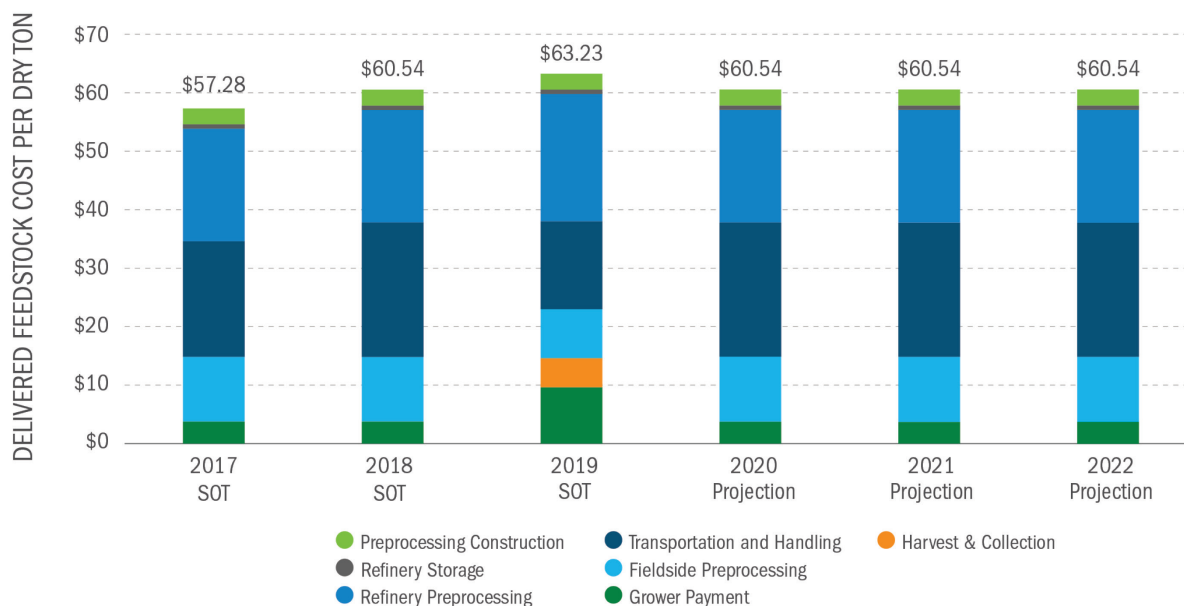


Figure 11: Cost contributions of on-spec feedstock delivered to the reactor throat for the IDL design case

Table 9: Cost Contributions of On-Spec Feedstock Delivered to Reactor Throat for the IDL Design Case

Cost per Dry Ton	2017 SOT	2018 SOT	2019 SOT	2020 Projection	2021 Projection	2022 Projection
Grower Payment	\$3.75	\$3.75	\$9.74	\$3.75	\$3.75	\$3.75
Harvest and Collection	\$0.00	\$0.00	\$4.94	\$0.00	\$0.00	\$0.00
Fieldside Preprocessing	\$11.08	\$11.08	\$8.41	\$11.08	\$11.08	\$11.08
Transportation and Handling	\$19.67	\$22.93	\$14.87	\$22.93	\$22.93	\$22.93
Refinery Preprocessing	\$19.38	\$19.38	\$21.87	\$19.38	\$19.38	\$19.38
Refinery Storage	\$0.67	\$0.67	\$0.67	\$0.67	\$0.67	\$0.67
Preprocessing Construction	\$2.73	\$2.73	\$2.73	\$2.73	\$2.73	\$2.73
Total Feedstock Production Cost	\$57.28	\$60.54	\$63.23	\$60.54	\$60.54	\$60.54

Figure 12 shows the impact of varying key operational parameters on feedstock cost. Because feedstock specifications for this design require minimal processing, relatively few model parameters impact the final delivered cost. The final parameters, which were chosen for their variability or their potential to cause variability in the preprocessing operations, were chipper throughput and energy consumption, and dryer throughput and energy consumption. Ranges were based on literature and observed process variation and compared with the 2022 design targets.^{33,34,35} The less stringent feedstock specifications for this pathway can significantly impact equipment energy consumption and throughput. Figure 12 shows that the delivered feedstock cost is most sensitive to chipper energy consumption, followed by chipper throughput. Chipper energy consumption is impacted by the variability in processing low-quality, low-cost logging residues. Throughput impacts are determined by distributing the capital equipment costs over the amount of material that is processed. When throughput decreases, the cost per unit increases; when throughput increases, costs decrease.

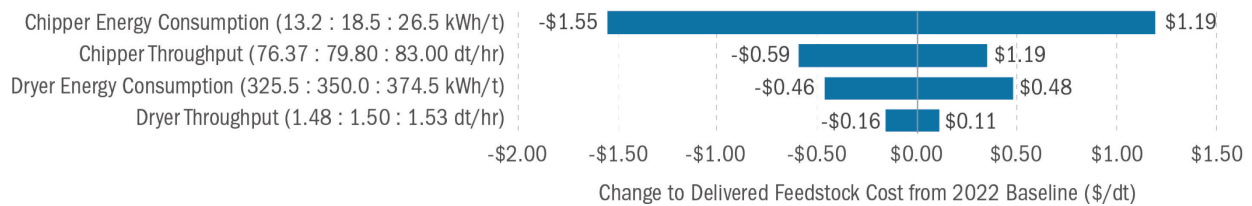


Figure 12: Impacts on cost of feedstock unit operations for the IDL design case

Logging residues and clean pine utilize conventional feedstock supply systems that are limited in their ability to adjust the quality of the material (for reference, see the appendix, barrier Ft-l). Reducing energy consumption and improving equipment throughput will require shifting to advanced feedstock supply systems with more active quality management and controls and additional preprocessing operations.

³³ C. W. Cao, D. Y. Yang, and Q. Liu, "Research on Modeling and Simulation of Mixed Flow Grain Dryer," *Drying Technology* 25, no. 4 (2007): 681–687, <https://doi.org/10.1080/07373930701290951>.

³⁴ R. Spinelli, E. Cavallo, A. Facello, N. Magagnotti, C. Nati, and G. Paletto, "Performance and energy efficiency of alternative comminution principles: chipping versus grinding," *Scandinavian Journal of Forest Research* 27, no. 4 (2012): 393–400, <https://doi.org/10.1080/02827581.2011.644577>.

³⁵ J. Thompson and W. Sprinkle, "Production, Cost and Chip Characteristics of In-Woods Microchipping," presented at the Council on Forest Engineering Annual Meeting, Missoula, Montana, July 7–10, 2013, https://www.srs.fs.usda.gov/pubs/ja/2013/ja_2013_thompson_001.pdf.

Conversion

In this design, woody biomass is converted to synthesis gas (i.e., syngas) via gasification, followed by gas cleanup and catalytic conversion of syngas to a methanol intermediate. The methanol intermediate is then dehydrated to dimethyl ether (DME) and catalytically converted via homologation reactions to high-octane gasoline (HOG) hydrocarbon fuel blendstocks. The resulting blendstock is high in branched paraffin content, similar to alkylates from petroleum refineries, and has a highly desirable octane number. This design case leverages technologies demonstrated in 2012 for the production of mixed alcohols from biomass^{36,37}; however, the HOG case uses much lower-severity fuel synthesis operating conditions, making it more economically competitive.

Similar to the direct liquefaction and upgrading pathway, many of BETO's efforts to reduce modeled fuel costs during upgrading focus on improving overall yield, increasing catalyst lifetime, and increasing process intensity (for reference, see the appendix, barriers Ct-E, Ct-F, Ct-G, and Ct-N). Figure 13 shows how these areas have a potentially high impact on the conversion contribution to the final modeled cost of fuel with this design.

Research for this pathway focuses on increasing the selectivity of C₅₊ products during upgrading with metal-modified beta-zeolite (BEA) catalysts.

³⁶ R. L. Bain, K. A. Magrini-Bair, J. E. Hensley, W. S. Jablonski, K. M. Smith, K R. Gaston, and M. M. Yung, "Pilot Scale Production of Mixed Alcohols from Wood," *Industrial & Engineering Chemistry Research* 53, no. 6 (2014): 2204–2218. <https://doi.org/10.1021/ie403631h>.

³⁷ A. Dutta, J. Hensley, R. Bain, K. Magrini, E. C. D. Tan, G. Apane, and D. Barton et al., "Technoeconomic Analysis for the Production of Mixed Alcohols via Indirect Gasification of Biomass Based on Demonstration Experiments," *Industrial & Engineering Chemistry Research* 53, no. 30 (2014): 12149–12159. <https://doi.org/10.1021/ie402045q>.

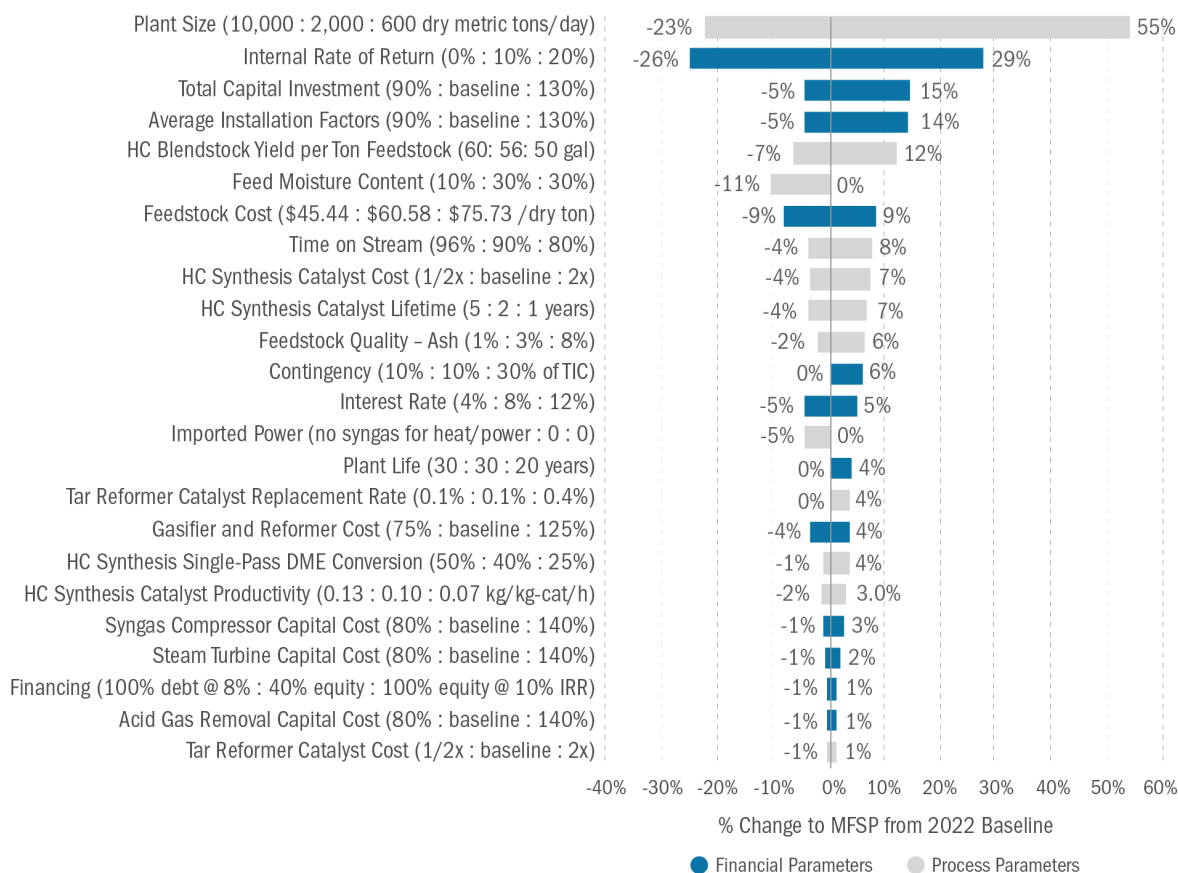


Figure 13: Key conversion factors impacting MFSP for the IDL design case

BETO currently supports work on computationally guided catalyst development with controlled ratios of ionic to metallic active sites to address this barrier through ChemCatBio and CCPC. ChemCatBio researchers also work to increase overall catalyst lifetime while maintaining higher selectivity. Recent SOT improvements shown in Figure 14 and Table 10 were achieved by increasing the single-pass DME conversion (from 19% in 2016 to 44% in 2019), and nearly doubling the hydrocarbon productivity over a Cu/BEA catalyst by operating at higher temperature and pressure.^{38,39}

³⁸ E. C. D. Tan, D. Ruddy, C. Nash, D. Dupuis, K. Harris, A. Dutta, D. Hartley, and H. Cai, *High-Octane Gasoline from Lignocellulosic Biomass via Syngas and Methanol/Dimethyl Ether Intermediates: 2019 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76619, 2020), <https://www.nrel.gov/docs/fy20osti/76619.pdf>.

³⁹ E. C. D. Tan, D. Ruddy, C. Nash, D. Dupuis, A. Dutta, D. Hartley, and H. Cai, *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, 2018), <https://www.nrel.gov/docs/fy19osti/71957.pdf>.

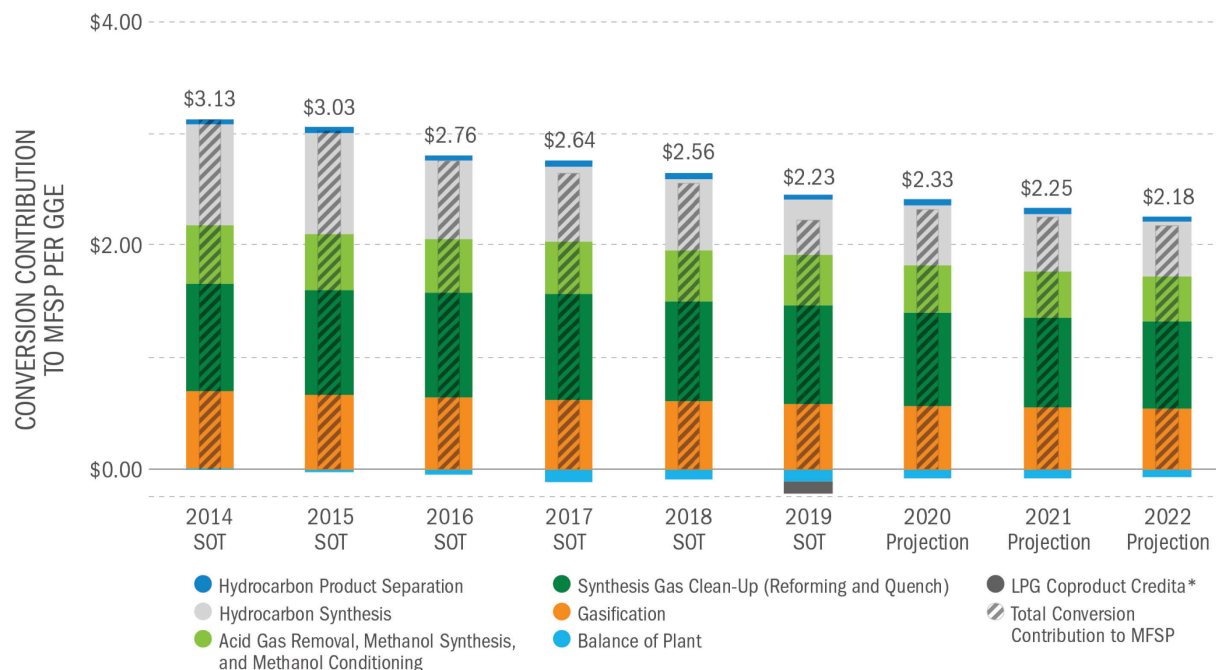


Figure 14: Conversion cost contributions for the IDL design case

Table 10: Conversion Cost Contributions for the Hydrocarbons via the IDL Design Case

Conversion Cost Breakdown (\$/GGE)	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	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
Balance of Plant	\$0.01	(\$0.02)	(\$0.05)	(\$0.11)	(\$0.09)	(\$0.09)	(\$0.11)	(\$0.08)	(\$0.07)
Liquefied Petroleum Gas (LPG) Coproduct Credit ^a	-	-	-	-	-	(\$0.11)	-	-	-
Conversion Contribution to MFSP	\$3.13	\$3.03	\$2.76	\$2.64	\$2.56	\$2.23	\$2.33	\$2.25	\$2.18

^a A small amount of LPG (primarily C₄s) coproduct was included in the FY19 SOT model to maintain C₄ recycle assumptions in the range of C₄ recycle tested experimentally.

Researchers have identified that understanding and controlling C₄ alkane dehydrogenation and alkene alkylation to maximize C₅₊ product selectivity remains the critical research challenge,

and accordingly, can significantly boost yields and reduce overall cost. The 2019 SOT focused on improvements in the recycling of C₄ hydrocarbons back to the DME-to-hydrocarbon reactor. The current process relies on a multi-step conversion of methanol to DME before upgrading to target fuels. Moving forward, research will also consider the possibility of utilizing alternate conversion methods of methanol to distillate fuels that are less severe or require fewer steps. Research on this pathway also considers the impact of using lower cost feedstocks on catalyst performance and the potential for utilization of waste streams such as CO₂ for coproduct production (for reference, see the appendix, barriers Ct-A, Ct-J, and Ct-K). The FCIC researches how feedstock quality impacts catalyst performance. If value-add coproducts are required to meet future cost targets, evaluating where in the process coproduct production can be introduced (either through new process steps or valorizing waste streams) will be critical. Research in this area is currently too preliminary to project 2030 modeled costs.

Table 11 presents the process efficiency metrics for the IDL design.

Table 12 includes the detailed cost and technical projections for the IDL design.

Table 11: Process Efficiency Metrics for the IDL Design Case

Sustainability and Process Efficiency Metrics	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 Projection	2021 Projection	2022 Projection (Design Case)
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 Coproduct	% 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/gal C ₅₊	11.7	11.8	7.9	8.4	8.1	7.6	7.4	7.2	7.0
Electricity Consumption	kWh/gal C ₅₊	11.7	11.8	7.9	8.5	8.1	7.6	7.4	7.2	7.0

Table 12: Unit Operation Cost Estimates and Technical Projections for Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels via Indirect Gasification and Methanol/DME Intermediates to High-Octane Gasoline

Processing Area Cost Contributions and 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, and Conversion to Hydrocarbons	Logging Residues	Logging Residues	Logging Residues	Logging Residues	Logging Residues	Logging Residues	50/50 Blend Logging Residues + Clean Pine	Logging Residues	Logging Residues	Logging Residues
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016	2016
C ₅₊ MFSP (per Actual Product Volume)	\$/gal	\$4.31	\$4.17	\$3.85	\$3.67	\$3.66	\$3.35	\$3.39	\$3.30	\$3.22
Mixed C ₄ MFSP (per Actual Product Volume) ^a	\$/gal	\$3.98	\$3.91	N/A	N/A	N/A	\$1.02	N/A	N/A	N/A
MFSP (per GGE)^a	\$/GGE	\$4.33	\$4.24	\$3.99	\$3.86	\$3.79	\$3.53	\$3.49	\$3.40	\$3.30
Conversion Contribution (per GGE) ^a	\$/GGE	\$3.13	\$3.03	\$2.76	\$2.64	\$2.56	\$2.23	\$2.33	\$2.25	\$2.18

Processing Area Cost Contributions and Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 Projection	2021 Projection	2022 Projection (Design Case)
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)	metric tons/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	gal/dry ton	36.2	36.4	51.4	50.0	51.4	51.6	54.1	55.1	56.0
Mixed C ₄ Coroduct Yield	gal/dry ton	16.3	16.2	0.0	0.0	0.0	5.6	0.0	0.0	0.0
Feedstock^b										
Total Cost Contribution	\$/GGE	\$1.20	\$1.21	\$1.24	\$1.22	\$1.23	\$1.31	\$1.17	\$1.14	\$1.12
Capital Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Operating Cost Contribution	\$/GGE	\$1.20	\$1.21	\$1.24	\$1.22	\$1.23	\$1.30	\$1.16	\$1.14	\$1.12
Feedstock Cost to Preheater	\$/dry ton	\$60.58	\$60.58	\$60.58	\$57.28	\$60.54	\$63.23	\$60.54	\$60.54	\$60.54
Additional Charge for Preheating	\$/dry 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 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 ₂ O	30%	30%	30%	30%	30%	30%	30%	30%	30%
Feed Moisture Content to Gasifier	wt % H ₂ O	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	\$/GGE	\$0.69	\$0.67	\$0.65	\$0.62	\$0.61	\$0.58	\$0.57	\$0.56	\$0.54
Capital Cost Contribution	\$/GGE	\$0.43	\$0.41	\$0.38	\$0.35	\$0.34	\$0.33	\$0.32	\$0.31	\$0.30

Processing Area Cost Contributions and Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 Projection	2021 Projection	2022 Projection (Design Case)
Operating Cost Contribution	\$/GGE	\$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)	mol %	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	\$/GGE	\$0.96	\$0.93	\$0.94	\$0.94	\$0.89	\$0.88	\$0.83	\$0.80	\$0.78
Capital Cost Contribution	\$/GGE	\$0.51	\$0.49	\$0.46	\$0.43	\$0.41	\$0.39	\$0.38	\$0.37	\$0.36
Operating Cost Contribution	\$/GGE	\$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)	mol %	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%
Acid Gas Removal, Methanol Synthesis, and Methanol Conditioning										
Total Cost Contribution	\$/GGE	\$0.52	\$0.50	\$0.47	\$0.47	\$0.45	\$0.45	\$0.42	\$0.41	\$0.40
Capital Cost Contribution	\$/GGE	\$0.35	\$0.33	\$0.30	\$0.28	\$0.28	\$0.27	\$0.26	\$0.25	\$0.24
Operating Cost Contribution	\$/GGE	\$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

Processing Area Cost Contributions and Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 Projection	2021 Projection	2022 Projection (Design Case)
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	gal/dry ton	143	142	138	144	141	137	137	136	134
Hydrocarbon Synthesis										
Total Cost Contribution	\$/GGE	\$0.91	\$0.91	\$0.70	\$0.67	\$0.64	\$0.49	\$0.54	\$0.51	\$0.48
Capital Cost Contribution	\$/GGE	\$0.56	\$0.56	\$0.46	\$0.44	\$0.42	\$0.34	\$0.36	\$0.34	\$0.32
Operating Cost Contribution	\$/GGE	\$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 BEA				National Renewable Energy Laboratory-modified BEA with Cu as active metal 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 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%

Processing Area Cost Contributions and Key Technical Parameters	Units	2014 SOT	2015 SOT	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2020 Projection	2021 Projection	2022 Projection (Design Case)
Carbon Selectivity to Coke and Precursors (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	\$/GGE	\$0.04	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05	\$0.05
Capital Cost Contribution	\$/GGE	\$0.03	\$0.03	\$0.04	\$0.04	\$0.04	\$0.03	\$0.04	\$0.03	\$0.03
Operating Cost Contribution	\$/GGE	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01
LPG Coproduct Credit										
Total Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$0.11)	\$0.00	\$0.00	\$0.00
Capital Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Operating Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	(\$0.11)	\$0.00	\$0.00	\$0.00
Balance of Plant										
Total Cost Contribution	\$/GGE	\$0.01	(\$0.02)	(\$0.05)	(\$0.11)	(\$0.09)	(\$0.11)	(\$0.08)	(\$0.08)	(\$0.07)
Capital Cost Contribution	\$/GGE	\$0.42	\$0.40	\$0.36	\$0.34	\$0.33	\$0.29	\$0.30	\$0.29	\$0.28
Operating Cost Contribution	\$/GGE	(\$0.41)	(\$0.42)	(\$0.42)	(\$0.45)	(\$0.42)	(\$0.41)	(\$0.38)	(\$0.37)	(\$0.36)

Integration and Scale-Up (Conversion and Advanced Development and Optimization)

Unit operations and processes proven at small-scale laboratory conditions would need to be scaled-up and assembled together in an integrated setup or pilot-scale facility to verify process performance. For this pathway, key integration challenges may include:

- Reliable and robust operations of feed handling systems, including feeding woody biomass into gasification reactors (for reference, see the appendix, barriers ADO-A and ADO-D)
- Addressing buildup of impurities in process recycle systems and its impact on catalyst performance and regeneration requirements for the conversion of syngas to high-octane gasoline blendstock (for reference, see the appendix, barrier ADO-F)
- The influence of inorganic species present in the feed on conversion efficiency to desired products (for reference, see the appendix, barrier ADO-F)
- Developing efficient product separation and purification schemes of syngas and high-octane gasoline
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barrier ADO-D)
- Minimizing abrasion and corrosion of plant equipment due to external contaminants present in the feed (for reference, see the appendix, barrier ADO-H).

Table 13: Supply Chain Sustainability Metrics for the IDL Design Case

	2016 SOT	2017 SOT	2018 SOT	2019 SOT	2022 Design Case	Petroleum Gasoline
Biofuel Yield						
MMBtu/dry ton	5.8	5.5	5.8	6.3	6.3	
Fossil Energy Consumption^a						
MJ/MJ	0.20 (-84%)	0.20 (-84%)	0.19 (-85%)	0.20 (-84%)	0.17 (-86%)	1.25
Net Energy Balance^b						
MJ/MJ	0.80	0.80	0.81	0.80	0.83	
GHG Emissions						
g CO ₂ e/MJ	16 (-83%)	17 (-82%)	16 (-83%)	21 (-78%)	14 (-85%)	95
g CO ₂ e/GGE	2,020	2,065	1,993	2,530	1,735	11,671
Water Consumption						
gal/MJ	0.04	0.04	0.04	0.04	0.03	0.03
gal/GGE	4.4	4.7	4.5	4.5	3.8	3.1
Total NO_x Emissions						
g NO _x /MJ	0.25	0.26	0.25	0.18	0.23	0.06
g NO _x /GGE	30.5	32.0	30.6	22.3	28.2	7.1
Urban NO_x Emissions^c						
g NO _x /MJ	0.020	0.020	0.020	0.021	0.020	0.024
g NO _x /GGE	2.4	2.4	2.4	2.5	2.4	2.9

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values.

^a This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

^b Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

^c Urban NO_x emissions account for emissions that occur in municipal statistical areas.

Supply Chain Sustainability Analysis

The SCSA for the IDL design assumes pine logging residues for the 2016, 2017, and 2018 SOTs and the 2022 feedstock design. The SCSA for the 2019 SOT assumes a combination

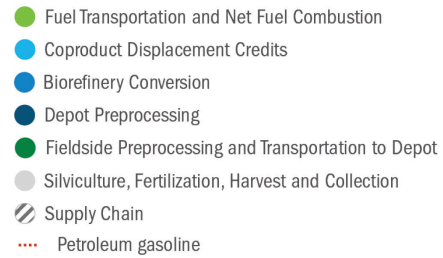
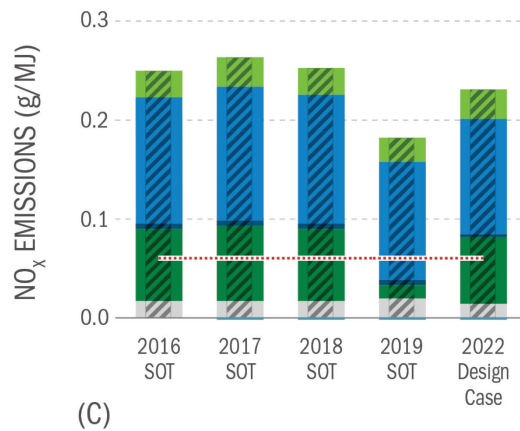
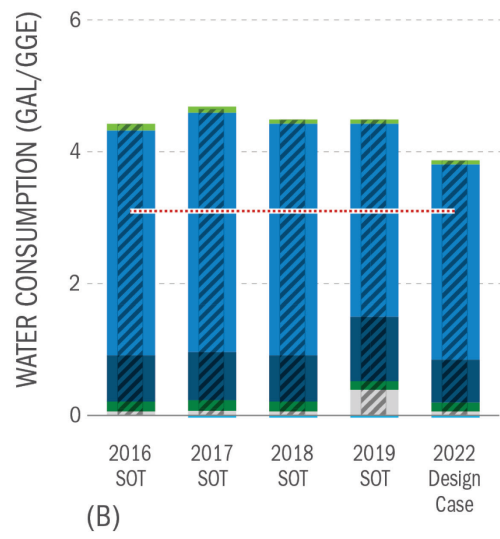
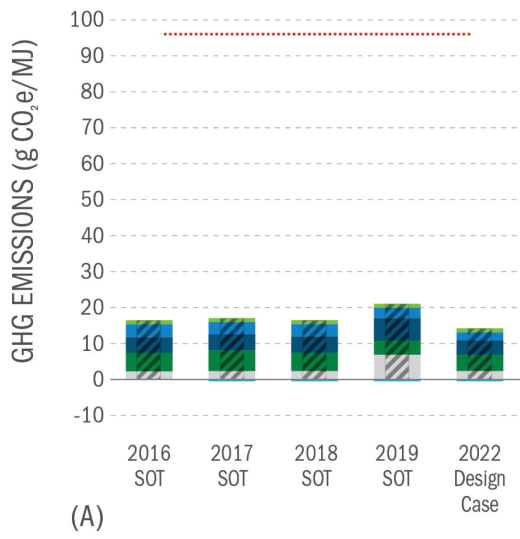
of pine logging residues and clean pine chips. The logging residues and clean pine do not require air classification or preprocessing in any of the SOT feedstock cases. Table 13 summarizes the supply chain sustainability metrics evaluated for the 2016–2019 SOT cases, as well as for the 2022 design case for the IDL design.⁴⁰

Figure 15A shows the supply chain GHG emissions and their key contributing supply chain processes, in g CO₂e/MJ. The GHG reductions of the SOT and design cases are relative to a life cycle carbon intensity of 95 g CO₂e/MJ for petroleum-derived gasoline. Figure 15A shows that a total GHG reduction of 85% compared to petroleum gasoline can be achieved by 2022 through reducing energy consumption in feedstock logistics, especially at the fieldside preprocessing step, and improvement in biofuel yield.

Figure 15B shows that reducing water consumption from about 4.4 gal/GGE in the 2016 SOT case to about 3.8 gal/GGE in the 2022 design case projection can be achieved through using low water-intensity feedstock (such as logging residues), switching from water-cooling technologies to novel air-cooling technologies in the conversion process, and improving biofuel yield.

Figure 15C shows that NO_x emissions exceed those of petroleum gasoline for all the SOT results and 2022 design case projections. The greatest opportunities for NO_x emission reduction is in NO_x emissions control of combusting intermediate bio-char and fuel gas inside of the biorefinery for process heat.

⁴⁰ H. Cai, L. Ou, M. Wang, E. Tan, R. Davis, A. Dutta, and L. Tao et al., *Supply Chain Sustainability Analysis of Renewable Hydrocarbon Fuels via Indirect Liquefaction, Ex Situ Catalytic Fast Pyrolysis, Hydrothermal Liquefaction, Combined Algal Processing, and Biochemical Conversion: Update of the 2019 State-of-Technology Cases* (Lemont, IL: Argonne National Laboratory, ANL/ESD-20/2, 2020), https://greet.es.anl.gov/publication-renewable_hc_2019.



Figures 15A–15C: Supply chain for the IDL design case for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions⁴¹

⁴¹ 2019 SOT data assumes a feedstock of 50% clean pine and 50% forest residues while all other years, including the 2022 projection, assume a feedstock of 100% forest residue. This impacts many of the SCSA metrics. Results from 2019 will be incorporated into future projections in outyear analyses. Additional details are available in the SOT reports referenced earlier.

Dry Feedstocks Converted via Low Temperature and Upgrading

Research into the pathway for dry feedstocks converted via low temperature and upgrading helps BETO identify key challenges and informs R&D priorities associated with areas including deconstruction of lignocellulosic biomass, hybrid conversion approaches (a combination of biochemical and catalytic), separation of desired intermediates, and upgrading of lignin. The design case configurations used to assess progress of technologies used in this pathway include low-temperature deconstruction of biomass into sugars and lignin, followed by fermentation of sugars to either a 2,3- BDO or mixed-acid intermediate followed by catalytic conversion of the resulting intermediate streams into fuels and coproducts as illustrated in Figure 16.⁴² The TEAs for these two design case variations for this pathway are described separately and the SCSA results for the two designs are presented together.

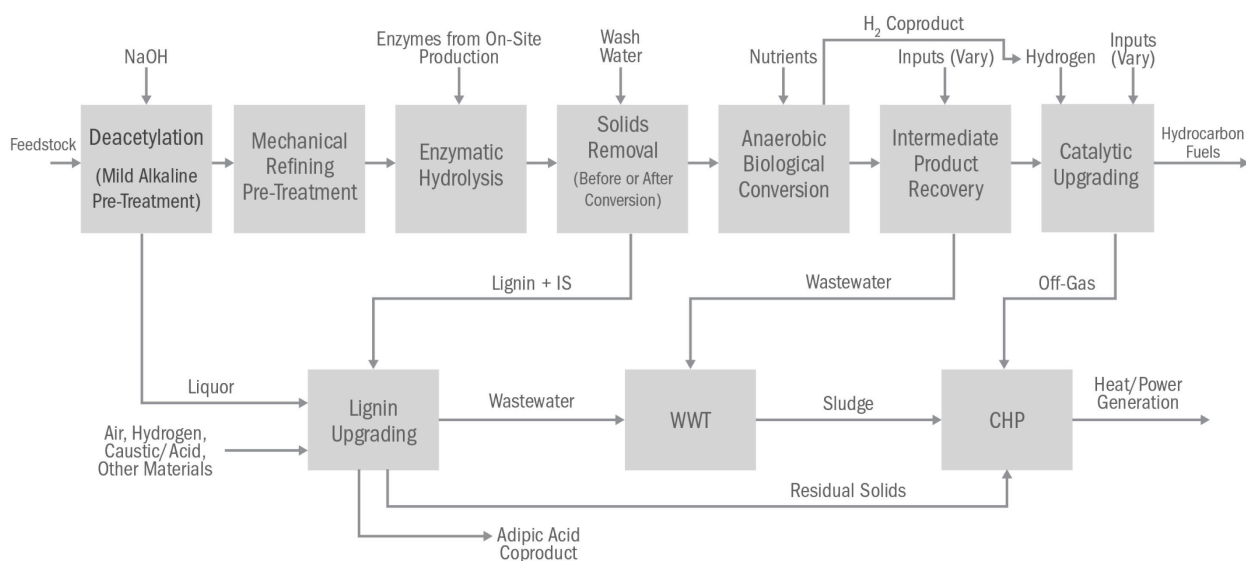


Figure 16: Process flow diagram for the conversion of dry feedstocks to hydrocarbon fuel and products via low-temperature deconstruction and upgrading

Feedstocks

The composition (including chemical, mechanical, and physical properties) of feedstocks being fed into the conversion processes is a key determinant of their convertibility into biofuels. MFSP

⁴² R. Davis, N. Grundl, L. Tao, M. J. Bidy, E. C. D. Tan, G. T. Beckham, D. Humbird, D. N. Thompson, and M. S. Roni, *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels and Coproducts: 2018 Biochemical Design Case Update* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-71949, 2018), <https://www.nrel.gov/docs/fy19osti/71949.pdf>.

projections for both low-temperature designs assume the compositional specifications shown in Table 14 can be met at the given delivered feedstock cost goal.⁴³

Table 14: Feedstock Composition Specifications for Low-Temperature Pathway Design Cases

Component	Composition (dry wt %)
Glucan	35.1
Xylan	19.5
Lignin	15.8
Inorganic Species	4.9
Acetate	1.8
Protein	3.1
Extractives	14.7
Arabinan	2.4
Galactan	1.4
Mannan	0.6
Sucrose	0.8
Total Structural Carbohydrate	59.0
Total Structure Carbohydrate Plus Sucrose	59.8
Moisture (bulk wt %)	20.0

The low-temperature pathway design case specifications assume use of herbaceous feedstocks (corn stover or a blend). Herbaceous biomass can be costly to handle, transport, and convey because of its low bulk density, high inorganic species content, fibrous nature, and relatively high and inconsistent moisture. It is subject to dry matter loss and degraded quality during biomass storage (for reference, see the appendix, barriers Ft-E, Ft-F, Ft-G, and Ft-J). FSL R&D focuses on understanding feedstock variability and interactions between feedstock quality and conversion performance, and on developing preprocessing technologies that can preserve and improve the physical,

chemical, and mechanical properties of harvested biomass. FSL R&D also explores how developing active feedstock quality post-harvest management (such as storage) and other preprocessing technologies (such as advanced fractionation, blending and formulation, and densification), could enable lignocellulosic biomass as well as low-cost and low-quality economically advantaged feedstock (such as municipal solid wastes) to be effectively fractionated and processed to meet conversion process in-feed specifications at cost targets.

The modeled delivered costs of on-spec herbaceous feedstocks for the low-temperature designs are shown in Figure 17 and Table 15.⁴⁴ The delivered cost of \$83.90/dry ton achieved by the 2017 SOT⁴⁵ exceeded the target set forth in the *2016 Multi-Year Program*

⁴³ R. Davis, N. Grundl, L. Tao, M. J. Bidy, E. C. D. Tan, G. T. Beckham, D. Humbird, D. N. Thompson, and M. S. Roni, *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels and Coproducts: 2018 Biochemical Design Case Update* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-71949, 2018), <https://www.nrel.gov/docs/fy19osti/71949.pdf>.

⁴⁴ M. Roni, Y. Lin, M. Griffel, D. Hartley, and D. N. Thompson, *Herbaceous Feedstock 2019 State of Technology Report* (Idaho Falls, ID: Idaho National Laboratory, INL/EXT-20-57182-Revision-0, 2020), https://indigitalibrary.inl.gov/sites/sti/sti/Sort_21886.pdf.

⁴⁵ M. Roni, D. N. Thompson, H. Hu, D. Hartley, Q. Nguyen, and H. Cai, *Herbaceous Feedstock 2017 State of Technology Report* (Idaho Falls, ID: Idaho National Laboratory, 2017). Reference contains proprietary information, please contact Damon Hartley at damon.hartley@inl.gov for additional details.

Plan⁴⁶ of \$85.04/dry ton (2016\$, originally \$84/ton in 2014\$). The 2019 herbaceous SOT feedstock cost, based on equipment and processes available now or in the near term is \$81.37/dry ton and represents a \$2.30/dry ton decrease from 2018.⁴⁷ The decreases in SOT costs are due to the incorporation of several technology changes in feedstock preprocessing, opportunities stemming from the integrated landscape management strategy, and reduced biomass access cost due to increased grower participation—while maintaining or improving grower profitability. All designs assume 90% time-on-stream performance of the feedstock preprocessing depots.

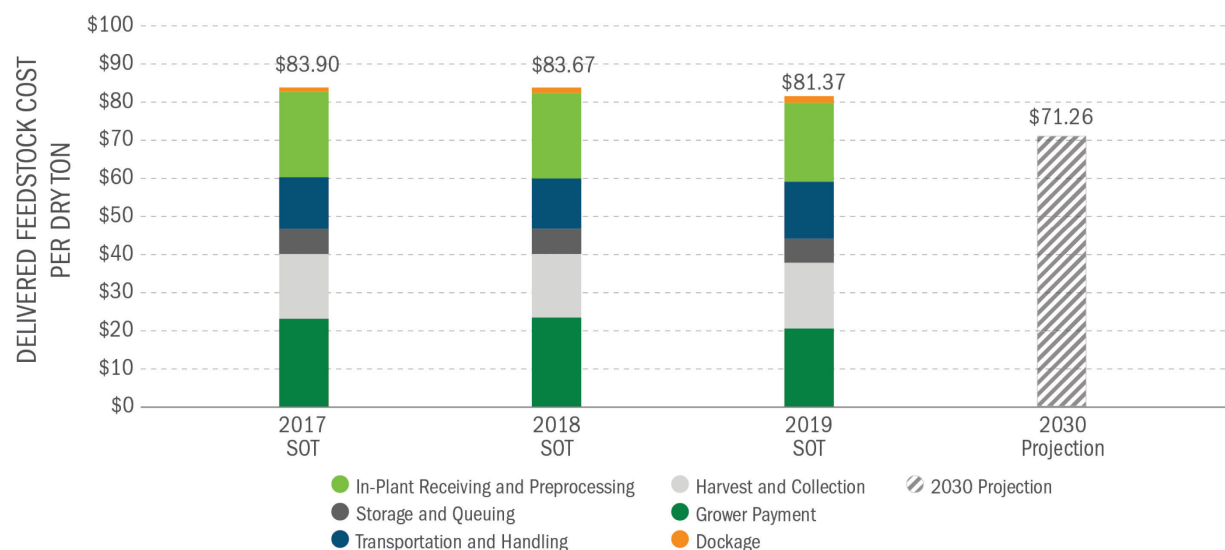


Figure 17: Cost contributions from herbaceous feedstock delivered to reactor throat for low-temperature design cases

⁴⁶ U.S. Department of Energy, *Bioenergy Technologies Office 2016 Multi-Year Program Plan* (Washington, DC: U.S. Department of Energy, DOE/EE-1385, 2016). https://www.energy.gov/sites/prod/files/2016/07/f33/mypp_march2016.pdf.

⁴⁷ M. Roni, D. S. Hartley, M. Griffel, H. Hu, Y. Lin, Q. Nguyen, H. Cai, and D. N. Thompson, *Herbaceous Feedstock 2018 State of Technology Report* (Idaho Falls, ID: Idaho National Laboratory, INL/EXT-18-51654-Revision-0, 2020), https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_7462.pdf.

Table 15: Cost Contributions from Herbaceous Feedstock Delivered to Reactor Throat for Low-Temperature Design Cases

Cost per Dry Ton	2017 SOT	2018 SOT	2019 SOT	2030 Projection
Feedstock Type	Blend ^a	Blend ^b	Blend ^c	Blend ^d
Grower Payment	\$23.24	\$23.54	\$20.56	TBD
Harvest and Collection	\$16.91	\$16.68	\$17.14	TBD
Storage and Queuing	\$6.54	\$6.45	\$6.49	TBD
In-Plant Receiving and Preprocessing ^e	\$22.52	\$22.49	\$20.84	TBD
Transportation and Handling	\$13.43	\$13.23	\$14.76	TBD
Dockage ^f	\$1.27	\$1.27	\$1.58	TBD
Delivered Feedstock Price	\$83.90	\$83.67	\$81.37	\$71.26^g

^a 2017 blend consists of 12.15% three-pass corn stover, 75.72% two-pass stover, 8.23% switchgrass, and 3.91% grass clippings.

^b 2018 blend consists of 12.74% three-pass corn stover, 73.22% two-pass stover, 9.83% switchgrass, and 4.21% grass clippings.

^c 2019 blend consists of 33.33% three-pass corn stover and 66.67% two-pass stover.

^d 2030 blend: TBD.

^e Includes depot deconstruction cost, bale processor, hammer mill, densifier, conveyors, blending equipment, dust collection equipment, bulk storage, and other miscellaneous equipment such as destringers, moisture meters, bale rejecters, and electromagnets used in preprocessing.

^f Dockage represents a cost adder over the baseline design needed to mitigate the impact of off-spec ash, moisture, and/or carbohydrate in the supplied biomass.

^g This out-year projection was established based on preliminary discussions between researchers and is expected to change as additional information becomes available. BETO will update these projections going forward as new research is completed.

Projected improvements between the SOT cases and the 2030 cost projection include:

- Incorporation of additional integrated land management strategies to reduce grower payments and increase biomass supply⁴⁸
- Optimized selection of biomass resource locations and depot sizes for least-cost blending
- Incorporating variable two-pass harvesting and collection methods to meet carbohydrate specifications

⁴⁸ M. Roni, Y. Lin, M. Griffel, D. Hartley, and D. N. Thompson, *Herbaceous Feedstock 2019 State of Technology Report* (Idaho Falls, ID: Idaho National Laboratory, INL/EXT-20-57182-Revision-0, 2020), https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_21886.pdf.

- Reduced dry matter losses from improved storage and handling
- The use of preprocessing and advanced fractionation equipment, for improved uniformity of biomass flow and critical quality attributes
- Improved size reduction, fractionation and conditioning performance to achieve high quality feedstock fractions and format
- Improved high-moisture pelleting throughput
- Lowering energy consumption due to low-moisture biomass from storage and eliminating cooling from high-moisture densification preprocessing.

Small improvements are also projected in transportation and handling costs. These costs are expected to be slightly offset by increased inorganic species in the blend (e.g., three-pass corn stover and grass clippings).

Figure 18 shows the impact of varying key operational parameters on delivered feedstock cost for the low-temperature design, based on actual process experience and from literature. Interest rate, hammer mill throughput, baling rate, bale density, and storage dry matter loss had the greatest impact. Costs are impacted by equipment performance (such as throughput and energy consumption) that is heavily impacted by the feedstock's physical, chemical, and mechanical properties (for reference, see the appendix, barriers Ft-E and Ft-J). Dry matter loss due to insufficient moisture management also impacts costs. The FCIC conducts research to develop a fundamental understanding of interactions between feedstock quality properties and preprocessing equipment performance (e.g., energy consumption, throughput, material loss, and wear) to identify underlying factors, critical quality attributes and critical process parameters that can support developing technologies that improve feedstock quality, reduce delivered feedstock cost, and improve feedstock preprocessing efficiency. The FCIC and FSL R&D also examines the gap between nth-plant design case assumptions and actual first-of-a-kind plant experience. These findings will shape future design case assumptions and inform future R&D needs.

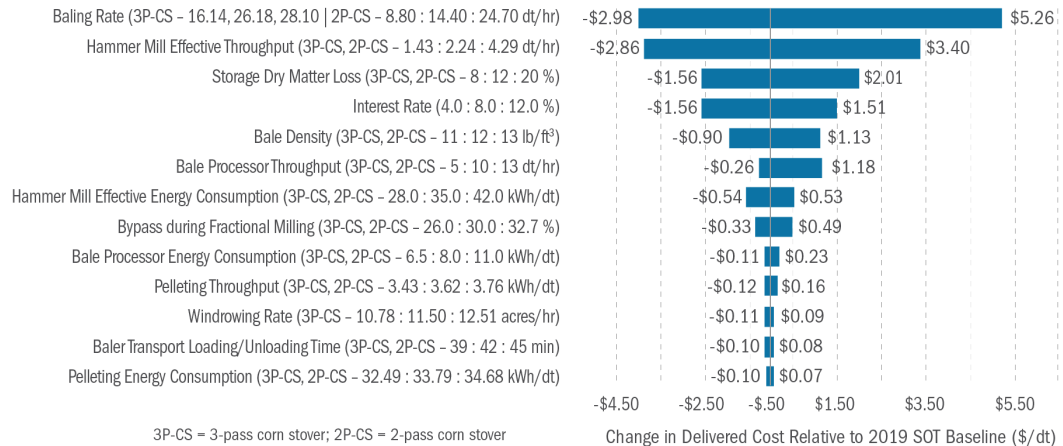


Figure 18: Key operational factors impacting costs in the 2019 herbaceous feedstock SOT design

Hydrocarbon Fuels and Coproducts from Dry Feedstocks via 2,3-BDO Intermediate Design Case

Figure 19 shows the modeled SOT and projected future production costs for the 2,3-BDO intermediate design case broken down by feedstock and conversion contributions.⁴⁹

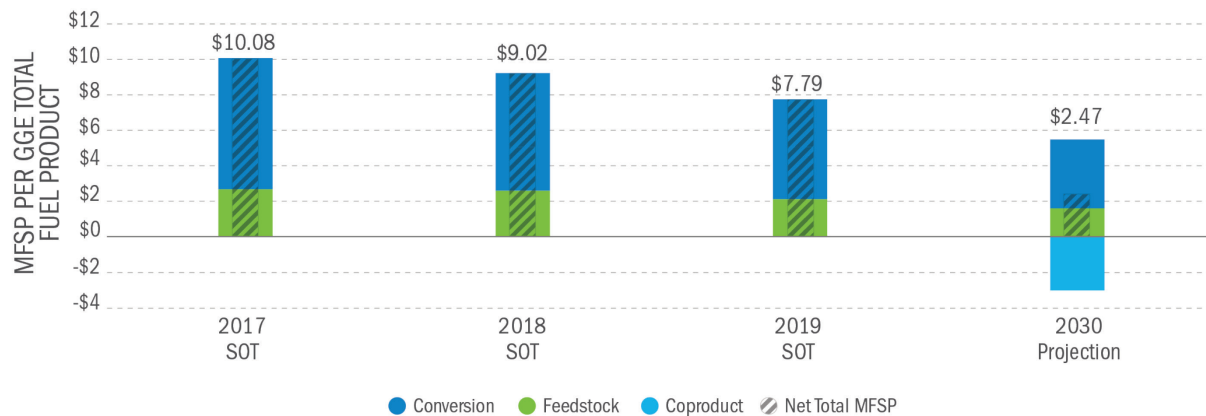


Figure 19: Cost contribution of feedstocks and conversion for the hydrocarbon biofuels 2,3-BDO intermediate design case

Conversion

This conversion process design case is based on deacetylation and mechanical refining (DMR) pretreatment of corn stover, followed by hydrolysis with cellulase and hemicellulase enzymes.

⁴⁹ R. Davis, A. Bartling, and L. Tao, *Biochemical Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels and Products: 2019 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76567, 2020), <https://www.nrel.gov/docs/fy20osti/76567.pdf>.

The resulting whole-slurry hydrolysate including solids is routed to fermentation with an engineered *Zymomonas mobilis* organism to produce 2,3-BDO.

The aqueous 2,3-BDO product is clarified and then undergoes a series of catalytic upgrading steps: dehydration, oligomerization, and hydroprocessing to produce finished hydrocarbon fuels. The lignin streams from the pretreatment and post-fermentation solids removal steps are commingled and undergo a separate upgrading process, starting with deconstruction to monomers and followed by upgrading to coproducts (adipic acid in this case). The revenue from this coproduct stream helps offset biorefinery costs of producing the hydrocarbon biofuel and reduces net MFSP.

Figure 20 illustrates that several of the largest sensitivity impacts to fuel selling price pertain to lignin deconstruction and upgrading (i.e., metabolically accessible lignin and the productivity of muconic acid, an intermediate). Based on experiments completed in 2019, and as shown in Figure 21, the current state of technology for lignin upgrading actually results in an increase in the net MFSP compared to SOT designs wherein lignin is sent to a boiler and combusted for heat and power.

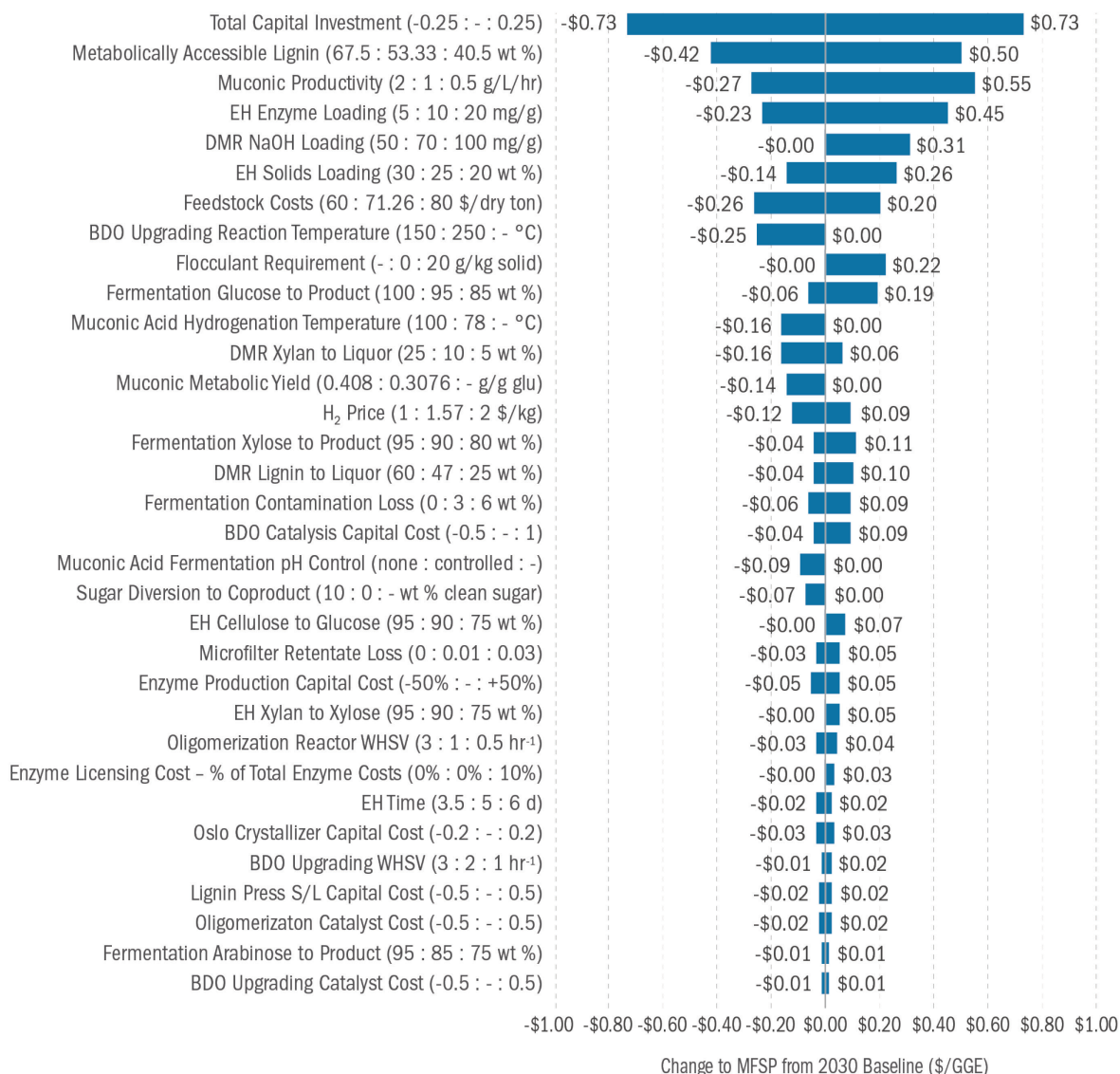


Figure 20: Major cost factors in the production of hydrocarbon biofuels via the 2,3-BDO intermediate design case

Future improvements to lignin deconstruction and upgrading are expected to achieve higher yields and, as technical performance improves, the revenue from coproducts is projected to lower MFSP (for reference, see the appendix, barriers Ct-C, Ct-F, and Ct-J). Figure 21 shows that meeting 2030 technical targets for lignin conversion to a coproduct alone can result in more than \$2.5/GGE net decrease in MFSP. Multiple deconstruction chemistries are being explored, including heterogeneous catalysis, solvent-based hydrolysis, and enzymatic treatments, all of which target specific linkages between lignin monomers to convert lignin macromolecules into smaller molecular weight species. For each of these deconstruction processes, ChemCatBio

R&D is focused on developing low-cost, robust catalysts to perform these oxidative and reductive chemistries. Additional R&D strategies to achieve ultimate goals for lignin deconstruction and upgrading include the use of solvents to drive toward higher levels of metabolically accessible lignin and, by extension, coproducts.

Conversion yields for each conversion step are also critical to achieving technical and economic feasibility. For the carbohydrate fractions, bioprocess development is critical to achieving high yields, rates of product formation, and product titers. Researchers employ genetic engineering to maximize the production of 2,3-BDO from carbohydrates, including:

- Knocking out competing metabolic pathways
- Heterologous expression of more active enzymes, and adaptation to higher concentrations of the resulting products
- Leveraging high-throughput genetic transformation techniques and genetic tools developed under the Agile BioFoundry (for reference, see the appendix, barriers Ct-D and Ct-L).

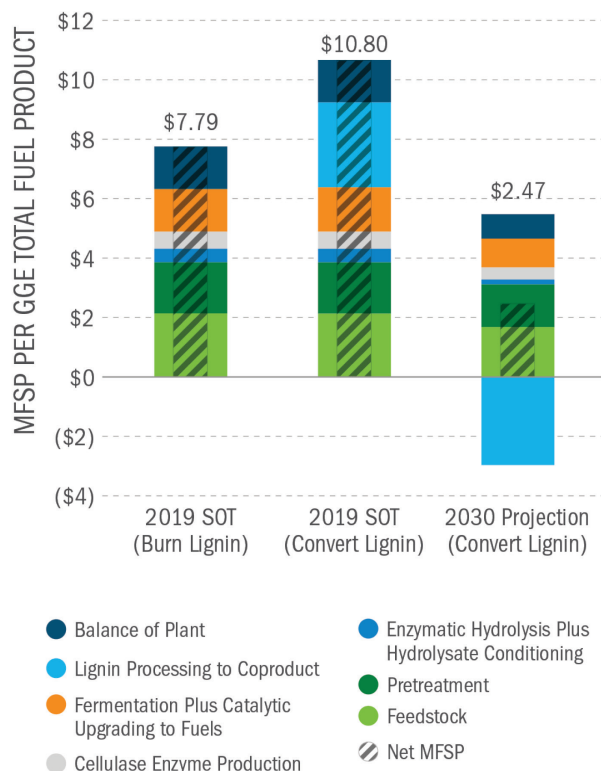


Figure 21: Modeled hydrocarbon biofuels production costs via the 2,3-BDO intermediate design case comparing SOT lignin conversion to coproduct versus burning

Figure 22 and Table 16 show significant decreases in modeled costs from knocking out competing metabolic pathways and increasing the titer of the 2,3-BDO as well as moving towards fermentation on whole-slurry hydrolysate rather than clarified sugars. These organism improvements have cascading economic impacts: increasing overall fuel yields, reducing the capital intensity of the process, and reducing the need for 2,3-BDO concentration prior to catalytic upgrading.

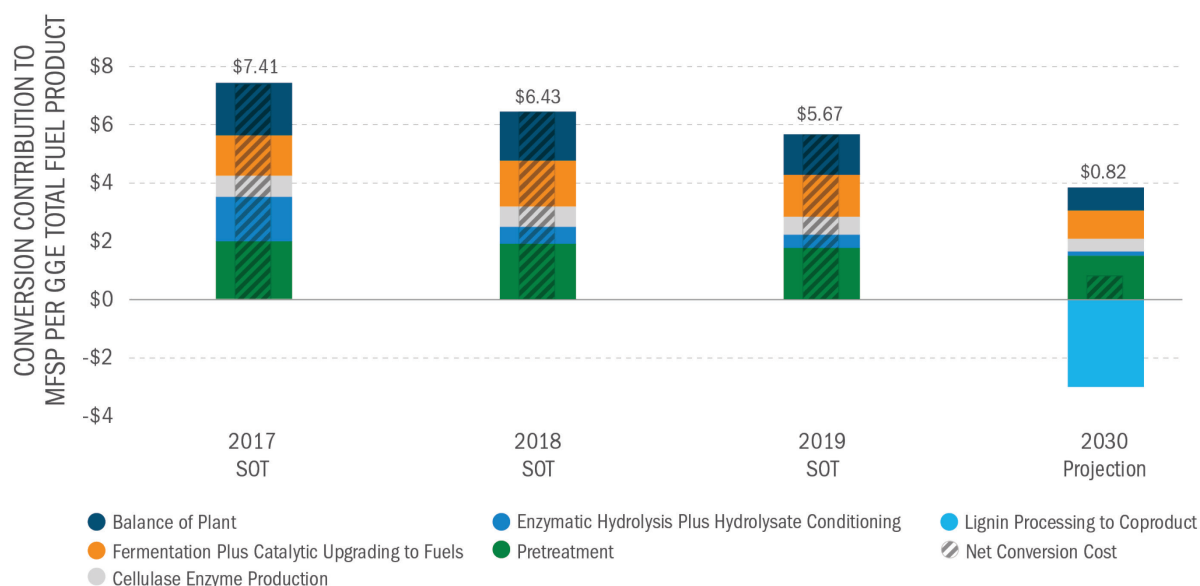


Figure 22: Conversion cost contributions for hydrocarbon biofuels via the 2,3-BDO intermediate design case

Table 16: Conversion Cost Contributions for Hydrocarbon Biofuels via the 2,3-BDO Intermediate Design Case

Conversion Cost Breakdown (\$/GGE)	2017 SOT	2018 SOT	2019 SOT	2030 Projection (Design Case)
Pretreatment	\$1.97	\$1.89	\$1.73	\$1.48
Enzymatic Hydrolysis + Hydrolysate Conditioning	\$1.53	\$0.58	\$0.47	\$0.15
Cellulase Enzyme Production	\$0.72	\$0.70	\$0.59	\$0.44
Fermentation + Catalytic Upgrading to Fuels	\$1.39	\$1.57	\$1.45	\$0.97
Lignin Processing to Coproduct	\$0.00	\$0.00	\$0.00	(\$3.00)
Balance of Plant	\$1.80	\$1.70	\$1.43	\$0.79
Net Conversion Contribution to MFSP	\$7.41	\$6.43	\$5.67	\$0.82

Other key areas for reducing MFSP include lowering reaction temperatures, reducing hydrogen requirements, and decreasing catalyst costs through improved catalyst lifetimes or novel chemistries (for reference, see the appendix, barriers Ct-E, Ct-F, and Ct-G). ChemCatBio activities focus on developing catalysts that can tolerate streams with >85% water (removing the need for intermediary evaporation steps) and developing oligomerization reactors that selectively produce jet- and diesel-range molecules.

Additional longer-term R&D activities include:

- Preprocessing and pretreatment improvements identified in the FCIC (for reference, see the appendix, barrier Ct-B)
- Developing next generation enzyme formulations and enzymatic hydrolysis processes (for reference, see the appendix, barrier Ct-B)
- Developing strategies to recapture and valorize waste streams, such as CO₂ and biogas (for reference, see the appendix, barrier Ct-H)
- Identifying and developing processes to produce novel coproducts from lignin or other streams, such as carbon fibers from lignin and coproducts from sugars (for reference, see the appendix, barriers Ct-J and Ct-K). The 2030 projection in Figure 22 and Table 16 illustrates the potential effect of such future technology development on MFSP.

Table 17 presents the process efficiency metrics for the 2,3-BDO intermediate design case.

Table 18 shows the detailed breakout of unit operation cost estimates and technical projections for this design.

Table 17: Process Efficiency Metrics for the 2,3-BDO Intermediate Design Case

Sustainability and Process Efficiency Metrics	Units	2017 SOT (Burn Lignin)	2018 SOT (Burn Lignin)	2019 SOT (Burn Lignin)	2019 SOT (Convert Lignin)	2030 Projection (Convert Lignin Design Case)
Fuel Yield by Weight of Biomass	% w/w of dry biomass	9.6%	9.9%	11.7%	11.7%	13.2%
Carbon Efficiency to Fuels	% C in feedstock	18.2%	18.7%	22.1%	22.1%	25.0%
Carbon Efficiency to Lignin Coproduct	% C in feedstock	N/A	N/A	N/A	2.3%	14.8%
Net Electricity Import (Entire Process)	kWh/GGE	12.3	5.1	5.7	12.5	10.5
Purchased Natural Gas Import (Entire Process)	Btu/GGE (LHV)	0	0	0	69,928	14,596

Table 18: Unit Operation Cost Estimates and Technical Projections for Conversion of Dry Herbaceous Feedstocks to Hydrocarbon Fuels via the 2,3-BDO Intermediate Design Case

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2019 SOT	2030 Projection (Design Case)
Year Dollar Basis		2016	2016	2016	2016	2016
Lignin Handling		Burn Lignin	Burn Lignin	Burn Lignin	Convert Lignin ^a	Convert Lignin
Projected MFSP	\$/GGE	\$10.08	\$9.02	\$7.79	\$10.80	\$2.47
Feedstock Contribution	\$/GGE	\$2.67	\$2.59	\$2.11	\$2.11	\$1.65
Conversion Contribution	\$/GGE	\$7.41	\$6.43	\$5.67	\$8.69	\$0.82
Total Gasoline Equivalent Yield	GGE/dry ton	31.4	32.3	38.5	38.5	43.2
Adipic Acid Coproduct Yield	lb/dry ton biomass	0	0	0	42	266
Feedstock						
Total Cost Contribution	\$/GGE	\$2.67	\$2.59	\$2.12	\$2.11	\$1.65
Capital Cost Contribution	\$/GGE	N/A	N/A	N/A	N/A	N/A
Operating Cost Contribution	\$/GGE	\$2.67	\$2.59	\$2.12	\$2.11	\$1.65

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2019 SOT	2030 Projection (Design Case)
Feedstock Cost ^b	\$/dry ton	\$83.90	\$83.67	\$81.37	\$81.37	\$71.26
Pretreatment						
Total Cost Contribution	\$/GGE	\$1.97	\$1.89	\$1.73	\$1.74	\$1.48
Capital Cost Contribution	\$/GGE	\$0.47	\$0.45	\$0.38	\$0.40	\$0.38
Operating Cost Contribution	\$/GGE	\$1.50	\$1.45	\$1.35	\$1.34	\$1.10
Method	-	DMR	DMR	DMR	DMR	DMR
Solids Loading	wt %	20%	20%	20%	20%	30%
Temperature	°C	92	92	90	90	92
Reactor Mode	batch versus counter-current	batch	batch	batch	batch	counter-current
Total Caustic (NaOH) Loading	mg/g dry biomass	70	70	80	80	70
Net Solubilized Lignin to Liquor	%	47%	47%	50%	50%	47%
Net Solubilized Glucan to Liquor	%	2%	2%	2%	2%	2%
Net Solubilized Xylan to Liquor	%	17%	17%	16%	16%	10%
Net Solubilized Arabinan to Liquor	%	46%	46%	46%	46%	30%
Enzymatic Hydrolysis						
Total Cost Contribution	\$/GGE	\$1.53	\$0.58	\$0.47	\$0.47	\$0.15
Capital Cost Contribution	\$/GGE	\$0.78	\$0.19	\$0.17	\$0.18	\$0.12
Operating Cost Contribution	\$/GGE	\$0.75	\$0.39	\$0.30	\$0.29	\$0.03
Hydrolysis Configuration	batch versus continuous enzymatic hydrolysis	batch	batch	batch	batch	batch
Total Solids Loading to Hydrolysis	wt %	20%	20%	20%	20%	25%
Enzymatic Hydrolysis Batch Time	days	5	5	5	5	5
Hydrolysis Glucan to Glucose	%	78%	78%	84%	84%	90%

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2019 SOT	2030 Projection (Design Case)
Hydrolysis Xylan to Xylose	%	85%	85%	82%	82%	90%
Sugar Loss (into Solid Stream after Enzymatic Hydrolysis Separation)	%	5%	N/A (whole slurry)	N/A (whole slurry)	N/A (whole slurry)	N/A (whole slurry)
Cellulase Enzyme Production						
Total Cost Contribution	\$/GGE	\$0.72	\$0.70	\$0.59	\$0.59	\$0.44
Capital Cost Contribution	\$/GGE	\$0.14	\$0.13	\$0.11	\$0.12	\$0.09
Operating Cost Contribution	\$/GGE	\$0.58	\$0.57	\$0.48	\$0.47	\$0.35
Enzyme Loading	mg/g cellulose	12	12	12	12	10
Fermentation, Catalytic Conversion, and Upgrading to Fuels						
Total Cost Contribution	\$/GGE	\$1.39	\$1.57	\$1.45	\$1.47	\$0.97
Capital Cost Contribution	\$/GGE	\$0.52	\$0.67	\$0.59	\$0.61	\$0.48
Operating Cost Contribution	\$/GGE	\$0.87	\$0.90	\$0.86	\$0.86	\$0.49
Bioconversion Volumetric Productivity	g/L/hour	1.7	1.1	1.4	1.4	2.6
Glucose to Product [Total Glucose Utilization] ^c	%	86% [100%]	95% [100%]	96% [99.6%]	96% [99.6%]	95% [98%]
Xylose to Product [Total Xylose Utilization] ^c	%	89% [97%]	90% [92%]	89% [92%]	89% [92%]	90% [92%]
Arabinose to Product [Total Arabinose Utilization] ^c	%	0% [0%]	0% [0%]	0% [0%]	0% [0%]	85% [89%]
Bioconversion Metabolic Yield (Process Yield)	g/g sugars	0.44 (0.42)	0.48 (0.46)	0.49 (0.46)	0.49 (0.46)	0.47 (0.45)
Fermentation Intermediate Product Recovery	wt %	99.70%	96.80%	97.65%	97.65%	96.40%
Aqueous BDO Upgrading: WHSV	hr ⁻¹	1	1	1	1	2
Aqueous BDO Upgrading: Per-Pass Conversion	wt % to desired products	89%	90%	100%	100%	100%

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2019 SOT	2030 Projection (Design Case)
Oligomerization: WHSV	hr ⁻¹	1	1	1	1	1
Oligomerization: Per-Pass Conversion	wt % to desired products	100%	100%	100%	100%	100%
Hydrotreating: WHSV	hr ⁻¹	5	5	5	5	5
Hydrotreating: Per-Pass Conversion	wt % to desired products	100%	100%	100%	100%	100%
Lignin Processing to Coproduct						
Total Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$2.92	(\$3.00)
Capital Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$2.39	\$1.01
Operating Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.53	(\$4.01)
Solid Deconstruction to Soluble Lignin	Wt % BCD lignin feed	-	-	-	85% ^e	53%
Convertible Components in Soluble Lignin	Wt % of total soluble lignin (APL +BCD)	-	-	-	16%	98%
Muconic Acid Process Yield from Lignin	g/g soluble lignin	-	-	-	0.16	1.59
Muconic Acid Metabolic Yield from Lignin	g/g lignin consumed	-	-	-	0.93	0.93
Overall Carbon Upgrading Efficiency to Coproduct ^d	mol%	-	-	-	3.80%	27.80%
Muconic Acid Productivity	g/L/hr	-	-	-	0.06	1
Adipic Acid Production	MMlb/yr	-	-	-	30	193
Balance of Plant						
Total Cost Contribution	\$/GGE	\$1.80	\$1.70	\$1.43	\$1.50	\$0.79
Capital Cost Contribution	\$/GGE	\$1.32	\$1.51	\$1.25	\$1.11	\$0.80
Operating Cost Contribution	\$/GGE	\$0.48	\$0.19	\$0.18	\$0.39	(\$0.01)

^a FY19 lignin conversion “base case” reflects performance on actual black liquor/base-catalyzed depolymerization (BCD) hydrolysate (better performance observed for model lignin monomers).

- ^b Feedstock costs shown here based on a 5% “ash equivalent” and 20% “moisture equivalent” basis for all years considered, consistent with values provided by Idaho National Laboratory for total feedstock costs and associated ash and moisture “dockage” costs for each year.
- ^c First number represents sugar conversion to desired product (BDO/acids); values in parentheses indicate total sugar utilization (including biomass organism propagation).
- ^d Includes fermentation of all convertible components, product recovery (crystallization) efficiencies, and hydrogenation yields to adipic acid (overall convertible C to adipic acid).
- ^e SOT assumes only post-enzymatic hydrolysis lignin solids are routed through BCD; target cases route both lignin solids and DMR liquor through BCD. “Solubilized” lignin remains low in convertible components for SOT cases relative to future targets, translating to lower overall carbon efficiency to adipic acid coproduct.

Integration and Scale-Up (Conversion and Advanced Development and Optimization)

Unit operations and process steps developed at lab-scale R&D for this design must be integrated and tested to verify that technical targets can be achieved when run as an integrated process. Examples of key integration challenges for this pathway may include:

- Reliable and robust operations of feed handling systems, including feeding herbaceous feedstocks into the pretreatment reactor (for reference, see the appendix, barrier ADO-A)
- Optimizing the DMR process to reduce refining operation energy requirements
- Devising control strategies to improve operability and process flexibility (for reference, see the appendix, barrier ADO-A)
- Developing efficient product separation and purification schemes for separating solids and optimal separation of desired intermediates and products
- Addressing the buildup of impurities in process recycle systems and its impact on catalyst performance and regeneration requirements for the conversion of 2,3-BDO to hydrocarbon fuels (for reference, see the appendix, barrier ADO-F)
- The influence of inorganic species present in the feedstock on conversion efficiency to desired products (for reference, see the appendix, barrier ADO-F)
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barrier ADO-D)
- Minimizing abrasion and corrosion of plant equipment due to external contaminants present in the feed (for reference, see the appendix, barrier ADO-H).

Hydrocarbon Fuels and Coproducts via Mixed-Acids Intermediate Design Case

This design provides a second option for assessing the progress of technologies used in the dry feedstock conversion via the low-temperature and upgrading pathway. Research into this pathway helps identify challenges in biomass deconstruction, hybrid biochemical and catalytic conversion approaches, innovative separations of desired intermediates, and lignin upgrading.

Figure 23 shows the SOT and projected future production costs for the mixed-acids design broken into feedstock and conversion contributions⁵⁰

⁵⁰ R. Davis, A. Bartling, and L. Tao, *Biochemical Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels and Products: 2019 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76567, 2020), <https://www.nrel.gov/docs/fy20osti/76567.pdf>.

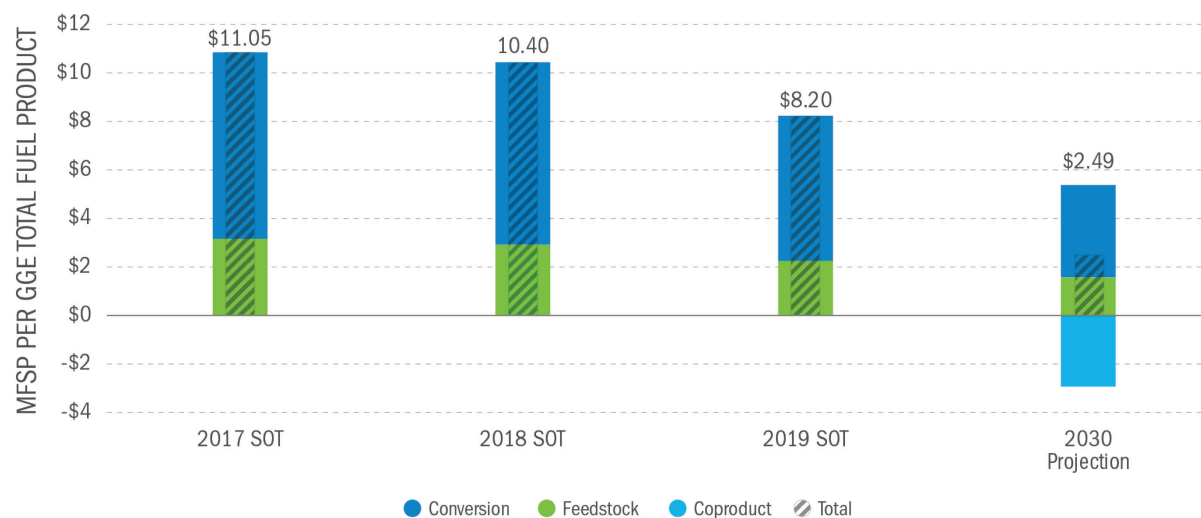


Figure 23: Cost contribution of feedstocks and conversion for hydrocarbon biofuels via the mixed-acid design

Conversion

This conversion design case uses DMR pretreatment of corn stover, followed by treatment with cellulase and hemicellulose enzymes in a novel continuous enzymatic hydrolysis (CEH) process with integrated solids removal. The sugar stream is concentrated for fermentation with an engineered *Clostridium* organism to produce acetic acid and butyric acids. These mixed-acids intermediates are recovered continuously from the fermentation broth via a membrane and extraction system prior to further purification. The resulting acids are catalytically upgraded, undergoing ketonization, condensation, and hydrodeoxygenation to produce jet- and diesel-range hydrocarbon fuels. Lignin streams from pretreatment and CEH filtration are commingled and upgraded to an adipic acid coproduct, whose revenue reduces net MFSP.

Figure 24 shows that many of the key cost drivers for this design are very similar to those in the 2,3-BDO intermediate design case, which illustrates how technological improvements for either of these designs would likely translate into cost improvements for a larger number of processes beyond these two configurations.

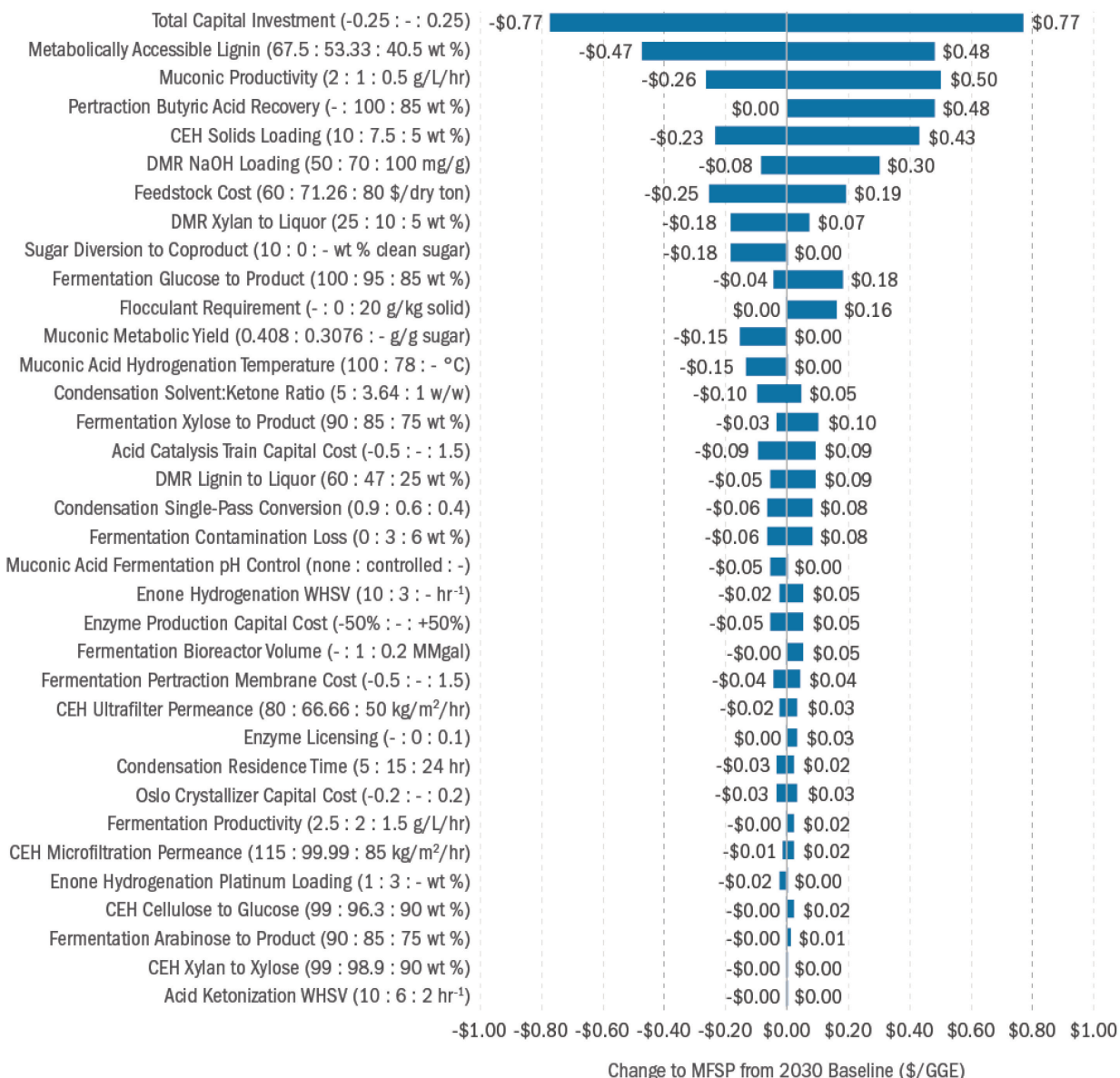


Figure 24: Major cost factors in the production of hydrocarbon biofuels via the mixed-acid intermediate design case

This design helps BETO identify a number of additional key areas for achieving future cost goals. For example, the fermentation to produce the mixed-acids intermediate is very closely integrated with acids recovery. Work within the Bioprocessing Separations Consortium has indicated that butyric acid more readily separates in the extractive separation process and that product yields are significantly higher when performed at a low pH (pH 5 and lower). To this end, BETO is prioritizing innovative approaches to simultaneously improve separation efficiency

of the acids during fermentation, genetically engineer the organism to function effectively under acidic conditions, and prioritize producing butyric acid. This continuous extraction approach also requires a novel fermentation configuration, improvements in long-term organism viability, and development of ways to avoid extraction membrane fouling to meet future year cost targets (for reference, see the appendix, barriers Ct-D and Ct-O).

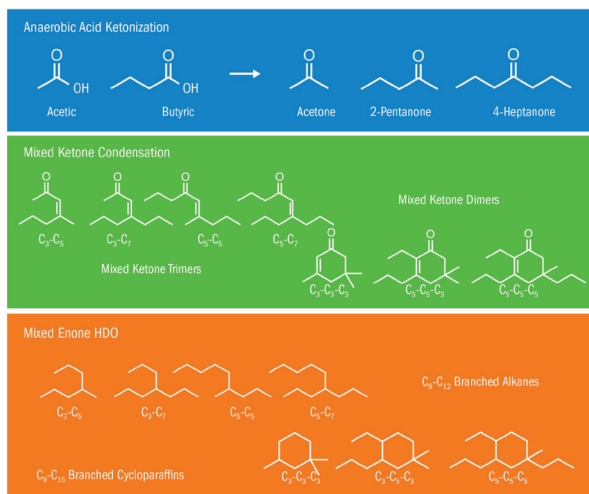


Figure 25: Mixed-acid catalytic upgrading reactions

Sensitivity analysis also identifies that following carboxylic acids purification, subsequent catalytic steps are key cost contributors. While the top-level barriers are similar to those discussed in the 2,3-BDO intermediate design case (for reference, see the appendix, barriers Ct-E, Ct-F, and Ct-G), in this design they are applied to significantly different chemical upgrading steps. In the catalytic first step, these acids can be coupled via ketonization. This step shows a further advantage of butyric acid, as each ketonization step results in the loss of a CO₂ equivalent, giving butyric acid

higher carbon efficiency compared to butyric/acetic or acetic/acetic acid coupling. ChemCatBio is developing catalysts capable of high yields irrespective of the acids ratios produced in the fermentation processes. After ketonization, efforts focus on decreasing the process capital intensity by combining the dehydration and reduction reactions in a single reactor. Like the ketonization catalytic steps, significant improvements can be achieved by developing catalysts that react the same regardless of the ketones supplied to the reactor (Figure 25).

Figure 26 and Table 19 show the cost contribution of conversion unit operations for this design case. Many additional early-stage research areas are part of BETO's broader strategy to reach future cost and performance goals, but are not reflected in the current modeled costs for this design.

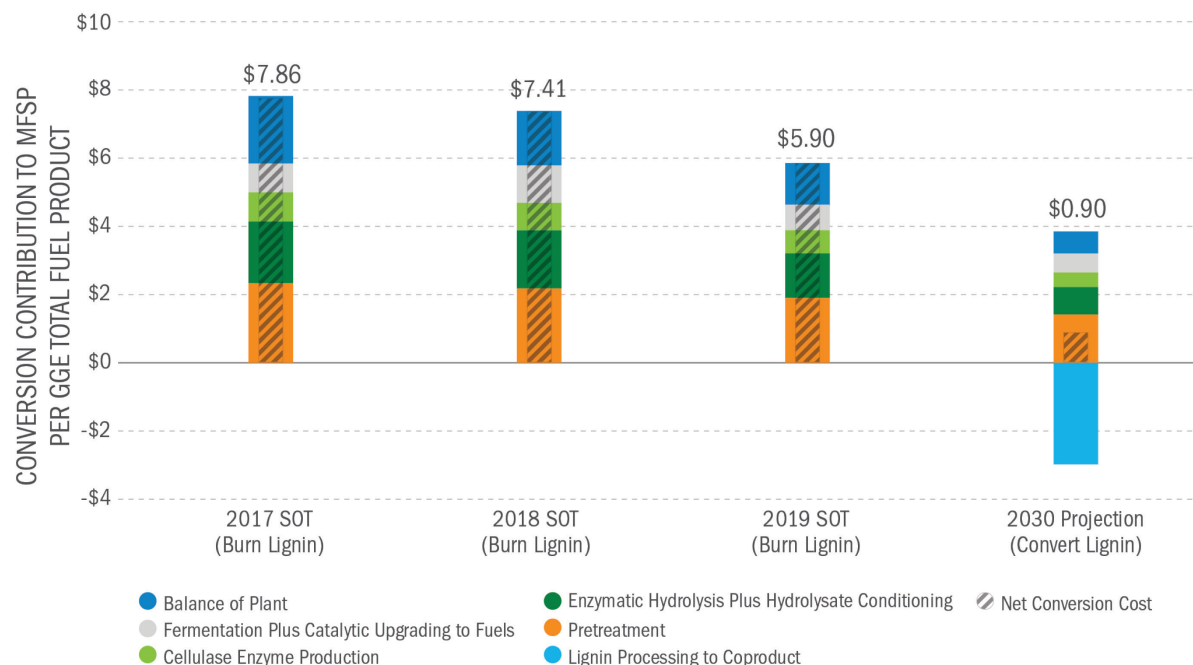


Figure 26: Conversion cost contributions for producing hydrocarbon biofuels via the mixed-acid intermediate design case

Table 19: Conversion Cost Contributions for Producing Hydrocarbon Biofuels via the Mixed-Acid Intermediate Design Case

Conversion Cost Breakdown (\$/GGE)	2017 SOT (Burn Lignin)	2018 SOT (Burn Lignin)	2019 SOT (Burn Lignin)	2030 Projection (Convert Lignin Design Case)
Pretreatment	\$2.34	\$2.19	\$1.89	\$1.42
Enzymatic Hydrolysis + Hydrolysate Conditioning	\$1.82	\$1.69	\$1.34	\$0.81
Cellulase Enzyme Production	\$0.86	\$0.81	\$0.64	\$0.43
Fermentation + Catalytic Upgrading to Fuels	\$0.85	\$1.09	\$0.73	\$0.56
Lignin Processing to Coproduct	\$0.00	\$0.00	\$0.00	(\$2.97)
Balance of Plant	\$1.99	\$1.63	\$1.30	\$0.65
Net Conversion Contribution to MFSP	\$7.86	\$7.41	\$5.90	\$0.90

Table 20 presents the process efficiency metrics for the mixed-acids intermediate design case.

Table 21 shows technical targets and a detailed breakdown of costs for this pathway

Table 20: Process Efficiency Metrics for the Mixed-Acids Intermediate Design Case

Sustainability and Process Metrics	Units	2017 SOT (Burn Lignin)	2018 SOT (Burn Lignin)	2019 SOT (Burn Lignin)	2019 SOT Convert Lignin (Base)	2030 Projection (Convert Lignin Design Case)
Fuel Yield by Weight of Biomass	% w/w of dry biomass	8.1%	8.6%	10.8%	10.8%	13.8%
Carbon Efficiency to Fuels	% C in feedstock	15.5%	16.3%	20.6%	20.6%	26.2%
Carbon Efficiency to Lignin Coproduct	% C in feedstock	NA	NA	NA	2.3%	14.4%
Net Electricity Import (Entire Process)	kWh/GGE	5.8	1.3	2.8	17.4	10.7
Purchased Natural Gas Import (Entire Process)	Btu/GGE (LHV)	0	15,790	11,803	11,803	9,055

Table 21: Unit Operation Cost Estimates and Technical Projections for Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels via the Mixed-Acid Intermediate Design Case

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2019 SOT	2030 Projection (Design Case)
Year Dollar Basis		2016	2016	2016	2016	2016
Lignin Handling		Burn Lignin	Burn Lignin	Burn Lignin	Convert Lignin ^a	Convert Lignin
Projected MFSP	\$/GGE	\$11.05	\$10.40	\$8.20	\$11.47	\$2.49
Feedstock Contribution	\$/GGE	\$3.19	\$2.99	\$2.30	\$2.30	\$1.59
Conversion Contribution	\$/GGE	\$7.86	\$7.41	\$5.90	\$9.17	\$0.90
Total Gasoline Equivalent Yield	GGE/dry ton	26.3	28	35.3	35.3	44.8
Adipic Acid Coproduct Yield	lb/dry ton biomass	0	0	0	42	259
Feedstock						
Total Cost Contribution	\$/GGE	\$3.19	\$2.99	\$2.30	\$2.30	\$1.59
Capital Cost Contribution	\$/GGE	NA	NA	NA	NA	NA
Operating Cost Contribution	\$/GGE	\$3.19	\$2.99	\$2.30	\$2.30	\$1.59

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2019 SOT	2030 Projection (Design Case)
Feedstock Cost ^b	\$/dry ton	\$83.90	\$83.67	\$81.37	\$81.37	\$71.26
Pretreatment						
Total Cost Contribution	\$/GGE	\$2.34	\$2.19	\$1.89	\$1.90	\$1.42
Capital Cost Contribution	\$/GGE	\$0.55	\$0.52	\$0.42	\$0.43	\$0.37
Operating Cost Contribution	\$/GGE	\$1.79	\$1.67	\$1.47	\$1.47	\$1.05
Method	-	DMR	DMR	DMR	DMR	DMR
Solids Loading	wt %	20%	20%	20%	20%	30%
Temperature	°C	92	92	90	90	92
Reactor Mode	batch versus counter-current	batch	batch	batch	batch	counter-current
Total Caustic (NaOH) Loading	mg/g dry biomass	70	70	80	80	70
Net Solubilized Lignin to Liquor	%	47%	47%	50%	50%	47%
Net Solubilized Glucan to Liquor	%	2%	2%	2%	2%	2%
Net Solubilized Xylan to Liquor	%	17%	17%	16%	16%	10%
Net Solubilized Arabinan to Liquor	%	46%	46%	46%	46%	30%
Enzymatic Hydrolysis						
Total Cost Contribution	\$/GGE	\$1.82	\$1.69	\$1.34	\$1.37	\$0.81
Capital Cost Contribution	\$/GGE	\$0.92	\$0.86	\$0.69	\$0.72	\$0.47
Operating Cost Contribution	\$/GGE	\$0.90	\$0.83	\$0.65	\$0.65	\$0.34
Hydrolysis Configuration	batch versus continuous enzymatic hydrolysis	batch	batch	batch	batch	continuous enzymatic hydrolysis
Total Solids Loading to Hydrolysis	wt %	20%	20%	20%	20%	7.60%
Enzymatic Hydrolysis Batch Time	days	5	5	5	5	continuous
Hydrolysis Glucan to Glucose	%	78%	78%	84%	84%	96%

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2019 SOT	2030 Projection (Design Case)
Hydrolysis Xylan to Xylose	%	85%	85%	82%	82%	99%
Sugar Loss (into Solid Stream after Enzymatic Hydrolysis Separation)	%	5%	5%	5%	5%	1%
Cellulase Enzyme Production						
Total Cost Contribution	\$/GGE	\$0.86	\$0.81	\$0.64	\$0.64	\$0.43
Capital Cost Contribution	\$/GGE	\$0.17	\$0.16	\$0.12	\$0.13	\$0.09
Operating Cost Contribution	\$/GGE	\$0.70	\$0.65	\$0.52	\$0.52	\$0.34
Enzyme Loading	mg/g cellulose	12	12	12	12	10
Fermentation, Catalytic Conversion, and Upgrading to Fuels						
Total Cost Contribution	\$/GGE	\$0.85	\$1.09	\$0.73	\$0.75	\$0.56
Capital Cost Contribution	\$/GGE	\$0.51	\$0.63	\$0.43	\$0.44	\$0.33
Operating Cost Contribution	\$/GGE	\$0.34	\$0.46	\$0.31	\$0.31	\$0.23
Bioconversion Volumetric Productivity	g/L/hour	1.1	0.3	0.6	0.6	2
Glucose to Product [Total Glucose Utilization] ^c	%	86% [100%]	90% [95%]	95% [97.5%]	95% [97.5%]	95% [100%]
Xylose to Product [Total Xylose Utilization] ^c	%	82% [100%]	77% [90%]	95% [97.5%]	95% [97.5%]	85% [100%]
Arabinose to Product [Total Arabinose Utilization] ^c	%	82% [100%]	32% [38%]	20% [29.0%]	20% [29.0%]	85% [87%]
Bioconversion Metabolic Yield (Process Yield)	g/g sugars	0.44 (0.44)	0.45 (0.41)	0.46 (0.44)	0.46 (0.44)	0.45 (0.43)
Fermentation Intermediate Product Recovery	wt %	60% (C ₂), 95% (C ₄)	60% (C ₂), 95% (C ₄)	76% (C ₂), 98% (C ₄)	76% (C ₂), 98% (C ₄)	100% (C ₄)
Ketonization: WHSV	hr ⁻¹	6	4	4	4	6
Ketonization: Per-Pass Conversion	wt % to desired products	100%	100%	100%	100%	100%
Condensation: WHSV	hr ⁻¹	0.5	10-hr residence time	10-hr residence time	10-hr residence time	15-hr batch time

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2019 SOT	2030 Projection (Design Case)
Condensation: Overall Conversion	wt % to desired products	81%	92%	92%	92%	60% pp
Hydrotreating: WHSV	hr ⁻¹	3	4.7	4.7	4.7	3
Hydrotreating: Per-Pass Conversion	wt % to desired products	100%	100%	100%	100%	100%
Lignin Processing to Coproduct						
Total Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$3.26	(\$2.97)
Capital Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$2.61	\$0.96
Operating Cost Contribution	\$/GGE	\$0.00	\$0.00	\$0.00	\$0.65	(\$3.93)
Solid Deconstruction to Soluble Lignin	Wt % BCD lignin feed	-	-	-	85% ^e	53%
Convertible Components in Soluble Lignin	Wt % of total soluble lignin (APL +BCD)	-	-	-	16%	98%
Muconic Acid Process Yield from Lignin	g/g soluble lignin	-	-	-	0.16	1.59
Muconic Acid Metabolic Yield from Lignin	g/g lignin consumed	-	-	-	0.93	0.93
Overall Carbon Upgrading Efficiency to Coproduct ^d	mol%	-	-	-	4.00%	30.10%
Muconic Acid Productivity	g/L/hr	-	-	-	0.06	1
Adipic Acid Production	MMlb/yr	-	-	-	31	187
Balance of Plant						
Total Cost Contribution	\$/GGE	\$1.99	\$1.63	\$1.30	\$1.25	\$0.65
Capital Cost Contribution	\$/GGE	\$1.64	\$1.81	\$1.36	\$1.07	\$0.79
Operating Cost Contribution	\$/GGE	\$0.36	(\$0.18)	(\$0.07)	\$0.18	(\$0.14)

^a FY19 lignin conversion “base case” reflects performance on actual black liquor/BCD hydrolysate (better performance observed for model lignin monomers).

^b Feedstock costs shown here based on a 5% “ash equivalent” and 20% “moisture equivalent” basis for all years considered, consistent with values provided by Idaho National Laboratory for total feedstock costs and associated ash and moisture “dockage” costs for each year.

- ° First number represents sugar conversion to desired product (BDO/acids); values in parentheses indicate total sugar utilization (including biomass organism propagation).
- ° Includes fermentation of all convertible components, product recovery (crystallization) efficiencies, and hydrogenation yields to adipic acid (overall convertible C to adipic acid).
- ° SOT assumes only post-enzymatic hydrolysis lignin solids are routed through BCD; target case routes both lignin solids and DMR liquor through BCD. “Solubilized” lignin remains low in convertible components for SOT cases relative to future targets, translating to lower overall carbon efficiency to adipic acid coproduct.

Integration and Scale-Up (Conversion and Advanced Development and Optimization)

Unit operations and process steps developed at lab-scale R&D for this design would need to be integrated at engineering scale and tested to verify that technical targets can be achieved in an integrated process. Key integration challenges for this pathway include:

- Reliable and robust operations of feed handling systems including feeding herbaceous feedstocks into the pretreatment reactor (for reference, see the appendix, barrier ADO-A)
- Optimizing the DMR process to reduce refining operation energy requirements
- Devising control strategies to improve operability and process flexibility and environmental compliance (for reference, see the appendix, barrier ADO-A)
- Developing efficient product separation and purification schemes for the separation of lignin and cellulosic sugars from the hydrolysate, and optimal continuous separation of desired intermediates and products to improve quality
- Addressing buildup of impurities in process recycle systems and their impact on catalyst performance and regeneration requirements for the conversion of carboxylic acid mixtures to hydrocarbon fuels (for reference, see the appendix, barrier ADO-F)
- Focusing on the influence of inorganic species present in the feed mixture on conversion efficiency to desired products (for reference, see the appendix, barrier ADO-F)
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barrier ADO-D)
- Minimizing abrasion and corrosion of plant equipment due to external contaminants present in the feed (for reference, see the appendix, barrier ADO-H).

Supply Chain Sustainability Analysis

The SCSA results include both low-temperature and upgrading designs. Both designs coproduce a significant amount of adipic acid and recover sodium sulfate salt from wastewater treatment that could displace both products produced from conventional methods. The feedstock blends used in the SCSA are the same as those listed in the footnotes to Table 15.

Table 22 summarizes the supply chain sustainability metrics, including fossil energy consumption, net energy balance, GHG emissions, water consumption, and NO_x emissions of the

renewable hydrocarbon fuels from these low-temperature conversion designs.⁵¹ A key issue in dealing with coproducts from these designs is how to capture their environmental impacts, especially under the current, fuel-focused GHG regulations. For integrated biorefineries coproducing significant quantities of bio-derived chemical coproducts (such as adipic acid), only the displacement method can fully account for the GHG emission reduction benefits and other sustainability metrics considered here that are offered by non-fuel products (relative to other allocation-based coproduct methods). Therefore, the supply chain results of these metrics represent a biorefinery-level assessment that considers the impacts of all the finished products from biorefineries of such designs.

⁵¹ H. Cai, L. Ou, M. Wang, E. Tan, R. Davis, A. Dutta, and L. Tao et al., *Supply Chain Sustainability Analysis of Renewable Hydrocarbon Fuels via Indirect Liquefaction, Ex Situ Catalytic Fast Pyrolysis, Hydrothermal Liquefaction, Combined Algal Processing, and Biochemical Conversion: Update of the 2019 State-of-Technology Cases* (Lemont, IL: Argonne National Laboratory, ANL/ESD-20/2, 2020), https://greet.es.anl.gov/publication-renewable_hc_2019.

Table 22: Supply Chain Sustainability Metrics for Renewable Diesel via the Low-Temperature Pathway

	2018 SOT				2019 SOT				2030 Design Case		Petroleum Diesel
	Via Acids (Burn Lignin)	Via Acids (Convert Lignin)	Via BDO (Burn Lignin)	Via BDO (Convert Lignin)	Via Acids (Burn Lignin)	Via Acids (Convert Lignin)	Via BDO (Burn Lignin)	Via BDO (Convert Lignin)	Via Acids (Convert Lignin)	Via BDO (Convert Lignin)	
Biofuel Yield											
MMBtu/dry ton	3.2	3.2	3.8	3.8	4.1	4.1	4.4	4.5	5.2	5.0	
Fossil Energy Consumption^a											
MJ/MJ	1.41	2.15	1.54	2.51	1.25	1.74	1.46	2.14	-1.33	-1.18	1.2
Net Energy Balance^b											
MJ/MJ	-0.41	-1.15	-0.54	-1.51	-0.25	-0.74	-0.46	-1.14	2.33	2.18	
GHG Emissions											
g CO ₂ e/MJ	103	143	111	158	91	112	104	132	-144 (-252%)	-141 (-250%)	94
G CO ₂ e/GGE	12,612	17,538	13,657	19,358	11,088	13,663	12,777	16,151	-17,579	-17,329	11,528
Water Consumption											
gal/MJ	0.6	0.6	0.3	0.4	0.5	0.5	0.3	0.3	0.4	0.3	0.02
gal/GGE	69	76	43	49	56	60	38	42	44	34	2.7
Total NO_x Emissions											
g NO _x /MJ	0.22	0.10	0.12	0.12	0.19	0.09	0.18	0.10	-0.61	-0.65	0.07
g NO _x /GGE	27.0	12.5	24.4	15.0	23.0	10.5	22.0	12.7	-74.5	-80.2	7.9
Urban NO_x Emissions^c											
g NO _x /MJ	0.035	0.049	0.036	0.045	0.034	0.044	0.035	0.041	0.031	0.032	0.03
g NO _x /GGE	4.2	6.0	4.4	5.5	4.2	5.4	4.3	5.1	3.8	3.9	3.5

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values.

^a This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

^b Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

^c Urban NO_x emissions account for emissions that occur in municipal statistical areas.

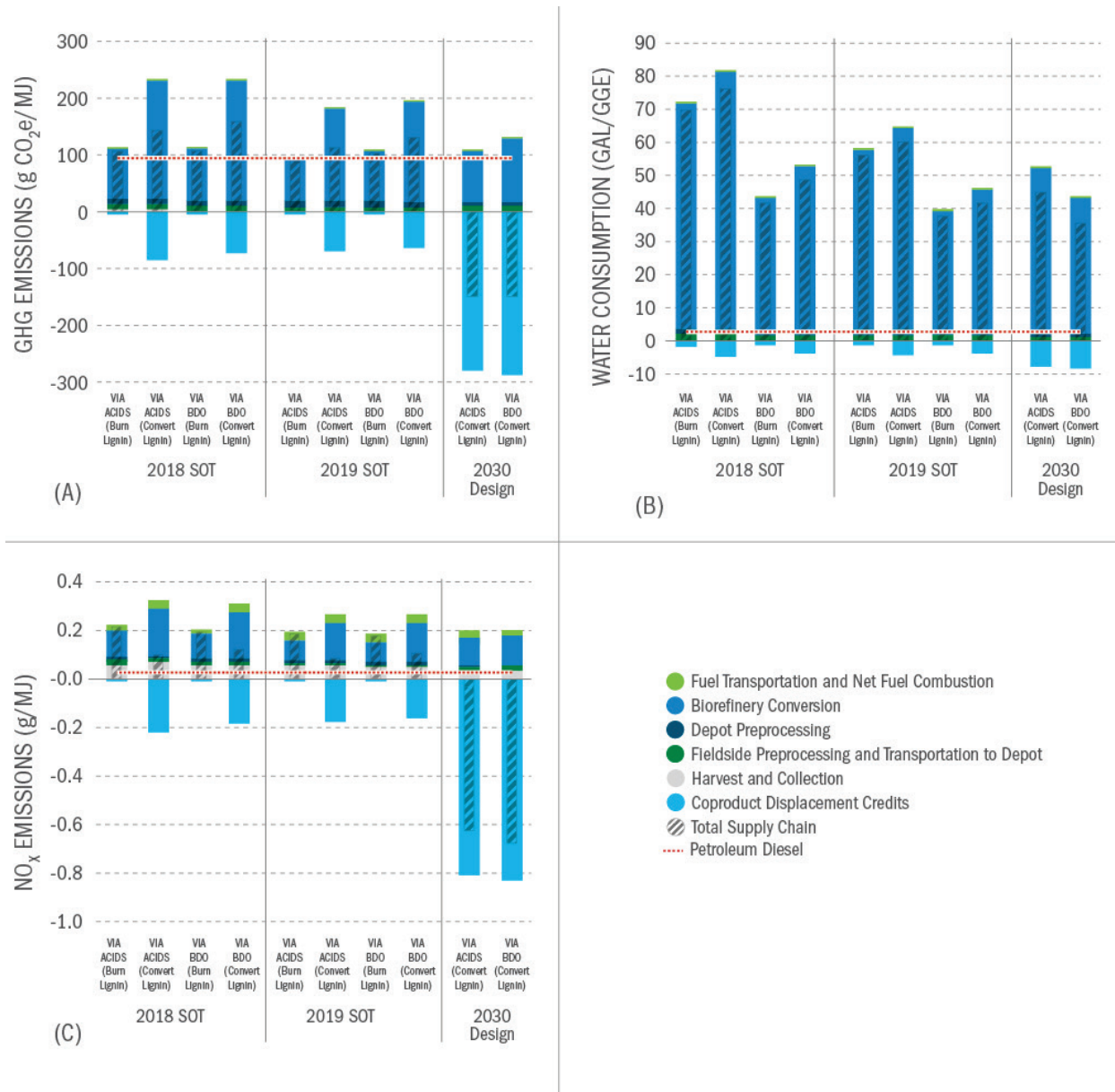
Figure 27A shows the supply chain GHG emissions and their key contributing supply chain processes, in g CO₂e/MJ, of fuel produced compared to a life cycle carbon intensity of 94 g CO₂e/MJ for petroleum diesel. Figure 27A shows that a total GHG reduction of 252% and 250% for the acids and BDO designs in the 2030 design case, respectively, can be achieved compared to petroleum diesel. Negative GHG emissions in the 2030 designs are mainly attributed to improvement in biofuel and coproduct yields, reduction in process energy consumption, and reduction in chemical consumption for coproduct production. Note that these GHG emission intensities are estimated with the displacement method, which takes into account the emission reduction benefits of large amounts of coproducts and normalizes the significant coproduct displacement credits to the biofuel product.⁵² Therefore, these GHG emission reduction results estimated with the displacement method must be interpreted with caution.⁵³

Figure 27B shows that both design cases have higher water consumption, relative to that of petroleum diesel, owing to significant embedded water consumption associated with the process chemical use, as well as to the process makeup water requirement during the biochemical conversion. Water consumption is noticeably reduced in the 2030 design case for both the acids and BDO intermediates scenarios due to improved biofuel and coproduct yields and process energy and chemical consumption reductions.

Figure 27C shows that total NO_x emissions could be lower than those of petroleum diesel in the 2030 design case when the significant coproducts displacement credits are included. Significantly higher coproduct yields contribute to a large reduction in total NO_x emissions in the 2030 design case for both the acids and BDO intermediates scenarios, compared to the SOT cases.

⁵² BETO is reevaluating how to assign the GHG impacts of coproducts. These changes will be reflected in future SOT publications and updates to this document.

⁵³ H. Cai, J. Han, M. Wang, R. Davis, M. Bidy, and E. Tan, "Life-cycle Analysis of Integrated Biorefineries with Co-Production of Biofuels and Bio-based Chemicals: Co-product Handling Methods and Implication," *Biofuels, Bioproducts and Biorefining* 12, no. 5 (2018): 815–833, <https://doi.org/10.1002/bbb.1893>.



Figures 27A–27C: Supply chain for renewable diesel via low-temperature design cases for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions⁵⁴

⁵⁴ Negative GHG emissions in the 2030 designs are mainly attributed to using the displacement method for accounting for coproducts. GHG emission reduction results estimated with the displacement method should be interpreted with caution. More information is available in the full text of this report, and this analysis will be subject to additional review moving forward as the effects of coproducts on SCSA metrics are better understood.

Technology Pathways Using Wet Feedstocks

BETO tracks progress for technologies used in two pathways using wet feedstocks: (1) conversion via low-temperature process and upgrading, and (2) conversion via high-temperature process and upgrading. Wet feedstocks, which include algal feedstocks and wet waste/biosolids, are suitable for conversion processes that can accept feedstocks (biomass that has undergone preprocessing) with higher than 50 wt % moisture content. As illustrated in Figure 28, pathways using algal feedstocks require significant improvements in feedstock production costs in contrast to wet wastes, where no feedstock cost reductions are needed to reach ultimate MFSP projections. This reflects the well-developed infrastructure for wet wastes produced by municipal wastewater treatment facilities.

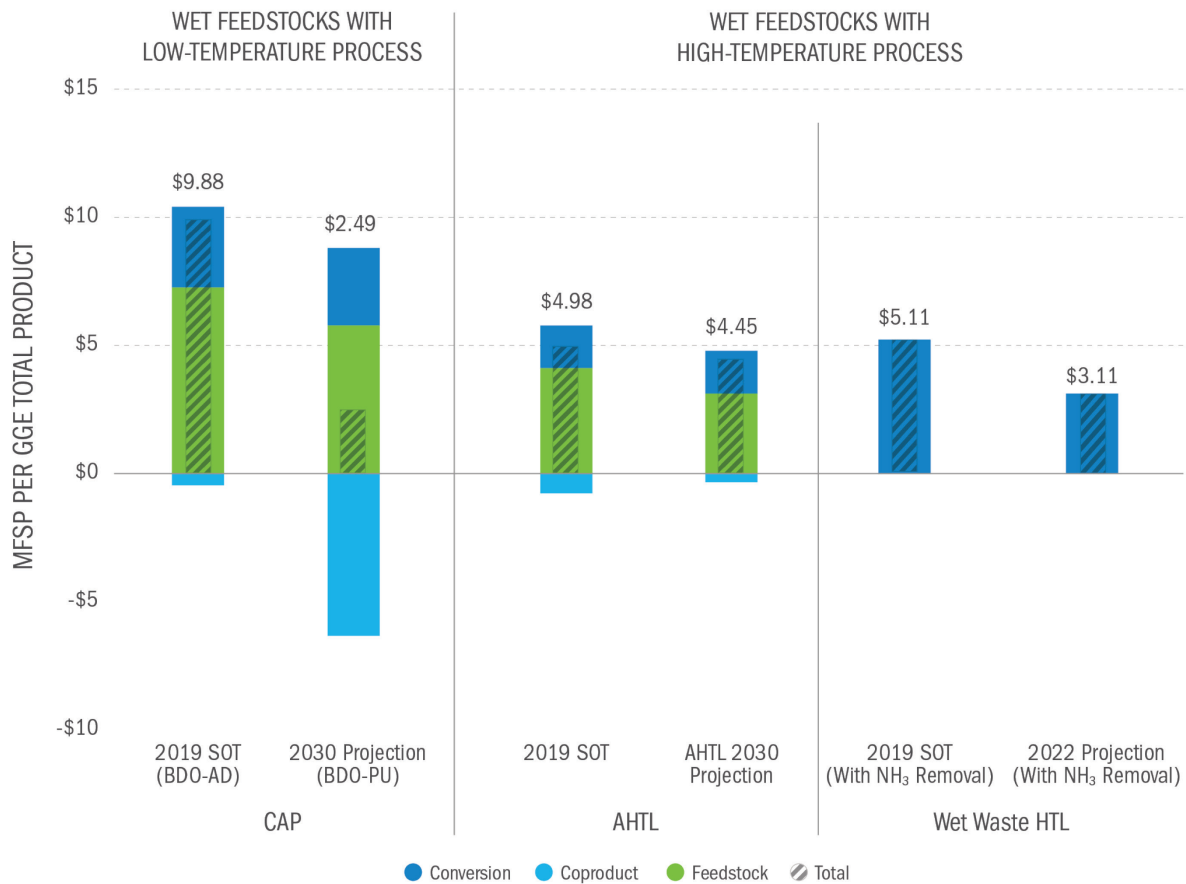


Figure 28: Cost breakdown for technology pathways using wet feedstocks

Algae Production

Both high- and low-temperature pathways using algal feedstock use the same biomass production configuration: the algae farm design.⁵⁵ This configuration identifies improvements needed for the cultivation and harvesting/dewatering (for reference, see the appendix, barrier Aft-D) of algal biomass grown photosynthetically in open, well-mixed, CO₂-enriched, low-cost ponds to reach cost goals expressed as minimum biomass selling prices (MBSPs).⁵⁶ Figure 29 and Table 23 show the MBSP SOT as well as projections assuming R&D improvements toward design targets and underlying productivities shown in Table 24 have been achieved.^{57,58}

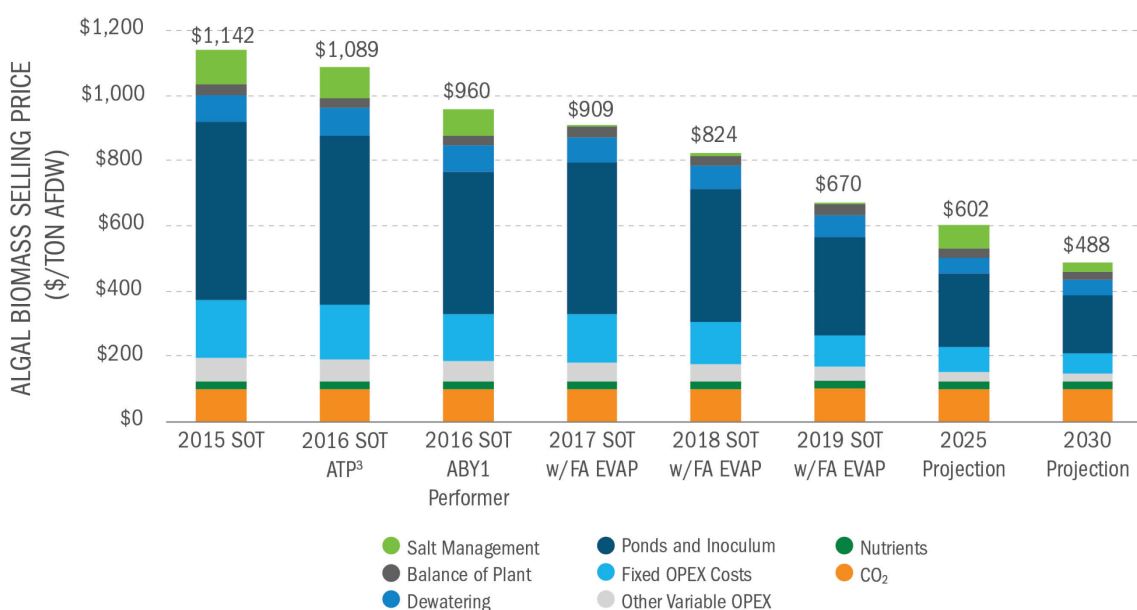


Figure 29: Cost contribution for algal biomass selling price by process area, assuming unlined ponds (pond liners increase costs, see Figure 30)⁵⁹

⁵⁵ R. Davis, J. Markham, C. Kinchin, N. Grundl, E. C. D. Tan, and D. Humbird, *Process Design and Economics for the Production of Algal Biomass: Algal Biomass Production in Open Pond Systems and Processing Through Dewatering for Downstream Conversion* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-64772, 2016), <http://www.nrel.gov/docs/fy16osti/64772.pdf>.

⁵⁶ MBSP is the minimum selling price needed to produce algae at a specified return on investment such that the net present value of the production facility equals zero.

⁵⁷ The algae farm design assumes process integration with the conversion facility but models a stand-alone MBSP. The MBSP SOT is based on cultivation data furnished by the Algae Testbed Public-Private Partnership (ATP³), projects awarded under the Algal Biofuel Yield Funding Opportunity (ABY1), and the national laboratory consortium, Development of Integrated Screening, Cultivar Optimization, and Verification Research (DISCOVER). All use comparable methodologies to those originally established by the ATP³ consortium. BETO requires in-house experimental data for critical variables in the design pathways to ensure results are publicly available, non-proprietary, and high quality, representing all seasons of the year in outdoor trials.

⁵⁸ R. Davis and L. Laurens, *Algal Biomass Production via Open Pond Algae Farm Cultivation: 2019 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76569, 2020), <https://www.nrel.gov/docs/fy20osti/76569.pdf>.

⁵⁹ The FY17–FY19 SOT bars are based on productivities demonstrated at the Arizona State University site using the Florida algae (FA) evaporation (EVAP) scenario. The biomass selling price is reported on an ash-free dry weight basis (AFDW).

Table 23: Cost Contribution for Algal Biomass Selling Price by Process Area

\$/ton AFDW	2015 SOT	2016 SOT ATP ³	2016 SOT ABY 1 Performer	2017 SOT w/FA EVAP	2018 SOT w/FA EVAP	2019 SOT w/FA EVAP	2025 Projection	2030 Projection
CO ₂	\$100	\$100	\$100	\$99	\$99	\$99	\$98	\$98
Nutrients	\$24	\$24	\$24	\$24	\$24	\$24	\$23	\$23
Other Variable OPEX	\$71	\$68	\$59	\$58	\$53	\$42	\$31	\$25
Fixed OPEX Costs	\$177	\$167	\$144	\$149	\$132	\$101	\$77	\$63
Ponds + Inoculum	\$548	\$515	\$437	\$463	\$408	\$302	\$226	\$179
Dewatering	\$82	\$86	\$84	\$77	\$69	\$66	\$49	\$46
Balance of Plant	\$35	\$31	\$29	\$33	\$30	\$31	\$29	\$23
Salt Management	\$105	\$98	\$83	\$5	\$9	\$6	\$70	\$31
Total Algae Biomass Selling Price*	\$1,142	\$1,089	\$960	\$909	\$824	\$670	\$602	\$488

*Note: Total selling price may differ from column totals by \$1 due to the way the values were rounded.

Table 24: Unit Operation Cost Contribution Estimates and Technical Projections for Algae Farm

Processing Area Cost Contributions and Key Technical Parameters	Units	2015 SOT ^a	2016 SOT ATP ^{3a}	2016 SOT ABY 1 ^a	2017 SOT ^{ab} w/FA EVAP	2018 SOT ^{ab} w/ FA EVAP	2019 SOT ^{ab} w/ FA EVAP	2025 Projection	2030 Projection
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016
Minimum Biomass Selling Price	\$/ton AFDW	\$1,142	\$1,089	\$960	\$909	\$824	\$670	\$602	\$488
Production Cost	\$/ton AFDW	\$999	\$947	\$824	\$775	\$704	\$556	\$509	\$400
Harvest/Dewatering Cost	\$/ton AFDW	\$105	\$110	\$107	\$97	\$87	\$82	\$62	\$63
Other Cost (Facility Circulation, Storage)	\$/ton AFDW	\$38	\$32	\$28	\$36	\$33	\$32	\$32	\$25
Net Biomass Production Yield	ton AFDW/acre-yr	12.4	13.2	15.6	15	17	23.1	29.9	37.2
Total Farm Power Demand	KWh/ton AFDW	860	831	739	717	647	529	395	334

Processing Area Cost Contributions and Key Technical Parameters	Units	2015 SOT ^a	2016 SOT ATP ^{3a}	2016 SOT ABY 1 ^a	2017 SOT ^{ab} w/ FA EVAP	2018 SOT ^{ab} w/ FA EVAP	2019 SOT ^{ab} w/ FA EVAP	2025 Projection	2030 Projection
Production									
Total Cost Contribution	\$/ton AFDW	\$999	\$947	\$824	\$775	\$704	\$556	\$509	\$400
Capital Cost Contribution	\$/ton AFDW	\$556	\$524	\$446	\$470	\$415	\$310	\$234	\$210
Operating Cost Contribution	\$/ton AFDW	\$443	\$424	\$379	\$305	\$289	\$245	\$275	\$190
Cultivation Productivity (Annual Average)	g/m ² /day AFDW	8.5	9.1	10.7	10.3	11.7	15.9	20	25
Seasonal Productivity	winter – spring – summer – fall (g/m ² /day)	5.0 – 11.4 – 10.9 – 6.8	5.0 – 11.1 – 13.3 – 7.0	4.8 – 13.0 – 17.5 – 7.8	5.5 – 13.2 – 14.1 – 8.5	7.7 – 15.2 – 15.4 – 8.5	6.5 – 18.7 – 27.1 – 11.4	10.0 – 24.0 – 27.7 – 18.4	11.7 – 28.5 – 35.0 – 24.9
Lipid Content ^c	dry wt % as FAME	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%
N Content ^c	wt % AFDW	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%
CO ₂ Utilization Efficiency ^d	% utilized for biomass	90%	90%	90%	90%	90%	90%	90%	90%
Gross CO ₂ + Nutrient Cost Contributions ^e	\$/ton AFDW	\$124	\$124	\$124	\$124	\$124	\$124	\$121	\$121
Operating Days Per Year	days/yr	330	330	330	330	330	330	330	330
Biomass Concentration at Harvest	g/L AFDW	0.27	0.26	~0.5	0.43	0.51	0.49	0.5	0.5
Dewatering									
Total Cost Contribution	\$/ton AFDW	\$105	\$110	\$107	\$97	\$87	\$82	\$62	\$63
Capital Cost Contribution	\$/ton AFDW	\$82	\$86	\$84	\$77	\$69	\$66	\$49	\$51
Operating Cost Contribution	\$/ton AFDW	\$23	\$24	\$23	\$20	\$18	\$17	\$13	\$12
Gross Dewatering Efficiency ^f	%	87%	87%	87%	87%	87%	87%	87%	87%
Net Dewatering Efficiency ^f	%	99%	99%	99%	99%	99%	99%	99%	99%
Final Concentration of Dewatered Biomass	g/L AFDW	200	200	200	200	200	200	200	200

Processing Area Cost Contributions and Key Technical Parameters	Units	2015 SOT ^a	2016 SOT ATP ^{3a}	2016 SOT ABY 1 ^a	2017 SOT ^{ab} w/ FA EVAP	2018 SOT ^{ab} w/ FA EVAP	2019 SOT ^{ab} w/ FA EVAP	2025 Projection	2030 Projection
Dewatering CAPEX ^g	\$/ (MMgal/day) from cultivation	\$119,600	\$105,500	\$89,400	\$102,300	\$104,200	\$91,300	\$100,200	\$91,300
Balance of Plant									
Total Cost Contribution	\$/ton AFDW	\$38	\$32	\$28	\$36	\$33	\$32	\$32	\$25
Capital Cost Contribution	\$/ton AFDW	\$28	\$22	\$20	\$26	\$23	\$22	\$21	\$17
Operating Cost Contribution	\$/ton AFDW	\$10	\$10	\$8	\$10	\$10	\$9	\$11	\$8

^a Base case assumes nth-plant facility utilizing low-cost unlined ponds; alternative SOT scenarios were also considered with fully lined ponds.

^b FY17–FY19 SOT columns shown here reflect Florida algae evaporation scenario, based on productivities demonstrated at the Arizona State University site.

^c SOT cases assume algal biomass composition consistent with 2025–2030 targets.

^d Fraction of CO₂ delivered to ponds that is utilized for biomass (currently assumed constant for all SOT cases relative to future 2030 targets).

^e Included as part of “operating cost contribution;” gross cost does not account for CO₂/nutrient recycling from conversion (recycling credits are taken downstream in conversion models).

^f “Gross” efficiency = product of individual operations’ dewatering efficiencies. “Net” efficiency = rate of algal biomass recovered in dewatered product to conversion relative to biomass produced from cultivation (including recycle of clarified effluent streams). SOTs assume same values as 2025–2030 targets.

^g Total installed dewatering cost based on peak season flow from cultivation.

As shown in Figure 30, algal productivity is a key factor in reducing the cost of algal biomass minimum selling prices (for reference, see the appendix, barriers Aft-A and Aft-C). Feedstock composition is another key determinant of whether algal feedstocks can be cost effectively converted into biofuels and bioproducts (for reference, see the appendix, barriers Aft-E and Aft-G). The projections for both the low- and high-temperature pathway designs using algal feedstocks assume that certain compositional specifications can be met at the target MBSP. The impact of those specifications on MBSP has not yet been modeled. To meet conversion specifications, alternative cultivation system configurations and operational practices may be needed that could add costs not reflected in the current algae farm design. Differences between actual algae composition (experimental data from harvested algae) used for SOT reporting and design case-specific composition requirements are discussed in each pathway section.

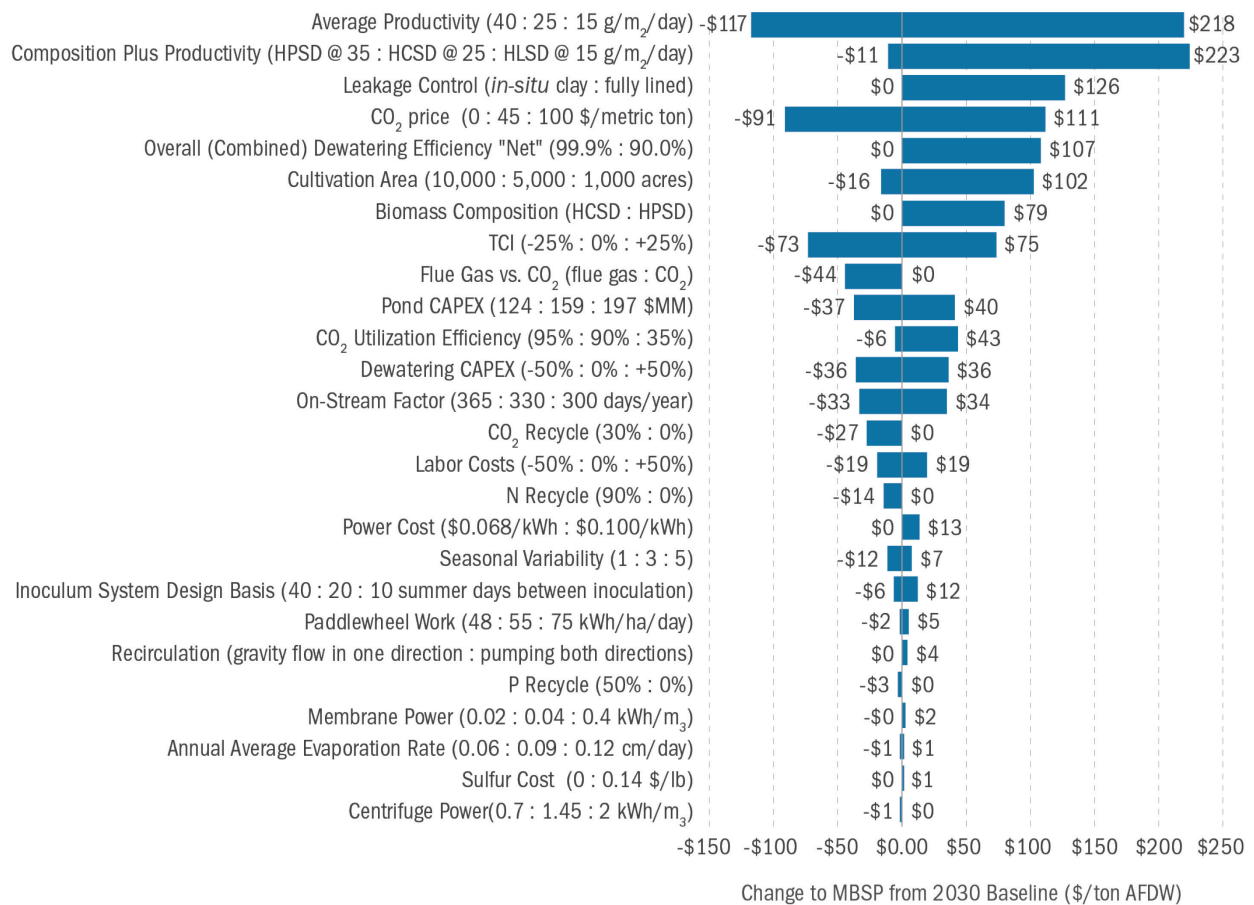


Figure 30: Key factors influencing algae production costs relative to the algae farm design 2030 projections

Wet Feedstocks Converted via Low Temperature and Upgrading

The configuration used to assess progress of technologies relevant to low temperature and upgrading of wet feedstocks to fuel blendstocks and products is the CAP design case.^{60,61} The CAP design case uses low-temperature deconstruction of algal feedstocks with dilute acid under low pressure to release fermentable sugars. This is followed by fermentation of the solubilized sugars and wet extraction and upgrading of lipids, as well as processing the fermentation and extraction stillage into fuels and products. This process concept is illustrated in Figure 31. Two different process designs illustrate either mixed-acids (i.e., carboxylic acids, or CA) or 2,3-BDO intermediates to produce renewable diesel as well as polyurethane (PU) and electricity coproducts. Figure 32 shows how the CAP design case estimates and projections combine algae MBSP from the algae farm design with conversion cost projections.⁶²

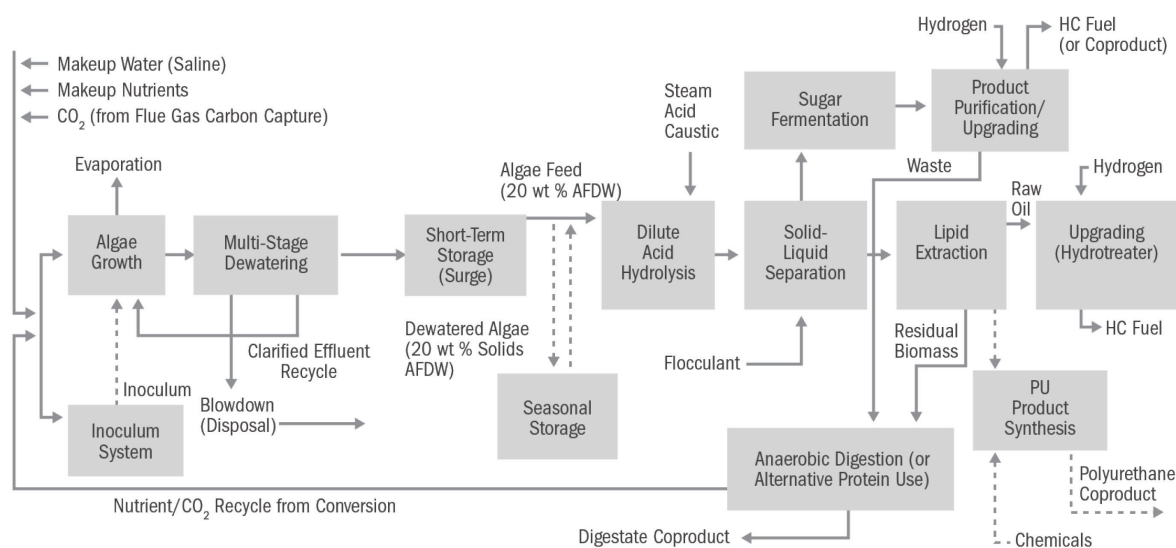


Figure 31: Process flow diagram for conversion of algal feedstocks to hydrocarbon fuels and coproducts via low-temperature deconstruction with upgrading

⁶⁰ R. Davis, C. Kinchin, J. Markham, E. C. D. Tan, L. M. L. Laurens, D. Sexton, D. Knorr, PSchoen, and J. Lukas, *Process Design and Economics for the Conversion of Algal Biomass to Biofuels: Algal Biomass Fractionation to Lipid- and Carbohydrate-Derived Fuel Products* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-62368, 2014), <http://www.nrel.gov/docs/fy14osti/62368.pdf>.

⁶¹ R. E. Davis, J. N. Markham, C. M. Kinchin, C. Canter, J. Han, Q. Li, A. Coleman, S. Jones, M. Wigmosta, and Y. Zhu, *2017 Algae Harmonization Study: Evaluating the Potential for Future Algal Biofuel Costs, Sustainability, and Resource Assessment from Harmonized Modeling* (Lemont, IL: Argonne National Laboratory; Golden, CO: National Renewable Energy Laboratory; Richland, WA: Pacific Northwest National Laboratory, ANL-18/12; NREL/TP-5100-70715; PNNL-27547, 2018), <https://www.nrel.gov/docs/fy18osti/70715.pdf>.

⁶² R. Davis and M. Wiatrowski, *Algal Biomass Conversion to Fuels via Combined Algae Processing (CAP): 2019 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76568, 2020), (<https://www.nrel.gov/docs/fy20osti/76568.pdf>).

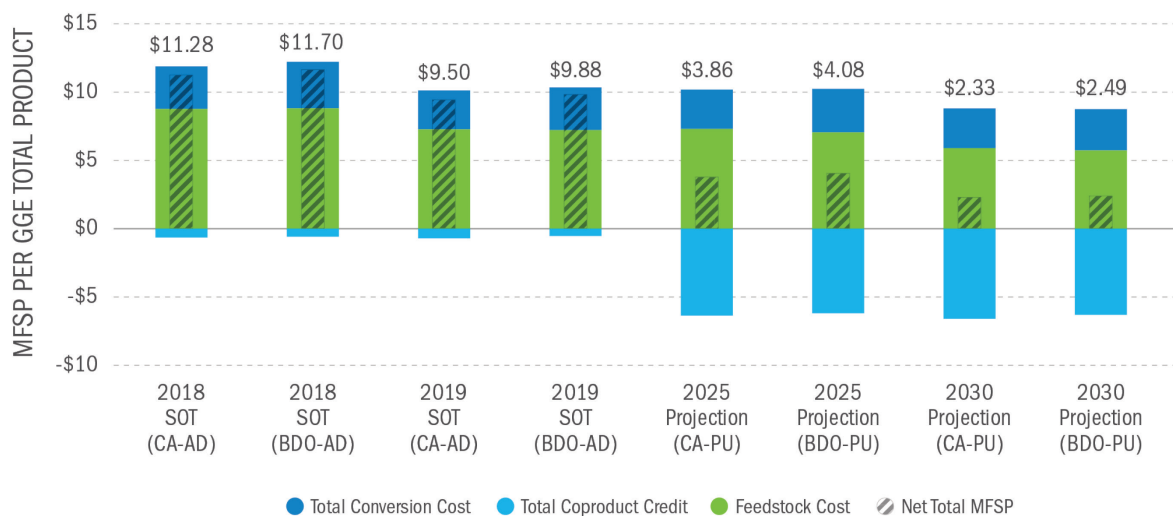


Figure 32: Cost breakdown of algae converted via the low-temperature and upgrading pathway

While feedstock cost is the largest driver of MFSP, the main cost drivers in the CAP conversion processes are conversion efficiencies and yield. BETO is researching various fuel/product combinations to optimize the MFSP. The original CAP design report included ethanol as a representative fermentative product from algal sugars as a proof of concept for efficient utilization of algal sugars into an energy product. This concept was first experimentally shown using algal sugars fermented to ethanol, lipids extracted and hydrotreated to fuels, and protein stillage sent to anaerobic digestion (AD) with biogas recovery. This design was projected to be able to reach only \$5/GGE MFSP, suggesting a need to incorporate higher value fuels and products to reach BETO performance goals.

The ultimate use of algal sugars is a key research area for lowering MFSP. The CAP pathway leverages sugar conversion technologies previously described in the section on dry feedstocks converted via low temperature and upgrading using the design cases for 2,3-BDO and mixed-acids intermediates. These intermediates will need to be catalytically upgraded to hydrocarbons suitable as fuels and/or fuel blendstocks. Figure 33 and Table 25 show the conversion cost projections for the CAP design. The 2018 and 2019 SOTs are based on experimental yields using algal feedstocks in these two design cases. The SOT and projection cases all assume that the protein fraction is sent to AD for conversion to biogas used for combined heat and power (CHP) production. A small coproduct credit results from sale of the AD biosolids for use as fertilizer.

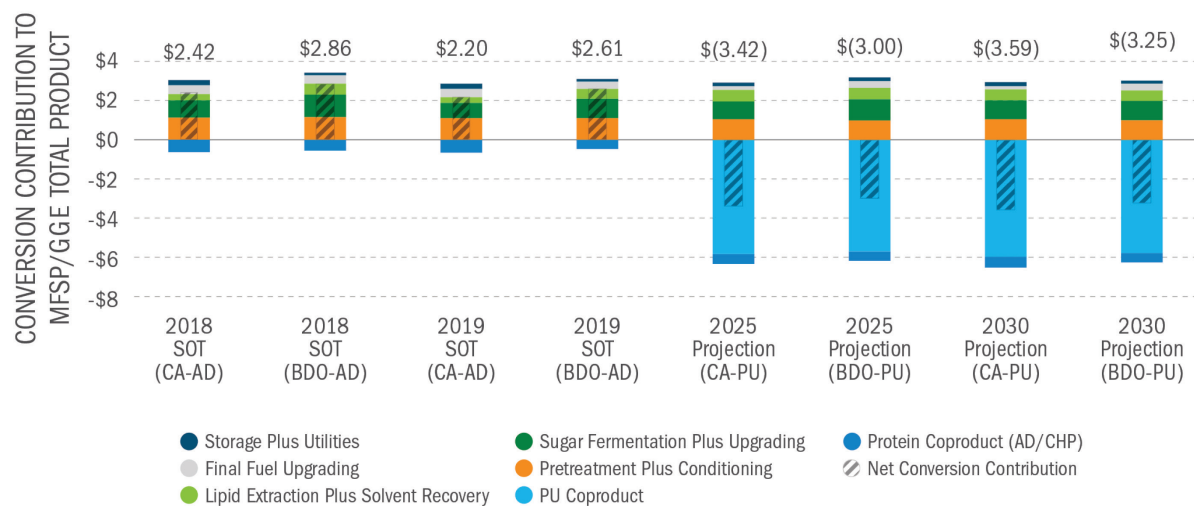


Figure 33: Cost projections for the conversion portion of the CAP design case

Table 25: Cost Projections and Coproduct Credits for the Conversion Portion of the CAP Design Case

Conversion Cost Breakdown (\$/GGE)	2018 SOT (CA AD)	2018 SOT (BDO AD)	2019 SOT (CA AD)	2019 SOT (BDO AD)	2025 Projection (CA PU)	2025 Projection (BDO PU)	2030 Projection (CA PU)	2030 Projection (BDO PU)
Pretreatment and Conditioning	\$1.13	\$1.15	\$1.09	\$1.10	\$1.03	\$1.00	\$1.04	\$0.99
Sugar Fermentation and Upgrading	\$0.86	\$1.16	\$0.77	\$0.99	\$0.90	\$1.06	\$0.95	\$0.98
Lipid Extraction and Solvent Recovery	\$0.32	\$0.56	\$0.29	\$0.50	\$0.60	\$0.58	\$0.56	\$0.54
Final Fuel Upgrading	\$0.47	\$0.41	\$0.45	\$0.38	\$0.17	\$0.36	\$0.16	\$0.34
Storage and Utilities	\$0.28	\$0.14	\$0.27	\$0.13	\$0.21	\$0.19	\$0.217	\$0.18
Net Conversion and Coproduct Contribution to MFSP	\$2.42	\$2.86	\$2.20	\$2.61	\$(3.42)	\$(3.00)	\$(3.59)	\$(3.25)
PU Coproduct	-	-	-	-	(\$5.85)	(\$5.72)	(\$5.96)	(\$5.80)
Protein Coproduct (AD/CHP)	(\$0.63)	(\$0.55)	(\$0.67)	(\$0.48)	(\$0.48)	(\$0.47)	(\$0.56)	(\$0.48)
Total Coproduct Credit	(\$0.63)	(\$0.55)	(\$0.67)	(\$0.48)	(\$6.33)	(\$6.18)	(\$6.52)	(\$6.28)

CAP 2025 and 2030 projections are based on a targeted elemental and component composition consistent with a *Scenedesmus* strain of algae as shown in Table 26 as the Design Case Basis (though this does not necessarily require that the demonstrated strain

actually be *Scenedesmus*). Table 26 also shows the algal feedstock compositions as measured from SOT cultivation trials.^{63,64}

The 2025 and 2030 MFSP projections are based on continued progress toward technical targets as a result of BETO R&D for these conversion pathways. A key feature in these future projections over the SOT cases is that a slip stream of lipids is isolated and upgraded to a PU foam coproduct. This will be enabled by R&D that results in increased lipid yields in algal biomass and the development of processes to convert algal lipids to high-value coproducts (e.g. PU). Figure 34 shows the key factors impacting cost relative to the 2030 Design Case for the CAP design. Table 27 details the technical targets and related cost projections for the CAP design cases.

⁶³ R. Davis and M. Wiatrowski, *Algal Biomass Conversion to Fuels via Combined Algae Processing (CAP): 2019 State of Technology and Future Research* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-76568, 2020), (<https://www.nrel.gov/docs/fy20osti/76568.pdf>).

⁶⁴ E. Knoshaug, L. M. L. Laurens, C. Kinchin, and R. Davis, *Use of Cultivation Data from the Algae Testbed Public Private Partnership as Utilized in NREL's Algae State of Technology Assessments* (Golden, CO: National Renewable Energy Laboratory, NREL/TP-5100-67289, 2016), (<http://www.nrel.gov/docs/fy17osti/67289.pdf>).

Table 26: CAP Design Case Algal Biomass Compositions Compared to Measured Values from 2019 SOT Cultivation Trials

Elemental (AFDW) ^{a,b}	Design Case Basis	Fall <i>Monoraphidium/Desmodesmus</i> ^f	Winter <i>Monoraphidium</i>	Spring <i>Monoraphidium/Scenedesmus</i> ^g	Summer <i>Scenedesmus</i>
Carbon	54	52.2 (49.2)	52.7	54.1 (52.9)	48.3
Hydrogen	8.2	7.8 (7.5)	7.8	7.9 (7.7)	7.2
Oxygen	35.5	29.7 (32.6)	29.4	27.0 (27.7)	33.6
Nitrogen	1.8	8.9 (9.4)	8.7	9.7 (10.2)	9.5
Sulfur	0.2	0.2 (0.2)	0.2	0.2 (0.2)	0.2
Phosphorus	0.22	1.2 (1.2)	1.2	1.2 (1.2)	1.2
Total	100.00%	100.00%	100.00%	100.00%	100.00%
Component (dry wt) ^b					
Ash	2.4	14.9 (17.5)	8.6	12.5 (9.2)	8.4
Protein	13.2	35.6 (36.9)	42.4	37.5 (44.5)	41.7
FAME Lipids ^c	26.0	8.5 (6.4)	8.8	6.8 (8.0)	9.3
Glycerol ^c	3.0	1.0 (0.7)	1	0.8 (0.9)	1.1
Non-Fuel Polar Lipid Impurities	1.0	5.1 (3.9)	5.3	4.1 (4.8)	5.6
Sterols ^d	1.8	0.5 (0.5)	0.5	0.5 (0.5)	0.5
Fermentable Carbohydrates ^e	47.8	21.2 (17.5)	21	19.4 (18.7)	17
Other Carbohydrates (Galactose)	3.2	4.0 (3.3)	3.9	3.6 (3.5)	3.2
Cell Mass	1.6	9.3 (13.2)	8.6	14.7 (10.0)	13.3
Total	100.00%	100.00%	100.00%	100.00%	100.00%

^a Carbon-hydrogen-nitrogen (CHN) composition is reported as measured CHN data corrected for ash content of the biomass. Oxygen was calculated as the difference from mass balance after estimating sulfur and phosphorus (as 0.2% and 1.2%, respectively) and adjusted to 100%.

^b SOT biomass compositions are less detailed than the high-carbohydrate *Scenedesmus* basis; CHN and composition data for *Scenedesmus* and *Monoraphidium* cases are based on measured averaged data for harvested production samples and are considered primarily representative for nutrient replete growth conditions. Composition data is currently broken down to ash, protein, and lipids as fatty acid methyl ester (FAME) (in this case triacylglycerol lipids measured as FAME, with an added estimate of 10% glycerol relative to measured FAME, and an assumed polar lipid headgroup fraction that increased the FAME content by at least 60%) and total carbohydrate content (reported here as 80% fermentable from the measured sum of monosaccharides detected, 20% non-fermentable and an additional 10% assumed unhydrolyzable or recalcitrant). A remaining component called “cell mass” accounts for between 5% and 18% of the biomass and reflects unidentified components that are not measured but are needed to account for the mass balance.

^c Lipids originally characterized as triglycerides (1:1 FAME equivalent); adjusted here to free fatty acids plus glycerol (as ~11% of the measured FAME content, and reflective of actual components in pretreated hydrolysate for *Scenedesmus* biomass).

^d Sterols originally included in “polar lipid impurity” fraction in prior models. Value currently estimated for high-carbohydrate *Scenedesmus*, based on a representative earlier-harvest biomass sample. For SOT biomass, sterol concentration is estimated at a flat 0.5% of the biomass, consistent with earlier observations at the National Renewable Energy Laboratory.

^e “Fermentable carbohydrates” typically consist of 75% glucose and 25% mannose for all species analyzed in FY19.

^f Fall: first value: *Monoraphidium* 26BAM (October–November); value in parentheses: *Desmodesmus* C046 (September).

^g Spring: first value: *Monoraphidium* 26BAM (March–April); value in parentheses: *Scenedesmus* UTEX393 (May).

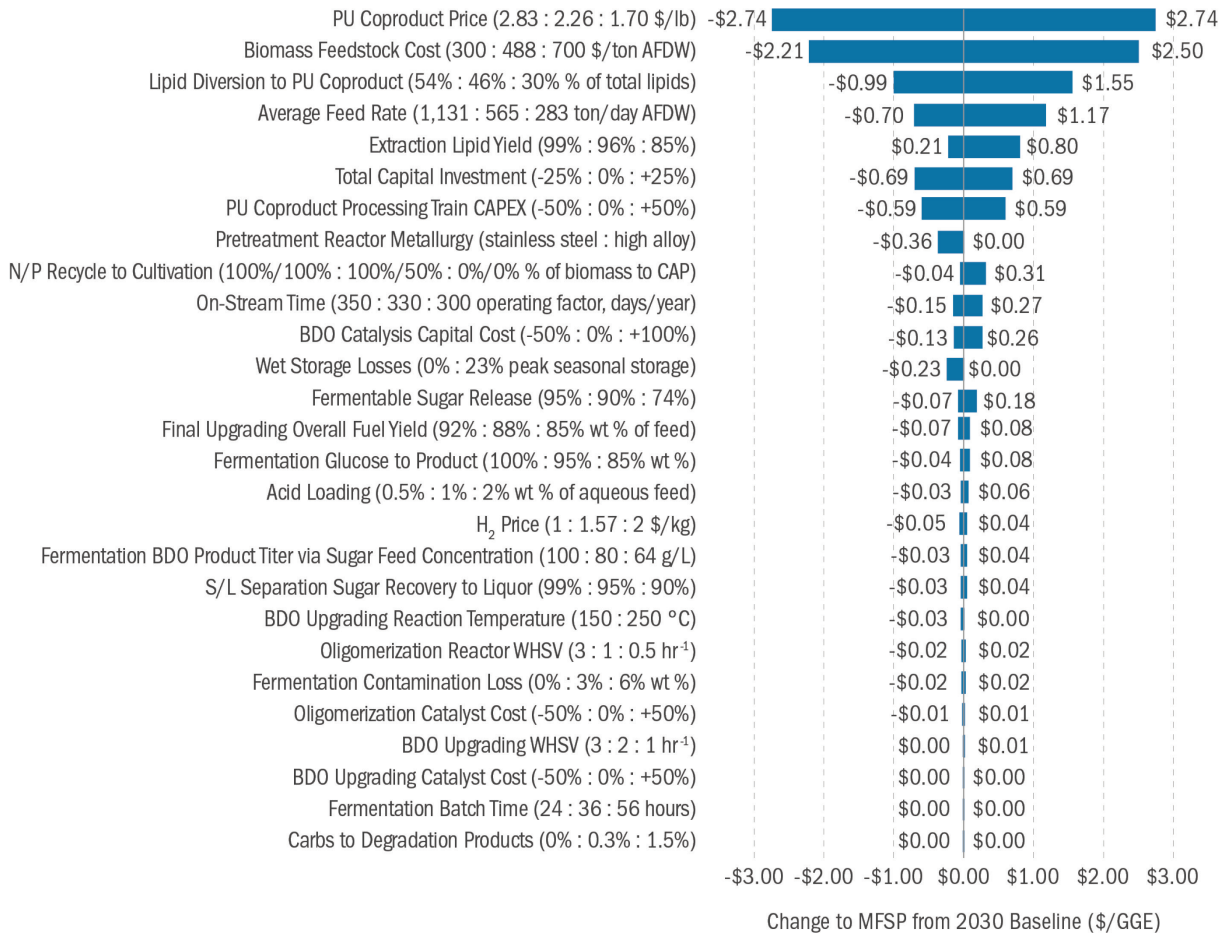


Figure 34: Factors influencing MFSP for the CAP design case (BDO fuel train pathway example)

Table 27: Unit Operation Cost Contribution Estimates and Technical Projections for Combined Algae Processing Design Case

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (CA AD) ^a	2018 SOT (BDO AD) ^a	2019 SOT (CA AD) ^a	2019 SOT (BDO AD) ^a	2025 Projection (CA PU) ^b	2025 Projection (BDO PU) ^b	2030 Projection (CA PU) ^b	2030 Projection (BDO PU) ^b
Year Dollar Basis		2016	2016	2016	2016	2016	2016	2016	2016
Minimum Fuel Selling Price	\$/GGE fuel	\$11.28	\$11.70	\$9.50	\$9.88	\$3.86	\$4.08	\$2.33	\$2.49
Net Conversion Contribution	\$/GGE	\$2.42	\$2.86	\$2.20	\$2.61	(\$3.42)	(\$3.00)	(\$3.59)	(\$3.25)
Diesel Production	MMGGE/yr	4.6	5.6	6.2	7.4	4.7	7.8	5.9	9.7
Naphtha Production	MMGGE/yr	3.2	2.3	4.3	3.1	7.6	4.8	9.4	6
Diesel Yield (AFDW Algae Basis)	GGE/ton algae	54	65	54	64	31	52	31	52
Naphtha Yield (AFDW Algae Basis)	GGE/ton algae	38	27	37	27	51	32	50	32
Total Fuel Yield from Algae Farm	GGE/acre/ yr	1,573	1,577	2,105	2,114	2,389	2,520	2,988	3,146
Natural Gas Usage (AFDW Algae Basis)	scf/ton algae	2,611 (4,307 including NG for off-site H ₂)	1,168 (2,764 including NG for off-site H ₂)	2,620 (4,292 including NG for off-site H ₂)	1,187 (2,747 including NG for off-site H ₂)	3,005 (3,064 including NG for off-site H ₂)	4,892 (6,166 including NG for off-site H ₂)	2,887 (2,941 including NG for off-site H ₂)	5,243 (6,510 including NG for off-site H ₂)
Carbon from Biomass in Fuels	%	46.1	44.3	46.3	43.7	39.3	40.2	39.2	40.2
Carbon from Biomass in Other Products ^c	%	methane: 14 products: 0	methane: 14 products: 0	methane: 14 products: 0	methane: 14 products: 0	methane: 11 products: 14.5	methane: 11 products: 14.5	methane: 11 products: 14.5	methane: 11 products: 14.5
Feedstock									
Total Cost Contribution	\$/GGE fuel	\$8.86	\$8.84	\$7.30	\$7.27	\$7.27	\$7.09	\$5.92	\$5.74
Feedstock Cost (AFDW Algae Basis)	\$/ton algae	\$824	\$824	\$670	\$670	\$602	\$602	\$488	\$488
Feedstock Solids Content	wt % AFDW	20%	20%	20%	20%	20%	20%	20%	20%
Feedstock Lipid/Carb/Protein Content ^d	dry wt %	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%	27%/51%/13%
Pretreatment									
Total Cost Contribution	\$/GGE fuel	\$1.13	\$1.15	\$1.09	\$1.10	\$1.04	\$1.00	\$1.05	\$0.99

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (CA AD) ^a	2018 SOT (BDO AD) ^a	2019 SOT (CA AD) ^a	2019 SOT (BDO AD) ^a	2025 Projection (CA PU) ^b	2025 Projection (BDO PU) ^b	2030 Projection (CA PU) ^b	2030 Projection (BDO PU) ^b
Capital Cost Contribution	\$/GGE fuel	\$0.58	\$0.58	\$0.56	\$0.56	\$0.65	\$0.63	\$0.61	\$0.59
Operating Cost Contribution	\$/GGE fuel	\$0.55	\$0.57	\$0.53	\$0.54	\$0.39	\$0.37	\$0.44	\$0.40
Pretreatment Solids Loading	wt % AFDW	20%	20%	20%	20%	20%	20%	20%	20%
Pretreatment Acid Loading	wt % of water feed	2%	2%	2%	2%	1%	1%	1%	1%
Fermentable Sugar Yield	%	74%	74%	74%	74%	90%	90%	90%	90%
Carbs to Degradation Products	%	1.50%	1.50%	1.50%	1.50%	0.30%	0.30%	0.30%	0.30%
Sugar Fermentation/Upgrading									
Total Cost Contribution	\$/GGE fuel	\$0.86	\$1.16	\$0.77	\$0.99	\$0.91	\$1.06	\$0.95	\$0.98
Capital Cost Contribution	\$/GGE fuel	\$0.40	\$0.60	\$0.35	\$0.53	\$0.50	\$0.60	\$0.49	\$0.54
Operating Cost Contribution	\$/GGE fuel	\$0.46	\$0.56	\$0.42	\$0.46	\$0.41	\$0.46	\$0.46	\$0.44
Fermentation Productivity	g/L/hr	0.3	56-hr batch time	0.3	56-hr batch time	2	36-hr batch time	2	36-hr batch time
Fermentation Glucose to Product	%	92%	74%	92%	74%	95%	95%	95%	95%
Fermentation Mannose to Product	%	92%	55%	92%	55%	95%	95%	95%	95%
Fermentation Process Yield	g product/g sugars ^e	0.48 (CA)	0.34 (BDO)	0.48 (CA)	0.34 (BDO)	0.48 (CA)	0.51 (BDO)	0.48 (CA)	0.51 (BDO)
Catalytic Upgrading Yield to HDO Feed ^f	wt % of recovered fermentation product	53%	60%	53%	60%	55%	61%	55%	61%
Catalytic Upgrading Carbon Yield to HDO Feed ^f	C yield from recovered fermentation product	57%	56%	57%	56%	81%	82%	81%	82%
Lipid Recovery and Processing									
Total Cost Contribution	\$/GGE fuel	\$0.32	\$0.56	\$0.29	\$0.50	(\$5.25)	(\$5.14)	(\$5.40)	(\$5.26)

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (CA AD) ^a	2018 SOT (BDO AD) ^a	2019 SOT (CA AD) ^a	2019 SOT (BDO AD) ^a	2025 Projection (CA PU) ^b	2025 Projection (BDO PU) ^b	2030 Projection (CA PU) ^b	2030 Projection (BDO PU) ^b
Capital Cost Contribution	\$/GGE fuel	\$0.19	\$0.32	\$0.17	\$0.29	\$1.21	\$1.17	\$1.12	\$1.08
Operating Cost Contribution	\$/GGE fuel	\$0.13	\$0.24	\$0.12	\$0.21	\$4.79	\$4.66	\$4.77	\$4.61
Lipid Coproduct Credit ^c	\$/GGE fuel					(\$11.25)	(\$10.96)	(\$11.28)	(\$10.95)
Extraction Configuration		2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR	2-solvent CSTR
Extraction Solvent Loading	non-polar: ethanol: dry biomass (wt basis)	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1	2.7:1.1:1
FAME Lipid Extraction Yield	%	96%	96%	96%	96%	96%	96%	96%	96%
Polar Lipid Impurity Partition to Extract	%	<11.5%	<11.5%	<11.5%	<11.5%	<11.5%	<11.5%	<11.5%	<11.5%
Fractional Diversion of Lipids to PU Coproduct Train	% of extracted lipids					46%	46%	46%	46%
Polyol Yield (Precursor to PU)	g polyol/g algae AFDW					0.12	0.12	0.12	0.12
PU Coproduct Yield	g PU/g algae AFDW					0.22	0.22	0.22	0.22
Final Fuel Upgrading									
Total Cost Contribution	\$/GGE fuel	\$0.47	\$0.41	\$0.45	\$0.38	\$0.17	\$0.36	\$0.16	\$0.34
Capital Cost Contribution	\$/GGE fuel	\$0.15	\$0.16	\$0.13	\$0.14	\$0.11	\$0.15	\$0.10	\$0.14
Operating Cost Contribution	\$/GGE fuel	\$0.32	\$0.25	\$0.32	\$0.24	\$0.06	\$0.21	\$0.06	\$0.20
Hydrotreating Diesel Yield	wt % of HDO feed ^h	51.9%	60.6%	51.9%	60.5%	34.2%	53.7%	34.2%	53.7%
Hydrotreating Naphtha Yield	wt % of HDO feed ^h	35.9%	25.3%	35.9%	25.4%	56.6%	34.3%	56.6%	34.3%
Hydrotreating H ₂ Consumption	wt % of HDO feed ^h	3.2%	3.0%	3.2%	2.9%	3.0%	2.7%	3.0%	2.7%

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (CA AD) ^a	2018 SOT (BDO AD) ^a	2019 SOT (CA AD) ^a	2019 SOT (BDO AD) ^a	2025 Projection (CA PU) ^b	2025 Projection (BDO PU) ^b	2030 Projection (CA PU) ^b	2030 Projection (BDO PU) ^b
Protein/Residual Processing									
Total Cost Contribution	\$/GGE fuel	(\$0.80)	(\$0.76)	(\$0.83)	(\$0.68)	(\$0.81)	(\$1.01)	(\$0.88)	(\$1.05)
Capital Cost Contribution	\$/GGE fuel	\$0.12	\$0.09	\$0.11	\$0.08	\$0.13	\$0.11	\$0.12	\$0.10
Operating Cost Contribution		\$0.07	\$0.07	\$0.06	\$0.05	\$0.06	\$0.05	\$0.08	\$0.05
Coproduct Credits ⁱ	\$/GGE fuel	(\$0.99)	(\$0.92)	(\$1.00)	(\$0.82)	(\$0.99)	(\$1.17)	(\$1.08)	(\$1.20)
Biogas Yield	L CH ₄ /g TS	0.26	0.25	0.26	0.25	0.28	0.27	0.28	0.27
Balance of Plant									
Total Cost Contribution	\$/GGE fuel	\$0.44	\$0.35	\$0.42	\$0.33	\$0.53	\$0.74	\$0.54	\$0.75
Capital Cost Contribution	\$/GGE fuel	\$0.20	\$0.18	\$0.19	\$0.17	\$0.23	\$0.28	\$0.23	\$0.28
Operating Cost Contribution	\$/GGE fuel	\$0.24	\$0.17	\$0.23	\$0.16	\$0.30	\$0.46	\$0.31	\$0.47

^a 2018 and 2019 SOT cases based on Florida algae evaporation scenario for biomass feed cost.

^b 2025–2030 columns represent example scenarios which may demonstrate achievement of BETO’s 2025 yield goals (80 GGE/ton) and 2030 cost goals (\$2.5/GGE), respectively, as proof of concept for coproduction of fuels and value-added products via CAP conversion, reflecting concepts presented in the *2017 Algae Harmonization Report* (these do not currently represent formal R&D pathway targets). CA = carboxylic acids (upgraded to hydrocarbon fuels); BDO = 2,3-butanediol (upgraded to hydrocarbon fuels); AD = anaerobic digestion; PU = polyurethanes.

^c “Other products” = biomethane from AD, as well as algal carbon yields to PU coproducts, as applicable.

^d SOT cases assume algal biomass feedstock composition consistent with 2025–2030 targets.

^e Includes glycerol conversion.

^f Represents overall catalytic upgrading yield of fermentation intermediate (after recovery) through feed to final fuel finishing (hydrotreating) step.

^g Lipid coproduct for 2025–2030 = lipid-derived polyurethanes.

^h Includes final fuel upgrading step for hydrotreating of lipids combined with CA- or BDO-derived intermediates (values based on combined feed).

ⁱ Includes coproduct credits for N/P nutrient recycling, CO₂ recycling, CHP power generation, and AD digestate fertilizer (minimal credit).

Integration and Scale-Up (Conversion and Advanced Development and Optimization)

Once the technical targets are reached through R&D, process steps developed at the R&D scale must be integrated at engineering scale and tested to ensure technical targets can be achieved when run as an integrated process (for reference, see the appendix, barrier Aft-H). Key integration challenges for CAP include:

- Integration of process steps to ensure robust pretreatment operations and efficient release of algal sugars for further processing (for reference, see the appendix, barriers Aft-I and ADO-A)
- Integration of fermentation and catalytic upgrading
- Improving lipid extraction and solvent recovery
- Addressing buildup of impurities in process recycle systems and its impact on catalyst performance for the conversion of 2,3-BDO and mixed-acids intermediates to hydrocarbon fuels (for reference, see the appendix, barriers Aft-J, ADO-A, and ADO-F)
- Optimizing nutrient recycle processes to improve and achieve cost targets
- Optimizing use of protein to maximize values
- Developing efficient product separation and purification schemes
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barrier ADO-D)
- Demonstration of ability to produce value-added coproducts at scale in integrated process
- Identifying efficient valorization methodologies of streams post fermentation and product conversion steps.

Supply Chain Sustainability Analysis

The two alternative CAP design case pathways (through 2,3-BDO or mixed-acids intermediates) both produce a diesel-range blendstock, as well as polyurethane and electricity as coproducts. The algae-derived PU in the design case is treated with a displacement credit in the SCSA for replacing petroleum-derived PU foam. This displacement method is also used to calculate the displacement credits of surplus electricity exported to the grid. The SCSAs for the 2018 and 2019 SOTs and for the 2025 and 2030 projections assume algae biomass cultivation with Florida

evaporation rates and unlined ponds using saline algae strains for both the 2,3-BDO and mixed-acids designs.

Table 28 summarizes the supply chain sustainability metrics, including fossil energy consumption, net energy balance, GHG emissions, water consumption, and NO_x emissions from the CAP design cases using the displacement method.⁶⁵ The SCSA results consider the impact of all finished products from the CAP designs. These results include a displacement credit for recycled nutrients such as ammonia (NH₃) and diammonium phosphate from anaerobic digester effluent that reduces the nutrient requirement for algae cultivation.

⁶⁵ H. Cai, L. Ou, M. Wang, E. Tan, R. Davis, A. Dutta, and L. Tao et al., *Supply Chain Sustainability Analysis of Renewable Hydrocarbon Fuels via Indirect Liquefaction, Ex Situ Catalytic Fast Pyrolysis, Hydrothermal Liquefaction, Combined Algal Processing, and Biochemical Conversion: Update of the 2019 State-of-Technology Cases* (Lemont, IL: Argonne National Laboratory, ANL/ESD-20/2, 2020), https://greet.es.anl.gov/publication-renewable_hc_2019.

Table 28: Supply Chain Sustainability Metrics for CAP Design Cases

	Scenario 1: Via Acids				Scenario 2: Via 2,3 BDO				Petroleum Diesel
	2018 SOT	2019 SOT	2025 Projection	2030 Projection	2018 SOT	2019 SOT	2025 Projection	2030 Projection	
Biofuel Yield									
MMBtu/dry ton	10.8	10.6	9.7	9.7	10.6	10.6	9.8	9.8	
Fossil Energy Consumption^a									
MJ/MJ	1.08	1.03	0.33	0.34	1.00	0.99	0.61	0.63	1.20
Net Energy Balance^b									
MJ/MJ	-0.08	-0.03	0.67	0.66	0.00	0.01	0.39	0.37	
GHG Emissions									
g CO ₂ e/MJ	80 (-14%)	75 (-20%)	5 (-95%)	6 (-94%)	75 (-20%)	71 (-25%)	21 (-77%)	23 (-76%)	94
g CO ₂ e/GGE	9,859	9,185	632	732	9,201	8,664	2,605	2,784	11,528
Water Consumption									
gal/MJ	0.28	0.27	0.29	0.36	0.21	0.19	0.21	0.21	0.02
gal/GGE	34.4	33.5	36.0	44.3	25.2	23.4	25.5	25.5	2.7
Total NO_x Emissions									
g NO _x /MJ	0.12	0.12	0.02	0.02	0.10	0.10	0.04	0.04	0.07
g NO _x /GGE	14.4	14.1	2.8	2.7	11.8	11.7	4.5	4.7	7.9
Urban NO_x Emissions^c									
g NO _x /MJ	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
g NO _x /GGE	4.0	3.8	3.5	3.5	4.1	4.0	3.5	3.5	3.5

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values.

^a This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

^b Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

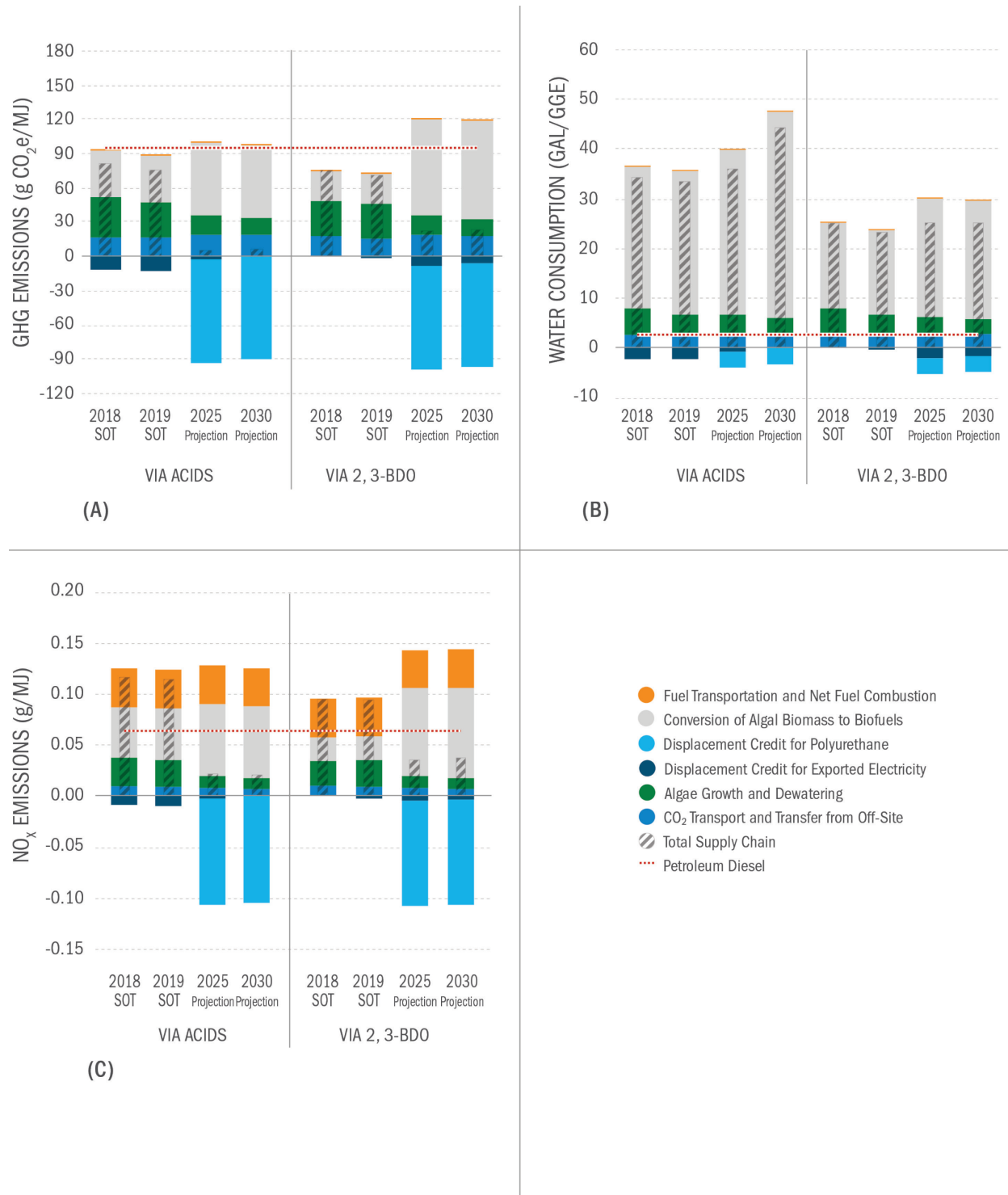
^c Urban NO_x emissions account for emissions that occur in municipal statistical areas.

Figure 35A shows the supply chain GHG emissions for the 2018 SOT, 2019 SOT, and 2025 and 2030 projections for the 2,3-BDO and mixed-acids intermediate design cases. These

compare to life cycle GHG emissions for petroleum-derived diesel of 94 g CO₂e/ MJ. Figure 35A shows that GHG emissions for the 2019 SOT for these two designs are about 20% to 24% lower than petroleum-derived diesel, while the 2025 and 2030 design case projections, which include significant emission displacement credit of coproduced PU, have substantially lower GHG emissions relative to petroleum-derived diesel. The major emission sources for the 2018 SOT, 2019 SOT, and 2025 and 2030 projections include manufacturing chemicals and catalysts used in the CAP conversion processes, as well as energy consumption for CO₂ capture and transportation to the algae farm, and for algae growth and dewatering.

Figure 35B shows significantly higher water consumption for the 2018 SOT, 2019 SOT, and the 2025 and 2030 projections relative to petroleum-derived diesel, due to the significant embedded water consumption associated with process chemical and catalyst use, as well as for process makeup water required by the CAP designs. Another major driver of water consumption is electricity generation and algae dewatering. However, cultivation of saline algae strains does not contribute to freshwater consumption.

Figure 35C shows that total NO_x emissions are higher for the 2018 SOT and 2019 SOT cases compared to petroleum-derived diesel, primarily due to embedded emissions from manufacturing the process chemicals and catalysts required for the CAP design case. However, the 2025 and 2030 projections for the CAP design cases may see benefits in NO_x emissions relative to other pathway designs due to significant NO_x emission displacement credits from coproduced PU.



Figures 35A–35C: Supply chain for the CAP design case for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions

Wet Feedstocks Converted via High Temperature and Upgrading

BETO R&D includes two configurations for assessing the progress of technologies used in converting wet feedstocks via the high-temperature and upgrading pathways. Both designs use HTL conversion processes; one with an algal feedstock and the second using wet waste from wastewater treatment facilities. Each of these designs is described separately.

Algal Hydrothermal Liquefaction Design Case

The AHTL design case⁶⁶ assumes the HTL reactor is located at the algae farm site. In this design, illustrated in Figure 36, a biomass slurry⁶⁷ is pumped to the HTL reactor. In the HTL reactor, hot, pressurized water converts the slurry to four phases: a thermally stable biocrude intermediate, an aqueous phase containing organic species, and solid and gaseous streams. These four streams are separated and the biocrude intermediate is hydrotreated to form diesel and some naphtha-range fuels. Process off-gas may be used to generate hydrogen, heat, and/or power. The aqueous phase contains significant levels of nitrogen and organic carbon that must be recovered for their value as nutrients and/or coproducts. The original AHTL design used catalytic hydrothermal gasification to recover and recycle nutrients (nitrogen and organic carbon). Subsequent research has identified nutrient recycling methods as the cost-efficient alternative. By recycling treated water containing dissolved CO₂ and NH₃, CO₂ containing flue gas, and phosphorus recovered from treated HTL solids, nutrients are recovered and fed back to the algae ponds. This design also co-locates a hydrogen generation plant for biocrude hydrotreating with the algae ponds and HTL conversion. A new design case is underway to incorporate the most recent algae HTL technology developments into this pathway.

Further cost reductions from the original AHTL design basis were achieved by addressing seasonal variability through co-processing algae with dry biomass (e.g., wood) during seasons of low algal productivity. This eliminated drying a portion of peak season algae for later use, thus reducing capital costs for dryers and operating costs for natural gas.

⁶⁶ S. Jones, R. Davis, Y. Zhu, C. Kinchin, D. Anderson, R. Hallen, and D. Elliott et al., *Process Design and Economics for the Conversion of Algal Biomass to Hydrocarbons: Whole Algae Hydrothermal Liquefaction and Upgrading* (Richland, WA: Pacific Northwest National Laboratory, PNNL-23227, 2014), http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23227.pdf.

⁶⁷ Primarily whole algae. The 2018 SOT assumes up to 20% minimally preprocessed (grinding only) forest residue mixed with the whole algae stream.

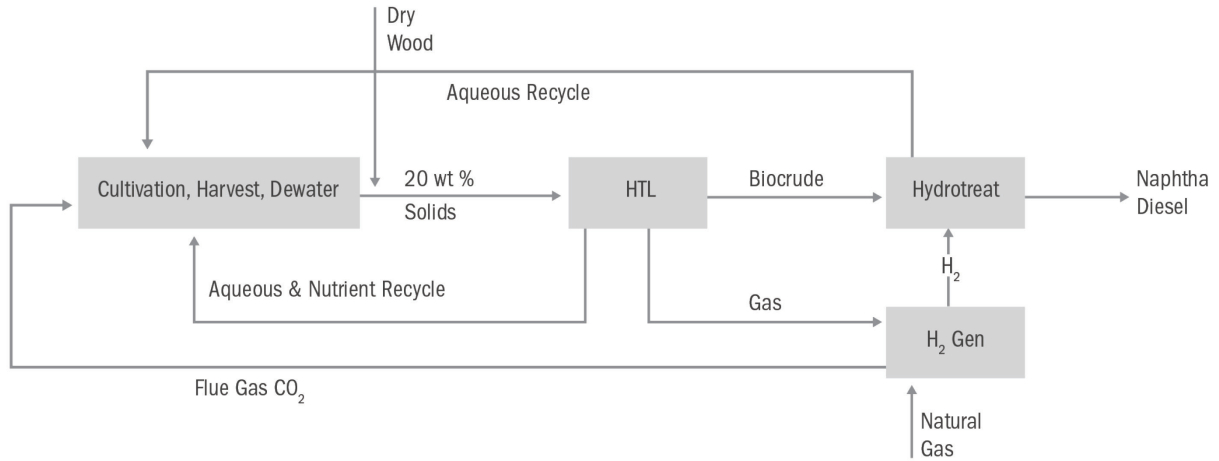


Figure 36: Process flow diagram for the conversion of algal feedstocks to hydrocarbon fuels via high-temperature deconstruction with upgrading

Figure 37 shows that costs for the AHTL design are dominated by algae feedstock production costs⁶⁸.

The biomass composition for the SOT and projections for the AHTL design case are shown in Table 29 and the woody biomass (forestry residue) elemental composition is shown alongside the 2017–2019 algae test material in Table 30.

⁶⁸ Y. Zhu, S. B. Jones, A. J. Schmidt, J. M. Billing, M. R. Thorson, D. M. Santosa, R. T. Hallen, and D. B. Anderson, *Algae/Wood Blends Hydrothermal Liquefaction and Upgrading: 2019 State of Technology* (Richland, WA: Pacific Northwest National Laboratory, PNNL-29861, 2020), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-29861.pdf.

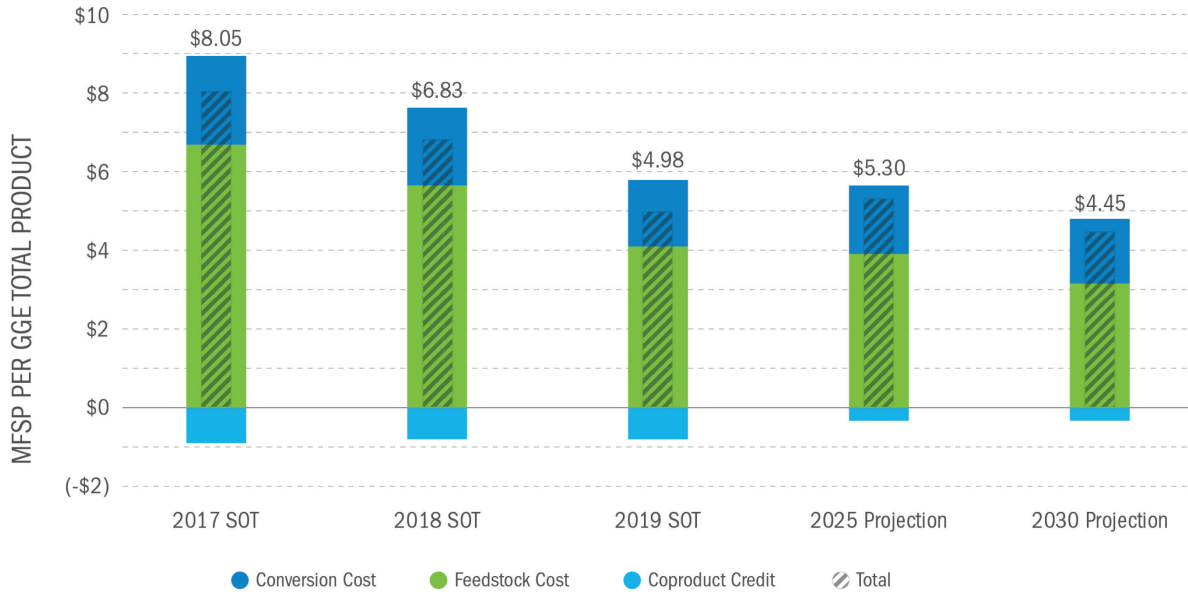


Figure 37: Cost contribution of feedstock and conversion for the algae converted via high-temperature and upgrading pathway⁶⁹

⁶⁹ The 2015 design included wastewater treatment for the 2025 projection. The 2017 SOT showed that wastewater treatment was not necessary, resulting in a reduction in 2018–2019 SOT costs. An update to the 2025 design is forthcoming in FY20.

Table 29: Algae Feedstock Composition for AHTL Design Case

Composition	2015 2016 SOTs	2017 2019 SOTs	2025 and 2030 Projections
Elemental (wt % AFDW)			
Carbon	49.5	53.8	59.4
Hydrogen	6.8	7.5	8.6
Oxygen	35.3	30.8	25.1
Nitrogen	6.4	7.2	5.5
Sulfur	2.1	0.6	0.7
Total	100	100	100
Component (dry wt %)			
Ash	23.4	13.9	13
Phosphorus (in Ash)	0.5	0.3	0.7
Carbohydrates	28.1	23.7	19.1
Protein	28.1	38.6	31.3
Lipids	11.8	23.7	20.8
Other*	6.7	--	14.5
Total	98	100	99

*For 2017 to 2019 HTL, the content data for “other” is unavailable and not listed in the table.

Table 30: Elemental Composition of Algal and Woody Biomass for 2017–2019 SOT Blended Feedstock for AHTL Design Case

Feedstock	Algae (<i>Chlorella</i>)	Woody Biomass (Forest Residue)*
Elemental (wt % AFDW)		
Carbon	53.8	50.0
Hydrogen	7.5	6.2
Oxygen	30.8	43.6
Nitrogen	7.2	0.2
Sulfur	0.6	0
Total	100	100
Inorganic Species (wt % Dry Basis)		
Phosphorus (in Ash)	0.3	0

*Woody biomass compositions at dry ash-free basis were converted from dry basis data from Pacific Northwest National Laboratory HTL testing. Inorganic species (ash) content is assumed to be 1% based on the *Bioenergy Technologies Office 2016 Multi-Year Program Plan*.⁷⁰

Figure 38 and Table 31 show the conversion cost contributions to MFSP for algae-based biofuel produced via the AHTL pathway based on the technical projections shown in Table 32.

⁷⁰ U.S. Department of Energy, *Bioenergy Technologies Office 2016 Multi-Year Program Plan* (Washington, DC: U.S. Department of Energy, DOE/EE-1385, 2016), https://www.energy.gov/sites/prod/files/2016/07/f33/mypp_march2016.pdf.

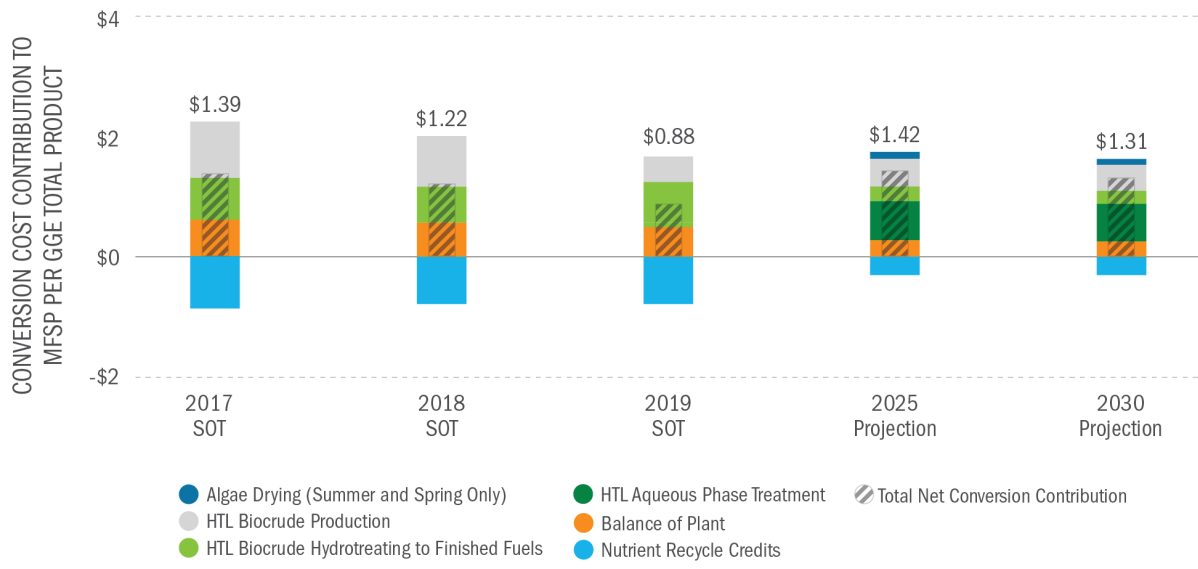


Figure 38: Conversion cost contributions for AHTL conversion and biocrude upgrading pathway

Table 31: Cost Contribution by Conversion Process Areas for the AHTL Design Case

Conversion Cost Breakdown (\$/GGE)	2017 SOT	2018 SOT	2019 SOT	2025 Projection	2030 Projection (Design Case)
Algae Drying (summer & spring only)*	\$0.00	\$0.00	\$0.00	\$0.11	\$0.12
HTL Biocrude Production	\$0.95	\$0.84	\$0.75	\$0.47	\$0.43
HTL Biocrude Hydrotreating to Finished Fuels	\$0.69	\$0.59	\$0.42	\$0.23	\$0.22
HTL Aqueous Phase Treatment	\$0.00	\$0.00	\$0.00	\$0.66	\$0.61
Balance of Plant	\$0.61	\$0.57	\$0.49	\$0.28	\$0.25
Nutrient Recycle Credits	(\$0.86)	(\$0.78)	(\$0.78)	(\$0.32)	(\$0.32)
Net Conversion Contribution to MFSP	\$1.39	\$1.22	\$0.88	\$1.42	\$1.31

*Note: The 2017, 2018, and 2019 SOT investigated blending woody biomass with the algae slurry to offset diminished algae biomass production during winter months, thus the cost of drying and storage is \$0.00 in these SOTs.

Table 32: Unit Operation Cost Contribution Estimates and Technical Projections for Algae Hydrothermal Liquefaction and Upgrading to Naphtha and Diesel*

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2025 Projection	2030 Projection (Design Case)
Year Dollar Basis		2016	2016	2016	2016	2016
Minimum Fuel Selling Price	\$/GGE	\$8.05	\$6.83	\$4.98	\$5.30	\$4.45
Conversion Contribution	\$/GGE	\$1.39	\$1.22	\$0.88	\$1.42	\$1.31
Production Diesel	MMGGE/yr	7.1	8.9	14	19	24
Production Naphtha	MMGGE/yr	3.6	4.0	6.6	3.8	4.7
Diesel Yield (AFDW Feedstock Basis)	GGE/ton feedstock	69	79	70	130	130
Naphtha Yield (AFDW Feedstock Basis)	GGE/ton feedstock	35	36	33	25	25
Diesel Yield (Areal Basis)	GGE/acre/yr	1,416	1,771	2,746	3,887	4,851
Naphtha Yield (Areal Basis)	GGE/acre/yr	724	800	1,310	759	948
Natural Gas Usage-drying (AFDW Feedstock Basis)	scf/ton feedstock	0	0	0	1,791	1,798
Natural Gas Usage-H ₂ Gen (AFDW Feedstock Basis)	scf/ton feedstock	4,078	4,228	4,085	1,473	1,473

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2025 Projection	2030 Projection (Design Case)
Carbon Efficiency, C in Fuel/C in Feedstock	%	54%	58%	53%	70%	70%
Feedstock						
Total Cost Contribution	\$/GGE fuel	\$6.66	\$5.61	\$4.10	\$3.87	\$3.14
Feedstock Type		algae/wood blend	algae/wood blend	algae/wood blend	algae only	algae only
Feedstock Cost (AFDW Basis)	\$/ton feedstock	\$694	\$643	\$421	\$602	\$488
Algae Drying (Summer and Spring Only)						
Total Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.11	\$0.12
Capital Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.05	\$0.05
Operating Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.06	\$0.06
HTL Biocrude Production						
Total Cost Contribution	\$/GGE fuel	\$0.95	\$0.84	\$0.75	\$0.47	\$0.43
Capital Cost Contribution	\$/GGE fuel	\$0.56	\$0.50	\$0.47	\$0.31	\$0.29
Operating Cost Contribution	\$/GGE fuel	\$0.39	\$0.34	\$0.28	\$0.16	\$0.14
Liquid Hourly Space Velocity	vol/h/vol	4.0	4.0	4.0	8.0	8.0
HTL Biocrude Yield (AFDW)	lb/lb feedstock	0.41	0.45	0.41	0.59	0.59
HTL Biocrude Hydrotreating to Finished Fuels						
Total Cost Contribution	\$/GGE fuel	\$0.69	\$0.59	\$0.42	\$0.23	\$0.22
Capital Cost Contribution	\$/GGE fuel	\$0.30	\$0.27	\$0.23	\$0.13	\$0.12
Operating Cost Contribution	\$/GGE fuel	\$0.39	\$0.32	\$0.19	\$0.10	\$0.09
Mass Yield on Dry HTL Biocrude	lb/lb biocrude	0.81	0.82	0.81	0.83	0.83
HTL Aqueous Phase Treatment						
Total Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.66	\$0.61
Capital Cost Contribution	\$/GGE fuel	\$0.00	\$0.00	\$0.00	\$0.38	\$0.35
Operating Cost Contribution	\$/GGE fuel	\$0.00	0.00	0.00	0.28	0.26
Balance of Plant						

Processing Area Cost Contributions and Key Technical Parameters	Units	2017 SOT	2018 SOT	2019 SOT	2025 Projection	2030 Projection (Design Case)
Total Cost Contribution	\$/GGE fuel	\$0.61	\$0.57	\$0.49	\$0.28	\$0.25
Capital Cost Contribution	\$/GGE fuel	\$0.29	\$0.28	\$0.23	\$0.17	\$0.15
Operating Cost Contribution	\$/GGE fuel	\$0.31	\$0.29	\$0.26	\$0.11	\$0.10
Nutrient Recycle Credits	\$/GGE fuel	(\$0.86)	(0.78)	(0.78)	(0.32)	(0.32)

*Note: The table may contain small (< \$0.01) errors due to the way the values were rounded.

Figure 39 shows that the main drivers influencing MFSP in the AHTL design case are the yield of bio-oil, the cost of hydrotreating, and the HTL reactor size. Although the AHTL process design is less sensitive to biomass composition than the CAP design, biomass composition still significantly affects the MFSP (for reference, see the appendix, barriers Aft-E and Aft-G).

Table 33 shows the energy inputs for the 2016 through 2018 SOTs for the AHTL design case.

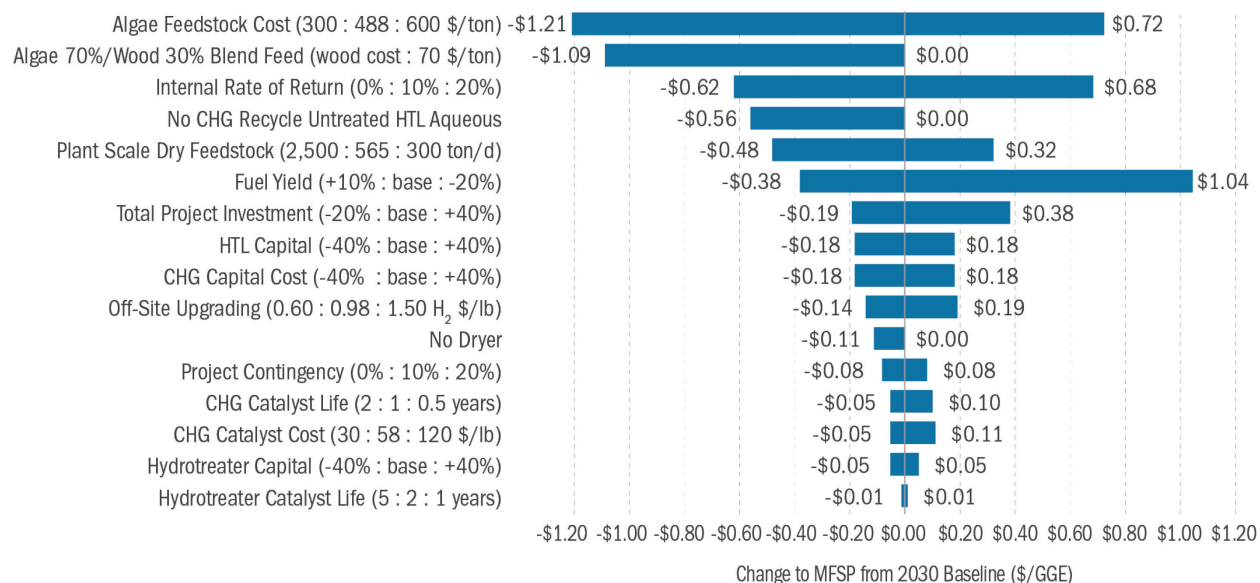


Figure 39: Key factors influencing MFSP for the AHTL design case compared with 2030 projections

Table 33: Energy Inputs for the AHTL Design Case

Input	2017 SOT	2018 SOT	2019 SOT
Fuel Yield (GGE Fuel/Ton AFDW Biomass)	104	115	106
Natural Gas (MMscf/yr)			
To Algae Dryers	0	0	0
To Hydrogen Plant	419	475	822
Total Natural Gas Usage	419	475	822
Natural Gas (scf/Ton Feedstock)	4,078	4,228	4,160
Natural Gas (scf/GGE Final Fuel)	39.2	36.9	39.4
Electricity (kWh/GGE Final Fuel)	0.76	0.70	0.73

Integration and Scale-Up (Conversion and Advanced Development and Optimization)

Process steps and unit operations developed for the AHTL pathway at the R&D scale will need to be integrated and tested to ensure technical targets can be reached when run as an integrated process.

Key integration challenges include:

- Robust operations for handling solid algal and woody biomass streams during co-processing operations, including reliably feeding materials into pressurized HTL reactors (for reference, see the appendix, barriers ADO-B and ADO-F)
- Achieving efficient separation of process streams from the HTL reactor, involving solid, liquid, and gas phases (for reference, see the appendix, barrier ADO-D)
- Improving the conversion of HTL oil phase into hydrocarbon fuels using hydrotreating operations (for reference, see the appendix, barrier ADO-G)
- Developing efficient product separation and purification schemes
- Successful scale-up of integrated process systems to engineering scale (for reference, see the appendix, barriers ADO-A and ADO-D)
- Addressing abrasion and corrosion of plant equipment due to ash and other inorganic species present in the algal and woody feedstocks (for reference, see the appendix, barrier ADO-H)
- Developing nutrient recycling methods to improve algal productivity and profitability (for reference, see the appendix, barriers Aft-J and ADO-F).

Supply Chain Sustainability Analysis

The 2017, 2018, and 2019 SOT SCSA results for the AHTL pathway are shown in Table 34.⁷¹ Results for the 2025 and 2030 projection cases will be included in future Statusupdates. The 2017, 2018, and 2019 SOT SCSAs assume algae cultivation in Florida with unlined ponds using saline algae strains. Fossil energy consumption is 42%–49% lower in the SOT cases relative to petroleum-derived diesel, resulting in a net energy balance of about 0.30 in the 2017 SOT and 0.39 MJ/MJ in the 2018 SOT and 2019 SOT cases.

⁷¹ H. Cai, L. Ou, M. Wang, E. Tan, R. Davis, A. Dutta, and L. Tao et al., *Supply Chain Sustainability Analysis of Renewable Hydrocarbon Fuels via Indirect Liquefaction, Ex Situ Catalytic Fast Pyrolysis, Hydrothermal Liquefaction, Combined Algal Processing, and Biochemical Conversion: Update of the 2019 State-of-Technology Cases* (Lemont, IL: Argonne National Laboratory, ANL/ESD-20/2, 2020), https://greet.es.anl.gov/publication-renewable_hc_2019.

Table 34: Supply Chain Sustainability Analysis for the AHTL Design Case

	2017 SOT	2018 SOT	2019 SOT	Petroleum Diesel
Biofuel Yield				
MMBtu/dry ton	12.1	13.3	11.9	
Fossil Energy Consumption^a				
MJ/MJ	0.70 (-42%)	0.61 (-49%)	0.61 (-49%)	1.2
Net Energy Balance^b				
MJ/MJ	0.30	0.39	0.39	
GHG Emissions				
g CO ₂ e/MJ	59 (-38%)	49 (-48%)	45 (-52%)	94
g CO ₂ e/GGE	7,185	5,946	5,500	11,528
Water Consumption				
gal/MJ	0.06	0.06	0.05	0.02
gal/GGE	7.8	6.8	5.8	2.7
Total NO_x Emissions				
g NO _x /MJ	0.12	0.09	0.09	0.07
g NO _x /GGE	14.8	10.7	10.1	7.9
Urban NO_x Emissions^c				
g NO _x /MJ	0.025	0.025	0.025	0.03
g NO _x /GGE	3.04	3.03	3.03	3.5

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values.

^a This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

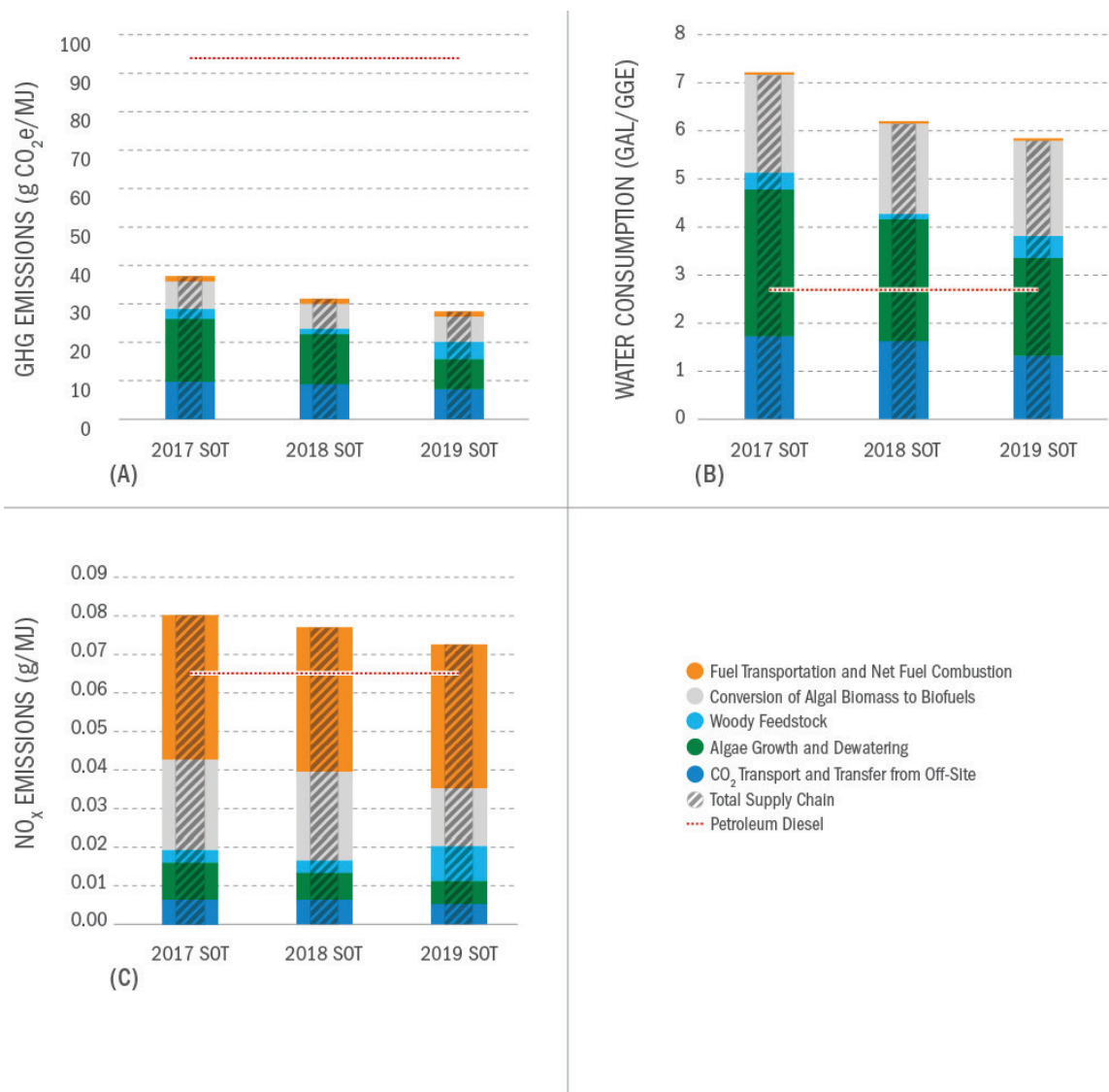
^b Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

Figure 40A shows the 2017, 2018, and 2019 SOT results for supply chain GHG emissions and their key contributing supply chain processes compared with a life cycle carbon intensity of 94 g CO₂e/MJ for petroleum-derived diesel. Figure 40A shows renewable diesel produced via the AHTL design case reduces GHG emissions by 52% for the 2019 SOT case. Natural gas consumption for on-site hydrogen production via steam methane reforming, and energy consumption for CO₂ capture and

transportation to the algae farm and for algae growth and dewatering are the major emission sources. Reduced energy consumption for algae dewatering and increased biofuel yield are the key factors driving improvements in GHG emissions from the 2017 to the 2019 SOT case.

Figure 40B shows that embedded water consumption associated with energy consumption for algae dewatering and for CO₂ capture and transportation to the algae farm are the major contributors to supply chain water consumption in all SOT cases.

Figure 40C shows that total NO_x emissions are 33% higher in the 2019 SOT case than those of petroleum-derived diesel. However, the AHTL design case may result in benefits in urban NO_x emission reductions, as shown in Table 34.



Figures 40A–40C: Supply chain for the AHTL design case for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions

Wet Waste Hydrothermal Liquefaction Design Case

Hydrothermal liquefaction of wet waste sludges (also called biosolids) produced by wastewater treatment facilities represents a second design used to assess technology development progress in the wet waste converted via the high-temperature and upgrading pathway. Research into this design helps identify key challenges and informs R&D priorities associated with conversion processes designed for distributed wet waste feedstocks and separations, and hydroprocessing of biocrude.

This pathway uses primary and secondary sludge from municipal wastewater treatment plants (WWTP). These facilities currently incur sludge disposal costs, including drying, dewatering, and costs for transportation to composting or landfilling, treatment for land application, or incineration. In addition, tipping fees are frequently levied on these wastes by landfills and composting facilities. These sludge disposal costs are expected to increase as states and local governments implement organics diversion regulations that often include municipal sludges.

In water treatment, raw wastewater is first screened to remove large debris and is then treated to separate solids through physical settling, often aided by chemical flocculants. This primary sludge

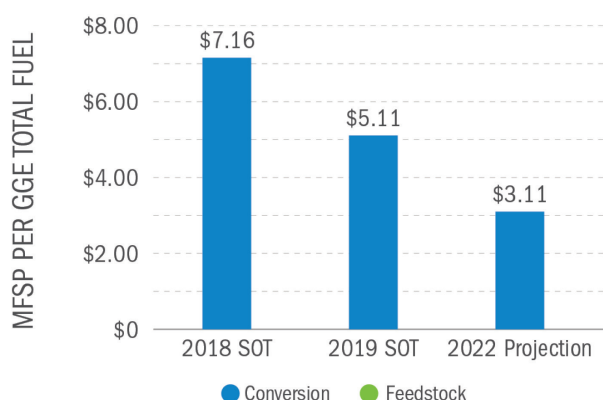


Figure 41: Cost breakdown showing no feedstock costs for wet waste converted via the high-temperature and upgrading pathway (with NH₃ removal from HTL water)

constitutes about 50%–60% of the total solids. Solids concentrations of the wastewater are then reduced to 4%–6% and sent to secondary (aerobic) treatment where a combination of aeration and exposure to microbes converts the remaining organic species, as well as nitrogen and phosphorus, into microbial biomass. After settling, this solids fraction is referred to as secondary sludge. In wastewater treatment operations where anaerobic digestion is employed as a means of managing primary and secondary sludge volumes, approximately 50% of the carbon in that stream is converted to biogas. This

remaining sludge requires further thermal or pressure treatment in order to conform to U.S. Environmental Protection Agency biosolids disposal regulations.⁷² Typically, the remaining, unconverted sludge is transported to landfills for disposal, further treated for land application, incinerated, or sent for composting posing significant transportation costs.

⁷² “Biosolids Laws and Regulations,” U.S. Environmental Protection Agency, accessed February 2019, <https://www.epa.gov/biosolids/biosolids-laws-and-regulations>.

As a resource, sludge is highly correlated with population areas—meaning that the proximity to fuel markets is high. This means that the most economically advantageous deployments of this technology would be located at or near the largest wastewater and sanitation facilities. While there may be opportunities to source sludge from multiple facilities, the transportation costs of aggregating sludge, which is commonly comprised of about 95% water, could make it cost-prohibitive. Unlike algae, where farms can potentially be upscaled, this creates challenges for economies of scale, requiring technologies that are down-scalable with a resulting energy-dense biocrude transported for centralized upgrading.

The design case for utilizing wastewater sludges is represented in Figure 42.⁷³ Primary and secondary sludge from a wastewater treatment facility is mixed and sent to an on-site HTL reactor. Hydrothermal liquefaction operates quite similar to the AHTL design described previously. In the HTL reactor, hot, pressurized water converts this slurry to four phases: a thermally stable biocrude intermediate, an aqueous phase containing organic species, and solid and gaseous streams. The biocrude fraction is transported to a centralized unit where it is hydrotreated to produce hydrocarbon fuel blendstocks. Ammonia is removed from the aqueous stream via an NH₃ stripping process to render the aqueous phase suitable for wastewater treatment. The composition of primary and secondary sludge, illustrated in Table 35, resembles algae due to the high water content and elevated levels of nitrogen and sulfur.

Collection practices and infrastructure for wastewater sludges are well developed in the wastewater treatment industry. The primary wet waste feedstock-related barrier is the cost of transportation, and by extension, dewatering costs. This is addressed in the design case by directly processing wet wastes at the wastewater treatment site, then transporting the resulting biocrude for centralized upgrading. Since this approach avoids sludge transportation and disposal costs, the current design and SOTs do not include feedstock production costs (Figure 41).⁷⁴ Additional technical challenges may be identified for using existing wastewater treatment collection practices and infrastructure. These challenges could require the development of technologies for wet waste feedstock.

The HTL plant in the design case is scaled to process 110 dry tons/day of municipal sludge at 25% solids. This plant scale was selected as the approximate minimum size that is economically

⁷³ L. J. Snowden-Swan, R. T. Hallen, Y. Zhu, T. R. Hart, M. D. Bearden, J. Liu, and T. E. Seiple et al., *Conceptual Biorefinery Design and Research Targeted for 2022: Hydrothermal Liquefaction Processing of Wet Waste to Fuels* (Richland, WA: Pacific Northwest National Laboratory, PNNL-27186, 2017), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-27186.pdf.

⁷⁴ L. J. Snowden-Swan, J. M. Billing, M. R. Thorson, A. J. Schmidt, D. M. Santosa, S. B. Jones, and R.T. Hallen, *Wet Waste Hydrothermal Liquefaction and Biocrude Upgrading to Hydrocarbon Fuels: 2019 State of Technology* (Richland, WA: Pacific Northwest National Laboratory, PNNL-29882, 2020), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-29882.pdf.

feasible (due to economies of scale) and corresponds to a WWTP that processes about 110 million gallons per day incoming wastewater. BETO is exploring ways to increase the available resources and take advantage of economies of scale through blending with other urban and suburban wastes (e.g., food waste and yard waste). The centralized upgrading plant in the design is sized to process the output of 10 HTL plants processing 110 dry tons/day, which corresponds to about 115,000 gal/day of biocrude. This corresponds to production of 2,700 barrels per stream day or 39 million GGE/year of fuel blendstocks.

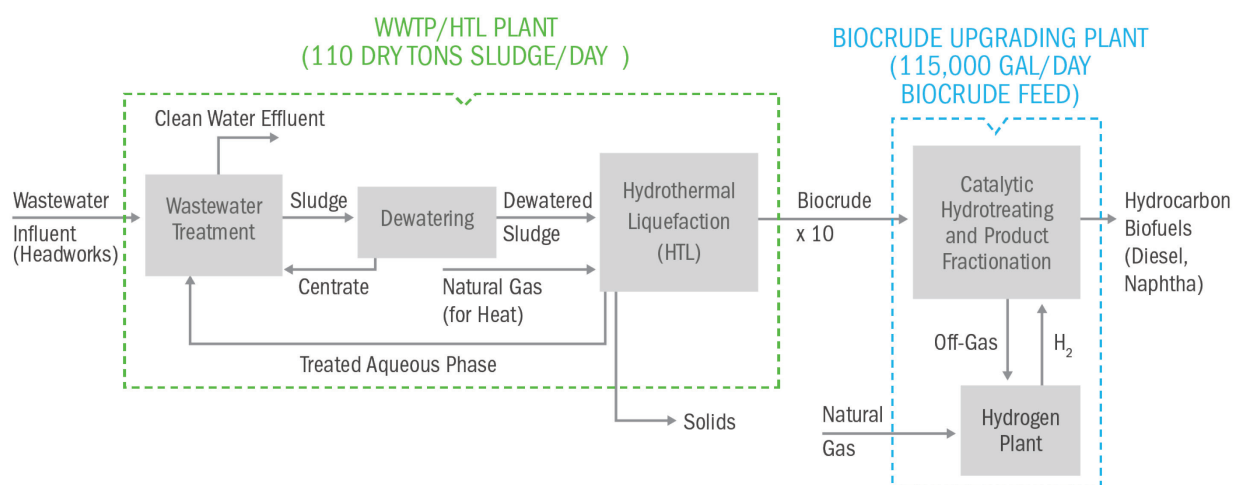


Figure 42: Process flow diagram for the conversion of wet waste feedstocks to hydrocarbon fuels via high-temperature deconstruction with upgrading

Table 35: Composition of Various Sludges (elemental content shown on a dry weight basis)^{75,76}

Feedstock	Weight %						Moisture Content (%)	Volatile Matter (%)	HHV (MJ/kg)
	C	H	N	O	S	Ash			
Primary Sludge	47.8	6.50	3.64	33.6	0.48	7.5	95.5	82.2	20.7
Secondary Sludge	43.6	6.55	7.90	29.0	0.72	16.2	96.1	76.3	19.6
Post-Digester Sludge	38.7	5.68	4.48	27.9	1.63	28.1	~72	N/A	16.8

⁷⁵ P. A. Marrone, *Genifuel Hydrothermal Processing Bench-Scale Technology Evaluation Report* (Alexandria, VA: Water Environment and Reuse Foundation; London: IWA Publishing, 2016), <https://doi.org/10.2166/9781780408408>.

⁷⁶ P. A. Marrone, D. C. Elliott, J. M. Billing, R. T. Hallen, T. R. Hart, P. Kadota, J. C. Moeller, M. A. Randel, and A. J. Schmidt, "Bench-Scale Evaluation of Hydrothermal Processing Technology for Conversion of Wastewater Solids to Fuels," *Water Environment Research* (April 2018): 329–342. <https://dl.uswr.ac.ir/bitstream/Hannan/95351/1/2018%20WER%20Volume%2090%20Issue%204%20April%20%285%29.pdf>.

Table 36 shows the variation in feedstock composition from three different locations. For the 2018 and 2019 SOTs and 2022 design case, sludge from the city of Detroit/Great Lakes Water Authority was used to develop the HTL experimental data and process models.

Figure 43 shows that biocrude yield from the hydrothermal liquefaction reactor is a significant contributor to the modeled MFSP for this process. BETO R&D focuses on improving the yield in several ways, such as incorporating other feedstocks (e.g., brown grease or food waste) frequently disposed at wastewater treatment facilities. These waste fractions also constitute disposal liabilities, as they require landfilling or incineration, and would be available at zero or negative costs. Further, researchers are working on optimizing the temperature and pressure conditions of the HTL reactor to convert additional organic species into biocrude (for reference, see the appendix, barrier Ct-I). Higher-temperature operation converts additional organics into biocrude, but can produce contaminants such as nitrogen and sulfur that result in increased hydrotreating severity.

Another significant opportunity to reduce costs is nitrogen management. At present, the aqueous stream in some cases cannot be directly recycled back to wastewater treatment because the nitrogen and carbon species in these streams can exceed effluent limits or cause operational upsets in the aerobic treatment process.

Table 36: Ultimate Analysis of 50/50 (wt) Primary/Secondary Wastewater Sludge Samples

50/50 Primary/Secondary Sludge Mixture Characteristics	Detroit/Great Lakes Water Authority ⁷⁷	Metro Vancouver ^{78,79}	Central Contra Costa Sanitation District ⁸⁰	2018 SOT, 2019 SOT, and 2022 Projection	2018 SOT, 2019 SOT, and 2022 Projection
Component	wt % dry basis	wt % dry basis	wt % dry basis	wt % dry basis	wt % dry, ash-free basis
Carbon	41.1	45.7	43.3	46.8	52.1
Hydrogen	5.8	6.5	6.3	6.5	7.2
Oxygen	26.1	31.3	30.2	29.7	33.1
Nitrogen	5	5.8	4.5	5.7	6.3
Sulfur	1	0.6	0.6	1.2	1.3
Ash	26.1	11.9	16.7	15	
Phosphorus	1.9	2	2.5	1.9	

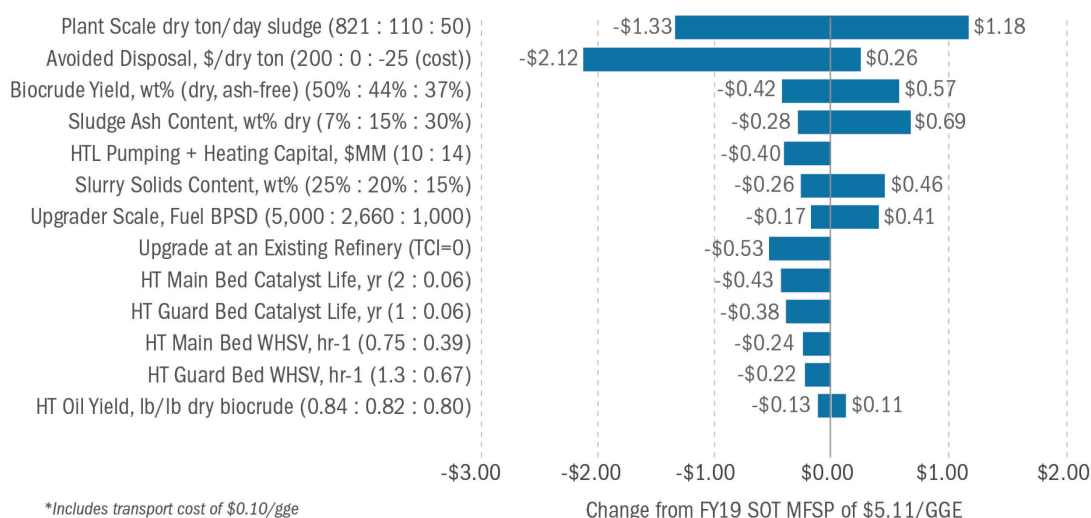


Figure 43: Key factors impacting production costs for the wet waste HTL design case

⁷⁷ L. J. Snowden-Swan, R. T. Hallen, Y. Zhu, T. R. Hart, M. D. Bearden, J. Liu, and T. E. Seiple et al., *Conceptual Biorefinery Design and Research Targeted for 2022: Hydrothermal Liquefaction Processing of Wet Waste to Fuels* (Richland, WA: Pacific Northwest National Laboratory, PNNL-27186, 2017), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-27186.pdf.

⁷⁸ P. A. Marrone, *Genifuel Hydrothermal Processing Bench-Scale Technology Evaluation Report* (Alexandria, VA: Water Environment and Reuse Foundation; London: IWA Publishing, 2016), <https://doi.org/10.2166/9781780408408>.

⁷⁹ P. A. Marrone, D. C. Elliott, J. M. Billing, R. T. Hallen, T. R. Hart, P. Kadota, J. C. Moeller, M. A. Randel, and A. J. Schmidt, "Bench-Scale Evaluation of Hydrothermal Processing Technology for Conversion of Wastewater Solids to Fuels," *Water Environment Research* (April 2018): 329–342. <https://dl.uswr.ac.ir/bitstream/Hannan/95351/1/2018%20WER%20Volume%2090%20Issue%204%20April%20285%29.pdf>.

⁸⁰ L. J. Snowden-Swan, J. M. Billing, M. R. Thorson, A. J. Schmidt, D. M. Santosa, S. B. Jones, and R.T. Hallen, *Wet Waste Hydrothermal Liquefaction and Biocrude Upgrading to Hydrocarbon Fuels: 2019 State of Technology* (Richland, WA: Pacific Northwest National Laboratory, PNNL-29882, 2020), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-29882.pdf.

Figure 44 and Table 37 show the projected cost reductions for the conversion portion of the wet waste HTL pathway between the 2019 SOT and the 2022 projected MFSP, both with and without NH₃ removal for the HTL aqueous phase recycle stream. Table 38 shows the unit operations cost contributions and technical targets for this design case. Figure 44 shows the MFSP for removing NH₃ versus managing through existing wastewater treatment infrastructure. R&D improvements in this area can also reduce the modeled MFSP by reducing the amount of pH adjustment and associated lime consumption/disposal.

Additional R&D areas include increasing the solids loading to the HTL unit (for reference, see the appendix, barrier Ct-B), improving the hydrotreater catalyst performance, including lifetime and yield (for reference, see the appendix, barriers Ct-E and Ct-F), and improving solid/liquid and liquid/liquid separations. Many of these research areas are in preliminary stages and do not yet contribute to modeled costs. They are part of broader BETO strategies for assessing options for reaching future cost and performance goals. In the future, more rigorous projections will be developed to establish key technical targets and research objectives toward achieving 2025 and 2030 cost goals.

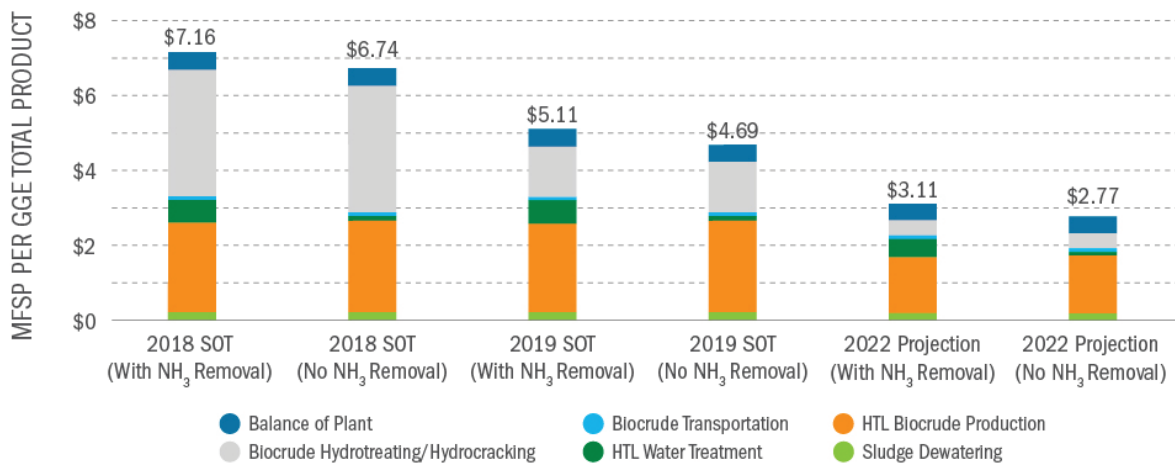


Figure 44: Cost projections for the wet waste HTL design case

Table 37: Cost Projections for the Wet Waste HTL Design Case

Conversion Cost Breakdown (\$/GGE)	2018 SOT (With NH ₃ Removal)	2018 SOT (No NH ₃ Removal)	2019 SOT (With NH ₃ Removal)	2019 SOT (No NH ₃ Removal)	2022 Projected (With NH ₃ Removal Design Case)	2022 Projected (No NH ₃ Removal Design Case)
Sludge Dewatering	\$0.20	\$0.20	\$0.20	\$0.20	\$0.18	\$0.18
HTL Biocrude Production	\$2.40	\$2.45	\$2.40	\$2.45	\$1.49	\$1.55
HTL Water Treatment	\$0.61	\$0.13	\$0.61	\$0.13	\$0.49	\$0.09
Biocrude Transportation	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10
Biocrude Hydrotreating/Hydrocracking	\$3.38	\$3.38	\$1.34	\$1.34	\$0.40	\$0.40
Balance of Plants	\$0.48	\$0.48	\$0.46	\$0.46	\$0.45	\$0.46
MFSP	\$7.16	\$6.74	\$5.11	\$4.69	\$3.11	\$2.77

Table 38: Unit Operation Cost Estimates and Technical Projections for the Wet Waste HTL Design Case

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (With NH ₃ Removal)	2018 SOT (No NH ₃ Removal)	2019 SOT (With NH ₃ Removal)	2019 SOT (No NH ₃ Removal)	2022 Projected (With NH ₃ Removal Design Case)	2022 Projected (No NH ₃ Removal Design Case)
Year Dollar Basis		2016	2016	2016	2016	2016	2016
Minimum Fuel Selling Price	\$/GGE	\$7.16	\$6.74	\$5.11	\$4.69	\$3.11	\$2.77
Conversion Contribution	\$/GGE	\$7.06	\$6.64	\$5.01	\$4.59	\$3.01	\$2.67
Performance Goal	\$/GGE					\$3	\$3
Production Diesel	MMgal/yr	27	27	27	27	28	28
Production Naphtha	MMgal/yr	9	9	9	9	9	9
Diesel Yield (AFDW Sludge Basis)	gal/ton sludge	79	79	79	79	89	89
Naphtha Yield (AFDW Sludge Basis)	gal/ton sludge	27	27	27	27	30	30
Natural Gas Usage (AFDW Sludge Basis)	scf/ton sludge	4,951	3,898	4,951	3,898	4,914	3,861
Feedstock							
Total Cost Contribution	\$/GGE fuel	\$0	\$0	\$0	\$0	\$0	\$0
Feedstock Cost (Dry Sludge Basis)	\$/ton sludge	\$0	\$0	\$0	\$0	\$0	\$0

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (With NH ₃ Removal)	2018 SOT (No NH ₃ Removal)	2019 SOT (With NH ₃ Removal)	2019 SOT (No NH ₃ Removal)	2022 Projected (With NH ₃ Removal Design Case)	2022 Projected (No NH ₃ Removal Design Case)
Sludge Dewatering							
Total Cost Contribution	\$/GGE fuel	\$0.20	\$0.20	\$0.20	\$0.20	\$0.18	\$0.18
Capital Cost Contribution	\$/GGE fuel	\$0.10	\$0.10	\$0.10	\$0.10	\$0.09	\$0.09
Operating Cost Contribution	\$/GGE fuel	\$0.10	\$0.10	\$0.10	\$0.10	\$0.09	\$0.09
Sludge HTL							
Total Cost Contribution	\$/GGE fuel	\$2.40	\$2.45	\$2.40	\$2.45	\$1.49	\$1.55
Capital Cost Contribution	\$/GGE fuel	\$1.46	\$1.46	\$1.46	\$1.46	\$0.83	\$0.83
Operating Cost Contribution	\$/GGE fuel	\$0.94	\$0.99	\$0.94	\$0.99	\$0.66	\$0.72
HTL Biocrude Yield (Dry)	lb/lb sludge	0.44	0.44	0.44	0.44	0.48	0.48
Liquid Hourly Space Velocity	vol/h/vol	3.6	3.6	3.6	3.6	6.0	6.0
Preheaters Capital Cost (Installed)	\$MM	12	12	12	12	6	6
HTL Water Recycle Treatment							
Total Cost Contribution	\$/GGE fuel	\$0.61	\$0.13	\$0.61	\$0.13	\$0.49	\$0.09
Capital Cost Contribution	\$/GGE fuel	\$0.21	\$0.00	\$0.21	\$0.00	\$0.16	\$0.00
Operating Cost Contribution	\$/GGE fuel	\$0.40	\$0.13	\$0.40	\$0.13	\$0.33	\$0.09
Balance of Plant HTL							
Total Cost Contribution	\$/GGE fuel	\$0.06	\$0.07	\$0.06	\$0.07	\$0.07	\$0.07
Capital Cost Contribution	\$/GGE fuel	\$0.04	\$0.04	\$0.04	\$0.04	\$0.04	\$0.04
Operating Cost Contribution	\$/GGE fuel	\$0.02	\$0.02	\$0.02	\$0.02	\$0.03	\$0.03
Biocrude Transport	\$/GGE fuel	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10	\$0.10
Biocrude Upgrading to Finished Fuels							
Total Cost Contribution	\$/GGE fuel	\$3.38	\$3.38	\$1.34	\$1.34	\$0.40	\$0.40
Capital Cost Contribution	\$/GGE fuel	\$0.40	\$0.40	\$0.34	\$0.34	\$0.25	\$0.25
Operating Cost Contribution	\$/GGE fuel	\$2.97	\$2.97	\$1.01	\$1.01	\$0.15	\$0.15
Hydrotreating Mass Yield on Dry Biocrude	lb/lb biocrude	0.82	0.82	0.82	0.82	0.84	0.84

Processing Area Cost Contributions and Key Technical Parameters	Units	2018 SOT (With NH ₃ Removal)	2018 SOT (No NH ₃ Removal)	2019 SOT (With NH ₃ Removal)	2019 SOT (No NH ₃ Removal)	2022 Projected (With NH ₃ Removal Design Case)	2022 Projected (No NH ₃ Removal Design Case)
Guard Bed WHSV	wt/hr/wt	0.46	0.46	0.67	0.67	1.30	1.30
Guard Bed Catalyst Lifetime	years	0.03	0.03	0.06	0.06	1	1
Hydrotreater WHSV	wt/hr/wt	0.29	0.29	0.39	0.39	0.75	0.75
Hydrotreater Catalyst Lifetime	years	0.03	0.03	0.06	0.06	2	2
Balance of Plant Upgrading							
Total Cost Contribution	\$/GGE fuel	\$0.42	\$0.42	\$0.40	\$0.40	\$0.39	\$0.39
Capital Cost Contribution	\$/GGE fuel	\$0.26	\$0.26	\$0.24	\$0.24	\$0.22	\$0.22
Operating Cost Contribution	\$/GGE fuel	\$0.16	\$0.16	\$0.16	\$0.16	\$0.17	\$0.17

Integration and Scale-Up (Conversion and Advanced Development and Optimization)

Due to challenging economies of scale, biocrude from multiple HTL units is expected to be transported to a centralized hydrotreating facility. Unit operations and processes proven at small-scale laboratory conditions would need to be scaled-up and assembled together in an integrated setup or pilot-scale facility to verify process performance (for reference, see the appendix, barriers ADO-A and ADO-D). Understanding integration and scale-up is essential to characterize the interactions between unit operations and generate predictive engineering models to guide process optimization and scale-up strategies. Even with combining biocrude from multiple locations, hydrotreating and hydrocracking represent the second largest contribution to MFSP, contributing \$1.34/GGE.

Key integration challenges include:

- Achieving efficient separation of process streams from the HTL reactor involving solid, liquid, and gas phases (for reference, see the appendix, barrier ADO-F)
- Improving the conversion of HTL biocrude into hydrocarbon fuels using hydrotreating operations (for reference, see the appendix, barrier ADO-G)
- Identifying efficient separations methods for inorganic species such as calcium, iron, silicon, nickel, and sulfur.

Significant improvements are needed in areas including the catalysts used in hydroprocessing (specifically on catalyst lifetime), increasing the liquid hourly space velocities, and managing key ash species such as calcium, iron, and silicon through the use of reactor guard beds. As observed in Figure 44 and shown in Table 38, a large portion of the reduction between the FY18 and FY19 SOTs was a result of the increased catalyst lifetime. Ongoing work within ChemCatBio will continue to inform future strategies for managing these species and other constituents that cause catalyst performance loss and issues with regenerability.

While further experimental validation (ASTM International testing) would be necessary to verify the performance of this as a finished fuel (for reference, see the appendix, barrier ADO-B), on a compositional basis, the resulting hydrotreated oil exhibits low oxygen, nitrogen, and sulfur levels, as well as boiling point distributions with high degrees of overlap with quality control diesel. Additionally, these biocrudes could be co-processed with petroleum-derived VGO in fluid catalytic cracking units (for reference, see the appendix, barrier ADO-G), similar to the dry feedstocks converted via the direct liquefaction pathway. This would help reduce the capital expenses of the process. To make co-

processing more feasible, the Bioprocessing Separations Consortium is exploring how to remove the remaining fractions of nitrogen, primarily found in the heavy ends.

Supply Chain Sustainability Analysis

The SCSA for the wet waste HTL pathway includes scenarios with and without NH₃ removal from the HTL aqueous phase. Table 39 summarizes SCSA results.⁸¹ These results show a small amount of fossil energy use for both the SOT cases and 2022 projections primarily associated with using natural gas and electricity during the HTL and upgrading processes. The net energy balance for the 2022 wet waste HTL design case is 0.52 MJ with NH₃ removal and 0.63 MJ without NH₃ removal.

Figure 45A shows that the supply chain GHG emissions for the wet waste HTL design case for the 2018 and 2019 SOTs and the 2022 design case are lower than for petroleum-derived diesel, especially without NH₃ removal. Higher GHG emission reduction without NH₃ removal is achieved by avoiding quicklime use and a reduction in the natural gas and electricity required for the removal process. The 2022 design case shows reduced GHG emissions from improved conversion efficiency and reduced energy requirement. In all scenarios, the major contributor to supply chain GHG emissions are from HTL biocrude production. The 2022 case relative to the SOT cases for HTL biocrude production shows significant improvement in energy efficiency and GHG emissions. The 2022 case without NH₃ removal also improves water consumption and fossil fuel consumption, compared to petroleum-derived diesel.

⁸¹ H. Cai, L. Ou, M. Wang, E. Tan, R. Davis, A. Dutta, and L. Tao et al., *Supply Chain Sustainability Analysis of Renewable Hydrocarbon Fuels via Indirect Liquefaction, Ex Situ Catalytic Fast Pyrolysis, Hydrothermal Liquefaction, Combined Algal Processing, and Biochemical Conversion: Update of the 2019 State-of-Technology Cases* (Lemont, IL: Argonne National Laboratory, ANL/ESD-20/2, 2020), https://greet.es.anl.gov/publication-renewable_hc_2019.

Table 39: Supply Chain Sustainability Metrics for Renewable Diesel via Wet Waste Sludge HTL

	Scenario 1: With NH ₃ Removal			Scenario 2: No NH ₃ Removal			Petroleum Diesel
	2018 SOT	2019 SOT	2022 Projection (Design Case)	2018 SOT	2019 SOT	2022 Projection (Design Case)	
Biofuel Yield							
MMBtu/dry ton	11.0	11.0	12.4	11.0	11.0	12.4	
Fossil Energy Consumption^a							
MJ/MJ	0.66 (-45%)	0.58 (-52%)	0.48 (-60%)	0.54 (-56%)	0.46 (-62%)	0.37 (-69%)	1.2
Net Energy Balance^b							
MJ/MJ	0.34	0.42	0.52	0.46	0.54	0.63	
GHG Emissions							
g CO ₂ e/MJ	54 (-42%)	49 (-48%)	40 (-58%)	38 (-60%)	32 (-66%)	25 (-73%)	94
g CO ₂ e/GGE	6,587	5,946	4,862	4,616	3,977	3,122	11,528
Water Consumption							
gal/MJ	0.044	0.037	0.029	0.033	0.026	0.019	0.022
gal/GGE	5.4	4.5	3.5	4.0	3.1	2.3	2.6
Total NO_x Emissions							
g NO _x /MJ	0.08	0.07	0.06	0.07	0.06	0.05	0.07
g NO _x /GGE	9.7	8.7	7.7	8.6	7.6	6.7	8.0
Urban NO_x Emissions^c							
g NO _x /MJ	0.028	0.028	0.027	0.028	0.027	0.026	0.030
g NO _x /GGE	3.4	3.4	3.3	3.4	3.3	3.2	3.0

Note: The values in parentheses are the percentage of difference compared to the petroleum diesel pathway. Reduction is represented with negative values.

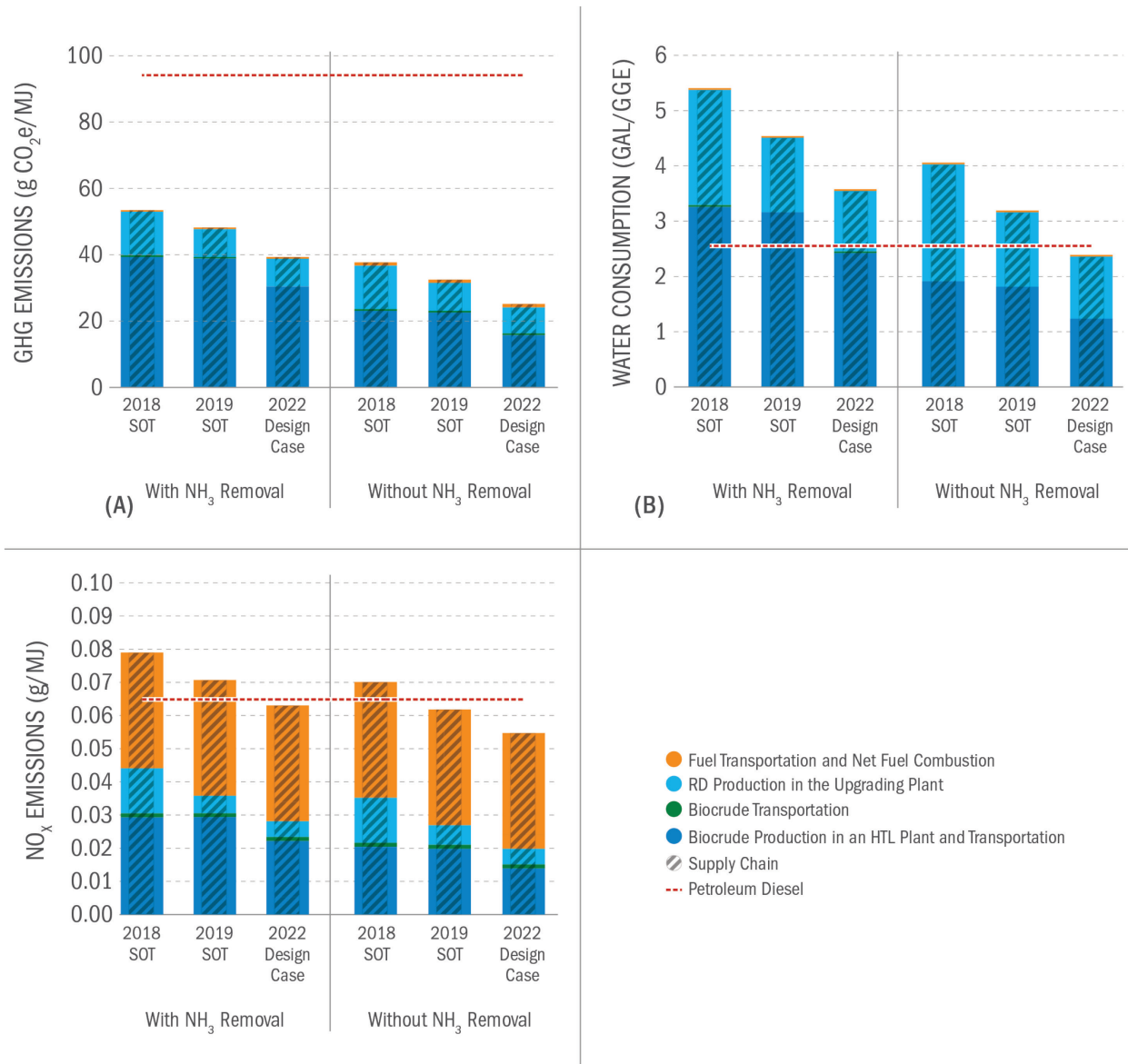
^a This is the amount of fossil energy consumed to produce and use a unit of fuel. For petroleum energy, this includes energy required for crude oil recovery and refining and the energy embedded in the final petroleum fuel consumed in a vehicle.

^b Net energy balance is calculated as the balance of biofuel energy output minus fossil energy consumption used to produce the biofuel. In this pathway, the values of this metric are normalized to a unit of biofuel output. Therefore, they represent the net energy balance of a combined product slate of the biorefinery (biofuel and surplus electricity) when the fossil energy displacement credit of the electricity coproduct is fully taken into account with the displacement coproduct handling method.

^c Urban NO_x emissions account for emissions that occur in municipal statistical areas.

Figure 45B shows the supply chain water consumption for the production of renewable diesel via the wet waste HTL design case. For both the SOT and design cases, supply chain water consumption of RD is higher than that of petroleum-derived diesel (see Table 39). The major contributor is water used in the production of chemicals such as quicklime and the dewatering polymer used in the biocrude production. However, without NH_3 stripping, water use during HTL biocrude production diminishes significantly, as no quicklime or polymers are needed. As a result, water consumption is reduced to 2 gal/GGE in the 2022 case, which is slightly lower than that of petroleum-derived diesel. More importantly, HTL of municipal waste sludges could enable lower costs of clean drinking water by reducing biosolids disposal costs.

Figure 45C shows that the total supply chain NO_x emissions in the 2022 design cases are below the petroleum diesel baseline and slightly reduced relative to the 2018 and 2019 SOT cases due to reduced chemical and energy inputs during production of biocrude. The main contributor of NO_x emissions in both the SOT and 2022 designs is fuel combustion, and the second largest contributor is NO_x emissions released during biocrude production.



Figures 45A–C: Supply chain for the west waste HTL design case for (A) GHG emissions, (B) water consumption, and (C) NO_x emissions

Appendix: Technology Barriers and Challenges

Bioenergy R&D is focused at addressing key technology barriers and challenges across the supply chain—from feedstocks to conversion—and across the technology development life cycle from early-stage to later-stage R&D, as well as cross-cutting considerations.⁸² This section outlines key barriers and challenges referenced throughout this document by barrier code, the leading characters for each barrier. These barriers are roughly categorized by the supply chain segment and technology development stage corresponding to the BETO program structure.

Overall Barriers and Challenges

Ot-B Availability of Quality Feedstock: There are a variety of technical, operational, and economic uncertainties in the availability of consistent and affordable quality feedstock supplies. Mobilizing large volumes of untapped resources will require establishing advanced supply chains to improve quality. This may require significant changes to existing agricultural and forestry practices as well as deploying new supply chains for other renewable carbon streams. Costs associated with grower inputs, establishing new supply chain infrastructure, and preprocessing to improve feedstock quality constrain the overall cost reduction potential for biomass. To meet quality requirements of conversion facilities, feedstock supply and logistics R&D will need to improve feedstock quality from harvest and collection through delivery while also meeting conversion performance and cost goals.

Ot-B – Cost of Production: Significant R&D is required to develop highly efficient and robust feedstock handling, pre-processing, and conversion processes to compete with conventional petroleum fuels. The distributed nature of biomass and waste streams requires greater conversion efficiency at smaller scales compared to petroleum refineries. This drives research in process integration, systems efficiencies, and advanced, robust separations and molecular efficiency to convert current waste streams (an expense) into desirable products (a revenue). This includes developing innovative ways to derive higher values from all primary and secondary product streams (such as lignin and carbon dioxide). As with petroleum refineries, product slates will need to include bioproducts to spread the costs of production across biofuels and higher-valued bioproducts and optimize the use of all feedstocks to be competitive in commodity markets.

Ot-C – Risk of Financing Large-Scale Biorefineries: Obtaining traditional financing is a challenge for new innovative bioenergy technologies, and most pioneer commercial-scale facilities require equity

⁸² U.S. Department of Energy, *Bioenergy Technologies Office 2020 Multi-Year Plan* (forthcoming).

financing of \$200 million or more. Biorefineries face significant first-of-a-kind risks in deploying technology.⁸³ For investors to gain confidence in a technology, processes must function efficiently and reliably with the full variability of feedstocks for significant lengths of time to reduce uncertainty around processing capability and verify that different newly developed technologies can be integrated successfully into a complete, reliable system. Investors also need assurance that operational performance can be scaled-up and transferred from smaller to larger scales. That requires a greater number of more cost-effective experiments be run on smaller-scale, integrated processes.

Feedstock Supply and Logistics R&D Barriers and Challenges

Ft-A. Feedstock Availability and Cost: Conversion technologies face a variety of technical, operational, and economic uncertainties. High-quality, affordable feedstock supplies are not consistently available, and supply and logistics systems can be unreliable due to a lack of fundamental understanding of properties and unique material handling challenges of many renewable carbon sources. Complete data on volumes, compositional variability, and characteristics by geographic location are needed to design and develop economical processes to deliver conversion-ready feedstocks.

Ft-B. Production: The production systems and performance of energy crop species are not well-characterized. The range of production-scale yields of energy crops across genetics, environments, and agronomic practices is not fundamentally understood and requires comprehensive characterization and reliable data from real-world production operations.

Scientific information is lacking on new varieties/cultivars of energy crops, to inform the degree to which they show performance improvements relative to better characterized predecessor varieties, how well adapted they are across regions, whether they may be more cost-effective to produce, and whether they can be shown to be more sustainable relative to a control variety and/or traditional cropping/pasture systems.

Ft-C. Feedstock Genetics and Variety Improvement: The productivity and robustness of bioenergy crops is not optimized for bioenergy applications, and could be significantly increased by traditional breeding and selection and/or modern genetic engineering technologies. Reduced production uncertainty associated with more stress-tolerant varieties is needed to encourage farmers, biorefineries, and financial institutions to seriously consider energy crops.

⁸³ S. E. Koonin and A. M. Gopstein, "Accelerating the Pace of Energy Change," *Issues in Science and Technology* 27, no. 2 (2011), <http://issues.org/27-2/koonin/>.

Ft-D. Sustainable Harvesting: Current crop harvesting machinery is unable to selectively harvest or collect preferred components of renewable carbon sources to meet the capacity, efficiency, quality, or delivered requirements of biorefineries. Harvest, collection, sorting, and transport systems and equipment are not optimized for bioenergy applications. Logistics costs need to be reduced while improving biomass quality and processing efficiency.

Ft-E. Feedstock Quality: Monitoring and Impact on Preprocessing and Conversion Performance: The physical, chemical, microbiological, and post-harvest physiological variations in renewable carbon sources can be significant. For bioenergy crops, variability can arise from differences in genetics, relative crop maturity, agronomic practices and harvest methods employed, soil type, geographical location, and climatic patterns and events. Available data and information are extremely limited to identify the key physical (e.g., particle size, shape, pore volume, surface area, bulk density, and thermal conductivity), mechanical (e.g., compressibility, yield stress, shear, cohesion, friction, and rheological behavior), and chemical (e.g., moisture, ash content/speciation, carbohydrate, lignin content/speciation, extractives, and problematic contaminants) quality characteristics of feedstocks, and to understand the magnitude of their impacts on feeding, preprocessing, and conversion performance (e.g., throughput, yield, and equipment failure). Methods and instrumentation are also lacking for quickly, accurately, and economically measuring these quality-related properties. Analytical and processing standards, understanding of causal relationships and mechanisms at the molecular level, and quality specifications for bioenergy feedstocks are not well developed and may vary from one conversion process to another.

Ft-F. Biomass Storage Systems: Current storage systems (especially for wet, herbaceous materials and wastes) often result in degraded quality between the time of harvest or collection and use. This leads to storage-related physical and chemical degradation, poor feeding and handling performance, and periodic shutdown related to mill and conveyor plugging. The effect of different storage methods, and specifically moisture management, is not adequately defined to enable design of cost-effective systems that preserve quality and increase the stability of downstream operations.

Ft-G. Biomass Physical State Alteration: The initial sizing and grinding, cell wall structure, and particle characteristics of biomass affect conversion efficiencies and yields of all downstream conversion operations. To design technologies and equipment to economically process renewable carbon feedstocks to conversion specifications, information is needed on how the specific differences in the physical and mechanical properties of each feedstock at the nano- and micro-scale impact feed handling as well as conversion cost and yields.

Ft-H. Material Handling and Transportation: Raw herbaceous biomass and other renewable carbon sources have very low bulk and energy density, making transport costly. Conventional handling systems cannot cost-effectively deliver high volumes and are not optimized for bioenergy processes.

Ft-I. Feedstock Supply System Integration and Infrastructure: Conventional supply systems used to harvest, collect, store, preprocess, handle, and transport biomass are not designed to satisfy the large-scale needs of a nationwide system of integrated biorefineries. The infrastructure for feedstock logistics has not been defined for the potential variety of locations, climates, feedstocks, storage methods, and processing alternatives that will need to be implemented on a national scale.

Ft-J. Operational Reliability: Recent evidence indicates that biorefinery development and operation have suffered from failing to account for the complexity and variability of lignocellulosic biomass, inconsistent feeding and handling, inadequate equipment design, and flawed integration. To reach cost-effective operation, biorefineries need to operate at a design capacity of at least 90% on-stream reliability. Fundamental R&D is needed to identify the key feedstock quality and operation factors affecting operational reliability, develop technologies to address contributing factors, and develop process or operational strategies for mitigation.

Advanced Algal Systems R&D Barriers and Challenges

Aft-A. Biomass Availability and Cost: The lack of sufficient data on potential price, location, seasonality, environmental sustainability, quality, and quantity of available algal biomass feedstock creates uncertainty. Established biomass production history is required to understand feedstock supply risks. Reliable, consistent, and sustainable biomass supply is needed to reduce financial, technical, and operational risk to downstream processes.

Aft-B. Sustainable Algae Production: The productivity, energy use, and environmental effects of algae production and harvest systems have not been comprehensively addressed. New production technologies for algae cultivation are needed to lower the resource intensity of algae production.

Aft-C. Biomass Genetics and Development: The productivity and robustness of algae strains against such factors as temperature, seasonality, predation, and competition could be improved by selection, screening, breeding, mixing cultures, and/or genetic engineering. These approaches require extensive ecological, genetic, and biochemical information. In addition, any genetically modified organisms deployed commercially will also require regulatory approval by the appropriate federal, state, and local government agencies.

Aft-D. Sustainable Harvesting: Harvesting and dewatering technologies can be costly and energy- and resource-intensive. Algae biomass harvesting technology must be scalable with low energy

intensity and high reliability. After removal of algae biomass, recycle of harvest water and media can be important.

Aft-E. Algal Biomass Characterization, Quality, and Monitoring: Physical, chemical, biological, and post-harvest physiological variations in algae affect the efficiency of downstream conversion processes. The fundamental components (lipids, carbohydrates, and proteins) of algal biomass vary greatly within strains, among strains, and in comparison to plants. A better understanding of the effects of the high variability in feedstock characteristics on biorefinery operations and performance is needed. Standard procedures to reliably and reproducibly quantify biomass components from algae and to close mass balances are necessary.

Aft-F. Algae Storage Systems: Characterization and analysis of different algae storage methods and strategies are needed to define storage requirements for seasonal variances or design flexibility. These storage methods should preserve harvested algal biomass or biofuel intermediates to maintain product yield over time. Energy use and environmental implications of storage methods must also be understood.

Aft-G. Algal Feedstock Material Properties: Data on algal feedstock quality and physical property characteristics in relation to conversion process performance characteristics are limited. Methods and instruments for measuring physical, chemical, and biomechanical properties of biomass are needed.

Aft-H. Integration: Integration of co-located inoculation, cultivation, primary harvest, concentration, and preprocessing systems is challenging and requires interdisciplinary expertise. In addition, the potential for co-location with other related bioenergy technologies to improve balance of plant costs and logistics may be important.

Aft-I. Algal Feedstock On-Farm Preprocessing: After cultivation and harvesting, algal biomass may require processing or fractionation into lipids, bio-oils, carbohydrates, and/or proteins before these individual components can be converted into the desired fuel and/or products. Integration of pre-processing with algae cultivation poses challenges in operations, as well as energy efficiency and capital costs.

Aft-J. Resource Recapture and Recycle: Residual materials remaining after preprocessing and/or residual processing may contain valuable nitrogen, phosphorus, carbon, or micronutrients, all of which can displace a portion of fresh fertilizer inputs in upstream cultivation. The recapture of these resources from harvest and logistics process waste streams may pose separation challenges, and the recovered materials may not be in biologically available chemical forms. In closed-loop systems, inhibitory compounds may also accumulate.

Conversion R&D Barriers and Challenges

Ct-A. Defining Metrics around Feedstock Quality: Discrete and quantifiable metrics relating feedstock quality characteristics (e.g., ash content, ash speciation, particle size distribution, particle shape distribution, surface roughness, concentration of contaminant species, and organic impurities) and their impact on conversion performance (e.g., yield, catalyst deactivation, and organism toxicity) is necessary. At a minimum, the upper and lower bounds of feedstock quality characteristics that can result in economically viable convertibility need to be identified. End-to-end system throughput analysis is needed to quantify trade-offs between cheaper, lower-quality feedstocks (including blends) and biofuel and coproduct yields, maintenance cycles, and costs.

Ct-B. Efficient Preprocessing and Pretreatment: Trade-off analysis is necessary to optimize pretreatment and preprocessing steps with further downstream processes. This relates to barrier Ct-A above, with respect to identifying unit operations that can mitigate against particular contaminant species or lower-quality feedstocks, as additional unit operations increase the overall energy intensity, capital expenditure, and costs of biomass processes. If/when pretreatment and preprocessing strategies are not available, then it may be necessary to further develop more robust downstream processes. Particle and reaction modeling, experimental evaluation, and concurrent development of subsequent conversion processes is needed to assess key parameters including sugar yields, lignin convertibility, pretreatment reactor uptime, and heat and mass transfer properties.

Ct-C. Process Development for Conversion of Lignin: Converting lignin into value-added products has been a widespread challenge associated with the development of lignocellulosic biofuels. Despite constituting between 15% and 40% of biomass by weight, lignin is generally burned in biorefineries for relatively low-value heat and power. The structural complexity of the lignin polymer makes it difficult to extract greater value from lignin. Recent advances in molecular understanding of this complex polymer point to the potential for lignin to play an increasingly important role in the development of biofuel and value-added bioproducts. In addition to fully deconstructing lignin into low molecular weight compounds, strategies for the synthesis of high-performance products that maintain some structural properties of native lignin (e.g., carbon fibers, resins, and foams) afford additional avenues for deriving value from lignin.

Ct-D. Advanced Bioprocess Development: Increasing titer, rates, and yields of bioproducts through metabolic engineering and fermentation processing improvements is correlated with lowering the costs of fuels and chemicals produced from biomass. In addition, continuous or semi-continuous bioprocessing strategies can reduce the needed capital and operating costs through increased

productivity and reduced organism propagation costs, compared to traditional batch fermentation. Unique challenges exist to develop robust organisms or biocatalysts, along with advanced bioreactors, that can achieve long efficacy times. Real-time measurement and adaptive control strategies that are tailored to the particular organism, catalyst, and/or product are also necessary.

Ct-E. Improving Catalyst Lifetime: There is a need both for catalysts that are more tolerant of lower-quality feedstocks and for pretreatment and separation processes that eliminate contaminant species from intermediate solutions. Developing these processes should be coupled with efforts to obtain a better understanding of the causes of catalyst poisoning and deactivation, specifically in bio-based processes, to more efficiently target contaminants. In addition to developing more robust catalysts and processes, there is a need to decrease the energy intensity and material demand required for catalyst regeneration.

Ct-F. Increasing the Yield from Catalytic Processes: There is also a need to identify catalysts and process conditions that increase overall yield. This can be accomplished by direct improvements to catalyst performance that minimize the loss of carbon and by process improvements that decrease the formation of undesirable intermediates. A better understanding of catalytic active sites and reaction mechanisms, across both low- and high-temperature processes, can be obtained through advanced characterization techniques. Advanced reactor modeling and developing bio-oil characterization techniques can help identify reaction conditions that impact the ratio of different intermediates in high-temperature processes that typically produce a wide range of intermediates. Challenges associated with hydrogen sourcing, cost, and utilization also must be addressed to enable the development of more efficient, highly active, selective, and durable catalysts. Current methods for generating hydrogen are not cost-efficient at the scale envisioned for most biorefineries, and a reliance on externally produced hydrogen contributes to operating costs.

Ct-G. Decreasing the Time and Cost to Develop Novel Industrially Relevant Catalysts: Emerging technologies and processes may require the design and synthesis of novel catalysts. Existing catalysts may also contain materials that become cost-prohibitive when used at larger scales. Researchers need to be able to respond to these needs and identify and synthesize novel catalysts that meet cost and performance targets on an industrially relevant time scale. Understanding the trade-offs between catalyst material and catalyst performance requires detailed information on material costs, as well as robust computational models that can predict reaction mechanisms and catalyst and reactor performance under different operating conditions.

Ct-H. Gas Fermentation Development: There are unique challenges that must be overcome for gaseous feedstocks to be processed viably. Gas fermentations inherently require continuous modes

of operation, as gas storage/recycle loops are largely infeasible (due to costs of compression and capital equipment sizing). Gas streams from biomass can be challenging to transition from gas to liquid, so novel reactors and/or process configurations to maximize the single-pass conversion of these feedstocks are needed.

Ct-I. Development of Processes Capable of Processing High-Moisture Feedstocks in Addition to

Conventional Anaerobic Digestion: Anaerobic digestion is a widely practiced method for waste management and biogas production from high-moisture feedstocks (e.g., sludge from wastewater treatment plants, manure, food waste, and other fractions of municipal solid waste). High-temperature processes, such as gasification or pyrolysis, are inherently inefficient, as a high amount of energy is expended in heating or drying. Additionally, anaerobic digestion requires significant feedstock volumes to offset the high capital costs. Furthermore, anaerobic digestion typically only converts 50% of the organic matter, which results in a significant disposal problem for waste producers. Developing systems with lower capital costs that can convert higher fractions of the waste and that can produce liquid fuels and bioproducts present unique opportunities. A number of unique challenges exist to developing these processes, including identifying individual organisms or consortia of organisms that can produce high quantities of product (e.g., organic acids), developing methods for continuous separations of these products, and testing and developing stable systems (>2,000 hours).

Ct-J. Identification and Evaluation of Potential Bioproducts: To more efficiently realize the full value of biomass feedstocks, conversion processes need to integrate bioproduct production with that of drop-in fuels. Experimental methods and computational analysis to link intermediates from specific processes with potential products (both drop-in replacements and novel molecules that utilize the unique characteristics of biomass feedstocks) need to be developed. Once potential structures are identified, novel molecules will also require high-throughput screening tools to characterize and optimize them for properties that are advantageous to the molecules already used in industrial processes. Metrics and protocols for high-throughput screening will need to be standardized. Additional analysis of molecules and their properties including machine learning will be required to develop a larger database of predictive structure-function relationships that will reduce development time. Experimental methods for comparing both drop-in replacements and novel products with existing products to assess purity and performance will need to be developed.

Ct-K. Developing Methods for Bioproduct Production: Bioproducts will be introduced into existing markets that typically have high requirements for purity. Additional separation steps or other unit operations may need to be added to existing processes to ensure that bioproducts are recovered with industrially relevant specs. Additionally, properties present in molecules that are tested at the

lab and bench scale must be understood fundamentally to enable a transfer to larger scales. Because production processes for many bio-based molecules cannot be scaled rapidly, this increases the risk associated with testing bio-based replacements in formulas.

Ct-L. Decreasing Development Time for Industrially Relevant Microorganisms: There are few public case studies of the overall cost to bring a bio-derived chemical to market outside of biological pharmaceuticals where the cost is upwards of \$1 billion.⁸⁴ For renewable chemicals, development of bio-based 1,3-propanediol by Dupont/Tate & Lyle and the development of NatureWorks' lactic acid process suggests that \$100 –\$200 million and 10–15 years of development time are a reasonable baseline for the current state of the art. While individual companies have made some progress on reducing this time and cost, they often rely on proprietary methods that are specific to individual organisms and product targets, limiting broad applicability. To decrease this time and cost for the bioeconomy as a whole, publicly available new biomanufacturing techniques are needed, as well as new microbial host organisms with improved industrial properties. Central to this challenge is the development of new microbiology techniques in conjunction with databases and machine learning methods to enable better, more automated design of bioprocesses with predictable performance and scaling, as well as significantly increased conversion efficiency. To be truly industrially useful, these efforts must be integrated into a methodology that enables faster and more efficient development cycles.

Ct-M. Current Reactors not Designed to Handle Harsh Conditions Inherent to Converting Biomass Feedstock: Current reactors must be improved to cost-effectively deliver an environment in which catalysts and organisms can be most efficient, including the ability to withstand highly corrosive bio-oil and cost-effectively handle harsh pretreatment conditions for low-temperature deconstruction. This involves developing reactors with cost-effective materials that are optimized for process conditions. In addition, it is currently difficult to precisely control many biological and other processes. New techniques, instruments, and methods are needed to maximize process operation efficiency.

Ct-N. Multi-Scale Computational Framework toward Accelerating Technology Development: Predictive models need to be integrated with experimental data and verified at multiple scales to accelerate technology development. Models must be developed for translating material behavior and performance from atomic scales to industrially relevant reactor scales and developing methods to

⁸⁴ J. A. DiMasi and H. G. Grabowski, "The Cost of Biopharmaceutical R&D: Is Biotech Different?," *Managerial and Decision Economics* 28, no. 4–5 (2007): 469–479, <https://doi.org/10.1002/mde.1360>.

reduce technology uncertainty and time requirements for the scale-up of advanced conversion technologies.

Ct-O. Selective Separations of Organic Species: Separation of organic species in biomass processes for upgrading to final fuel and bioproduct molecules has high energy requirements. Desirable compounds are often closely related structurally to undesired intermediates. These separations require a more thorough compilation of physical properties for complex mixtures of process intermediates, and better modeling methods to improve predictions of acid-water interactions. Low-cost purification technologies need to be developed to remove other organic contaminants and provide concentrated, clean intermediates from which biofuels and bio-based chemicals can be manufactured.

Ct-P. Selective Separations of Inorganic Contaminants: Inorganic species found in feedstocks or in intermediate streams can be incompatible with conversion processes, as they can result in issues such as catalyst poisoning and side reactions. Additionally, their presence in product streams can lead to off-specification products that are unacceptable for fuels or bioproducts. Effective mitigation strategies, such as treatments that can be applied for their selective removal, are needed. Absent these mitigation strategies, these feedstocks may be limited to conversion processes that are insensitive to these feedstock compositions.

Advanced Development and Optimization R&D Barriers and Challenges

ADO-A. Process Integration: The concept of an integrated biorefinery encompasses a wide range of process steps and technical issues. These include collecting, storing, transporting, and processing diverse feedstocks and moving feedstocks through multiple complex conversion subsystems to produce fuel and/or product outputs. The technical performance and operational behavior of unit operations during individual component verification could be significantly different when the same set of individual unit operations are assembled together to form an integrated system. Researching that systems perform as designed when integrated is a challenging and time-consuming process. Understanding process integration is essential to: (1) characterize the interactions between unit operations, (2) identify the impacts of inhibitors and contaminants on processing systems, (3) generate predictive engineering models to guide process optimization and scale-up efforts and develop process control methodologies, and (4) devise equipment design parameters and operational considerations to improve reliability of operations and increase on-stream performance of equipment.

ADO-B. Feedstock Supply Chain Infrastructure: The supply chain infrastructure capable of handling large volumes of highly variable feedstocks is limited. Variable composition, geographical diversity,

and diverse physical properties (such as particle size, bulk density, moisture content, and inorganic species present) impact supply chain costs. Feedstock infrastructure, such as handling and storage facilities, must also meet existing construction, safety, and fire codes, which, in most cases, were not developed for large-scale lignocellulosic biomass operations.

ADO-C. Codes, Standards, and Approval for Use: New biofuels and biofuel blends are not available in sufficient volumes required to perform product certification prescreening requirements. Biofuels and biofuel blends must comply with federal, state, and regional regulations before being approved and certified for end use. Codes and standards are adopted by federal, state, and regional jurisdictions to ensure product safety and reliability, and reduce liability.

ADO-D. Technology Uncertainty of Integration and Scaling: Unit operations proven at small scale under laboratory conditions need to be scaled up and assembled together in an integrated setup or pilot-scale facility to verify process performance. Determining scaling factors for industry best practice of stepwise scaling needs to be based on credible data from operations at the appropriate level of process integration and scale.⁸⁵ This enables subsequent robust, full integration and development of equipment specifications for commercial application.

ADO-E. Co-Development of Fuels and Engines: There are numerous pathways for producing biofuel blendstocks, but current efforts target engines and vehicles that are on the road today. At the same time, most advanced engine development efforts are constrained by the fuels in the market today. Co-development of fuels and engines has the potential to increase vehicle engine efficiency, improve fuel economy, and reduce emissions. Realizing these benefits requires improved understanding of what fuel properties are needed to optimize advanced engine performance and what desirable properties can be provided by biofuel blendstocks.

ADO-F. First-of-a-Kind Technology Development: Studies have shown that the number and complexity of new process steps implemented in first-of-a-kind technology projects are a strong predictor of the challenges to be encountered with reliable performance and operations. Understanding relationships between and within unit operations is useful to inform R&D gaps and for further technology development. Heat and mass balances, along with other implications, including characterization of bioprocessing streams, are not likely to be well understood in new technologies. Additional challenges can be attributed to handling of non-pristine solids; buildup of impurities in process recycle streams; degradation of chemical or catalyst performance; inorganic species in the process streams, char, and slag buildup; and abrasion, fouling, and corrosion of plant equipment.

⁸⁵ M. S. Peters, K. D. Timmerhaus, and R. E. West, *Plant Design and Economics for Chemical Engineers* (New York, NY: McGraw-Hill, 2003).

Furthermore, reliable databases providing interactions of various feedstocks with processing equipment, efficient handling of feedstocks, and predictive methods for feedstock properties are not readily available.

ADO-G. Co-Processing with Petroleum Refineries: Bio-oil and bio-intermediates are composed of components and mixtures different than those found in petroleum refineries, and knowledge on the influence of bio-intermediates blending with petroleum processing is still in the developmental stage. Material characteristics such as physiochemical properties, reactivities, and compatibilities of bio-intermediates with petroleum derivatives need to be well understood. To be accepted for co-processing, petroleum refineries need to understand how a bio-oil or bio-intermediates will perform when integrated into existing operations. The results will be useful to address the GHG effects of co-processed fuel products.

ADO-H. Materials Compatibility, and Equipment Design and Optimization: Current equipment may not be designed to handle the harsh conditions inherent to biofuels production; for example, they may be incompatible with the highly corrosive and erosive nature of feedstocks, biomass, and bio-intermediates. Methods are needed to identify appropriate construction materials and establish process optimization conditions to co-develop equipment. In addition, procedures employed from current refinery practices must be extended to include characteristics of biomass and bio-intermediates.

Analysis and Sustainability Barriers and Challenges

At-A. Analysis to Inform Strategic Direction: Analysis is needed to better understand factors influencing the growth and development of the bioenergy and bioproducts industries, identify the most impactful R&D strategies, define BETO goals, and inform BETO strategic direction.

At-B. Analytical Tools and Capabilities for System-Level Analysis: High-quality analytical tools and models are needed to better understand bioenergy supply chain systems, linkages, and dependencies. Models need to be developed and refined to reflect new knowledge, scientific breakthroughs, and enable informed decision-making. Improvements in model components and linkages are necessary to improve utility, consistency, and reliability.

At-C. Data Availability across the Supply Chain: Understanding the biomass-to-bioenergy supply chain and its economic, environmental, and other impacts requires complete and comparable data. Filling data gaps and improving data accessibility would improve efforts to understand all relevant dimensions of bioenergy and bioproducts production and use and inform model development.

At-D. Identifying New Market Opportunities for Bioenergy and Bioproducts: Biofuels and bioproducts can potentially offer performance advantages relative to other technology options, and they can also provide unique solutions in certain sectors that have limited energy alternatives, such as aviation and marine. Ongoing, forward-looking analyses are needed to identify these opportunities so that R&D priorities can be adjusted appropriately.

At-E. Quantification of Economic, Environmental, and Other Benefits and Costs: When the economic, environmental, and other benefits of bioenergy and bioproducts are uncertain or not quantified, it is difficult to define their value proposition and to make comparisons among energy alternatives. This makes bioenergy technologies less likely to be adopted by the private sector. It is necessary to quantify both the costs and benefits so that synergies can be enhanced, trade-offs can be minimized, and R&D can be directed toward more sustainable outcomes. Furthermore, analyses must use transparent and defensible assumptions to be properly interpreted and to drive toward agreement across the stakeholder community.

At-F. Science-Based Methods for Improving Sustainability: Once the costs and benefits of a given bioenergy or bioproduct system are evaluated, solutions must be developed that improve system performance and economic and environmental outcomes. Furthermore, as bioenergy and bioproduct production from cellulosic, algal, and waste feedstocks is relatively new, few “best practices” are defined for all components of the supply chain. This requires research and development of science-based tools and improved practices in a variety of contexts to accelerate learning and continuous improvement across the emerging bioeconomy.

At-G. Stakeholder Acceptance and Involvement: The successful transfer of bioenergy technologies to the private sector will require significant involvement from landowners, technology developers, local communities, environmental organizations, regulatory bodies, and the broader public. Improved mechanisms are needed to better inform and involve these stakeholders in developing context-specific goals that consider local opportunities and constraints.

At-H. Consensus, Data, and Proactive Strategies for Improving Land-Use Management: The limitations of existing data sources to capture the dynamic state of land use and management, as well as an incomplete understanding of the drivers of land-use and land-management changes, have undermined efforts to assess the environmental effects of bioenergy production and consumption. Science-based, multi-stakeholder strategies are needed to integrate bioenergy with agricultural and forestry systems in a way that reduces wastes, maintains crop yields, enhances resiliency, and supports multiple ecosystem services without increasing pressure on native habitats and wildlife.

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