Biofpr Biofuels Bioproducts & Biorefining

A techno-economic review of hydroprocessed renewable esters and fatty acids for jet fuel production

Matthew Pearlson, Christoph Wollersheim and James Hileman, MIT, Cambridge, MA, USA

Received August 3, 2012; revised October 3, 2012; accepted October 4, 2012
View online at Wiley Online Library (wileyonlinelibrary.com); DOI: 10.1002/bbb.1378;
***Biofuels, Bioprod. Bioref.* 7:89–96 (2013)**

Abstract: Jet fuels produced from sources other than petroleum are receiving considerable attention because they offer the potential to diversify energy supplies while mitigating the net environmental impacts of aviation. The hydroprocessed esters and fatty acids (HEFA) process is a commercially deployed technology that converts vegetable oils and animal fats from triglycerides into hydrocarbons suitable for use in diesel and jet fuels. The technical means of producing alternative fuels from renewable oils, and the resulting carbon intensity has been documented in previous work. However, the cost of production is not available in the literature. This work reviews HEFA fuel production, and estimates the gate price of fuel for several plant sizes and operating conditions. Aspen Plus was used to model biorefinery material and energy balances for unit operations and supporting utilities. A discounted-cash-flow-rate-of-return (DCFROR) economic model was used for sensitivity analysis. The gate price was found to range between \$1.00 L^{-1} for a 378 MML yr^{-1} HEFA facility, and \$1.16 L^{-1} for a 116 MML yr^{-1} facility. Maximizing jet fuel production ranged between \$0.07 and \$0.08 L^{-1} due to increased hydrogen use and decreased diesel and jet fuel yield. While feedstock cost is the most significant portion of fuel cost, facility size, financing, and capacity utilization also influence production costs. © 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

Keywords: techno-economic model; hydroprocess renewable fuels; renewable jet fuel; middle distillates; DCFROR

Introduction

Alternative fuel use is motivated by trends in petroleum prices, concerns about the environment, and the desire for a distributed, domestic, and renewable fuel production infrastructure. Hydroprocessed esters and fatty acids (HEFA) fuels have been certified for use in commercial aviation and military applications and have reported lifecycle greenhouse gas (GHG) emissions 60% lower than petroleum-based fuels.[1] However, the introduction of alternative fuels is not only dependent on technical feasibility and environmental impact, but also on economic viability. This work provides insight into the costs of HEFA production and examines the gate price of renewable diesel and jet fuels under various economic and operating conditions.

Correspondence to: Matthew Pearlson, Laboratory for Aviation and the Environment, Massachusetts Institute of Technology, 77 Massachusetts Avenue, Building 33 Room 115, Cambridge, MA 02139, USA. E-mail: pearlson@alum.mit.edu

Renewable diesel and jet fuels from the hydroprocessed esters and fatty acids process

HEFA uses proven technologies operating at commercial scales around the world to produce drop-in quality, synthetic middle distillate fuels (a.k.a. green jet fuel and green diesel fuel, HRJ/HRD, HEFA, etc). Several companies are already producing HEFA fuels at commercial scales including Neste Oil in Europe and Asia, and Syntroleum's joint venture with Tyson Foods, known as Dynamic Fuels, in Louisiana. Two additional plants are planned or under construction in Louisiana by Valero and Emerald Biofuels. The purpose of the HEFA process is to convert vegetable oils and animal fats into liquid transportation fuels that are chemically equivalent to transportation fuels from fossil resources. The details of the HEFA reaction, including mechanism, yield, and selectivities are reviewed and available in the literature.[2] The main advantages of HEFA fuels are high cetane values, and low aromatic and sulfur content. Additionally, the fuels are 'drop-in' quality, meaning they are synthetic equivalents of petroleum products and compatible with existing production, storage, distribution, and combustion equipment. The performance properties are equivalent to conventional petroleum fuels, but with potentially lower greenhouse gas emissions from renewable feedstocks.[1,3]

Modeling: hydroprocessing plant design

A notional commercial HEFA plant design was modeled in Aspen Plus with process information from the literature.[4,5] The model was used to examine two production profiles and two hydrogen gas sources. The design is based on hydrotreating and isomerization technology available from the literature and other standard petrochemical support processes such as storage tanks, hydrogen gas production, cooling water tower, etc.

The hydroprocessed esters and fatty acids process

The HEFA process model was developed based on the work by Huo[4] and engineering judgment. The additional plant costs, known as balance of plant expenses, were taken from petroleum industry handbooks because of the similarity with petroleum refining.[5] The plant was modeled as eight unit processes, which are described in the following sections: (i) vegetable oil feedstock storage, (ii) hydrodeoxygenation, (iii) selective isomerization and catalytic cracking, (iv) heat integration for steam generation and cooling water, (v) fuel gas cleanup and recycle, (vi) hydrogen gas production, (vii) product separation, and (viii) product storage and blending. Other facility systems were not modeled explicitly, but were included in offsites and special costs for the economic evaluation. Details of the model can be found in Pearlson.[2]

An overview of the process is presented in Fig. 1. Vegetable oil is taken from feed storage and fed into a hydrotreator with hydrogen gas. The deoxygenated effluent is cooled by steam generation, and sent to an isomerization unit. The isomerized hydrocarbon product is then cooled with cooling water before being sent to a separation tower where mixed paraffin gases, carbon dioxide, and excess hydrogen are separated from the liquid products. The paraffin gases and hydrogen are separated from carbondioxide and recycled to the hydrotreator. Liquid products are separated into liquified petroleum gases (LPG), naphtha, jet, and diesel streams and then sent to product storage tank farms. Wastewater is separated from the product stream and sent to treatment units.

Product profiles

Soybean oil was used as the feedstock material in the process model. Since this feedstock is predominately a C_{18} oil, the products are mostly diesel fuel range molecules. However, a producer could choose to produce more jet fuel by cracking the diesel down to the jet range. Two product profiles were modeled to compare this choice: (i) maximum distillate production, and (ii) maximum jet production.

The maximum distillate profile meets diesel specifications, and minimizes LPG and naphtha co-products. The option to separate the jet fuel fraction from the distillate product stream would be available, and is considered. UOP-Honeywell reports that the jet fraction is approximately 15% by volume for its Econfining technology and is used for the basis of all calculations.[6]

The maximum jet profile produces more jet fuel by catalytically cracking diesel range molecules. In theory, jet-range fuel and naphtha could be created by converting $C_{18} \rightarrow C_{10} + C_8$, with no additional by-products. However, in reality the selectivity of the cracking reaction is difficult to control and the products range in size from C_3 through C_{15}. Since the higher molecular weight products have more economic value, not all of the diesel fuel is cracked in the maximum jet scenario even though it is technically possible. The product quantities are calculated from reported literature values and were used in subsequent

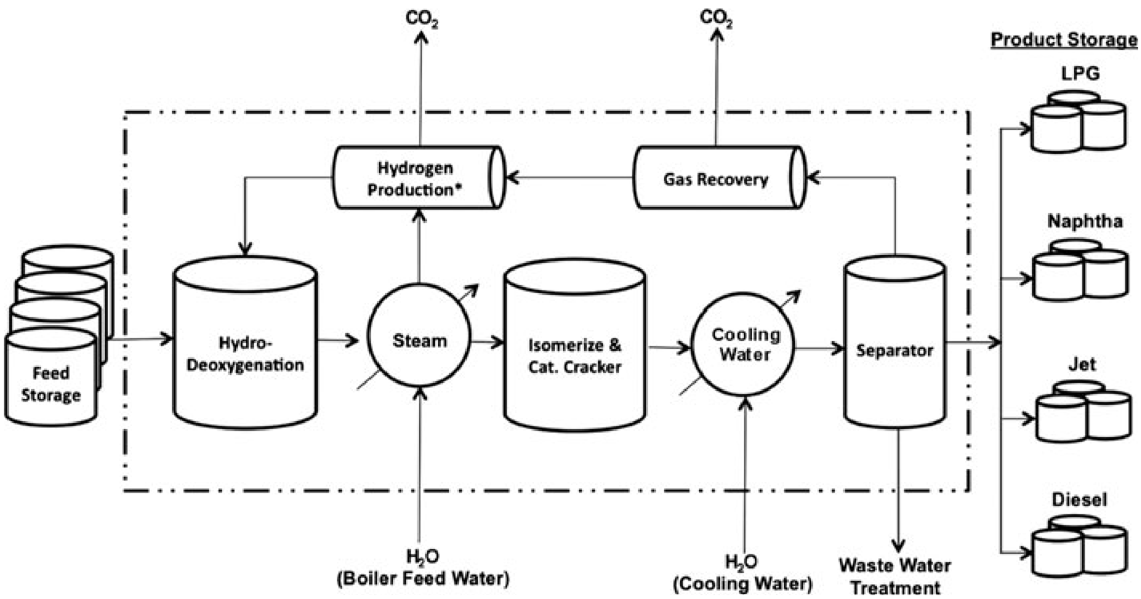


Figure 1. Simplified hydroprocessed esters and fatty acids (HEFA) system design.

calculations.[3,4,7,8] Soybean oil and a consistent product profile were assumed in this work and Table 1 summarizes the product profiles for both scenarios.

Two additional scenarios were considered to understand hydrogen production: (i) on-site steam methane reformer (SMR) hydrogen production scenario, and (ii) 'over-the-fence' hydrogen purchase. In the first scenario, an onsite SMR facility is included in the material and energy balances of the inside battery limits. The second scenario assumes an industrial gas company would supply hydrogen. These scenarios are identical in the assumptions and processing equipment except for the capital and operating expenses associated with an SMR.

Table 1. Mass-based product yields by product profile. The product yields for each product profile are both based on 100 pounds of soybean oil feed. Quantities are based on material balances provided in the literature for a decarboxylation reaction, such as the UOP process.[3,4,7,8]

Product profiles [wt%]	Maximum distillate	Maximum jet
Soybean Oil	100.0	100.0
Hydrogen	2.7	4.0
Total In	102.7	104.0
Water	8.7	8.7
Carbon Dioxide	5.5	5.4
Propane	4.2	4.2
LPG	1.6	6.0
Naphtha	1.8	7.0
Jet	12.8	49.4
Diesel	68.1	23.3
Total Out	102.7	104.0

Process utilities

The utility requirements for the process units were obtained from petroleum handbooks, literature reports on the process, and the modified Aspen Simulation.[4,5,7,9] These include boiler feed water, steam, cooling water, electric power, and natural gas. A summary of utility requirements is described in the literature.[2]

Techno-economic model

A techno-economic model was created with the material and energy requirements to estimate capital and operating expenses and the gate price of distillate fuel from the refinery. Various sensitivity analyses were performed with the model including variations in plant size, production profiles, hydrogen source, project finance structure, and production ramp-up schedules.

Capital equipment estimation

The installed capital cost for HEFA process equipment was estimated from petroleum cost curves.[5] The core process equipment was based on published descriptions of processes and engineering judgment. The inside battery limits (ISBL) include engineered equipment expenses such as the cost of purchasing and installing unit operations and supporting processes. The HEFA ISBL includes a hydrotreating reactor, isomerizing reactor, and saturated gas plant. A steam-methane-reforming hydrogen facility was also included in the ISBL requirements when hydrogen was produced on-site, but excluded when an over-the-fence hydrogen supply was assumed. Additional equipment is required outside the battery limits (OSBL). OSBL and offsite equipment includes product and feed storage, process utilities such as cooling towers, and office and laboratory space. These costs are estimated from petroleum industry heuristics because of the similarity with petroleum refineries.[5] Estimates from this method are assumed to be accurate to +/–25% of the actual project cost.[5] The installed costs for three facility sizes, 116, 232, and 377 MML yr^{-1} (corresponding to 2000, 4000, and 6500 barrels per day) of process capacity were investigated.[2]

Table 2. Historic annual average variable operating expenses and refinery product gate prices in 2010 $US. Gasoline prices are used as a surrogate for naphtha, and propane as a surrogate for LPG.[5,10–13]

Variable expenses	Unit	5yr Avg	20yr Avg	Max	Min
Electric power	[$ kWh^{-1}]	0.06	0.05	0.07	0.04
Natural gas	[$ scm^{-1}]	0.28	0.17	0.34	0.23
Makeup water	[$ Mkg^{-1}]	0.09	0.09	0.09	0.07
Soybean oil	[$ L^{-1}]	0.69	0.42	1.05	0.24
Hydrogen	[$ kg^{-1}]	1.45	1.19	1.49	0.90
Product Values	Unit	5yr Avg	20yr Avg	Max	Min
Propane	[$ L^{-1}]	0.47	0.27	0.59	0.15
LPG	[$ L^{-1}]	0.47	0.27	0.59	0.15
Gasoline	[$ L^{-1}]	0.54	0.29	0.68	0.14
Jet fuel	[$ L^{-1}]	0.56	0.28	0.80	0.12
Diesel fuel	[$ L^{-1}]	0.56	0.28	0.79	0.12

Operating expenses and gross income

Fixed operating expenses were estimated from capital expenses, based on heuristics in the literature, and personal interviews with industry experts familiar with the process.[5] These expenses include insurance, taxes, maintenance, and plant staff salaries. Variable operating expenses include utility costs, such as electricity, natural gas, boiler feed water, and soybean oil. The model was based on soybean oil because it is the primary oil produced in the USA, and many other vegetable oils share similar properties. Nonetheless, the HEFA process could use any oil, fat, or grease feedstock.[6]

Gross income from refinery sales was calculated from prices at the refinery gate and include the cost of production and refiner profit. It does not include the costs for distribution, transportation, retail markup, or taxes. Price supports for renewable fuel production and revenues from trading renewable identification numbers (RINs) are not included in the gate costs. Table 2 lists the five-year average, the 20-year average, maximum and minimum prices for variable operating expenses and the fuel products. The five-year average price, from Table 2 was used as the basis for the gross income calculation.

Utility and input prices in Table 2 were taken from commodity reports by government agencies, commodity market prices, industry sources, and recent techno-economic reports in the literature. Natural gas and electricity prices were estimated from national monthly average industrial prices given by the the US Energy Information Agency (EIA) and scaled for inflation using the Consumer Price Index (CPI) as needed.[10,12] The cost of make-up water was scaled from a value of \$0.08 ML^{-1} using the CPI.[5,12] The cost of purchasing hydrogen was calculated to be \$1.45 kg^{-1} in 2010, which agrees with published literature values, and was then scaled using the CPI.[13]

Similarly, fuel product price data was taken from the EIA for petroleum with corrections for inflation.[10,12] Propane, butane, and pentane are products used for heating applications and sold as LPG. Since LPG prices were not available from EIA, propane prices were used as a substitute. The naphtha product stream results from the cracking reaction. It consists almost entirely of normal and iso-paraffins (>93 wt%) and is a good feedstock for olefins production.[14] However, the octane rating of the naphtha stream is too low for use as a direct substitute for motor gasoline because it lacks aromatic molecules such as benzene and toluene.[7] Since the EIA does not report prices for naphtha, gasoline was used as a price surrogate. The jet fuel and diesel fuel prices were determined in the model, and the five year average price of \$0.56 L^{-1} was used for comparison. There was less than \$0.01 L^{-1} difference between jet fuel and diesel fuel gate prices over the five-year period sampled, but that premium disappears in the 20-year average.

Discounted cash flow rate of return

A discounted cash flow rate of return (DCFROR) analysis was used to evaluate the gate cost of distillate fuel for each of the three plant sizes considered. The distillate fuel gate price was found such that the net present value (NPV)

  | *Biofuels, Bioprod. Bioref.* **7**:89–96 (2013); DOI: 10.1002/bbb

of the project was zero while keeping propane, LPG, and naphtha prices constant. The baseline scenario uses the maximum distillate product profile. A discount rate of 15%, with a loan interest rate of 5.5% and 10-year term on 80% debt financing was used. Capital expenses during construction are spread over three years and distributed as 8%, 60%, and 32% of the total project investment, respectively. Depreciation is scheduled over 10 years, and uses the variable declining balance method. The plant operates at 100% of its name-plate capacity in the base case.

Distillate fuel production results and sensitivity to economic and operating conditions

A DCFROR analysis was used to determine the gate cost of the HEFA distillate fuels that would be needed to satisfy the constraints on the model. The results of the economic analysis are presented in this section. Furthermore, to understand how gate prices vary, the base case was expanded to investigate the effects of hydrogen source, equity structure, and production capacity utilization. Purchasing hydrogen from an industrial supplier in an over-the-fence sale of gas arrangement was compared to the cost of on-site production to determine the effect of economies of scope. The cost of financing was determined by comparing a 100% equity structure with the baseline (20% equity structured project at 5.5% interest). Two plant ramp-up scenarios were investigated to determine the additional cost of running below capacity. The results are presented as baseline prices with additional add-on costs that account for changes from the baseline in Table 3. The increase in gate cost for the various design, operation, or financing changes are shown for a 232 ML yr-1 HEFA facility in Figure 2 and discussed in the following sections.

Baseline results for distillate fuel prices

The results of the baseline scenario for fuel production are reported in Table 3 with the cost of upgrading being $0.46, $0.35, and $0.31 L^{-1} for 116, 232, 378 MML yr^{-1} facilities, respectively. With a feedstock cost of $0.70 L^{-1}, the total baseline gate cost was $1.16, $1.05, and $1.01 L^{-1}. These gate prices are between $0.59 and $0.44 L^{-1} higher than the diesel fuel prices listed in Table 2, and would require a price-support in order to be economically competitive.

Product slate and co-product price

The chemistry of maximum jet fuel production results in higher operating costs and lower revenues. The additional

Table 3. DCFROR gate cost and sensitivity results given in $ L^{-1}. Credits shown in parenthesis. The costs and credits reported are cumulative, (e.g. maximum jet production from a 232 MML yr^{-1} brownfield facility is $1.05 + $0.07 - $0.05 = $1.17 L^{-1}.)

DCFROR results	Facility size	[MML yr^{-1}]	
Baseline	116	232	378
Upgrading cost	$0.46	$0.35	$0.31
Soybean oil	$0.70	$0.70	$0.70
Total gate cost	$1.16	$1.05	$1.01
Sensitivities			
Product Slate			
Naphtha discount, 50%	$0.01	$0.01	$0.01
Maximum jet fuel production	$0.08	$0.07	$0.07
Location			
Brownfield offsites	$(0.07)	$(0.05)	$(0.04)
On-site hydrogen production	$0.09	$0.06	$0.05
Financing			
100% equity	$(0.10)	$(0.07)	$(0.06)
25% discount rate	$0.04	$0.03	$0.02
Production Level			
3 year ramp-up: 50%/75%/100%	$0.14	$0.10	$0.08
Feedstock shortage: 50%	$0.56	$0.40	$0.34

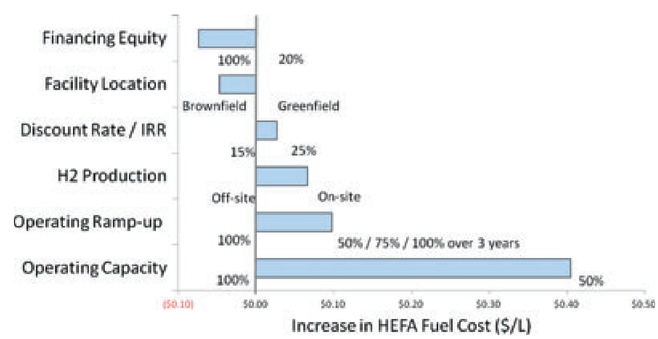


Figure 2. Gate costs for various operational changes to a 232 MML yr^{-1} HEFA facility considered in the DCFROR sensitivity analysis.

cost is due to additional natural gas needed for hydrogen production and reduced revenues from lower quantities of diesel fuel and jet fuel products (Table 1). This means that maximum distillate producers can afford to pay more for their feedstock. This puts the jet fuel producers at a strategic disadvantage, and to maintain the same net present value, they would have to pay between \$0.32 and \$1.11 L^{-1} of vegetable oil more than the maximum distillate producer when fuel prices are between \$0.79 and \$1.59 L^{-1}, respectively.

The difference in gate cost for lower naphtha co-product price and the maximum jet fuel production profile were investigated next. A parametric study was performed on the naphtha price with a range of discount factors between 15% and 50% (approximately \$0.06–0.27 L^{-1}) being applied to account for transport, upgrading, and blending of naphtha at another facility such that it could be used in the motor gasoline pool. However, a 50% naphtha price discount had a negligible effect (less than one cent per liter) on the results and was not a sensitive parameter because it is such a small portion of the product stream.

Producing the maximum jet fuel profile requires an additional cost of \$0.08 L^{-1} for the 116 MML yr^{-1} plant and \$0.07 L^{-1} for the larger plants, thus yielding a finished jet fuel price between \$1.07 and \$1.24 L^{-1}. These values are roughly two times higher than the five year average prices for jet fuel and diesel fuel. A price support would be required to incentivize maximum jet fuel production since the historic annual average price difference for diesel fuel and jet fuel has never been greater than \$0.02 L^{-1}.

Brownfield and onsite hydrogen production

The credit for building the facility at a brownfield site with existing infrastructure ranges between \$0.04 for larger plants, and \$0.07 L^{-1} for smaller plants as shown in Table 3.

The additional cost of on-site hydrogen production was calculated and found to add \$0.10 L^{-1} for 116 MML yr^{-1}, \$0.07 L^{-1} for 232 MML yr^{-1}, and \$0.05 L^{-1} for 378 MML yr^{-1} capacity. This cost comes from additional capital costs, and operating expenses. However, the gate cost of liquid fuels produced with on-site hydrogen could be reduced by between \$0.01 and \$0.02 L^{-1} if the facility were 100% financed (not shown in the table).

Financing

The equity structure was changed from 20% to 100% to determine the effect of capital financing on the gate price. Financing the project with 80% debt costs approximately \$0.10 L^{-1}. This additional cost comes from interest on the capital project over the 10-year lifetime of the loan. In other words, the gate cost of diesel fuel could be reduced by as much as \$0.10 L^{-1} if the project does not require debt financing.

Additionally, reducing financing costs increase the maximum feedstock price the refinery could pay. With 100% equity financing (e.g. no loan payments) could enable a producer to pay between \$0.58 L^{-1} and \$0.95 L^{-1} more for vegetable oil than a producer with debt financing. This additional purchasing power improves economic competitiveness of equity financed plants and makes them better prepared for fluctuations in feedstock prices.

Finally, changing the discount rate from 15% to 25% would result in an additional cost of \$0.04 L^{-1} for 116 MML yr^{-1}, \$0.03 L^{-1} for 232 MML yr^{-1}, and \$0.02 for 378 MML yr^{-1} of capacity on top of the baseline distillate fuel cost.

Production level and ramp-up

New production facilities may not achieve 100% utilization of capacity because of industrial start-up practices or feedstock shortages. Two ramp-up scenarios were considered. The first assumes a notional schedule of 50% capacity in the first year, 75% utilization in the second year, and full capacity in the beginning of the third year and maintained thereafter. This ramp-up schedule requires an additional cost of \$0.14, \$0.10, and \$0.08 L^{-1} over the baseline for 116, 232, and 378 MML yr^{-1} facility sizes, respectively. These added expenses are approximately 10% of the baseline gate cost and show the importance of quickly reaching name plate capacity, as well as being realistic about sources of feedstock during project planning.

The second scenario assumes the plant operates at 50% of nameplate capacity for the entire lifetime because of chronic industrial feedstock limitations. This means, for instance, that a 232 MML yr^{-1} facility will process 116 MML yr^{-1} of feedstock. As a result of lower fuel production volumes an additional \$0.56 L^{-1} is needed for 116 MML yr^{-1}, \$0.40 L^{-1} is needed for 232 MML yr^{-1}, and \$0.34 L^{-1} is needed for 378 MML yr^{-1} of nameplate capacity. This sensitivity highlights a significant financial consequence of insufficient feedstock availability.

Viability

While biomass-based fuels are being produced as petroleum substitutes, there are several economic and environmental trade offs that have not been completely addressed by policy. While the idle biodiesel fuel infrastructure in the US has several economic advantages over new HEFA facilities, the technical advantages of HEFA motivates their production. However, the limited availability of inexpensive feedstocks

  | *Biofuels, Bioprod. Bioref.* **7**:89–96 (2013); DOI: 10.1002/bbb

and easy access to project finance limit the viability of HEFA market penetration. Such limitations could be addressed with policies that support new feedstock production, specifically for producing shorter chain oils to reduce the quantity of low-value light-end co-products and make HEFA jet fuel more economically and environmentally competitive.

Conclusion

As part of continuing research on alternative and renewable fuel production, this work modeled the cost of producing HEFA-derived renewable jet and diesel fuels from soybean oil under various economic scenarios, process designs, and product profiles. The baseline gate cost for distillate fuels, and the additional cost for maximum jet fuel production, onsite hydrogen gas production, financing, and ramp-up were presented. It was found that the baseline cost for HEFA fuel production ranges between \$1.01 and \$1.16 L^{-1} depending on the size of the facility. Producing a maximum jet fuel profile requires approximately \$0.07 L^{-1} more to cover increased operating expenses and reduced middle distillate product revenues.

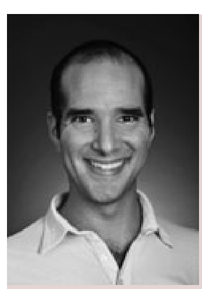
The location, hydrogen source, and ramp-up schedule of a plant also strongly influence the gate price of finished fuels. Co-locating on existing industrial sites, or deactivated refineries can reduce gate prices by up to \$0.07 L^{-1}. Similarly, the cost of production can be reduced by up to \$0.10 L^{-1} if the plant does not require debt financing. The ramp-up scenarios and feedstock simulations demonstrated that in the worst case it is better to build to size than over-build and risk cost penalties in the range of \$0.08 to \$0.61 L^{-1}.

Acknowledgments

The authors would like to thank Mr Russell Stratton and Mr Michael Hagerty for their assistance and feedback in preparing this work; Mr Michael Peters of McKinsey and Co. and Mr Brian Morrissey of Citizen's Energy for their wealth of economic and project financing knowledge and acumen; and Mr Ramin Abhari of Syntroleum for sharing his HEFA processing expertise. The authors are grateful to AspenTech for providing a license to the AspenOne software package, Dr Randy Field of the MIT Energy Initiative for his generosity and kindness assisting with Aspen and to Wilfried Mofor and Enrique Citron who modeled some of the auxiliary processes used in the analysis. This work was funded by the Federal Aviation Administration and the Air Force Research Labs through PARTNER Project 28 with project management provided by Mr Warren Gillette, Dr Tim Edwards, and Mr Bill Harrison.

References

1. Stratton RW, Wong HM, and Hileman JI, Quantifying variability in life cycle greenhouse gas inventories of alternative middle distillate transportation fuels. *Environ Sci Technol* **45**(10):4637–4644 (2011).
2. Pearlson M, *A techno-economic and environmental assessment of hydroprocessed renewable distillate fuels*, Master's thesis. Massachusetts Institute of Technology, Cambridge, MA (2011).
3. Bailis RE and Baka JE, Greenhouse gas emissions and land use change from jatropha curcas-based jet fuel in brazil. *Environ Sci Technol* **44**(22):8684–8691 (2010).
4. Huo H, Wang M, Bloyd C and Putsche V, Life-cycle assessment of energy use and greenhouse gas emissions of soybean-derived biodiesel and renewable fuels. *Environ Sci Technol* **43**(3):750–756 (2009).
5. Gary JH, Handwerk GE and Kaiser MJ, *Petroleum Refining: Technology and Economics,* 5th edn. Taylor & Francis, Basel, Switzerland (2007).
6. Shonnard D, Koers K, Kalnes T and Marker T, Green diesel production by hydrorefining renewable feedstocks. *Biofuels Technology* (2008). Available from: http://www.uop.com/wp-content/uploads/2011/01/UOP-Hydrorefining-Green-Diesel-Tech-Paper.pdf [December 8, 2010].
7. Marker T, Opportunities for biorenewables in oil refineries, technical report. UOP, Des Plains, IL (2005).
8. Donnis B, Egeberg R, Blom P and Knudsen K, Hydroprocessing of bio-oils and oxygenates to hydrocarbons. Understanding the reaction routes. *Top Catal* **52**:229–240 (2009).
9. Parkash S, *Petroleum Fuels Manufacturing Handbook: Including Specialty Products and Sustainable Manufacturing Techniques*. McGraw-Hill, New York, NY (2009).
10. US Energy Information Administration. Petroleum and Other Liquids. Available from: http://www.eia.gov/petroleum/data.cfm [December 8, 2010] (2011).
11. US Department of Agriculture Economic Research Service, *Oilseed crop yearbook.* Washington, DC (2010).
12. US Bureau of Labor Statistics, *Economic news release.* Washington, DC (2010).
13. Wright MM, Daugaard DE, Satrio JA and Brown RC, Techno-economic analysis of biomass fast pyrolysis to transportation fuels. *Fuel* **89**:S2–S10 (2010).
14. Pyl SP, Schietekat CM, Reyniers M-F, Abhari R, Marin GB and Van Geem KM. Biomass to olefins: Cracking of renewable naphtha. *Chem Eng J* **176/177**:178–187 (2011).



Matthew Pearlson

Matthew is a research specialist at MIT's Laboratory for Aviation and the Environment. His research is focused on the technical and economic aspects of alternative transportation fuel production. The work quantifies life cycle greenhouse gas intensity, consumptive water intensity and production costs of various alternative and renewable fuels.

Christoph Wollersheim

As a Laboratory Executive Officer at MIT's Department of Aeronautics and Astronautics, Christoph is researching environmental effects of aviation. His projects focus on the social cost of aircraft-related noise, market-based measures in aviation, alternative jet fuels, and fuel price impacts on US airlines.

James Hileman

Dr Hileman is presently the Chief Scientific and Technical Advisor for the Environment at the Federal Aviation Administration in Washington DC. His research is devoted to understanding and mitigating the impact of aviation on the environment. Previously he served as the Associate Director for the Partnership for AiR Transportation Noise and Emissions Reduction (PARTNER Lab) in the Department of Aeronautics and Astronautics at MIT.

  | *Biofuels, Bioprod. Bioref.* **7**:89–96 (2013); DOI: 10.1002/bbb