Appendix A: Technical Projection Tables

Table A-1: Biomass Volume and Price Projections through 2030 (Minus Allocations for Losses, Chemicals, and Pellets) at an Estimated $80/Dry Ton Delivered Feedstock Cost**

Feedstock Category	Feedstock Resource	Feedstock Available for Cellulosic Fuel Production (MM Dry Tons/Year)							
		SOT	Projection						
		2013	2014	2015	2016	2017	2018	2022	2030
Agricultural Residues	Corn Stover	70.7	83.2	106.7	131.8	138.1	150.7	154.1	172.5
	Wheat Straw	11.2	12.9	13.9	15.9	17.1	18.7	13.9	35.6
Energy Crops	Herbaceous Energy Crops	-	0.5	1.9	3.3	6.4	9.2	10.7	50.2
	Woody Energy Crops	-	-	-	-	-	0.2	5.0	22.9
Forest Residues	Pulpwood	0.8	1.2	1.6	2.1	2.7	3.3	1.7	31.4
	Logging Residues and Fuel Treatments	60.6	56.6	55.1	34.0	50.2	50.5	67.1	60.9
	Other Forestland Removals	0.6	0.8	0.4	0.6	1.3	1.2	0.9	2.9
	Urban and Mill Wood Wastes	32.3	31.3	31.0	27.0	29.9	29.7	31.0	33.8
Totals (MM Dry Tons/Year)		**176.1**	**186.5**	**210.6**	**214.7**	**245.7**	**263.4**	**284.5**	**410.2**

**Volumes presented estimate quantities available at $80/dry ton delivered to the throat of a conversion reactor. This cost is calculated based on current and projected biomass availability at a given stumpage fee/grower payment, combined with logistics cost estimated for the various feedstocks. The estimated logistics costs are based on a 2017 design.

[1] Note that transport distance and other factors impact feedstock logistics cost, and therefore, the biomass volumes at $80/dry ton is an estimate.

[1] Idaho National Laboratory (2014), "Feedstock Supply System Design and Analysis," INL/EXT-14-33227.

Table A-2: Unit Operation Cost Contribution Estimates (2011$) and Technical Projections for Algal Lipid Upgrading

Processing Area Cost Contributions & Key Technical Parameters	Metric	2014 SOT[1]		2022 Projected[2]
Fuel Selling Price	$/GGE fuel	$14.66		$4.35
Conversion Contribution	$/GGE	$1.56		$1.30
Performance Goal	$/GGE	$3		$3
Diesel Production	mm gallons/yr	44		44
Ethanol Production	mm gallons/yr	24		24
Production Co-Product Naphtha	mm gallons/yr	1		1
Diesel Yield (AFDW algae basis)	gal/U.S. ton algae	100		100
Ethanol Yield (AFDW algae basis)	gal/U.S. ton algae	54		54
Naphtha Yield (AFDW algae basis)	gal/U.S. ton algae	2		2
Natural Gas Usage (AFDW algae basis)	scf/U.S. ton algae			2,693 (4,327 including NG for off-site H_2)
Feedstock				
Total Cost Contribution	$/GGE fuel	$10.60		$3.05
Feedstock Cost (AFDW algae basis)	$/U.S. ton algae	$656.47		$430.00
Conversion				
Total Cost Contribution	$/GGE fuel	$1.56		$1.11
Capital Cost Contribution	$/GGE fuel	$0.84		$0.66
Operating Cost Contribution	$/GGE fuel	$0.72		$0.45
Ethanol + Extracted Raw Lipid Yield (dry)	lb /lb algae (AFDW)			0.59
ALU Lipid Hydrotreating to Finished Fuels				
Total Cost Contribution	$/GGE fuel	$1.40		$0.29
Capital Cost Contribution	$/GGE fuel	$0.97		$0.20
Operating Cost Contribution	$/GGE fuel	$0.44		$0.14
Naphtha Credit ($3.25/gal)	$/GGE fuel	($0.05)		($0.05)
Diesel Mass Yield on Dry Purified Oil Feed	lb/lb oil	0.80		0.80
Anaerobic Digestion + Combined Heat & Power				
Total Cost Contribution	$/GGE fuel	($1.49)		($0.18)
Capital Cost Contribution	$/GGE fuel	$0.46		$0.09
Operating Cost Contribution	$/GGE fuel	$0.19		$0.02
AD Coproduct Credits (power, digestate, N/P/CO_2 recycle)	$/GGE fuel	($2.14)		($0.30)
Balance of Plant				
Total Cost Contribution	$/GGE fuel	$0.08		$0.08
Capital Cost Contribution	$/GGE fuel	$0.04		$0.04
Operating Cost Contribution	$/GGE fuel	$0.04		$0.04
Models: Case References		*HLSD + Store*		*HLSD + Store*

[1] R. Davis, D. Fishman, E. Frank, et al. (2012), "Renewable Diesel from Algal Lipids: An Integrated Baseline for Cost, Emissions, and Resource Potential from a Harmonized Model," Argonne National Laboratory, ANL/ESDA/12-4, http://greet.es.anl.gov/publication-algae-harmonization-2012.

[2] R. Davis, C. Kinchin, J. Markham, E.C.D. Tan, et al. (2014), "Process Design and Economics for the Conversion of Algal Biomass to Biofuels," National Renewable Laboratory.

Table A-3: Unit Operation Cost Contribution Estimates (2011$) and Technical Projections for Whole Algae Hydrothermal Liquefaction and Upgrading to Diesel

Processing Area Cost Contributions & Key Technical Parameters	Metric	2014 SOT[1]		2022 Projected[2]
Diesel selling price	$/gal diesel	$15.57		$4.49
Conversion Contribution, Diesel	$/GGE	$2.36		$1.18
Performance Goal	$/GGE	-		$3
Diesel Production	mm gallons/yr	34		54
Production Co-Product Naphtha	mm gallons/yr	11		11
Diesel Yield (AFDW algae basis)	gal/U.S ton algae	77		122
Naphtha Yield (AFDW algae basis)	gal/U.S. ton algae	25		25
Natural Gas Usage (AFDW algae basis)	scf/U.S. ton algae	2,805		2,946
Feedstock				
Total Cost Contribution	$/GGE fuel	$13.21		$3.31
Feedstock Cost (AFDW algae basis)	$/U.S. ton algae	$1,092		$430.00
AHTL				
Total Cost Contribution	$/GGE fuel	$1.78		$0.62
Capital Cost Contribution	$/GGE fuel	$1.36		$0.46
Operating Cost Contribution	$/GGE fuel	$0.42		$0.16
AHTL Oil Yield (dry)	lb /lb algae	0.40		0.59
AHTL Oil Hydrotreating to Finished Fuels				
Total Cost Contribution	$/GGE fuel	$0.34		$0.35
Capital Cost Contribution	$/GGE fuel	$0.22		$0.14
Operating Cost Contribution	$/GGE fuel	$0.12		$0.21
Mass Yield on dry AHTL Oil	lb/lb AHTL oil	0.86		0.83
Catalytic Hydrothermal Gasification of AHTL Aqueous Phase				
Total Cost Contribution	$/GGE fuel	$0.74		$0.63
Capital Cost Contribution	$/GGE fuel	$0.39		$0.37
Operating Cost Contribution	$/GGE fuel	$0.35		$0.26
Balance of Plant				
Total Cost Contribution	$/GGE fuel	($0.50)		($0.42)
Capital Cost Contribution	$/GGE fuel	$0.24		$0.18
Operating Cost Contribution	$/GGE fuel	$0.24		$0.04
Naphtha Credit ($3.25/gal)	$/GGE fuel	($0.99)		($0.63)
Models: Case References		TO1014-SOT		030114P

scf = standard cubic feet.

[1] Jones et al. (2014), "Process Design and Economics for the Conversion of Algal Biomass to Hydrocarbons: Whole Algae Hydrothermal Liquefaction and Upgrading" Pacific Northwest National Laboratory Report 23227.
[2] S.B. Jones, Y. Zhu, L.J. Snowden-Swan, D.B. Anderson, R.T. Hallen, A.J. Schmidt, K.A. Albrecht, D.C. Elliott (2014), "Whole Algae Hydrothermal Liquefaction: 2014 State of Technology Pacific Northwest Laboratory.

Table A-4: Unit Operation Cost Contribution Estimates (2011$) and Technical Projections for Fast Pyrolysis Conversion to Gasoline and Diesel Baseline Process Concept[6]

(Process Concept: Woody Feedstock, Fast Pyrolysis, Bio-Oil Upgrading, Fuel Finishing)*

Processing Area Cost Contributions & Key Technical Parameters	Metric	2009 SOT†	2010 SOT	2011 SOT	2012 SOT	2013 SOT	2014 SOT	2015 Projection*	2016 Projection*	2017 Projection*
Conversion Contribution	$/gal gasoline blendstock	$12.40	$9.22	$7.32	$6.20	$4.51	$4.02	$3.63	$2.96	$2.44
	$/gal diesel blendstock	$13.03	$9.69	$7.69	$6.52	$5.01	$4.48	$4.03	$3.29	$2.70
Conversion Contribution, Combined Blendstocks	$/GGE	$12.02	$8.94	$7.10	$6.02	$4.60	$4.09	$3.69	$3.01	$2.47
Performance Goal	$/GGE	-	-	-	-	-	-	-	-	$3
Combined Fuel Selling Price	$/GGE	$13.40	$10.27	$8.26	$7.04	$5.77	$5.26	$4.75	$4.01	$3.39
Production Gasoline Blendstock	mm gallons/yr	30	30	30	30	29	29	29	29	29
Production Diesel Blendstock	mm gallons/yr	23	23	23	23	32	32	32	32	32
Yield Combined Blendstocks	GGE/dry U.S. ton	78	78	78	78	87	87	87	87	87
Yield Combined Blendstocks	mmBTU/dry U.S. ton	9	9	9	9	10	10	10	10	10
Natural Gas Usage	scf/dry U.S. ton	1,115	1,115	1,115	1,115	1,685	1,742	1,685	1,685	1,685
Feedstock										
Total Cost Contribution	$/GGE fuel	$1.38	$1.33	$1.17	$1.03	$1.01	$1.17	$1.06	$0.99	$0.92
Capital Cost Contribution	$/GGE fuel	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Operating Cost Contribution	$/GGE fuel	$1.38	$1.33	$1.17	$1.03	$1.17	$1.17	$1.06	$0.99	$0.92
Feedstock Cost	$/dry U.S. ton	$106.92	$102.96	$90.57	$79.71	$102.12	$101.45	$92.36	$86.72	$80.00
Fast Pyrolysis										
Total Cost Contribution	$/GGE fuel	$0.97	$0.93	$0.91	$0.90	$0.78	$0.78	$0.77	$0.76	$0.76
Capital Cost Contribution	$/GGE fuel	$0.82	$0.79	$0.76	$0.75	$0.66	$0.66	$0.65	$0.65	$0.64
Operating Cost Contribution	$/GGE fuel	$0.15	$0.15	$0.15	$0.15	$0.12	$0.12	$0.12	$0.12	$0.11
Pyrolysis Oil Yield (dry)	lb organics/lb dry wood	0.60	0.60	0.60	0.60	0.62	0.62	0.62	0.62	0.62
Upgrading to Stable Oil via Multi-Step Hydrodeoxygenation/Hydrocracking										
Total Cost Contribution	$/GGE fuel	$10.07	$7.05	$5.23	$4.17	$2.88	$2.40	$2.01	$1.35	$0.95

[6] S. Jones. et al. (2013), "Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels: Fast Pyrolysis and Hydrotreating Bio-Oil Pathway." PNNL-23053. Richland, WA: Pacific Northwest National Laboratory, http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23053.pdf.

Processing Area Cost Contributions & Key Technical Parameters	Metric	2009 SOT†	2010 SOT	2011 SOT	2012 SOT	2013 SOT	2014 SOT	2015 Projection*	2016 Projection*	2017 Projection*
Capital Cost Contribution	$/GGE fuel	$0.71	$0.68	$0.66	$0.65	$0.59	$0.62	$0.51	$0.45	$0.42
Operating Cost Contribution	$/GGE fuel	$9.36	$6.37	$4.57	$3.52	$2.29	$1.78	$1.50	$0.90	$0.52
Annual Upgrading Catalyst Cost, mm$/year	Annual cost is a function of WHSV[2], number of reactors, catalyst replacement rate, and $/lb	512	344	243	184	130	97	80	43	19.4
Upgraded Oil Carbon Efficiency on Pyrolysis Oil	wt%	65%	65%	65%	65%	68%	68%	68%	68%	68%
Fuel Finishing to Gasoline and Diesel via Hydrocracking and Distillation										
Total Cost Contribution	$/GGE fuel	$0.25	$0.24	$0.24	$0.24	$0.25	$0.24	$0.24	$0.24	$0.14
Capital Cost Contribution	$/GGE fuel	$0.16	$0.15	$0.15	$0.15	$0.16	$0.15	$0.16	$0.16	$0.07
Operating Cost Contribution	$/GGE fuel	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.07
Balance of Plant										
Total Cost Contribution	$/GGE fuel	$0.74	$0.72	$0.71	$0.71	$0.68	$0.68	$0.67	$0.66	$0.63
Capital Cost Contribution	$/GGE fuel	$0.36	$0.34	$0.33	$0.33	$0.29	$0.30	$0.29	$0.29	$0.29
Operating Cost Contribution	$/GGE fuel	$0.38	$0.38	$0.38	$0.38	$0.39	$0.38	$0.38	$0.37	$0.34
Models: Case References		2009 SOT 090913	2010 SOT 090913	2012 SOT 090913	2012 SOT 090913	2013 SOT 122013	2014 SOT 123014	2015 P 123013	2016 P 121913	2017 P 093013

*Pyrolysis conversion performance tests conducted through 2017 are based on dried, debarked pine that has been ground to a 2mm particle size. As explained in Section 2.1.1.5, research funded by FSL aims to develop a blend that will support comparable conversion performance as a pure pine feedstock.
† SOT: State of Technology

1. Note: The table may contain very small (< $0.01) rounding errors due to the difference between the way that Microsoft Excel™ displays and calculates rounded values.
2. WHSV=weight hourly space velocity: weight of oil feed per hour per weight of catalyst.

Note that while the blend is under development, research will continue to expand the specification accepted by the pyrolysis process, making it more robust. Relying solely on pine as a feedstock will not only limit the amount of material available for fuel production via pyrolysis, but will also influence the delivered cost of feedstock to the throat of the conversion process (Figure A-1).

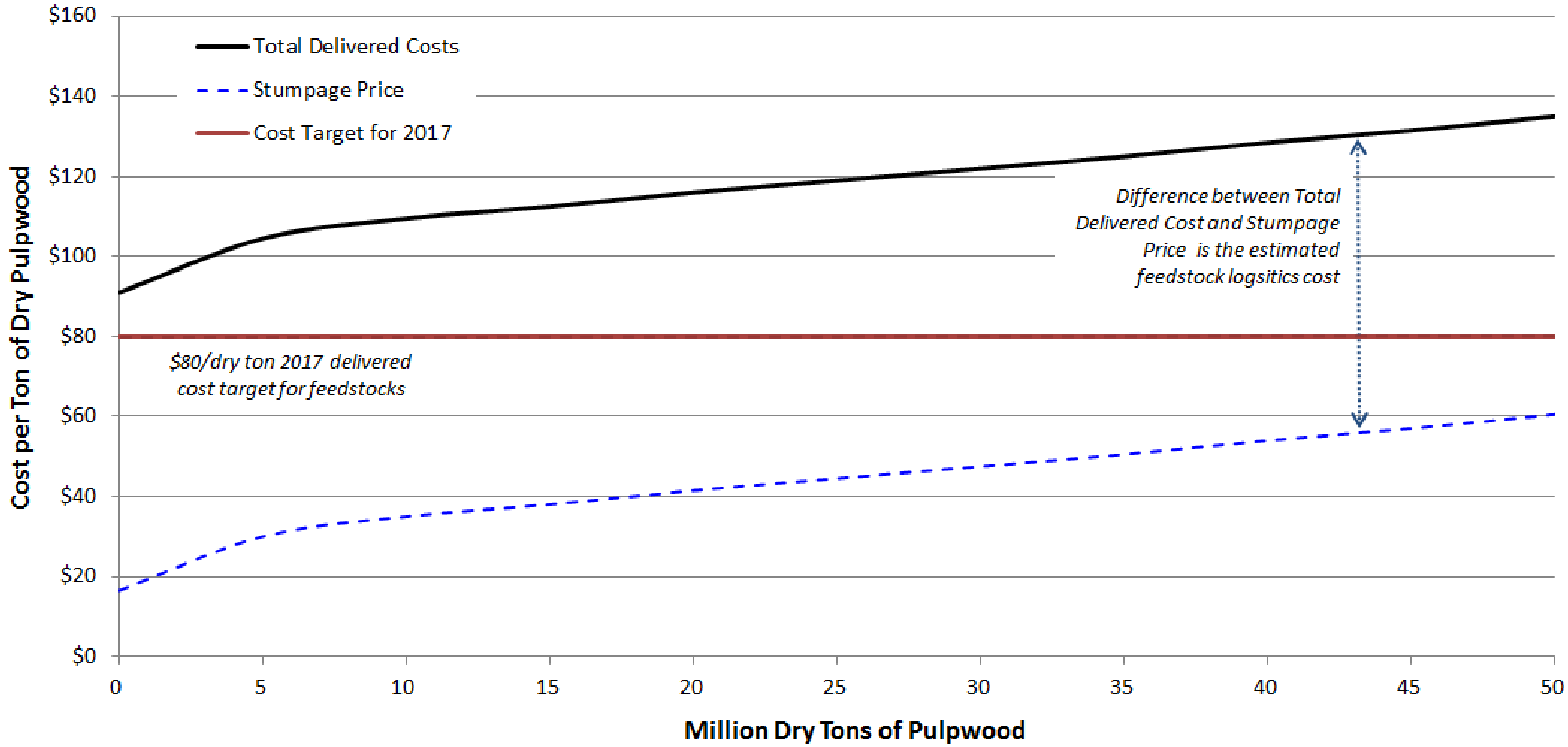

Figure A-1: Estimated total delivered cost of debarked, dried, ground pulpwood, delivered to the throat of the reactor and meeting the conversion specifications for pyrolysis. Pulpwood prices are based on values presented in the *U.S. Billion-Ton Update* (2011) for the year 2017.

As demonstrated in Figure A-1, pulpwood resources are available for conversion in 2017; however, they are more expensive and available in lower volumes than the woody blend scenario presented in Table 2-4. The volumes presented in Figure A-1 are consistent with and are generated from the same data as those presented in Table A-1. However, the volumes presented in Table A-1 were constrained to those available at a low-enough stumpage price such that the total delivered cost target of $80/dry ton could be met.

Table A-5: Processing Area Cost Contribution (2011$) and Key Technical Parameters for Ex Situ Pyrolysis Vapors Baseline Process Concept[7]

(Process Concept: Hydrocarbon Fuel Production via Ex Situ Upgrading of Fast Pyrolysis Vapors)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection/ Design Case
		Pulpwood	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend
Year $ Basis		2011	2011	2011	2011	2011	2011	2011	2011	2011
Projected Minimum Fuel Selling Price▲	$/GGE*	$6.47	$5.92	$5.24	$4.58	$4.33	$4.07	$3.82	$3.57	$3.31
Conversion Contribution	$/GGE*	$4.03	$3.82	$3.47	$3.12	$2.96	$2.79	$2.62	$2.45	$2.28
Total Project Investment per Annual GGE	$/GGE-yr	$19.92	$18.74	$16.71	$14.72	$13.77	$12.81	$11.86	$10.90	$9.94
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
Total Gasoline Equivalent Yield	GGE/dry U.S. ton	42	44	50	56	60	64	69	73	78
Diesel Product Proportion (GGE* basis)	% of fuel product	15%	15%	14%	14%	22%	30%	38%	47%	55%
Feedstock										
Total Cost Contribution	$/GGE	$2.44	$2.10	$1.77	$1.46	$1.37	$1.29	$1.20	$1.12	$1.03
Capital Cost Contribution	$/GGE	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Operating Cost Contribution	$/GGE	$2.44	$2.09	$1.77	$1.45	$1.37	$1.29	$1.20	$1.12	$1.03
Feedstock Cost	$/dry U.S. ton	$101.45	$92.36	$86.72	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00
Feedstock Moisture at Plant Gate	Wt % H_2O	10%	10%	10%	10%	10%	10%	10%	10%	10%
Feed Moisture Content to Pyrolyzer	wt % H_2O	10%	10%	10%	10%	10%	10%	10%	10%	10%

[7] A. Dutta, A. Sahir, E. Tan, D. Humbird, L. Snowden-Swan, P. Meyer, J. Ross, D. Sexton, R. Yap, J. Lukas (2015), "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," NREL/TP-5100-62455, PNNL-23823.

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection/ Design Case
Energy Content (LHV, Dry Basis)	BTU/lb	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
Pyrolysis and Vapor Upgrading										
Total Cost Contribution	$/GGE	$2.46	$2.32	$2.07	$1.85	$1.73	$1.62	$1.51	$1.39	$1.28
Capital Cost Contribution	$/GGE	$1.10	$1.03	$0.93	$0.82	$0.78	$0.73	$0.68	$0.63	$0.58
Operating Cost Contribution	$/GGE	$1.36	$1.28	$1.15	$1.02	$0.96	$0.89	$0.83	$0.77	$0.71
Gas Phase	wt % of dry biomass	35%	34%	32%	30%	29%	27%	26%	24%	23%
Aqueous Phase	wt % of dry biomass	25%	25%	25%	26%	27%	27%	28%	29%	30%
Carbon Loss	% of C in biomass	2.9%	2.9%	2.4%	2.3%	2.1%	1.9%	1.7%	1.5%	1.3%
Organic Phase	wt % of dry biomass	17.5%	18.5%	20.2%	22.0%	23.0%	24.1%	25.1%	26.2%	27.2%
H/C Molar Ratio	ratio	1.1	1.1	1.2	1.3	1.3	1.4	1.5	1.5	1.6
Oxygen	wt % of organic phase	15.0%	14.8%	14.0%	12.5%	11.3%	10.1%	8.8%	7.6%	6.4%
Carbon Efficiency	% of C in biomass	27%	28%	31%	34%	36%	38%	40%	42%	44%
Solid Losses (Char + Coke)	wt % of dry biomass	23%	23%	23%	22%	22%	21%	21%	20%	20%
Char	wt % of dry biomass	12%	12%	12%	12%	12%	12%	12%	12%	12%
Coke	wt % of dry biomass	11.0%	10.8%	10.5%	10.2%	9.8%	9.3%	8.9%	8.4%	8.0%
Pyrolysis Vapor Quench										
Total Cost Contribution	$/GGE	$0.38	$0.35	$0.32	$0.28	$0.26	$0.24	$0.22	$0.20	$0.18
Capital Cost Contribution	$/GGE	$0.23	$0.21	$0.19	$0.17	$0.16	$0.14	$0.13	$0.12	$0.11
Operating Cost Contribution	$/GGE	$0.15	$0.14	$0.13	$0.11	$0.10	$0.09	$0.09	$0.08	$0.07
Hydroprocessing and Separation										
Total Cost Contribution	$/GGE	$0.34	$0.34	$0.32	$0.29	$0.28	$0.27	$0.26	$0.25	$0.24
Capital Cost Contribution	$/GGE	$0.19	$0.19	$0.18	$0.16	$0.16	$0.15	$0.14	$0.14	$0.13

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection/ Design Case
Operating Cost Contribution	$/GGE	$0.15	$0.15	$0.14	$0.13	$0.12	$0.12	$0.11	$0.11	$0.10
Carbon Efficiency of Organic Liquid Feed to Fuels	%	88%	88%	89%	90%	91%	92%	93%	93%	94%
Hydrotreating Pressure	Psia	2,000	2,000	2,000	2,000	1900	1800	1700	1600	1,500
Oxygen Content in Cumulative Fuel Product	wt %	0.8%	0.8%	0.8%	0.7%	0.6%	0.6%	0.5%	0.4%	0.4%
Hydrogen Production										
Total Cost Contribution	$/GGE	$0.67	$0.65	$0.62	$0.58	$0.56	$0.53	$0.51	$0.48	$0.46
Capital Cost Contribution	$/GGE	$0.45	$0.44	$0.42	$0.39	$0.37	$0.35	$0.34	$0.32	$0.30
Operating Cost Contribution	$/GGE	$0.23	$0.21	$0.21	$0.19	$0.19	$0.18	$0.17	$0.16	$0.15
Additional Natural Gas***	% of biomass LHV	0.3%	0.1%	0.1%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%
Balance of Plant										
Total Cost Contribution	$/GGE	$0.17	$0.16	$0.14	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13
Capital Cost Contribution	$/GGE	$0.93	$0.85	$0.71	$0.59	$0.54	$0.48	$0.43	$0.37	$0.32
Operating Cost Contribution	$/GGE	($0.76)	($0.68)	($0.57)	($0.46)	($0.41)	($0.35)	($0.30)	($0.25)	($0.19)
Electricity Production from Steam Turbine (credit included in operating cost above)	$/GGE**	($1.12)	($1.02)	($0.85)	($0.69)	($0.62)	($0.54)	($0.47)	($0.39)	($0.32)
Sustainability and Process Efficiency Metrics										
Fuel Yield by Weight of Biomass	% w/w of dry biomass	13.7%	14.5%	16.1%	17.9%	19.2%	20.6%	21.9%	23.2%	24.6%
Carbon Efficiency to Fuels	% C in feedstock	23.5%	25.0%	27.6%	30.6%	32.8%	34.9%	37.1%	39.3%	41.5%
Overall Carbon Efficiency to Fuels	% C in feedstock + NG	23.5%	25.0%	27.6%	30.6%	32.8%	34.9%	37.1%	39.3%	41.5%

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection/ Design Case
Overall Energy Efficiency to Fuels	% LHV of feedstock + NG	30.4%	32.3%	36.0%	40.2%	43.5%	46.8%	50.0%	53.3%	56.6%
Electricity Production	kWh/GGE	21.0	19.2	16.0	13.1	11.7	10.3	8.9	7.6	6.2
Electricity Consumption (Entire Process)	kWh/GGE	12.7	12.0	10.4	9.1	8.4	7.8	7.1	6.4	5.7
Water Consumption	gal H_2O/GGE	1.4	1.3	1.2	1.1	1.0	0.9	0.8	0.8	0.7
Fossil GHG Emissions (with electricity credit)	g CO_2e/MJ fuel	(41.5)	(36.5)	(27.9)	(19.3)	(15.7)	(12.0)	(8.4)	(4.8)	(1.2)
Fossil Energy Consumption (with electricity credit)	MJ fossil energy/MJ fuel	(0.5)	(0.4)	(0.3)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	0.0
TEA Reference File		PyVPU-v218g ES - 2014.xlsm	PyVPU-v218g ES - 2015.xlsm	PyVPU-v218g ES - 2016.xlsm	PyVPU-v218g ES - 2017.xlsm					PyVPU-v218 ES - 2022.xlsm

▲Conceptual design result with margin of error +/- 30%

† SOT: State of Technology
* Note: The projections for 2018–2021 are based solely on an interpolated linear reduction in costs between 2017 and 2022.
* Gallon Gasoline Equivalent (GGE) on a Lower Heating Value (LHV) basis

** A negligible stream was maintained in the model to allow natural gas use if necessary.

NG = natural gas; Psia = pounds per square inch absolute.

Table A-6: Processing Area Cost Contribution ($2011) and Key Technical Parameters for In Situ Catalytic Pyrolysis Vapors to Gasoline and Diesel Baseline Process Concept[8]

(Process Concept: Hydrocarbon Fuel Production via In Situ Upgrading of Fast Pyrolysis Vapors)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection / Design Case
		Pulpwood	**Woody Blend**	**Woody Blend**	**Woody Blend**	**Woody Blend**	**Woody Blend**	**Woody Blend**	**Woody Blend**	**Woody Blend**
Year $ Basis		2011	2011	2011	2011	2011	2011	2011	2011	2011
Projected Minimum Fuel Selling Price▲	$/GGE*	$6.16	$5.65	$5.13	$4.46	$4.26	$4.06	$3.86	$3.66	$3.46
Conversion Contribution	$/GGE*	$3.92	$3.73	$3.45	$3.08	$2.94	$2.80	$2.66	$2.52	$2.38
Total Project Investment per Annual GGE	$/GGE/yr	$16.26	$15.37	$14.18	$12.58	$11.98	$11.38	$10.79	$10.19	$9.59
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
Total Gasoline Equivalent Yield	GGE/dry U.S. ton	46	49	52	59	62	65	68	72	75
Diesel Product Proportion (GGE** basis)	% of fuel product	17%	17%	17%	17%	19%	21%	23%	25%	27%
Feedstock										
Total Cost Contribution	$/GGE	$2.23	$1.92	$1.68	$1.38	$1.32	$1.26	$1.20	$1.14	$1.08
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	$2.23	$1.92	$1.68	$1.38	$1.32	$1.26	$1.20	$1.14	$1.08
Feedstock Cost	$/dry U.S. ton	$101.45	$92.36	$86.72	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00
Feedstock Moisture at Plant Gate	Wt % H_2O	10%	10%	10%	10%	10%	10%	10%	10%	10%
Feed Moisture Content to Pyrolyzer	wt % H_2O	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	8,000	8,000	8,000	8,000

[8] A. Dutta, A. Sahir, E. Tan, D. Humbird, L. Snowden-Swan, P. Meyer, J. Ross, D. Sexton, R. Yap, J. Lukas (2015), "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," NREL/TP-5100-62455, PNNL-23823.

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection / Design Case
Pyrolysis and Vapor Upgrading										
Total Cost Contribution	$/GGE	$2.47	$2.31	$2.11	$1.82	$1.71	$1.60	$1.49	$1.38	$1.28
Capital Cost Contribution	$/GGE	$0.76	$0.71	$0.65	$0.58	$0.55	$0.52	$0.49	$0.46	$0.43
Operating Cost Contribution	$/GGE	$1.71	$1.60	$1.45	$1.24	$1.16	$1.08	$1.00	$0.92	$0.84
Gas Phase	wt % of dry biomass	31%	30%	29%	27%	26%	25%	24%	24%	23%
Aqueous Phase	wt % of dry biomass	26%	26%	26%	27%	27%	28%	28%	28%	29%
Carbon Loss	% of C in biomass	3.2%	3.1%	2.6%	2.4%	2.3%	2.3%	2.2%	2.2%	2.1%
Organic Phase	wt % of dry biomass	19.5%	20.6%	21.6%	24.0%	24.9%	25.7%	26.6%	27.5%	28.3%
H/C Molar Ratio	ratio	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.5
Oxygen	wt % of organic phase	15.6%	15.5%	14.4%	14.0%	13.3%	12.6%	11.9%	11.2%	10.5%
Carbon Efficiency	% of C in biomass	29%	31%	33%	37%	38%	40%	41%	43%	44%
Solid Losses (Char + Coke)	wt % of dry biomass	24%	24%	23%	23%	22%	22%	21%	21%	20%
Char	wt % of dry biomass	12%	12%	12%	12%	12%	12%	12%	12%	12%
Coke	wt % of dry biomass	12.0%	11.6%	11.2%	10.6%	10.1%	9.6%	9.1%	8.6%	8.1%
Pyrolysis Vapor Quench										
Total Cost Contribution	$/GGE	$0.30	$0.28	$0.25	$0.22	$0.21	$0.20	$0.19	$0.18	$0.17
Capital Cost Contribution	$/GGE	$0.18	$0.17	$0.15	$0.13	$0.13	$0.12	$0.12	$0.11	$0.11
Operating Cost Contribution	$/GGE	$0.12	$0.11	$0.10	$0.08	$0.08	$0.08	$0.07	$0.07	$0.07
Hydroprocessing and Separation										
Total Cost Contribution	$/GGE	$0.35	$0.34	$0.32	$0.31	$0.30	$0.30	$0.29	$0.28	$0.27
Capital Cost Contribution	$/GGE	$0.19	$0.19	$0.18	$0.17	$0.17	$0.16	$0.16	$0.16	$0.15
Operating Cost Contribution	$/GGE	$0.15	$0.15	$0.14	$0.14	$0.14	$0.13	$0.13	$0.13	$0.12

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection / Design Case
Carbon Efficiency of Organic Liquid Feed to Fuels	%	88%	88%	89%	89%	90%	90%	90%	91%	91%
Hydrotreating Pressure	psia	2,000	2,000	2,000	2,000	1960	1920	1880	1840	1,800
Oxygen Content in Cumulative Fuel Product	wt %	0.7%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.5%	0.5%
Hydrogen Production										
Total Cost Contribution	$/GGE	$0.63	$0.62	$0.59	$0.57	$0.55	$0.54	$0.53	$0.51	$0.50
Capital Cost Contribution	$/GGE	$0.42	$0.42	$0.40	$0.38	$0.37	$0.36	$0.35	$0.34	$0.33
Operating Cost Contribution	$/GGE	$0.21	$0.20	$0.20	$0.19	$0.18	$0.18	$0.18	$0.17	$0.17
Additional Natural Gas***	% of biomass LHV	0.3%	0.0%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%
Balance of Plant										
Total Cost Contribution	$/GGE	$0.18	$0.19	$0.18	$0.17	$0.17	$0.16	$0.16	$0.16	$0.16
Capital Cost Contribution	$/GGE	$0.83	$0.76	$0.69	$0.57	$0.53	$0.49	$0.45	$0.41	$0.37
Operating Cost Contribution	$/GGE	($0.64)	($0.58)	($0.51)	($0.41)	($0.37)	($0.33)	($0.29)	($0.25)	($0.21)
Electricity Production from Steam Turbine (credit included in operating cost above)	$/GGE**	($0.98)	($0.89)	($0.79)	($0.64)	($0.59)	($0.53)	($0.48)	($0.42)	($0.36)
Sustainability and Process Efficiency Metrics										
Fuel Yield by Weight of Biomass	% w/w of dry biomass	15.0%	15.8%	17.0%	19.0%	19.9%	20.9%	21.9%	22.8%	23.8%
Carbon Efficiency to Fuels	% C in Feedstock	25.8%	27.3%	29.2%	32.6%	34.1%	35.7%	37.3%	38.8%	40.4%
Overall Carbon Efficiency to Fuels	% C in Feedstock + NG	25.8%	27.3%	29.2%	32.6%	34.1%	35.7%	37.3%	38.8%	40.4%
Overall Energy Efficiency to Fuels	% LHV of Feedstock + NG	33.2%	35.3%	37.9%	42.4%	44.8%	47.2%	49.6%	52.0%	54.3%
Electricity Production	kWh/GGE	18.5	16.8	14.9	12.2	11.1	10.1	9.1	8.1	7.0
Electricity Consumption (Entire Process)	kWh/GGE	11.7	10.9	10.0	8.7	8.2	7.7	7.2	6.8	6.3

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection / Design Case
Water Consumption	gal H_2O/GGE	1.3	1.2	1.1	0.9	0.9	0.9	0.8	0.8	0.8
Fossil GHG Emissions (with electricity credit)	g CO_2e/MJ fuel	(32.8)	(28.6)	(23.8)	(16.1)	(13.4)	(10.7)	(8.0)	(5.3)	(2.6)
Fossil Energy Consumption (with electricity credit)	MJ fossil energy/MJ fuel	(0.4)	(0.3)	(0.3)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	0.0
TEA Reference File		PyVPU-v218g IS - 2014.xlsm	PyVPU-v218g IS - 2015.xlsm	PyVPU-v218g IS - 2016.xlsm	PyVPU-v218g IS - 2017.xlsm					PyVPU-v218 IS - 2022.xlsm

▲Conceptual design result with margin of error +/- 30%
† SOT: State of Technology
* Note: The projections for 2018–2021 are based solely on an interpolated linear reduction in costs between 2017 and 2022.

** Gallon Gasoline Equivalent (GGE) on a Lower Heating Value (LHV) basis

*** A negligible stream was maintained in the model to allow natural gas use if necessary.

Table A-7: Unit Operation Cost Contribution Estimates (2011$) and Technical Projections for Low-Temperature Deconstruction and Fermentation Process Concept[9,10]

(Process Concept: Dilute Acid Pretreatment, Enzymatic Hydrolysis, Biological Upgrading, Succinic Acid/Apipic Acid Co-Product)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2022 Projection
Process Concept: Hydrocarbon Fuel Production via Biological Upgrading of Sugars		**Stover**	**Stover**	**Blend**	**Blend**	**Blend**
Year $ Basis	-	2011	2011	2011	2011	2011
Projected Minimum Fuel Selling Price	$/GGE	$12.97	$10.14	$7.43	$5.03	$3.00
Conversion Contribution[1]	$/GGE	$9.09	$6.93	$4.97	$3.16	$1.67
Plant Capacity (Dry Feedstock Basis)	metric tons/day	2,000	2,000	2,000	2,000	2,000
Total Gasoline Equivalent Yield	GGE/dry U.S. ton	18	20	20	22	44
Succinic Acid Yield	lb/dry ton biomass	197	206	232	270	0
Feedstock						
Total Cost Contribution	$/GGE	$3.88	$3.20	$2.47	$1.87	$1.33
Capital Cost Contribution	$/GGE	NA	NA	NA	NA	$0.00
Operating Cost Contribution	$/GGE	$3.88	$3.20	$2.47	$1.87	$1.33
Feedstock Cost[2]	$/dry U.S. ton	$130	$115	$95	$80	$80
Feedstock Moisture at Plant Gate	wt % H_2O	20%	20%	20%	20%	20%
Pretreatment						
Total Cost Contribution	$/GGE	$1.96	$1.77	$1.73	$1.62	$1.01
Capital Cost Contribution	$/GGE	$1.09	$0.99	$0.97	$0.93	$0.54
Operating Cost Contribution	$/GGE	$0.87	$0.78	$0.76	$0.70	$0.47
Solids Loading	wt%	30%	30%	30%	30%	30%
Xylan to Xylose (including conversion in C5 train)	%	73%	75%	78%	78%	>73%
Hydrolysate solid-liquid separation	-	Yes	Yes	Yes	Yes	No

[9] Davis et al. (2013), "Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons: Dilute-Acid and Enzymatic Deconstruction of Biomass to Sugars and Biological Conversion of Sugars to Hydrocarbons," National Renewable Energy Laboratory, NREL/TP-510060223, http://www.nrel.gov/docs/fy14osti/60223.pdf.

[10] Davis, R et al. "Update to NREL/TP-510060223," *Manuscript in Preparation*.

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection		2022 Projection
Xylose Sugar Loss (into C6 stream after acid PT separation)	%	5.0%	4.0%	2.5%	1.0%		NA
Enzymatic Hydrolysis, Conditioning, Bioconversion							
Total Cost Contribution	$/GGE	$3.05	$2.90	$2.61	$2.40		$0.94
Capital Cost Contribution	$/GGE	$1.69	$1.60	$1.42	$1.32		$0.46
Operating Cost Contribution	$/GGE	$1.36	$1.30	$1.19	$1.08		$0.48
Total Solids Loading to Hydrolysis	wt%	15%	15%	17.5%	17.5%		20%
Enzymatic Hydrolysis Time	days	3.5	3.5	3.5	3.5		3.5
Hydrolysis Glucan to Glucose	%	77%	85%	85%	90%		90%
Hydrolysis Residual Xylan to Xylose	%	30%	30%	30%	30%		>30%
Glucose Sugar Loss (into solid lignin stream after EH separation)	%	5%	4%	2.5%	1%		1%
Bioconversion Volumetric Productivity	(g/L-hr)	0.29	0.30	0.35	0.40		1.30
Lipid Content	wt%	57%	57%	60%	60%		NA
Glucose to Product [total glucose utilization] [3]	%	75% [100%]	75% [100%]	78% [100%]	78% [100%]		87% [95%]
Xylose to Product [total xylose utilization] [3]	%	74% [98%]	74% [98%]	76% [98%]	76% [98%]		82% [86%]
C6 Train Bioconversion Metabolic Yield (Process Yield)	g/g sugars	0.26 (0.26)	0.26 (0.26)	0.27 (0.27)	0.27 (0.27)		0.34 (0.28)
Intermediate Product Recovery	%	90%	90%	90%	90%		97%
Carbon Yield to RDB from Biomass	%	10.4%	11.4%	11.8%	12.5%		25.6%
Cellulase Enzyme Production							
Total Cost Contribution	$/GGE	$1.30	$1.02	$0.85	$0.82		$0.39
Capital Cost Contribution	$/GGE	$0.30	$0.23	$0.23	$0.21		$0.10
Operating Cost Contribution	$/GGE	$1.00	$0.79	$0.63	$0.61		$0.29
Enzyme Loading	mg/g cellulose	14	12	10	10		10
Product Recovery + Upgrading							
Total Cost Contribution	$/GGE	$1.04	$1.03	$1.00	$1.00		$0.33
Capital Cost Contribution	$/GGE	$0.55	$0.54	$0.53	$0.53		$0.21
Operating Cost Contribution	$/GGE	$0.49	$0.49	$0.47	$0.47		$0.12
Natural Gas Usage[4]	scf/GGE fuel blendstock	10	10	10	10		18

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2022 Projection
C5 Coproduct Processing Train						
Total Cost Contribution	$/GGE	($1.06)	($2.38)	($3.75)	($5.16)	$0.00
Capital Cost Contribution	$/GGE	$3.93	$3.05	$2.96	$2.93	$0.00
Operating Cost Contribution	$/GGE	($4.99)	($5.43)	($6.72)	($8.09)	$0.00
Bioconversion Volumetric Productivity	g/L-hr	0.3	1	1.5	2	NA
C5 Train Bioconversion Metabolic Yield (Process Yield)	g/g sugars	0.63 (0.59)	0.64 (0.60)	0.66 (0.65)	0.795 (0.74)	NA
Carbon Yield to Succinic Acid from Biomass	%	8.9%	9.3%	10.5%	12.2%	NA
Lignin Utilization						
Total Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00	($1.89)
Capital Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00	$0.31
Operating Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00	($2.20)
Balance of Plant						
Total Cost Contribution	$/GGE	$2.80	$2.60	$2.53	$2.47	$0.89
Capital Cost Contribution	$/GGE	$3.76	$3.44	$3.30	$3.12	$1.06
Operating Cost Contribution	$/GGE	($0.96)	($0.83)	($0.77)	($0.65)	($0.17)
Sustainability and Process Efficiency Metrics [5]						
Fuel Yield by Weight of Biomass	% w/w of dry biomass	5.5%	6.1%	6.2%	6.6%	13.6%
Carbon Efficiency to Fuels	% C in Feedstock	10.4%	11.4%	11.8%	12.5%	25.6%
Overall Carbon Efficiency to Fuels	% C in Feedstock + NG	10.4%	11.4%	11.8%	12.5%	25.6%
Net Electricity Import (Entire Process)	kWh/GGE	19.9	19.8	21.1	24.0	0.29
Water Consumption	gal H_2O/GGE	42	48	45	42	12.3
Fossil GHG Emissions	g CO_2e/MJ fuel	145.5	141.1	145.6	160.2	24.4
Fossil GHG Emissions Credits	g CO_2e/MJ fuel	-209.3	-199.1	-217.7	-238.8	-325
Net Fossil GHG Emissions	g CO_2-e/MJ fuel	-63.8	-58.0	-72.0	-78.6	-301
Fossil Energy Consumption	MJ fossil energy/MJ fuel	1.9	1.9	1.9	2.1	0.40
Fossil Energy Consumption Credits	MJ fossil energy/MJ fuel	-2.8	-2.6	-2.9	-3.2	-1.70

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection		2022 Projection
Net Fossil Energy Consumption	MJ fossil energy/MJ fuel	-0.9	-0.8	-1.0	-1.1		-1.30

[1] Cost breakdowns to feedstock vs. conversion cost contributions are re-allocated in new target case according to carbon efficiency to renewable diesel blendstock (RDB) fuel vs. succinic acid (feedstock contribution reflects cost allocated to "C6 train" for RDB production)

[2] Feedstock costs shown here based on a 5% "ash equivalent" basis for all years considered, consistent with values provided by INL for total feedstock costs and associated ash "dockage" costs for each year.

[3] First number represents sugar conversion to desired product (free fatty acids); values in parentheses indicate total sugar utilization (including biomass organism propagation).

[4] Represents natural gas (NG) demand implicit in H_2 usage delivered from off-site steam methane reformer

[5] Succinic acid life-cycle inventory based on maleic anhydride proxy.

† SOT: State of Technology

scf = standard cubic feet.

Table A-8: Unit Operation Cost Contribution Estimates (2011$) and Technical Projections for Enzymatic Deconstruction and Catalytic Sugar Upgrading Process Concept[11]

(Process Concept: Dilute Acid Pretreatment, Enzymatic Hydrolysis, Chemocatalytic Upgrading to Hydrocarbons)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2022 Projection
Process Concept: Hydrocarbon Fuel Production via Catalytic Upgrading of Sugars		**Stover**	**Stover**	**Blend**	**Blend**	**Blend**
Year $ Basis		2011	2011	2011	2011	2011
Projected Minimum Fuel Selling Price	$/GGE	$7.29	$5.89	$4.83	$4.05	$3.00
Conversion Contribution	$/GGE	$4.71	$3.94	$3.42	$3.03	$1.98
Plant Capacity (Dry Feedstock Basis)	metric tons/day	2,000	2,000	2,000	2,000	2,000
Total Gasoline Equivalent Yield	GGE/dry U.S. ton	50	59	68	78	76
Feedstock						
Total Cost Contribution	$/GGE	$2.58	$1.95	$1.41	$1.02	$1.02
Capital Cost Contribution	$/GGE	NA	NA	NA	NA	NA
Operating Cost Contribution	$/GGE	$2.58	$1.95	$1.41	$1.02	$1.02
Feedstock Cost[1]	$/dry U.S. ton	$130	$115	$95	$80	$80
Feedstock Moisture at Plant Gate	wt % H_2O	20%	20%	20%	20%	20%
Pretreatment						
Total Cost Contribution	$/GGE	$0.70	$0.59	$0.52	$0.44	$0.44
Capital Cost Contribution	$/GGE	$0.38	$0.32	$0.28	$0.24	$0.24
Operating Cost Contribution	$/GGE	$0.32	$0.27	$0.24	$0.20	$0.20
Solids Loading	wt%	30%	30%	30%	30%	30%
Xylan to Xylose Conversion (overall)[2]	%	81%	84%	87%	90%	90%

[11] R. Davis, L. Tao, C. Scarlata, E.C.D. Tan et al. (2015), "Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons: Dilute-Acid and Enzymatic Deconstruction of Biomass to Sugars and Catalytic Conversion of Sugars to Hydrocarbons," NREL/TP-5100-62498, http://www.nrel.gov/docs/fy15osti/62498.pdf.

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2022 Projection
Enzymatic Hydrolysis and Conditioning						
Total Cost Contribution	$/GGE	$0.71	$0.59	$0.52	$0.45	$0.45
Capital Cost Contribution	$/GGE	$0.50	$0.41	$0.36	$0.31	$0.27
Operating Cost Contribution	$/GGE	$0.21	$0.18	$0.16	$0.14	$0.18
Solids Loading	wt%	20%	20%	20%	20%	20%
Enzymatic Hydrolysis Time	days	3.5	3.5	3.5	3.5	3.5
Glucan to Glucose Conversion [2]	%	77%	85%	85%	90%	90%
Sugar Loss in S/L Separation	%	5%	4%	2.5%	1%	1%
Microfiltration Soluble Retention Loss	%	10%	10%	10%	10%	10%
Cellulase Enzyme Production						
Total Cost Contribution	$/GGE	$0.44	$0.32	$0.25	$0.21	$0.21
Capital Cost Contribution	$/GGE	$0.10	$0.08	$0.07	$0.06	$0.06
Operating Cost Contribution	$/GGE	$0.34	$0.25	$0.18	$0.15	$0.15
Enzyme Loading	mg/g cellulose	14	12	10	10	10
Conversion and Upgrading						
Total Cost Contribution	$/GGE	$2.06	$1.77	$1.56	$1.42	$1.39
Capital Cost Contribution	$/GGE	$0.54	$0.47	$0.42	$0.38	$0.35
Operating Cost Contribution	$/GGE	$1.52	$1.29	$1.14	$1.05	$1.04
Hydrogen Feed Molar Ratio (H2 : total APR feed)		9.8	9.8	9.8	9.8	9.8
Total Hydrogen Consumption (wt % vs APR feed)	%	4.6%	5.3%	5.9%	6.5%	6.5%
Hydrogenation WHSV	h^{-1}	0.7	0.85	1.0	1.2	1.2
APR WHSV	h^{-1}	0.7	0.8	0.9	1.0	1.0
Condensation WHSV	h^{-1}	0.7	0.85	1.0	1.2	1.2
Hydrogenation catalyst lifetime	years	0.5	0.6	0.8	1.0	1.0
APR catalyst lifetime	years	1.0	1.3	1.6	2.0	2.0
Condensation catalyst lifetime	years	1.0	1.3	1.6	2.0	2.0
Natural Gas Usage[3]	scf/GGE fuel blendstock	102	100	99	97	97
Overall C Yield to Fuels vs APR Feed Components	%	64%	70%	78%	86%	86%
Overall C Yield to Fuels vs Biomass C (vs Total C) [4]	%	29% (25%)	34% (28%)	39% (32%)	45% (36%)	44% (35%)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT†	2015 Projection	2016 Projection	2017 Projection	2022 Projection
Lignin Utilization						
Total Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00	($1.07)
Capital Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00	$0.15
Operating Cost Contribution	$/GGE	$0.00	$0.00	$0.00	$0.00	($1.22)
Balance of Plant						
Total Cost Contribution	$/GGE	$0.79	$0.68	$0.58	$0.49	$0.56
Capital Cost Contribution	$/GGE	$1.07	$0.89	$0.74	$0.61	$0.68
Operating Cost Contribution	$/GGE	($0.28)	($0.21)	($0.16)	($0.12)	($0.12)
Sustainability and Process Efficiency Metrics						
Fuel Yield by Weight of Biomass	% w/w of dry biomass	16%	18%	21%	24%	24%
Carbon Efficiency to Fuels	% C in feedstock	29%	34%	39%	45%	41%
Overall Carbon Efficiency to Fuels	% C in feedstock + NG	25%	28%	32%	36%	35%
Net Electricity Export (Entire Process)	kWh/GGE	4.7	3.5	2.5	1.5	0.63
Water Consumption	gal H_2O/GGE	12.0	9.4	7.6	5.8	5.31
Fossil GHG Emissions	g CO_2e / MJ fuel	64.8	61.4	58.9	57.3	64.5
Fossil GHG Emissions Credits	g CO_2e / MJ fuel	(25.0)	(18.6)	(13.1)	(8.3)	(134)
Net Fossil GHG Emissions	g CO_2e / MJ fuel	39.8	42.7	45.8	49.1	(69.4)
Fossil Energy Consumption	MJ fossil energy / MJ fuel	1.0	1.0	0.9	0.9	1.0
Fossil Energy Consumption Credits	MJ fossil energy / MJ fuel	(0.3)	(0.2)	(0.1)	(0.1)	-0.7
Net Fossil Energy Consumption	MJ fossil energy / MJ fuel	0.7	0.8	0.8	0.8	0.3

[1] Feedstock costs shown here based on a 5% “ash equivalent” basis for all years considered, consistent with values provided by INL for total feedstock costs and associated ash “dockage” costs for each year (see Table 1).

[2] For this pathway, values represent glucan/xylan conversion to both monomeric and oligomeric sugars given flexibility in downstream conversion step.

[3] Represents natural gas (NG) demand implicit in H_2 usage delivered from off-site steam methane reformer (SMR).

[4] “Total carbon” includes external natural gas carbon implicit in SMR-derived H_2 (0.44 mol C in natural gas/mol H_2 product)

† SOT: State of Technology

Table A-9: Processing Area Cost Contribution (2011$) and Key Technical Parameters for Indirect Gasification and Methanol Intermediate Conversion to High-Octane Fuels[12]

(Process Concept: Gasification, Syngas Clean-Up, Methanol/Dimethyl Ether [DME] Synthesis & Conversion to Hydrocarbons)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT †	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
		Pulp wood	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend	Woody Blend
C_5+ Minimum Fuel Selling Price (per Actual Product Volume) ▲	$/gallon	$5.42	$4.97	$3.86	$3.55	$3.49	$3.43	$3.37	$3.31	$3.25
Mixed C_4 Minimum Fuel Selling Price (per Actual Product Volume) ▲	$/gallon	$3.59	$3.27	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Minimum Fuel Selling Price (per Gallon of Gasoline Equivalent) ▲	$/GGE	$5.45	$5.09	$4.04	$3.72	$3.66	$3.59	$3.53	$3.47	$3.41
Conversion Contribution (per Gallon of Gasoline Equivalent) ▲	$/GGE	$3.45	$3.27	$2.56	$2.40	$2.34	$2.28	$2.22	$2.16	$2.10
EIA Reference Case Gasoline Plant-Gate Price ‡	$/GGE	$2.68	$2.52	$2.44	$2.40	$2.40	$2.41	$2.44	$2.48	$2.51
Year for USD ($) Basis	-	2011	2011	2011	2011	2011	2011	2011	2011	2011
Total Capital Investment per Annual Gallon	$	$14.60	$14.55	$8.99	$8.51	$8.48	$8.45	$8.43	$8.40	$8.37
Plant Capacity (Dry Feedstock Basis)	tonnes/ dry	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
High-Octane Gasoline Blendstock (C_5+) Yield	gallons/ dry ton	39.7	40.4	61.8	64.2	64.4	64.5	64.6	64.8	64.9
Mixed C_4 Co-Product Yield	gallons / dry ton	17.9	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feedstock										
Total Cost Contribution	$/GGE	$1.99	$1.82	$1.48	$1.32	$1.31	$1.31	$1.31	$1.31	$1.30
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	$1.99	$1.82	$1.48	$1.31	$1.31	$1.31	$1.31	$1.30	$1.30
Feedstock Cost	$/dry U.S. ton	$101.45	$92.36	$86.72	$80.00	$80.00	$80.00	$80.00	$80.00	$80.00
Feedstock Moisture at Plant Gate	wt % H_2O	10%	10%	10%	10%	10%	10%	10%	10%	10%

[12] E. Tan, M. Talmadge, A. Dutta, J. Hensley, J. Schaidle, M. Biddy, D. Humbird, L. Snowden-Swan, J. Ross, D. Sexton, J. Lukas (2015), "Process Design for the Conversion of Lignocellulosic Biomass to High Octane Gasoline - Thermochemical Research Pathway With Indirect Gasification and Methanol Intermediate," NREL/TP-5100-62402, PNNL-23822.

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT †	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
In-Plant Handling and Drying / Preheating	$/dry U.S. ton	$0.54	$0.55	$0.72	$0.72	$0.72	$0.72	$0.71	$0.71	$0.71
Cost Contribution	$/gallon	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Feed Moisture Content to Gasifier	wt % H_2O	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	8,000	8,000	8,000	8,000
Gasification										
Total Cost Contribution	$/GGE	$0.70	$0.67	$0.56	$0.54	$0.53	$0.52	$0.52	$0.51	$0.50
Capital Cost Contribution	$/GE	$0.47	$0.44	$0.36	$0.34	$0.34	$0.33	$0.32	$0.32	$0.31
Operating Cost Contribution	$/GGE	$0.23	$0.23	$0.20	$0.19	$0.19	$0.19	$0.19	$0.19	$0.19
Raw Dry Syngas Yield	lb/lb dry feed	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78	0.78
Raw Syngas Methane (Dry Basis)	mole %	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%	15.4%
Gasifier Efficiency (LHV)	% LHV	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%	72.5%
Synthesis Gas Clean-Up (Reforming and Quench)										
Total Cost Contribution	$/GGE	$1.06	$1.00	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84	$0.84
Capital Cost Contribution	$/GGE	$0.58	$0.54	$0.44	$0.41	$0.42	$0.42	$0.43	$0.43	$0.43
Operating Cost Contribution	$/GGE	$0.48	$0.46	$0.40	$0.42	$0.42	$0.41	$0.41	$0.41	$0.40
Tar Reformer (TR) Exit CH_4 (Dry Basis)	Mole %	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
TR CH_4 Conversion	%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
TR Benzene Conversion	%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
TR Tars Conversion	%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%	99.9%
Catalyst Replacement	% of inventory / day	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
Acid Gas Removal, Methanol Synthesis, and Methanol Conditioning										
Total Cost Contribution	$/GGE	$0.59	$0.55	$0.44	$0.42	$0.42	$0.41	$0.41	$0.40	$0.39
Capital Cost Contribution	$/GGE	$0.41	$0.37	$0.29	$0.28	$0.27	$0.27	$0.26	$0.26	$0.25
Operating Cost Contribution	$/GGE	$/GGE	$0.18	$0.15	$0.15	$0.14	$0.14	$0.14	$0.14	$0.14
Methanol Synthesis Reactor Pressure	psia	730	730	730	730	730	730	730	730	730
Methanol Productivity	kg / kg-cat / hr	3.4	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT †	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
Methanol Intermediate Yield	gallons/ dry ton	156	156	145	145	144	144	143	143	142
Hydrocarbon Synthesis										
Total Cost Contribution	$/GGE	$1.01	$1.01	$0.67	$0.60	$0.55	$0.51	$0.47	$0.42	$0.38
Capital Cost Contribution	$/GGE	$0.65	$0.65	$0.45	$0.40	$0.37	$0.34	$0.30	$0.27	$0.24
Operating Cost Contribution	$/GGE	$0.36	$0.36	$0.22	$0.19	$0.18	$0.17	$0.16	$0.15	$0.14
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	-	Commercally available beta-zeolite		NREL modified beta-zeolite with copper (Cu) and gallium (Ga) as active metals for activity and performance improvement						
Utilization of C_4 Reactor Products	-	Co-Product	Co-Product	Recycle	Recycle	Recycle	Recycle	Recycle	Recycle	Recycle
Single-Pass DME Conversion	%	15%	15%	20%	30%	32%	34%	36%	38%	40%
Overall DME Conversion	%	81%	86%	84%	88%	89%	90%	91%	92%	93%
Hydrocarbon Synthesis Catalyst Productivity	kg / kg-cat / hr	0.02	0.03	0.04	0.05	0.06	0.07	0.08	0.09	0.10
Carbon Selectivity to C_5+ Product	% C in reactor feed	46.2%	50.8%	86.1%	89.9%	90.5%	91.2%	91.8%	92.4%	93.1%
Carbon Selectivity to Total Aromatics (Including Hexamethylbenzene)	% C in reactor feed	25.0%	15.0%	8.0%	4.0%	3.3%	2.6%	1.9%	1.2%	0.5%
Carbon Selectivity to Coke and Pre-Cursors (Hexamethylbenzene Proxy)	% C in reactor feed	10.0%	7.0%	4.0%	2.0%	1.7%	1.4%	1.1%	0.8%	0.5%
Dimerization of C_4-C_8 Olefins to Jet / Kerosene-Range Hydrocarbons		Not considered	Production of jet / kerosene range hydrocarbons will be considered as sensitivity case or modified design case starting in FY 2015							
Hydrocarbon Product Separation										
Total Cost Contribution	$/GGE	$0.05	$0.05	$0.05	$0.04	$0.04	$0.04	$0.04	$0.04	$0.04
Capital Cost Contribution	$/GGE	$0.04	$0.04	$0.04	$0.03	$0.03	$0.03	$0.03	$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
Balance of Plant										
Total Cost Contribution	$/GGE	$0.04	($0.00)	($0.00)	($0.04)	($0.04)	($0.04)	($0.05)	($0.05)	($0.05)
Capital Cost Contribution	$/GGE	$0.47	$0.43	$0.35	$0.33	$0.32	$0.31	$0.30	$0.29	$0.28
Operating Cost Contribution	$/GGE	($0.43)	($0.43)	($0.35)	($0.36)	($0.36)	($0.35)	($0.34)	($0.34)	($0.33)

Processing Area Cost Contributions & Key Technical Parameters	Units	2014 SOT †	2015 Projection	2016 Projection	2017 Projection	2018 Projection*	2019 Projection*	2020 Projection*	2021 Projection*	2022 Projection (Design Case)
Sustainability and Process Efficiency Metrics										
Carbon Efficiency to C_5+ Product	% C in feedstock	20.7%	21.1%	29.9%	31.0%	31.0%	31.0%	31.1%	31.1%	31.2%
Carbon Efficiency to Mixed C_4 Co-Product	% C in feedstock	7.5%	7.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Overall Carbon Efficiency to Hydrocarbon Products	% C in feedstock	28.2%	28.7%	29.9%	31.0%	31.0%	31.0%	31.1%	31.1%	31.2%
Overall Energy Efficiency to Hydrocarbon Products	% LHV of feedstock	37.3%	38.0%	43.1%	44.6%	44.7%	44.8%	44.9%	45.0%	45.0%
Electricity Production	kWh/gallon C_5+	11.4	11.4	6.7	6.4	6.3	6.3	6.3	6.2	6.2
Electricity Consumption	kWh/gallon C_5+	11.4	11.4	6.7	6.4	6.3	6.3	6.3	6.2	6.2
Water Consumption	gal H_2O/gal C_5+	12.4	9.3	5.8	5.2	4.5	3.8	3.1	2.4	1.7
Fossil GHG Emissions	g CO_2e / MJ Fuel	1.64	1.42	0.81	0.96	0.88	0.81	0.74	0.67	0.60
Fossil Energy Consumption	MJ fossil energy/MJ fuel	0.023	0.019	0.011	0.013	0.011	0.010	0.009	0.007	0.006
TEA Reference File		2014 SOT Rev4a.xlsm	2015 Target Rev4a.xlsm	2016 Target Rev4a.xlsm	2017 Target Rev4a.xlsm					H09G1e Rev4-Final1a Final5a.xlsm

▲ Conceptual design result with margin of error +/- 30%

† SOT: State of Technology

‡ Energy Information Administration (EIA), *Annual Energy Outlook 2014* Early Release, Table 12, Petroleum Product Prices, http://www.eia.gov/forecasts/aeo/er/tables_ref.cfm (accessed June 2014).
"EIA Reference Case Gasoline Plant-Gate Price" calculated based on AEO projections and EIA FAQ "What do I pay for in a gallon of regular gasoline?" http://www.eia.gov/tools/faqs/faq.cfm?id=22&t=10 (accessed June 2014).

LHV = lower heating value.

Appendix B: Calculation Methodology for Cost Goals

The two primary goals of this appendix are as follows:

1. Summarize the bases for the Bioenergy Technologies Office's performance goal
2. Explain the general methodology used to develop the cost goals and projections and adjust them to different year dollars.

Table B-1 describes the primary documents—including the Multi-Year Program Plan (MYPP)—that cover the evolution of technology design and cost projections for specific conversion concepts. Additional details for the technical performance targets and cost goals can be found in Appendix A.

Table B-1: Primary Source Documents for Office Cost Goals

Document	Design and Cost Information: Bases and Differences
2002 Corn Stover to Ethanol Design Report[1]	• Ethanol market target of $1.07/gallon (2000$) to be competitive with corn ethanol. • First design report for an agricultural residue feedstock. • Assumed $30/dry ton (DT) feedstock cost delivered to the plant in bales. • Detailed conversion plant process design, factored capital cost estimate, operating cost estimate, and discounted cash-flow rate of return used to determine ethanol cost target. • Costs based on 2000 dollars.
2005 MYPP[2] with Feedstock Logistics Estimates	• Ethanol cost target of $1.08/gallon (2002$) in 2020. • First program plan with feedstock cost components identified. • Feedstock grower payment assumed at $10/ton, although it is understood that this is a point on the supply curve that would correspond to a relatively low level of available agricultural residue type feedstock. • Feedstock logistics estimated cost at $25/DT based on unit operations breakdown, including preprocessing and handling, with equipment and operations up to the pretreatment reactor throat. • Detailed conversion plant design virtually the same as in the 2002 design report, but it excluded feedstock handling system equipment and operation, which are now included in feedstock logistics. Several additional minor modifications and corrections were made to original design with no significant cost impact. • Conversion costs escalated to 2002 dollars.
2007 MYPP	• Cost target of approximately $1.30/gallon (2007$) in 2012. • Feedstock grower payment escalated to $13/ton, although it is still an assumed number and understood that it is a point on the supply curve that would correspond to a relatively low level of available agricultural residue type feedstock. • Feedstock logistics cost breakdown updated based on first detailed design report covering this portion of the supply chain. • Detailed conversion plant design virtually the same as used in the 2005 MYPP case. • All costs escalated to 2007 dollars.

[1] A. Aden, M. Ruth, et al. (2002), "Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover," National Renewable Energy Laboratory, NREL/TP-510-32438, http://www1.eere.energy.gov/biomass/pdfs/32438.pdf.
[2] U.S. Department of Energy, Bioenergy Technologies Office (2005), *Multi-Year Program Plan 2007–2012*, Washington: Government Printing Office.

Document	Design and Cost Information: Bases and Differences
2009 MYPP[3]	• Program cost target of $1.76/gallon (2007$) in 2012 is based on the Energy Information Administration's (EIAs) reference case wholesale price of motor gasoline for 2012[4] and calculations to adjust for the energy density of ethanol relative to gasoline (0.67 gallon gasoline/gallon ethanol conversion factor). Program cost target of $1.76/gallon (2007$) in 2017 reflects the addition of new feedstocks, new conversion technologies, and new cellulosic biofuels in the program portfolio. • Cost projection of $1.49/gallon (2007$) in 2012 for the Biochemical Conversion Platform projected nth plant ethanol cost. • Introduction of first projection of woody feedstock costs. • Feedstock grower payment escalated to $15.90/ton, although it is still assumed and understood that it is a point on the supply curve that would correspond to a relatively low level of available agricultural residue type feedstock. • Thermochemical conversion model updated based on first detailed design report for gasification, synthesis gas cleanup, and mixed alcohol synthesis. • Thermochemical conversion model included based on first design report for pyrolysis, pyrolysis-oil upgrading and stabilization, and fuel synthesis to gasoline/diesel blendstock. • All costs escalated to 2007 dollars using actual economic indices up to 2007. • Feedstock models significantly improved and refined, which resulted in a price increase.
2010 MYPP	• Program performance goals are based on the EIA reference case wholesale price of motor gasoline. The 2012 goal is based on the EIA pre-American Recovery and Reinvestment Act of 2009 (ARRA) reference case for gasoline.[5] The 2017 goals for gasoline, diesel, and jet fuel are based on the EIA post-ARRA reference case.[6] • Thermochemical conversion models updated based on first detailed design report for pyrolysis to hydrocarbon biofuels.[7]
2011 MYPP	• Thermochemical conversion models, including preliminary technical projections, further detailed for pyrolysis to hydrocarbon fuels. • Updated financial assumptions for biochemical and gasification design cases. • Gasification to ethanol design case with cost target, projections, and back-cast state of technology (SOT) results updated for technology advancements and revised cost of capital equipment. • Biochemical Conversion Research and Development cost target projections revised for updated design case, including "back-cast" SOT. Design cases and future projections are modeled production costs for a plant converting dry corn stover to ethanol at 2,000 DT feedstock per day, via dilute acid pretreatment, enzymatic hydrolysis, and ethanol fermentation and recovery, with lignin combustion for combined heat and power production. • Feedstock supply models updated providing assumed $23.50/DT grower payment for corn stover, and $15.20/DT grower payment for pulpwood for 2012. Woody feedstock logistics models updated to reflect all logistics handling to the reactor throat for thermochemical conversion.

[3] S. Phillips, A. Aden, et al. (2007), "Thermochemical Ethanol via Indirect Gasification and Mixed Alcohol Synthesis of Lignocellulosic Biomass," National Renewable Energy Laboratory, NREL/TP-510-41168, http://www.nrel.gov/docs/fy07osti/41168.pdf.
[4] U.S. Department of Energy (2009), *Annual Energy Outlook 2009: Table 112*, Washington: Government Printing Office, http://www.eia.doe.gov/oiaf/archive/aeo09/supplement/suptab_112.xls.
[5] U.S. Department of Energy (2009), *Annual Energy Outlook 2009: Table 112*, Washington: Government Printing Office, http://www.eia.doe.gov/oiaf/archive/aeo09/supplement/suptab_112.xls.
[6] U.S. Department of Energy (2009), *Annual Energy Outlook 2009: Table 112*, Washington: Government Printing Office, http://www.eia.doe.gov/oiaf/archive/aeo09/supplement/suptab_112.xls.
[7] S.B. Jones, C. Valkenburg, C.W. Walton, et al. (2009), "Production of Gasoline and Diesel from Biomass via Fast Pyrolysis, Hydrotreating and Hydrocracking: A Design Case," Pacific Northwest National Laboratory, PNNL-18284, http://www.pnl.gov/main/publications/external/technical_reports/pnnl-18284.pdf.

Document	Design and Cost Information: Bases and Differences
2012 MYPP	• The Program's 2017 performance goals are based on the EIA reference case projections for the wholesale price of gasoline, diesel, and jet fuel.[8] • Updated financial assumptions and cost indexes for calculating cost goals. • Algae cost goals added for the Algae Lipid Upgrading pathway based on 2012 technical report.[9]
2014 MYPP	• Thermochemical conversion cost goals revised based on updated design report for fast pyrolysis and upgrading to hydrocarbon biofuels.[10] • Biochemical conversion interim cost goal based on first detailed design report for biological conversion of sugars to hydrocarbon biofuels.[11] • Feedstocks cost goals were revised to $80/DM ton, including both grower payment and logistics, based on updated cost projections that incorporate the need for higher volumes and the need to address feedstock quality. Grower payments were based on resource assessment analyses, rather than a fixed cost as in 2011. • Algae design reports for the Lipid Extraction and Upgrading[12] and Hydrothermal Liquefaction[13] pathways were added and updated to reflect changes from the harmonized baseline.
2015 MYPP	• Combined Conversion R&D section cost goals for combined supported by additional design cases for *Ex Situ* and *In Situ* Upgrading of Fast Pyrolysis Vapors,[14] Low-Temperature Deconstruction and Catalytic Sugar Upgrading,[15] and Hydrocarbons via Indirect Liquefaction[16] pathways. • Fast Pyrolysis and Low-Temperature Deconstruction and Fermentation pathways updated. • 2014 woody feedstock costs updated from projection to actual modeled cost. • Herbcaceous feedstock costs added to support biochemical conversion cost tables.

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[8] U.S. Department of Energy (2012), *Annual Energy Outlook 2012: Table 131*, Washington: Government Printing Office, http://www.eia.gov/oiaf/aeo/supplement/suptab_131.xlsx.

[9] R. Davis et al. (2013), "Renewable Diesel from Algal Lipids: An Integrated Baseline for Cost, Emissions, and Resource Potential from a Harmonized Model," Argonne National Laboratory, ANL/ESD/12-4, http://greet.es.anl.gov/publication-algae-harmonization-2012.

[10] S. Jones et al. (2013), "Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels: Fast Pyrolysis and Hydrotreating Bio-Oil Pathway," Pacific Northwest National Laboratory, PNNL-23053, http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23053.pdf.

[11] R. Davis et al. "Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons: Dilute-Acid and Enzymatic Deconstruction of Biomass to Sugars and Biological Conversion of Sugars to Hydrocarbons," National Renewable Energy Laboratory, NREL/TP-5100-60223 (2013), http://www.nrel.gov/docs/fy14osti/60223.pdf.

[12] R. Davis, C. Kinchin, J. Markham, E. Tan, et al. (2014), "Process Design and Economics for the Conversion of Algal Biomass to Biofuels," National Renewable Laboratory.

[13] S. Jones, et al. (2014), "Process Design and Economics for the Conversion of Algal Biomass to Hydrocarbons: Whole Algae Hydrothermal Liquefaction and Upgrading," Pacific Northwest National Laboratory, PNNL-23227, http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23227.pdf .

[14] A. Dutta, A. Sahir, E. Tan, D. Humbird, L. Snowden-Swan, P. Meyer, J. Ross, D. Sexton, R. Yap, J. Lukas (2015), "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," National Renewable Energy Laboratory, NREL/TP-5100-62455, Pacific Northwest National Laboratory, PNNL-23823.

[15] R. Davis, et al. "Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbons: Dilute-Acid and Enzymatic Deconstruction of Biomass to Sugars and Catalytic Conversion of Sugars to Hydrocarbons" NREL/TP-5100-62498. Golden, CO: National Renewable Energy Laboratory, *In press*.

[16] E. Tan, M. Talmadge, A. Dutta, J. Hensley, J. Schaidle, M. Biddy, D. Humbird, L. Snowden-Swan, J. Ross, D. Sexton, J. Lukas (2015), "Process Design for the Conversion of Lignocellulosic Biomass to High Octane Gasoline - Thermochemical Research Pathway With Indirect Gasification and Methanol Intermediate," National Renewable Energy Laboratory, NREL/TP-5100-62402, Pacific Northwest National Laboratory, PNNL-23822.

Office's Performance Goal: Calculation Methodology

The Office's performance goals are based on commercial viability, specifically the Energy Information Administration's (EIA's) oil price outlook for future motor gasoline, diesel, and jet wholesale prices. The underlying assumptions include the following:

- Refinery gate production cost of gasoline can be compared to the biorefinery production cost of biomass-based renewable gasoline and ethanol (adjusted for Btu content). Similarly, refinery gate production cost of diesel and jet fuel can be compared to the biorefinery production cost of biomass-based renewable diesel and jet fuel.
- Downstream distribution costs are excluded as are subsidies and tax incentives.

The historical crude oil prices and EIA projections are presented in Figure B-1.

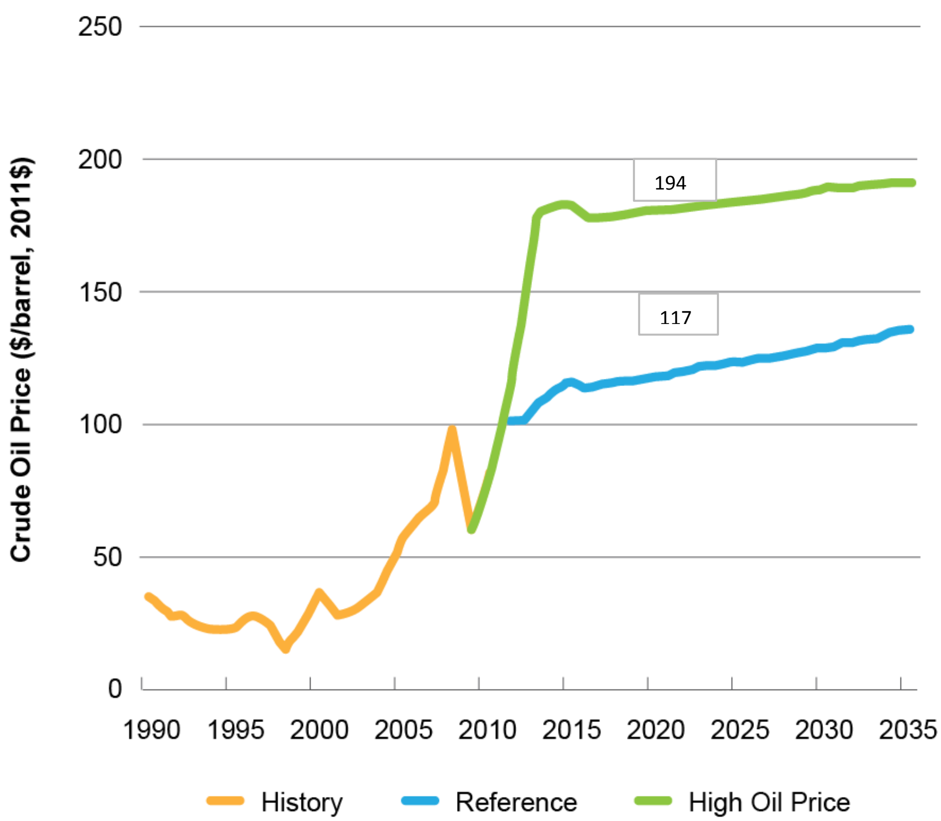

Figure B-1: EIA projections for crude oil prices[17]

The crude oil, gasoline, diesel, and jet prices for EIA's reference and high oil cases are summarized in Table B-2.

[17] U.S. Department of Energy (2012), *Annual Energy Outlook 2012 with Projections to 2035*, Washington: Government Printing Office, DOE/EIA-0383.

Table B-2: EIA Oil Price Forecasts[18]

	Wholesale Prices in 2011$[19]	2017	2020	2022	2035
Reference Case[20]					
	Crude oil ($/barrel)	116	118	121	136
	Diesel ($/gallon)	3.31	3.42	3.49	3.95
	Jet ($/gallon)	3.29	3.39	3.45	3.93
	Gasoline ($/gallon)	3.11	3.21	3.25	3.59
High Oil Price Case[21]					
	Crude oil ($/barrel)	178	181	183	191
	Diesel ($/gallon)	4.71	4.68	4.80	4.95
	Jet ($/gallon)	4.75	4.67	4.80	5.00
	Gasoline ($/gallon)	4.63	4.63	4.64	4.60

Table B-2 shows that the Office performance goal of producing biofuels at around $3/gallon by 2017 is consistent with the EIA projections for diesel, jet, and gasoline prices in the reference case.

Cost Goals and Projections
Specific cost goals and projections are based on published design cases and state of technology (SOT) reports as defined below.

Design Case: A design case is a techno-economic analysis that outlines a target case and preliminary identification of data gaps and research and development (R&D) needs and is used by the Office as a basis for setting technical targets and cost of production goals.

- Design cases and related goals and targets serve four purposes:
    1. Provide goals and targets against which technology progress is assessed
    2. Provide goals and targets against which processes are validated at increasing scale and integration
    3. Identify optimal R&D areas for prioritizing funding and focus
    4. Provide justification for budget requests.
- A design case is documented in a peer-reviewed design report that represents a particular example of a technology pathway and which encompasses a set of technologies across the entire biomass-to-bioenergy supply chain—from feedstock input through product production (i.e., total feedstock cost: harvest, collection, storage, grower payment, handling, size reduction, moisture control, and total conversion costs).

[18] U.S. Department of Commerce, Bureau of Economic Analysis, *National Income and Product Accounts: Table 1.1.9*, http://www.bea.gov/iTable/index_nipa.cfm.
[19] Note: Fuel prices are reported in 2010$ in the *Annual Energy Outlook 2012*. They have been adjusted from 2010$ to 2011$ by using the gross domestic product implicit price deflators (1.110 for 2010; 1.133 for 2011) obtained from the U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts. U.S. Department of Energy (2012), *Annual Energy Outlook 2012 with Projections to 2035*, Washington: Government Printing Office, DOE/EIA-0383. .
[20] U.S. Department of Energy (2012), *Annual Energy Outlook 2012: Table 131*, Washington: Government Printing Office, http://www.eia.gov/oiaf/aeo/supplement/suptab_131.xlsx.
[21] U.S. Department of Energy (2012), *Annual Energy Outlook 2012: High Oil Price Case, Table 70* (2012), Washington: Government Printing Office.

- Design case technical targets and cost goals must be adequately detailed to fully integrate across all supply chain elements in order to credibly represent a total finished product cost (excluding distribution, taxes, and tax credits).
- A design case is based on (1) best available information at date of the associated design reports and (2) current projections of nth plant capital and operating costs. Depending on the maturity of technology development of a particular technology pathway, design cases can range from high-level conceptual, literature-based process flows with material balances for earlier-stage technologies, to more fully detailed and specified processes with material and energy balances and capital and operating estimates based on actual, experimental data. In more mature forms, design cases are based on design reports that include detailed, peer-reviewed process simulation based on ASPEN, Chemcad, or other process models.
- As technology development progresses, design cases generally become more detailed and are reconfigured, which results in changes to technical targets and cost goals to reflect advances in the R&D knowledge base.
- Over the time span from initial to final design case for a given technology pathway, the range of uncertainty around the associated technical targets and cost estimates is expected to decrease.

State of Technology: An SOT assessment is a periodic (usually annual) assessment of the status of technology development for a biomass to biofuels/products pathway. An SOT assesses progress within and across relevant technology areas based on actual experimental results relative to technical targets and cost goals from design cases and includes technical, economic, and environmental criteria as available.

Table B-3 shows the cost breakdown of the projected cost goals for the fast pyrolysis pathway as a result of updating the dollar year from 2007 to 2011 and adjusting other key assumptions, as shown in Table B-4. It also shows the changes resulting from the updated fast pyrolysis design report.[22] The cost components are based on the first two major elements of the biomass-to-biofuels supply chain (delivered cost of feedstock production and feedstock conversion) and their associated sub-elements.

The costs for feedstock production are based on simulated feedstock supply curves developed and published in the *U.S. Billion-Ton Update*.[23] This analysis projects feedstock production scenarios based on a series of factors that impact feedstock production decisions. The supply curves project the amount of feedstock produced at various market prices for each of several feedstock categories identified in Table A-1. The grower payment in Tables A-4 through A-9 reflects the component of the total feedstock cost paid to the producer. This grower payment

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[22] Jones et al. (2013), "Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels," Pacific Northwest National Laboratory, PNNL-23053, http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23053.pdf.

[23] R. Perlack, B. Stokes, et al. (2011), "U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry," Oak Ridge National Laboratory, ORNL/TM-2011/224, http://www1.eere.energy.gov/biomass/pdfs/billion_ton_update.pdf.

corresponds to the estimated average price required to procure total volumes available using U.S. Billion-Ton data, e.g., Figure 2-9.

The projected production cost goals represent mature technology processing costs, which means that the capital and operating costs are assumed to be for an "nth plant," where several plants have been built and are operating successfully, no longer requiring increased costs for risk financing, longer startups, under-performance, and other costs associated with pioneer plants.

Table B-3: Production Cost Breakdown by Supply Chain Element

Supply Chain Areas	Units	2009 Wood/ Pyrolysis to Hydrocarbon Fuel Design Report	2012 MYPP 2017 Goals/Targets	2014 MYPP 2017 Goals/Targets
Year $	Year	2007	2011	2011
Feedstock Production				
Grower Payment	$/DT	$22.60	$26.25	$21.90
Feedstock Logistics				
Harvest and Collection	$/DT	$18.75	$19.53	$10.47
Landing Preprocessing	$/DT	$11.42	$11.73	$10.24
Transportation and Handling	$/DT	$8.95	$6.37	$7.52
Plant Receiving and In-Feed Preprocessing	$/DT	$17.65	$16.88	$29.87
Logistics Subtotal	**$/DT**	**$56.77**	**$54.50**	**$58.10**
Feedstock Total	**$/DT**	**$79.37**	**$80.75**	**$80.00**
Fuel Yield	(gal gasoline + diesel)/DT	106	106	84 (87 DT/GGE)
Feedstock Production				
Grower Payment	$/gal total fuel	$0.21	$0.25	$0.26
Feedstock Logistics				
Harvest and Collection	$/gal total fuel	$0.18	$0.18	$0.12
Landing Preprocessing	$/gal total fuel	$0.11	$0.11	$0.12
Transportation and Handling	$/gal total fuel	$0.08	$0.06	$0.09
Plant Receiving and In-Feed Preprocessing	$/gal total fuel	$0.17	$0.16	$0.34
Logistics Subtotal	$/gal total fuel	$0.54	$0.51	$0.66
Feedstock Total	**$/gal total fuel**	**$0.75**	**$0.76**	**$0.94 ($0.92/GGE)**
Biomass Conversion				
Feedstock Drying, Sizing, Fast Pyrolysis	$/gal total fuel	$0.34	$0.39	$0.76/GGE
Upgrading to Stable Oil	$/gal total fuel	$0.47	$0.55	$0.95/GGE
Fuel Finishing to Gasoline and Diesel	$/gal total fuel	$0.11	$0.13	$0.14/GGE
Balance of Plant	$/gal total fuel	$0.65	$0.75	$0.63/GGE
Conversion Total	**$/gal total fuel**	**$1.57**	**$1.83**	**$2.47/GGE**
Fuel Production Total	***$/gal total fuel***	***$2.32***	***$2.83***	***$3.39/GGE***

Table B-4 outlines changes in the analysis assumptions for the fast pyrolysis pathway, as well as other conversion design reports.

Table B-4: 2012 Changes to Conversion Cost Assumptions

	Prior Values	2012 Updated Values
% Equity / % Debt Financing	100%	40% / 60%
Loan Terms (% Rate, Term)	N/A	8%, 10 years
Discount Factor	10%	10%
Year-Dollars	2007 dollars	2011 dollars
Depreciation Method, Time	MACRS 7 years general plant 20 years steam/boiler	MACRS 7 years general plant 20 years steam/boiler (if exporting electricity)
Cash Flow / Plant Life	20 years	30 years
Income Tax	39%	35%
Online Time	90%	90%
Indirect Costs (Contingency, Fees, etc.)	51% of total installed costs	60% of total direct costs*
Lang Factor	3.7	4.7 (fast pyrolysis case)

* Total direct costs include installed costs plus other direct costs (buildings, additional piping, and site development).

General Cost Estimation Methodology

The Office uses consistent, rigorous engineering approaches for developing detailed process designs, simulation models, and cost estimates, which in turn are used to estimate the minimum selling price for a particular biofuel using a standard discounted cash-flow rate of return calculation. The feedstock logistics element uses economic approaches to costing developed by the American Society of Agricultural and Biological Engineers. Details of the approaches and results of the technical and financial analyses are thoroughly documented in the Office's conceptual design reports[24] and are not included here. Instead, a high-level general description of how costs are developed and escalated to different year dollars is provided below.

Cost estimate development is slightly different between the feedstock logistics and biomass conversion elements, but generally both elements include capital costs, costs for chemicals and other material, and labor costs. The indices for plant capital chemicals and materials have increased significantly since 2003, while the labor index has shown a consistent and steady rise of about 2.5% per year.

[24] S.B. Jones, C. Valkenburg, C.W. Walton, et al. (2009), "Production of Gasoline and Diesel from Biomass via Fast Pyrolysis, Hydrotreating and Hydrocracking: A Design Case," Pacific Northwest National Laboratory, PNNL-1828, http://www.pnl.gov/main/publications/external/technical_reports/pnnl-18284.pdf.

The total project investment (based on total equipment cost), as well as variable and fixed operating costs, are developed first using the best available cost information. Cost information typically comes from a range of years, requiring all cost components to be adjusted to a common year. For the case shown in Appendix B, each cost component was adjusted based on the ratio of the 2011 index to the actual index for the particular cost component. The delivered feedstock cost was treated as an operating cost for the biomass conversion facility. With these costs, a discounted cash-flow analysis of the conversion facility was carried out to determine the selling price of fuel when the net present value of the project is zero.

Design reports added in the 2015 MYPP update have utilized updated published index values, which are summarized in each respective design report. This minor inconsistency across design cases will be resolved in future MYPP updates.

Total Project Investment Estimates and Cost Escalation

The Office design reports include detailed equipment lists with sizes and costs, as well as details on how the purchase costs of all equipment were determined. For the feedstock logistics element, some of the equipment, such as harvesters and trucks, do not require additional installation cost; however, other logistics equipment and the majority of the conversion facility equipment will be installed.

For the types of conceptual designs the Office carries out, a “factored” approach is used. Once the installed equipment cost has been determined from the purchased cost and the installation factor, it can be indexed to the project year being considered. The purchase cost of each piece of equipment has a year associated with it. The purchased cost year will be indexed to the year of interest using the Chemical Engineering Plant Cost Index.

Figure B-2 and Table B-5 show the historical values of the index. Notice that the index was relatively flat between 2000 and 2002 with less than a 0.4% increase, while there was a jump of nearly 18% between 2002 and 2005. Changes in the plant cost indices can drive dramatic increases in equipment costs, which directly impact the total project capital investment.

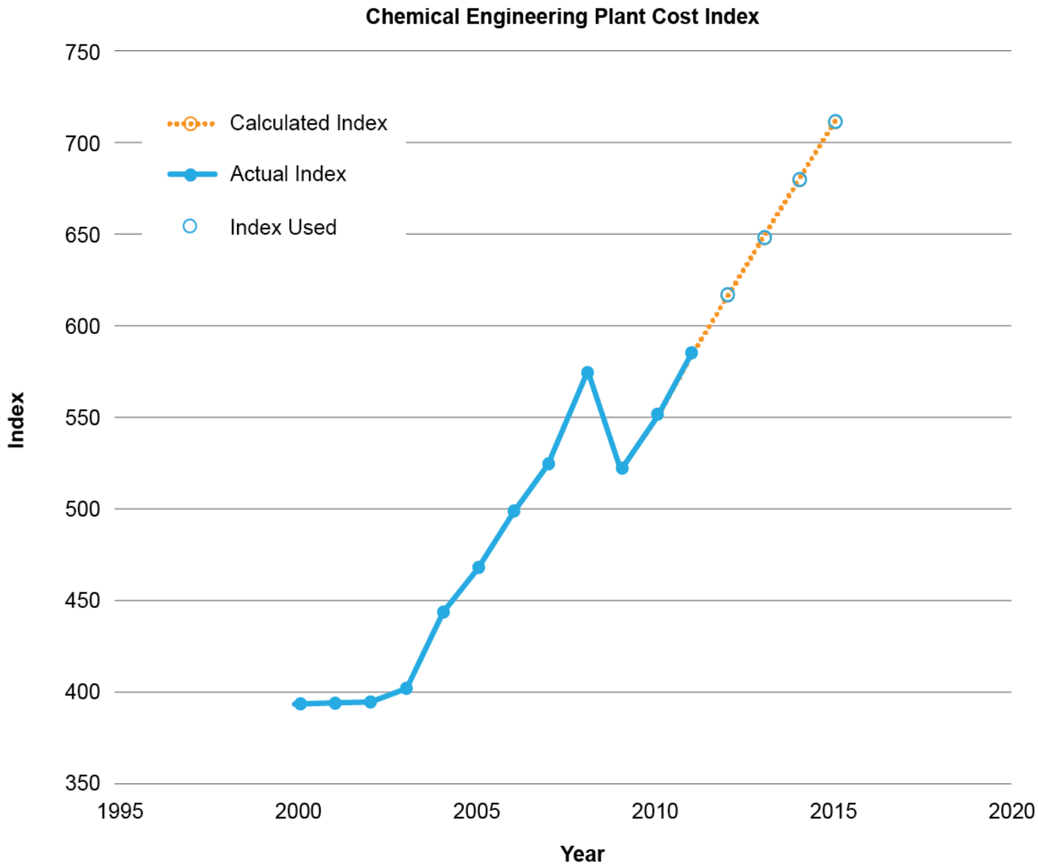

Figure B-2: Actual and extrapolated plant cost index (see Table B-5 for values)

Table B- 5: Plant Cost Indices

Source	Year	CE Annual Index	Calculated Index	Index Used in Calculations
(1)	2000	394.1		394.1
(2)	2001	394.3		394.3
(2)	2002	395.6		395.6
(3)	2003	402.0		402.0
(3)	2004	444.2		444.2
(3)	2005	468.2		468.2
(4)	2006	499.6		499.6
(4)	2007	525.4		525.4
(4)	2008	575.4		575.4
(4)	2009	521.9	520.9	521.9
(5)	2010	550.8	552.8	550.8
(5)	2011	585.7	584.7	585.7
	2012		616.6	617.6
	2013		648.5	649.5
	2014		680.4	681.4
	2015		712.3	713.3

Source	Year	CE Annual	Calculated	Index Used in
Sources:				
(1) *Chemical Engineering Magazine*, April 2002				
(2) *Chemical Engineering Magazine*, December 2003				
(3) *Chemical Engineering Magazine*, May 2005				
(4) *Chemical Engineering Magazine*, April 2009				
(5) *Chemical Engineering Magazine*, April 2012				
Current indices at http://www.che.com/ei				

Any extrapolation of this data is extremely difficult. Trends prior to 2003 were nearly linear, followed by significant increases until an economic downturn in 2009. As additional data points become available, the extrapolation will be refined.

For equipment cost items in which actual cost records do not exist, a representative cost index is used. For example, the U.S. Department of Agriculture (USDA) publishes Prices Paid by Farmers indexes that are updated monthly. These indexes represent the average costs of inputs purchased by farmers and ranchers to produce agricultural commodities and a relative measure of historical costs. For machinery list prices, the Machinery Index was used. The Repairs Index was used for machinery repair and maintenance costs. These USDA indices were used for all machinery used in the feedstock supply system analysis, including harvest and collection machinery (combines, balers, tractors, etc.), loaders and transportation-related vehicles, grinders, and storage-related equipment and structures.

Operating Cost Estimates and Cost Escalation

For the different design cases, variable operating costs—which include fuel inputs, raw materials, waste handling charges, and byproduct credits—are incurred when the process is operating and are a function of the process throughput rate. All raw material quantities used and wastes produced are determined as part of the detailed material and energy balances calculated for all the process steps. As with capital equipment, the costs for chemicals and materials are associated with a particular year. The U.S. Producer Price Index from SRI Consulting was used as the index for all chemicals and materials. Available data were regressed to a simple equation and used to extrapolate to future years, as shown in Figure B-3 and Table B-6.

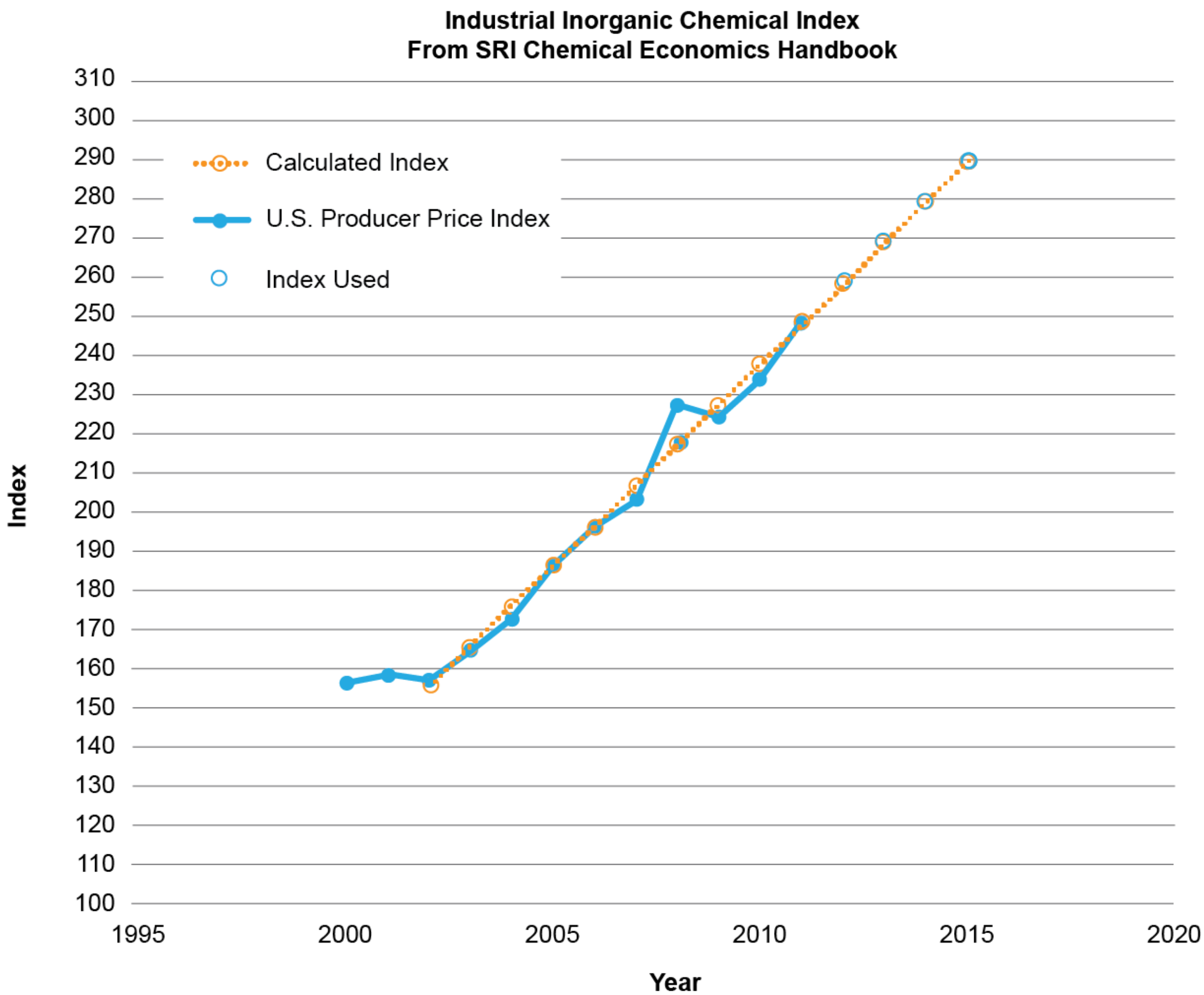

Figure B-3: Actual and extrapolated chemical cost index (see Table B-6 for values)

Table B-6: U.S. Producer Price Index—Total, Chemicals and Allied Products

Year	U.S. Producer Price Index	Calculated Index	Index Used
2000	156.7		156.7
2001	158.4		158.4
2002	157.3	155.4	157.3
2003	164.6	165.7	164.6
2004	172.8	176.0	172.8
2005	187.3	186.3	187.3
2006	196.8	196.6	196.8
2007	203.3	207.0	203.3
2008	228.2	217.3	228.2
2009	224.7	227.6	224.7
2010	233.7	237.9	233.7
2011	249.3	248.2	249.3
2012		258.5	259.6
2013		268.8	269.9
2014		279.1	280.2
2015		289.4	290.5

Source:
SRI International Chemical Economics Handbook, Economic Environment of the Chemical Industry 2011. Current indices at http://chemical.ihs.com/CEH/Private/EECI/EECI.pdf.

Some types of labor—especially related to feedstock production and logistics—are variable costs, while labor associated with the conversion facility are considered fixed operating costs.

Fixed operating costs are generally incurred fully, whether or not operations are running at full capacity. Various overhead items are considered fixed costs in addition to some types of labor. General overhead is often a factor applied to the total salaries and covers items such as safety, general engineering, general plant maintenance, payroll overhead (including benefits), plant security, janitorial and similar services, phone, light, heat, and plant communications. Annual maintenance materials are generally estimated as a small percentage (e.g., 2%) of the total installed equipment cost. Insurance and taxes are generally estimated as a small percentage (e.g., 1.5%) of the total installed cost. The index to adjust labor costs is taken from the Bureau of Labor Statistics and is shown in Figure B-4 and Table B-7. The available data were regressed to a simple equation and the resulting regression equation used to extrapolate to future years.

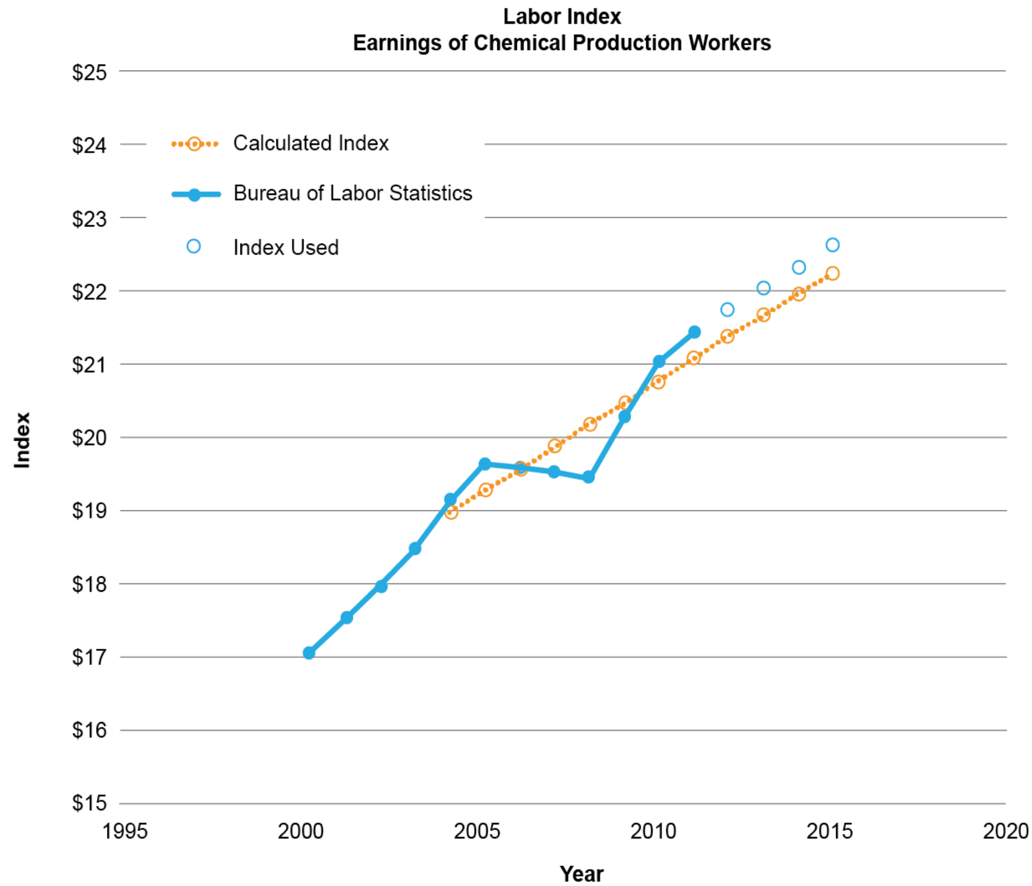

Figure B-4: Actual and extrapolated labor cost index (see Table B-7 for values)

Table B-7: Labor Index

Year	Reported	Calculated	Index Used
2000	17.09		17.09
2001	17.57		17.57
2002	17.97		17.97
2003	18.50		18.50
2004	19.17	19.00	19.17
2005	19.67	19.29	19.67
2006	19.60	19.59	19.60
2007	19.55	19.89	19.55
2008	19.50	20.19	19.50
2009	20.30	20.49	20.30
2010	21.07	20.79	21.07
2011	21.46	21.09	21.46
2012		21.38	21.76
2013		21.68	22.06
2014		21.98	22.36
2015		22.28	22.65

Source:
Bureau of Labor Statistics, Series ID: CEU3232500008
Chemicals Average Hourly Earnings of Production Workers
Current indices from http://data.bls.gov/cgi-bin/srgate.

Discounted Cash-Flow Analysis and the Selling Price of Biofuels

Once the two major cost areas—total project investment and operating costs—have been determined, a discounted cash-flow analysis can be used to determine the minimum selling price per gallon of biofuel produced. The discounted cash-flow analysis program iterates on the selling price of the biofuel until the net present value of the project is zero. This analysis requires that the discount rate, depreciation method, income tax rates, plant life, and construction startup duration be specified. The Office has developed a standard set of assumptions for use in the discounted cash-flow analysis.

Appendix C: 2012 Cellulosic Ethanol Success

The Bioenergy Technologies Office has supported research, development, and demonstration for the production of cellulosic ethanol, focusing on three key areas: feedstock logistics, biochemical conversion, and thermochemical conversion. In September 2012, after 10 years of dedicated research and development (R&D) at the lab/bench and pilot[1] scales, the Office's research, development, and demonstration (RD&D) activities resulted in a four-fold reduction in cost and ultimately demonstrated two biofuels pathways that can produce cellulosic ethanol at a modeled nth plant cost of approximately $2 per gallon. This equates to a 77% reduction in the minimum ethanol selling price (MESP) from an estimated $9.16 (2007$U.S.) in 2001.

This achievement marks a critical milestone for the industry that was accomplished with strong bipartisan federal support across two presidential administrations. This milestone was achieved through U.S. Department of Energy (DOE) support of R&D at DOE national laboratories, academic institutions, and industry. RD&D was specifically focused on improving the efficiency and economics around biomass harvesting and feedstock supply system logistics, developing techno-economically viable process steps for both biochemical and thermochemical conversion processes, and through process integration. Reduced costs, technology improvements, and progress in scale-up and integration of processes represent major successes in cost-competitive cellulosic ethanol production. With conservative economic assumptions and proven process parameters, the technologies demonstrated at pilot scale[1] are modeled to produce cellulosic ethanol at commercial-scale costs that are competitive with gasoline production at $110/barrel of crude oil.

Many industry partners are also demonstrating their proprietary technology pathways to produce biofuel at pilot, demonstration, and commercial scales. Some of these technologies are similar to those demonstrated in the recent R&D accomplishment, while others demonstrate or commercialize newly developed technologies for cellulosic ethanol production.

Feedstock Logistics

Improvements in biomass harvesting and feedstock supply system logistics are crucial to meeting modeled 2,200 U.S. tons (2,000 tonne) per day refinery input/uptake/requirement for commercial-scale production costs of cellulosic ethanol. For 2012, research focused on corn stover as a model agricultural residue feedstock and purpose-grown trees as a model woody feedstock for biochemical and gasification routes, respectively.

Key advances in sustainable harvesting and collection include using the Residue Removal Tool[2] for accurate area assessments, improved storage strategies for preservation of biomass quantity and quality, and more energy- and cost-efficient mechanisms for preprocessing of biomass appropriate for introduction into the conversion processing system. Additional improvements included increased harvest efficiency, which contributes to higher sustainable yields, and improved biomass quality through ash content reduction. Higher bale density and reduced losses during handling and storage further contributed to meeting cost targets by lowering the cost of

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[1] Pilot throughput is defined as ½ to ≥ 1 dry ton per day.

[2] D. Muth, K.M. Bryden, (2012), "An Integrated Model for Assessment of Sustainable Agricultural Residue Removal Limits for Bioenergy Systems," *Environmental Modelling and Software*, 39(1).

transporting feedstocks. Other contributions to cost reduction include lower-cost storage methods, reduced uncertainty associated with storage losses through meeting a 59% carbohydrate preservation target, and direct improvements in grinder efficiency and capacity. These feedstock advancements, paired with increases in conversion yield/efficiency, resulted in a \$0.42 and \$0.67[3] per gallon reduction in biochemical and thermochemical cellulosic ethanol production costs, respectively.

Biochemical Conversion

Biochemical conversion route costs were significantly impacted through an approximate 90% reduction in enzyme cost (enabled by development of new enzymes and enzyme cocktails) and the engineering of microorganisms that can more effectively utilize multiple sugars produced from hydrolyzed plant cell wall cellulose and hemicellulose (i.e., glucose, xylose, and arabinose). A biochemical conversion pilot plant demonstrated a fully integrated suite of technologies capable of producing cellulosic ethanol from corn stover at a cost of \$2.15 per gallon ethanol (\$3.20 gasoline gallon equivalent [GGE]) when modeled at commercial scale.

Biochemical conversion of biomass to cellulosic ethanol can involve many steps, including pretreatment, conditioning, and enzymatic hydrolysis, followed by fermentation. Key breakthroughs in these process steps included the development of more efficient pretreatment processes, resulting in increased sugar yields; improved enzyme production method and enzymes that reduced enzyme loading and associated enzyme costs; and more robust fermentation organisms that were able to utilize sugars in the presence of biomass-derived inhibitors, ultimately achieving significantly higher ethanol yields. The deconstruction strategy, tested at bench and pilot scales, resulted in greater than 80% conversion of the xylan to desired xylose monomer in whole slurry mode while simultaneously lowering acid usage from 3.0% to 0.3%. An improved neutralization step reduced conditioning-related sugar losses from 13% to undetectable amounts. Increased enzyme efficiency resulted in reduced enzyme loading and cellulose-to-glucose yields of nearly 80%, contributing to an overall reduction in enzyme costs by 20-fold. Improvements in fermentation and microbial strain development resulted in the industrially relevant strains capable of converting cellulosic sugars at total conversion yields greater than 95% and tolerant of ethanol titers of approximately 72 gram/liter.

[3] Reductions in feedstock costs resulted in cost/ton of \$58.50 for corn stover and \$61.57 for white oak chips.

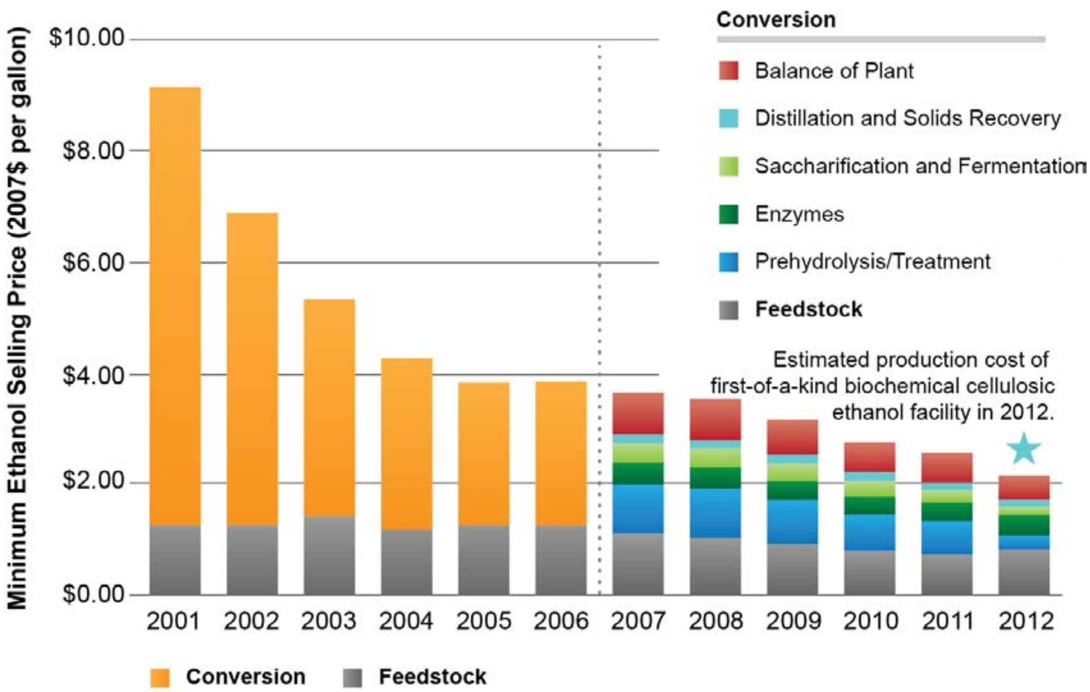

Figure C-1: Biochemical R&D impact on MESP from corn stover

Figure C-1 illustrates the R&D impact on MESP of corn stover to ethanol via biochemical conversion, from 2001 to 2012. The dotted line denotes success at varying scales: bench scale prior to 2007 and pilot and modeled nth plant scale thereafter, until 2012. The star represents the published production cost[4] expected at one of the first cellulosic ethanol facilities to come online.

Thermochemical Conversion

The thermochemical conversion process used for cellulosic ethanol production included a gasifier, syngas clean-up, and catalytic fuel synthesis reactors. Significant process engineering improvements were achieved within the gasifier and fuel synthesis steps, and technical improvements were achieved in the syngas cleanup and catalytic fuels synthesis steps.

After developing, improving, and down-selecting a variety of technologies for each process step, the Office demonstrated a configuration capable of producing cellulosic ethanol from a woody feedstock at a cost of $2.05 per gallon ethanol ($3.06 GGE) when modeled at commercial scale (using the pilot plant at its thermochemical users facility). The Office's notable technical breakthroughs included the optimization of its indirectly heated fluidized bed gasifier; the development of tar- and methane-reforming catalysts that increased methane conversion to syngas from 20% to more than 80%; and development of catalysts and operational strategies for the conversion of syngas to mixed alcohols production. These key improvements resulted in an increase in ethanol yield from 62 gallons to greater than 84 gallons per ton of biomass.
Figure C-2 illustrates the R&D successes contributing to the decrease in MESP for a gasification process between 2007 and 2012.

[4] Chris Standlee (2014), "Advanced Ethanol: Coming Online," National Ethanol Conference, February 18, 2014, Orlando, Florida.

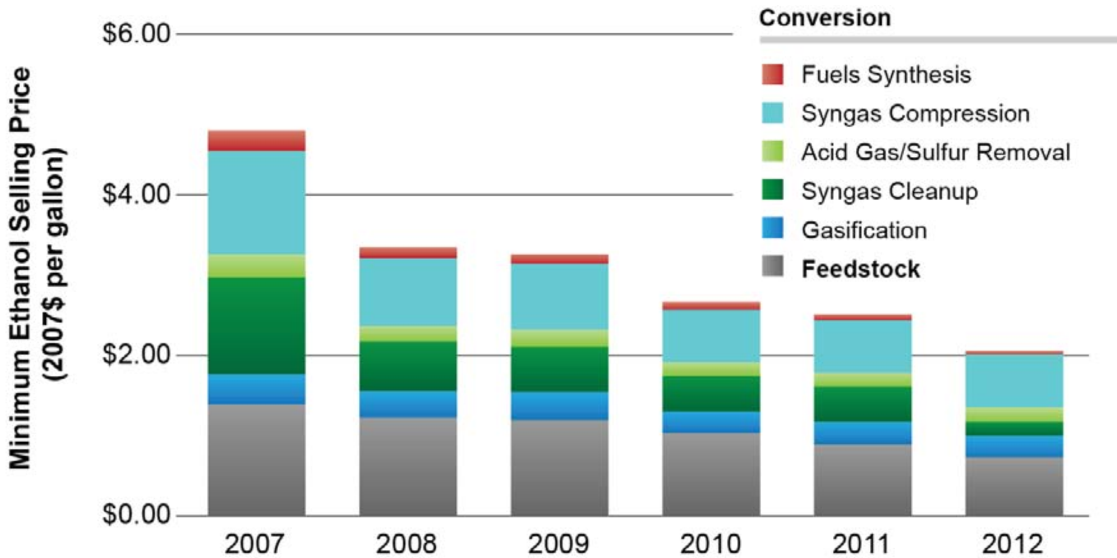

Figure C-2: Thermochemical R&D impact on MESP from woody feedstock

Figure C-2 illustrates the R&D impact on MESP of woody feedstocks to ethanol via thermochemical conversion, from 2007 to 2012.

Leveraging Success

More than 10 years of dedicated RD&D enabled the breakthroughs necessary for the production of cost-competitive cellulosic ethanol. Meeting cost-competitive production targets is important because cellulosic ethanol represents a very significant life-cycle reduction in greenhouse gas emissions compared to petroleum gasoline (roughly 80% and roughly 90% for fermentation and gasification pathways, respectively).[5] This does not suggest that these processes cannot be further improved. Updated design cases have shown that the escalation of costs to 2011 U.S. dollar bases increased the MESP and helps to identify further process efficiencies that could be addressed through additional R&D.

These R&D achievements demonstrated in 2012 and since for cellulosic ethanol production provide the groundwork for the development and optimization of biomass conversion technologies and techniques capable of producing hydrocarbon liquids that are virtually indistinguishable from gasoline, diesel, jet fuel, and other petroleum products, and that are fully compatible with existing fuel handling and distribution infrastructures. These breakthroughs will be repurposed and leveraged to accelerate the commercialization of new, renewable fuels and chemicals from biomass.

[5] J.B. Dunn, M. Johnson, M. Wang (2013), "Supply Chain Sustainability Analysis of SOT Pathways," BETO Quarterly Meeting, January 17, 2013, Washington, D.C.

Appendix D: Matrix of Revisions

Section Name	Specific Reference	Revision	Version Change was Implemented
July 2014			
All Sections	Throughout	Major and minor updates to all sections.	July 2014
Feedstock Supply and Logistics R&D	Section 2.1	Terrestrial Feedstocks and Algal Feedstocks separated into two sub-sections	July 2014
Thermochemical Conversion R&D	Section 2.2.2	Oils and Gaseous Intermediate Sections combined into Thermochemical Conversion R&D	July 2014
Demonstration and Deployment	Section 2.3	Combined Integrated Biorefinery and Distribution Infrastructure and End Use sections and redrafted/refocused D&D section	July 2014
November 2014			
Terrestrial Feedstock Supply & Logistics R&D	Section 2.1.1 and Appendix B	Updates to reflect volume revisions associated with goals and changes in blending strategies. Added feedstock logistics costs table to Appendix B	November 2014
Algal Feedstocks	Section 2.1.2	Inclusion of Algal Lipid Upgrading and Algal Hydrothermal Liquefaction design cases	November 2014
Thermochemical Conversion R&D	Section 2.2.2 and Appendix B	Added 2013 Sustainability metrics and feedstock costs to out-year projections	November 2014
March 2015			
Introduction to Research, Development, and Demonstration	Section 2	Inclusion of Wet Waste to Energy Feedstocks and change to Demonstration and Market Transformation	March 2015
Feedstocks Supply and Logistics	Section 2.1	Define Wet Waste to Energy Feedstocks	March 2015

Section Name	Specific Reference	Revision	Version Change was Implemented
Terrestrial Feedstocks Supply and Logistics	Section 2.1.1	Added herbaceous feedstocks cost tables	March 2015
Algal Feedstocks	Section 2.1.2	Minor clarifications	March 2015
Conversion R&D	Section 2.2	Integration of themo- and bio-chemical activities, strategic refocus on technology building blocks, additional technology pathways for hydrocarbon-based fuels, and addition of co-products to enable cost competitive biofuels	March 2015
Demonstration and Market Transformation	Section 2.3	Renamed	March 2015
Sustainability	Section 2.4	Milestone modifications	March 2015
Appendices		Former Appendix A removed and subsequent appendices renamed	March 2015
Technical Project Tables	Appendix A	Tables added for new conversion pathways.	March 2015