PROCESS DESIGN AND ECONOMICS FOR BIOCHEMICAL CONVERSION OF SOFTWOOD LIGNOCELLULOSIC BIOMASS TO ISOPARAFFINIC KEROSENE AND LIGNIN CO-PRODUCTS

Authors	ORGANIZATION
Gevan Marrs	Gevan Marrs LLC
Tom Spink	Thomas Spink Inc. (TSI)
Allan Gao	Washington State University

COMPLETED 2016

TABLE OF CONTENTS

LIST OF FIGURES....5
LIST OF TABLES....6
LIST OF ACRONYMS....7
EXECUTIVE SUMMARY....8

1 INTRODUCTION
1.1 BACKGROUND AND MOTIVATION....10
1.2 PROCESS OVERVIEW....10
1.2.1 PROCESS DEPARTMENTS AND BRIEF DESCRIPTIONS....10
1.3 TECHNO-ECONOMIC ANALYSIS APPROACH....11
1.4 ABOUT NTH-PLANT ASSUMPTIONS....12
1.5 REVIEW OF RELATED TECHNO ECONOMIC STUDIES....12
1.6 ABOUT THE NARA ASPEN MODEL....13

2 DESIGN BASIS AND CONVENTIONS....13
2.1 PLANT SIZE....13
2.2 FEEDSTOCK COMPOSITION....16
2.3 DESIGN REPORT CONVENTIONS....18
2.3.1 UNITS....18

3 PROCESS DESIGN AND COST ESTIMATION DETAILS....18
3.1 MAJOR OPERATING COSTS AND SOURCES....18
3.2 OPERATING COST ASSUMPTIONS DETAILS....19
3.2.1 FOREST HARVEST RESIDUALS FEEDSTOCK....19
3.2.2 HOG FUEL....19
3.2.3 ELECTRICITY....19
3.2.4 NATURAL GAS....20
3.2.5 DIESEL FUEL....20
3.3 DEPARTMENT 1: FEEDSTOCK RECEIPT, STORAGE AND HANDLING AND PREPARATION....20
3.3.1 OVERVIEW....20
3.3.2 DESIGN BASIS....21
3.3.3 FEEDSTOCK HANDLING AREA COST ESTIMATION....21
3.4 DEPARTMENT 2: MBS PRETREATMENT OF SOFTWOOD BIOMASS....26
3.4.1 OVERVIEW....26
3.4.2 DESIGN BASIS....26
3.4.3 COST ESTIMATION....27
3.4.4 ACHIEVING THE PRE-TREATMENT 27 DESIGN CASE....28
3.5 DEPARTMENT 3: ENZYMATIC HYDROLYSIS....28
3.5.1 PROCESS OVERVIEW....28
3.5.2 ENZYMATIC HYDROLYSIS (EH) DESIGN BASIS....28
3.5.3 CAPITAL COST....29
3.5.4 OPERATING COST....29
3.5.5 ACHIEVING THE DESIGN CASE....29
3.6 DEPARTMENT 4: FERMENTATION, SEPARATION, AND ALCOHOL-TO-JET (F,S&ATJ)....30
3.6.1 OVERVIEW....30
3.6.2 DESIGN BASIS....30
3.6.3 COST ESTIMATION....31
3.6.4 ACHIEVING THE DESIGN CASE – F,S&ATJ....31
3.7 DEPARTMENT 5: IPK STORAGE AND DISTRIBUTION....31
3.7.1 OVERVIEW....31
3.7.2 DESIGN BASIS....32

TABLE OF CONTENTS

3.7.3 COST ESTIMATION 32
3.8 DEPARTMENT 6: CO-PRODUCTS 32
3.8.1 OVERVIEW 32
3.8.2 DESIGN BASIS 32
3.8.3 COST ESTIMATION 33
3.9 DEPARTMENT 7: BOILERS....34
3.9.1 OVERVIEW 34
3.9.2 DESIGN BASIS 34
3.9.3 COST ESTIMATION 34
3.10 DEPARTMENT 8: UTILITIES....35
3.10.1 OVERVIEW 35
3.10.2 DESIGN BASIS - UTILITIES 35
3.10.3 COST ESTIMATION 36
3.11 FIXED OPERATING COSTS....39
3.11.1 LABOR COST DETAILS....39
3.12 SUMMARY OF OPERATING AND CAPITAL COST ESTIMATES....40

4 PROCESS ECONOMICS 40
4.1 ABOUT COST-YEAR INDICES 40
4.2 TOTAL CAPITAL INVESTMENT (TCI) 40
4.3 VARIABLE OPERATING COSTS 41
4.4 FIXED OPERATING COSTS....41
4.5 REVENUE ASSUMPTIONS 41
4.5.1 LIGNOSULFONATES (LS) REVENUE....41
4.5.2 ACTIVATED CARBON (AC) REVENUE....41
4.5.3 ISOPARAFFINIC KEROSENE (IPK) REVENUE 41
4.5.4 RENEWABLE IDENTIFICATION NUMBERS (RINS) REVENUE....41

5 DISCOUNTED CASH FLOW ANALYSIS AND THE MINIMUM SELLING PRICE OF IPK....42
5.1 DISCOUNT RATE AND PLANT LIFE....42
5.2 EQUITY FINANCING....42
5.3 DEPRECIATION 42
5.4 TAXES 42
5.4.1 FEDERAL INCOME TAX 42
5.4.2 STATE TAXES....42
5.5 CONSTRUCTION TIME 42
5.6 START-UP TIME 43
5.7 WORKING CAPITAL 43
5.8 LAND COST....43
5.9 SUMMARY FINANCIAL PARAMETERS 43

6 ANALYSIS AND DISCUSSION 44
6.1 MARKET PRICE OF IPK, BIO-FUELS PREMIUMS, AND IRR 45
6.1.1 PETRO-JET PRICING....45
6.1.2 RINS – D3 RINS VALUATION....47
6.1.3 INTERNAL RATE OF RETURN 48
6.2 CARBON AND ENERGY BALANCE....49
6.3 WATER BALANCE 49
6.4 COST SENSITIVITY ANALYSIS....49
6.4.1 BASE CASE 49
6.4.2 FEEDSTOCK COST SENSITIVITY....49
6.4.3 CAPITAL COSTS SENSITIVITY....50
6.4.4 TOTAL ANNUAL OPERATING COSTS....50
6.4.5 ANNUAL OPERATING COST ELEMENTS....50

TABLE OF CONTENTS

6.4.6 ELECTRICAL RATE SENSITIVITY....................50
6.4.7 REVENUE SENSITIVITY....................51
6.4.8 LIGNIN RESIDUE CO-PRODUCTS REVENUE SENSITIVITY....................53
6.4.9 TOTAL REVENUE SENSITIVITY....................53
6.4.10 SUMMARY OF SENSITIVITY ANALYSIS....................53

7 COMPARISON OF RESULTS TO RELATED TECHNOECONOMIC ANALYSES....................53
7.1 MSP RESULTS COMPARISON....................54
7.2 CAPITAL COSTS COMPARISON OVERVIEW RESULTS....................54
7.2.1 TOTAL CAPITAL INVESTMENT....................54
7.2.2 CAPITAL INVESTMENT PER GALLON BIOFUEL PRODUCT....................55
7.2.3 STATE OF TECHNOLOGY....................57
7.3 CAPITAL COST ELEMENTS INVESTIGATION....................59
7.3.1 INDIRECT COSTS FACTOR(S)....................59
7.3.2 EQUIPMENT INSTALLATION FACTORS....................59
7.3.3 PURCHASED EQUIPMENT COST ESTIMATES....................61
7.3.4 INSTALLED EQUIPMENT COST ESTIMATES....................61
7.3.5 CONCLUSIONS FOR FEEDSTOCK AND PRETREATMENT CAPITAL COST DIFFERENCES....................63
7.4 OPERATING COSTS COMPARISON....................63
7.4.1 FIXED COSTS DIFFERENCES....................64
7.4.2 LIGNIN CO-PRODUCTS OPERATING 64 COST DIFFERENCES....................64
7.4.3 UTILITIES OPEX DIFFERENCES....................64
7.4.4 FERMENTATION, SEPARATION, AND ATJ OPEX DIFFERENCES....................64
7.4.5 FEEDSTOCK COST....................64
7.4.6 OTHER OPERATING COST ELEMENTS....................65
7.5 REVENUE COMPARISON....................65
7.6 OVERALL CAPEX, OPEX, REVENUE COMPARISON....................65

8 CONCLUDING REMARKS....................67
8.1 SUMMARY....................67
8.2 FUTURE WORK....................67

9 LIST OF REFERENCES....................68

10 APPENDIX....................71

NARA is led by Washington State University and supported by the Agriculture and Food Research Initiative Competitive Grant no. 2011-68005-30416 from the USDA National Institute of Food and Agriculture.

Any opinions, findings, conclusions, or recommendations expressed in this publication are those of the author(s) and do not necessarily reflect the view of the U.S. Department of Agriculture.

LIST OF FIGURES

FIGURE NO.	FIGURE TITLE	PAGE NO.
TEA-ES.1.	A high level diagram of the NARA process	8
TEA-ES.2.	Summary of NARA Greenfield IBR TEA – MSP @ 10% IRR	9
TEA-1.1.	Overview of the NARA process for production of isoparaffinic kerosene (IPK), lignosulfonate (LS), and activated carbon (AC) from softwood forest harvest residues (FHR).	10
TEA-2.1.	Timber harvest by county in western WA and OR in 2005, from which forest harvest residuals are derived, showing general geographic zones of highest feedstock density.	13
TEA-2.2.	Incremental and average delivered FHR feedstock curves for western WA or OR highest-feedstock county blocks.	14
TEA-2.3.	Forest harvest residuals sourcing curves for various regions and demand levels.	15
TEA-2.4.	Tradeoff of economy of scale for annualized capital investment against rising feedstock cost as scale of facility changes.	15
TEA-2.5.	March 2016 sourcing curve for NARA TEA using Longview region and LURA model.	16
TEA-2.6.	Facility scale optimization with March 2016 data..	16
TEA-3.1.	Historical hog fuel prices for mill residues and forest harvest residuals..	19
TEA-3.2.	Commercial energy prices in the U.S.	19
TEA-3.3.	Historical industrial natural gas prices in Washington.	20
TEA-3.4.	Projected US industrial prices for natural gas.	20
TEA-3.5.	Forest harvest residuals receipt, storage, preparation and delivery to conversion.	21
TEA-3.6.	Typical PNW forest harvest residuals woods grinding – western Oregon.	21
TEA-3.7.	Circular chip outstock and reclaim storage systems.	21
TEA-3.8.	Generalized feedstock handling system layout for CLE feedstock handling.	24
TEA-3.9.	NARA Mild Bisulfite pretreatment process flow.	26
TEA-3.10.	Enzymatic hydrolysis (including enzyme production).	28
TEA-3.11.	Fermentation to IBA, separation and ATJ conversion to IPK.	30
TEA-3.12.	IPK storage and distribution department	31
TEA-3.13.	Lignin co-products – lignosulfonate and activate carbon	32
TEA-3.14.	Hog fuel and volatile gas boilers.	34
TEA-3.15.	Elements of utilities “department”.	35
TEA-3.16.	First level organization chart for NARA IBR staffing and labor cost estimate.	39
TEA-3.17.	Operations organization chart for NARA IBR.	39
TEA-6.1.	Jet Fuel monthly price basis for early-year jet fuel prices.	45
TEA-6.2.	Jet fuel pricing dropped dramatically in 2014-2015.	45
TEA-6.3.	US EIA price forecasts for key liquid transportation fuels.	46
TEA-6.4.	Projection of EIA jet fuel forecasts for 2017 out through 30-year project life (2047).	46
TEA-6.5.	Price history of D4, D5 and D6 RINs.	47
TEA-6.6.	Historical CWC prices as set by EPA. .	47
TEA-6.7.	EIA history and projections of retail gasoline, diesel and jet fuel.	48
TEA-6.8.	Projections of D5 RINs bounded by the “high” and “low” biofuels production cases. .	48
TEA-6.9.	NARA TEA IRR sensitivity to delivered feedstock cost.	49
TEA-6.10.	NARA TEA IRR sensitivity to fixed capital investment.	50
TEA-6.11.	NARA TEA IRR sensitivity to operating costs.	50
TEA-6.12.	IRR sensitivity to electrical rates	51
TEA-6.13.	NARA TEA IRR sensitivity to revenue from selling price of IPK.	51
TEA-6.14.	Selling price for IPK portion of blends with bio-premium on the blend.	52
TEA-6.15.	Alternatives for blend percent and bio-premium for the blend – impact on IRR.	52
TEA-7.1.	NARA IPK revenue needed to give 10% IRR (MSP), compared to literature TEA reports.	54
TEA-7.2.	Total capital investment, TCI, in $2014 for 2,200 BDST scale.	55
TEA-7.3.	Total capital investment on a per-gallon biofuel annual capacity basis.	55
TEA-7.4.	Yields of biofuels, on a gallon gasoline equivalence, per dry ton of feedstock.	56
TEA-7.5.	Cumulative effect of major process and feedstock differences for NARA compared most recent NREL TEAs, and CSTE in particular.	57
TEA-7.6.	NARA capital per annual gallon compared to most recent NREL hydrocarbon TEA routes.	57
TEA-7.7.	Impact of State of Technology (SOT) assumption on fast pyrolysis capital costs.	58
TEA-7.8.	Total capital investment for current (2014) SOT for 3 recent BETO MYPP pathways to hydrocarbons.	58
TEA-7.9.	Main installed equipment cost (IEC) differences by unit process for NARA compared to NREL CSTE, sorted by magnitude of difference.	62
TEA-7.10.	Total annual operating costs for reported TEAs.	63
TEA-7.11.	Annual operating costs by process department.	63
TEA-7.12.	Fixed costs components for NARA and NREL CSTE.	64
TEA-7.13.	Reported feedstock cost to gate.	64
TEA-7.14.	Annual revenue, annual operating costs, and total capital investment for NARA and NREL TEAs.	65
TEA-7.15.	Approximated annualized Capex compared to Revenue, Opex and Net Before Taxes	66
TEA-7.16.	Capex, Opex and Revenue for future and current SOT compared to NARA.	66
TEA-7.17.	For the MSP version of NARA TEA, the total revenue is higher due to co-products, thus it can cover the higher capital costs.	66
TEA-7.18.	Summary MSP for 11 pathways.	67

LIST OF TABLES

FIGURE NO.	FIGURE TITLE	PAGE NO.
TEA-1.1.	Results of key model versions over NARA project life.	12
TEA-2.1.	Forest harvest residuals availability in highest-productivity adjacent county blocks in WA and OR .	13
TEA-2.2.	Forest harvest residuals availability in highest-productivity adjacent county blocks in MT and ID.	14
TEA-2.3.	Accumulation of delivered feedstock costs for varying sources and hauling distances in WA and OR highest feedstock density counties.	14
TEA-2.4.	Mill-simulated process screening.	16
TEA-2.5.	Laboratory moisture content, particle size classification and bark content of gyratory screen accepts.	17
TEA-2.6.	Chemical composition of accepts and screen fines – sugar polymers.	17
TEA-2.7.	Chemical composition of accepts and screen fines – extractives and lignin.	17
TEA-2.8.	Chemical composition of accepts and screen fines – ash content.	17
TEA-2.9.	Species identification (from microscopic fiber analysis)	17
TEA-3.1.	Key operating cost values used in various departments.	18
TEA-3.2.	Bulk chemicals price assumptions.	19
TEA-3.3.	Enzyme production nutrients price assumptions.	19
TEA-3.4.	NARA levelized stumpage cost	23
TEA-3.5.	Softwood forest harvest residuals annual supply estimates for varying marginal cost categories and harvest site types.	23
TEA-3.6.	Average cost of residue to Longview WA at varying annual scales.	23
TEA-3.7.	Hauling distances, total miles from harvest to mill gate by tonnage harvest type.	23
TEA-3.8.	Average hauling costs for varying annual tonnages to Longview, WA.	23
TEA-3.9.	Harvesting cost components for woods harvesting steps – 846,000 BDST/yr to Longview, WA.	23
TEA-3.10.	Feedstock delivered cost components for NARA Base Case 846,000 BDST/yr to Longview, WA.	24
TEA-3.11.	Feedstock handling operating costs inside plant gate.	24
TEA-3.12.	CLE feedstock handling for 2,400 bone dry metric ton per day design criteria adjusted to NARA 2,200 BDST/day capacity.	25
TEA-3.13.	CLE/WY feedstock handling capital estimates for 2400 BDMTPD (2,650 BDSTPD) adjusted to NARA scale in 2014$.	26
TEA-3.14.	Operating costs for pretreatment.	27
TEA-3.15.	Installed equipment costs for pretreatment area.	28
TEA-3.16.	Installed equipment cost estimates for enzymatic hydrolysis department.	29
TEA-3.17.	Enzymatic hydrolysis department operating costs.	29
TEA-3.18.	Operating costs for fermentation, separation and alcohol-to-jet department.	31
TEA-3.19.	Storage and distribution department IEC.	32
TEA-3.20.	Storage and distribution department operating costs.	32
TEA-3.21.	Capital cost for lignosulfonate production.	33
TEA-3.22.	Operating costs for lignosulfonate production.	33
TEA-3.23.	Activated carbon production capital costs.	33
TEA-3.24.	Operating costs for activated carbon production.	34
TEA-3.25.	Boilers capital expense.	34
TEA-3.26.	Operating cost for hog fuel and volatile gas boilers.	35
TEA-3.27.	Capital costs for utilities department.	36
TEA-3.28.	Flow rates of streams going to wastewater treatment system	38
TEA-3.29.	Wastewater treatment system cost estimate.	38
TEA-3.30.	Utilities operating costs.	39
TEA-3.31.	Fixed operating costs.	39
TEA-3.32.	Annual labor cost assumptions for NARA IBR.	40
TEA-3.33.	Summary of capital and operating cost elements by department.	40
TEA-5.1.	Construction period activities used by NREL and adopted by NARA TEA.	43
TEA-5.2.	Discounted cash flow analysis parameters	44
TEA-5.3.	Summary results for NARA final TEA.	44
TEA-6.1.	NARA TEA summary results if 30-year IPK pricing is at EIA projected petro-jet price ($2.56/gal IPK) and RINs projected value is $2.46 / gal IPK.	49
TEA-6.2.	Major components of annual operating costs	50
TEA-6.3.	Scenarios for a “bio-premium” adder to total fuel blend price varying IPK blend percentages and all premium accruing to the renewable fuel portion (IPK).	52
TEA-7.1.	Comparing the NARA IBR TCI to the 3 most recent BETO hydrocarbon pathways that convert cellulosic to hydrocarbon fuels	58
TEA-7.2.	NARA indirect costs as a percentage of total direct costs (TDC) are from Humbird 2011 NREL CTSE.	59
TEA-7.3.	NREL CSTE equipment installation cost factors.	59
TEA-7.4.	NREL CSTE TEA feedstock handling installed equipment costs.	60
TEA-7.5.	NREL Fast Py TEA feedstock handling installed equipment costs.	60
TEA-7.6.	NARA TEA woodyard handling installed equipment costs..	61
TEA-7.7.	Purchased equipment cost estimate sources for major cost items	61
TEA-10.1.	Discounted cash flow rate of return worksheet	71-73
TEA-10.2.	NARA TEA task deliverables and reporting	74
TEA-10.3.	NARA TEA model versions listing	75-76

LIST OF ACRONYMS

AFEX	ammonia fiber explosion
ATJ	alcohol-to-jet
BDST	Bone dry short tons
BET	Brunauer–Emmett–Teller (basis for surface area measurement)
BETO	Bio-Technology Energy Office (DOE)
BETO MYPP	Bio-Technology Energy Office Multi-Year Program Plan
BFW	boiler feed water
BLS	Bureau of Labor Statistics
C5/C6	ratio of mixtures of (mostly) xylose (a C5 sugar) and glucose (a C6 sugar)
Capex	Capital Expense
CBP	consolidated bioprocessing
CIP	clean-in-place
CLE	Catchlight Energy, LLC (a joint venture of Chevron and Weyerhaeuser)
COD	chemical oxygen demand
CSL	corn steep liquor
CSTE	corn stover to ethanol (specifically, the 2011 Humbird et. al. reported process)
DAP	diammonium phosphate
DCFROR	discounted cash flow rate of return
DOE	(U.S.) Department of Energy
FCI	fixed capital investment
FGD	flue gas desulfurization
FHR	Forest Harvest Residuals (aka "Slash")
FRS	Fermentation Residual Solids
F,S&ATJ	Fermentation, Separation and Alcohol-to-Jet
GPD	gallons per day
GPH	gallons per hour
GPM	gallons per minute
HHV	higher heating value
HMF	5-hydroxymethyl furfural
IBA	IsoButyl Alcohol, or Isobutanol
IBR	Integrated Bio-Refinery
IEC	Installed Equipment Cost
IF	Installation Factors
INL	Idaho National Laboratory
IPK	isoparaffinic kerosene
IRR	internal rate of return
ISBL	inside battery limits (of the plant)
LHV	lower heating value
MBS	Mild Bisulfite
MESP	minimum ethanol selling price MM million (e.g., MMBtu or $ MM)
MSP	minimum selling price (usually to achieve 10% IRR)
MSSP	minimum sugar selling price MYPP OBP's Multi-Year Program Plan
NARA	Northwest Advanced Renewables Alliance
NPV	net present value
NREL	National Renewable Energy Laboratory
OBP	Office of the Biomass Program
OSBL	Outside the Battery Limit
OTR	oxygen transfer rate
Opex	Operating Expense
OUR	oxygen uptake rate
PEC	Purchased Equipment Cost
PCS	pretreated corn stover
PFD	process flow diagram
PNNL	Pacific Northwest National Lab
RJF	renewable jet fuel
SCFM	standard cubic feet per minute
SHF	separate (or sequential) hydrolysis and fermentation
SOT	annual State of Technology case
SSCF	simultaneous saccharification and co-fermentation
SSL	spent sulfite liquor—the liquid filtered off the pulp solids from pretreatment
TCI	total capital investment
TDC	total direct cost
TEA	techno-economic assessment
TPH	tons per hour
USG	U.S. gallons
VOC	volatile organic compound
VVM	volume (of gas) per volume (of liquid) per minute
WWT	wastewater treatment
WY	Weyerhaeuser

EXECUTIVE SUMMARY

A Techno-Economic Assessment (TEA) has been prepared for a greenfield integrated biorefinery (IBR) to produced renewable jet fuel from Pacific Northwest softwoods. Specifically, this base case "NARA process" produces jet fuel (isoparaffinic kerosene, IPK) from Northwest USA forests with a feedstock consisting of softwood Forest Harvest Residuals (FHR). The NARA process employs a mild bisulfite process (MBS) for pretreatment of the feedstock, with enzymatic hydrolysis of the pretreated wood fiber, and fermentation of pentose and hexose sugars to Isobutanol (IBA), and then conversion of the IBA to C12 and C16 alkane hydrocarbons (IPK) via an alcohol-to-jet (ATJ) process. Marketable co-products of lignosulfonates (LS) and activated carbon (AC) are produced from the residual lignin-rich streams. A high level diagram of the NARA process is shown in figure TEA-ES.1.

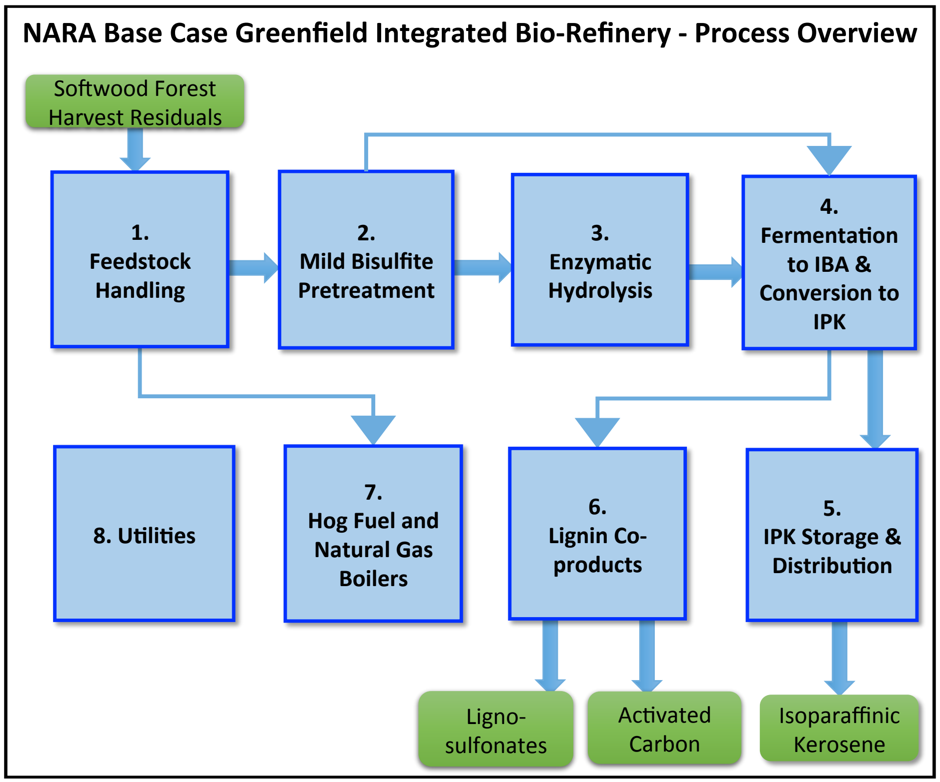

Figure TEA-ES.1. A high level diagram of the NARA process.

For the techno-economic analysis (TEA) presented here, the NARA process is detailed into the eight separate departments shown in Figure TEA-ES.1 that together comprise a complete "nth plant" biorefinery. Process flow diagrams have been developed for each department, and an ASPEN model was created for mass and energy balances. Capital costs and operating costs for each department have been developed and are presented in detail.

Feedstock costs are a large expense item for the NARA process. As a result, considerable effort is devoted to estimating the delivered cost of feedstock and the attendant size of the process plant. The plant is sized at 2,200 bone dry short tons (BDST) per day, with a feedstock cost of $61.55/BDST delivered to a hypothetical site somewhere near Longview, WA. Process material and energy balances were developed at Washington State University (WSU) and Gevo Inc. utilizing ASPEN modeling.

The summary of key TEA results is shown in Figure TEA-ES.2. This version of the TEA (V13.50 MSP) calculates a Minimum Selling Price (MSP) of IPK to achieve a 10% internal rate of return (the same basis as the NREL (Swanson, Saterio, and Hu, 2010) (Humbird et al., 2011) TEAs for biofuels production). This economic result is based on four streams of revenue: 1) IPK; 2) A "Biofuel Premium" (akin to Renewable Identification Number (RINS) for the renewable IPK; 3) Lignosulfonate (LS); and 4) Activated Carbon (AC). Lignosulfonates and Activated Carbon are two high margin co-products identified to improve the economics of the NARA process. The Total Capital Investment (TCI) estimate is $1,100 MM, and the annual operating cost (Opex) is $246 MM/yr. The total yearly production of IPK is 35.7 MM gallons. A discounted cash flow / rate of return (DCF/ROR) analysis with depreciation and income taxes for a 30-year project life results in a minimum selling price (MSP) for IPK of $7.267 gallon to achieve 10% internal rate of return (IRR)[1].

Alternatively, we can calculate a project IRR based on a forecast price of IPK, RINS, LS, and AC. Using EIA projections for jet fuel, an IPK value of $2.56/gal IPK is projected for the 30-year project life, and RINs values (or some equivalent form biofuel premium) are projected at $2.46/gal IPK. With the LS and AC revenue shown in Figure TEA-ES.2, the result of this analysis gives a 3.7% IRR.

[1] The choice of 10% IRR here is not intended to suggest this is a widely accepted hurdle rate for an investment of this risk level. It is chosen to be consistent with BETO MYPP methodology and assumptions.

This level of return seems unlikely to induce investment in the production of IPK from forest harvest residuals in the Northwest via the process described and projected revenue streams. Sensitivity analyses indicate that given the current estimated revenue, even very large Capex and/or Opex reductions cannot increase the IRR to the 10% IRR benchmark rate used. The most feasible large economic improvement would be to increase revenue. The most plausible future changes over projections used here that might foster commercialization of this process would be some form of higher premium placed on the greenhouse gas reduction benefits of displacing petroleum-based jet fuel with a renewable source based upon woody feedstocks.

Review of the comparative biofuels TEA literature found none for a process of converting softwood feedstocks to a bio-based jet fuel with lignin-derived co-products. The most similar recent processes converting cellulosic feedstocks into hydrocarbon fuels, as reported in the BETO MYPP reports, have quite similar MSP values to NARA (U.S. Department of Energy [DOE], 2015), suggesting that all these routes face similar economic difficulties with the current state of technology.

NARA PNW Forest Feedstocks to Bio Jet Fuel - Techno-Economics

Revised 29-Nov-16 Case: 13.50

Authors Gevan Marrs & Tom Spink

NARA $

PNW Softwood to renewable IPK, LS, AC

Feedstock: OR Douglas-fir Forest Residuals (like FS-10)

Mild Bisulfite Pretreatment

Case 13.50 MSP - Integrated Facility producing IPK, Lignosulfonates, and Activated Carbon

Annual Revenue

Product	Annual Product	Units	Revenue $/Unit	Total Annual Revenue, $MM	MSP
					$/gal IPK
Iso-Paraffinic Kerosene - IPK	35.7	MM gallons	$ 2.56	$ 91.49	**$ 2.56**
BioFuel Premium(s) / gal IPK	35.7	MM RINS	$ 4.71	$ 168.31	**$ 4.71**
		MSP $/gal IPK	***$ 7.27***		**$ 7.27**
Lignosulfonates	196,224	Dry tons	$ 200	$ 39.24	
Activated Carbon	66,192	Dry tons	$ 1,500	$ 99.29	
Total Annual Revenue (million $ per year)				**$ 398.34**	

Feedstock Supply to Mill Gate	846	Thousand BDT/yr
Feedstock to Conversion	770	Thousand BDT/yr
IPK BioJet Production	**35.7**	**million gallons per year**
IPK Yield	46.4	gal / dry U.S. ton feedstock
Feedstock Cost to Mill Gate	$61.55	/dry U.S. ton
Equity Percent of Total Investment	100%	
Internal Rate of Return (After-Tax)	**10.00%**	

Capital Costs, million $	
Feedstock handling	$56.5
Pretreatment	$105.0
Enzymatic Hydrolysis	$27.7
Fermentation, Separation & Alcohol-to-Jet	$146.0
Lignin Co-products	$123.9
IPK Product Storage and Distribution	$10.0
Multi-fuel Boiler	$43.2
Utilities	$124.7
Total Installed Equipment Cost	**$636.91**
Added Direct + Indirect Costs	$472
(% of TCI)	43%
Total Capital Investment (TCI)	**$1,109.1**

Manufacturing Costs (million $ per year)	
Feedstock + Handling	$64.7
Pretreatment Opex	$14.0
Enzymatic Hydrolysis	$29.4
Fermentation, Separation & Alcohol-to-Jet	$28.2
IPK Product Storage and Distribution	$0.05
Power Boiler	$3.2
Lignin Co-products	$24.8
Utilities	$13.5
Fixed Costs (Labor, Prop Tax, Insurance, Maint.)	$67.6
Total Manufacturing Costs	**$245.51**
Annual "Average" Income Tax	**$26.7**
Average Annual Cash Flow After-tax	**$126.0**

Figure TEA-ES.2. Summary of NARA greenfield IBR TEA – IPK MSP @ 10% IRR

PROCESS DESIGN AND ECONOMICS FOR BIOCHEMICAL CONVERSION OF SOFTWOOD LIGNOCELLULOSIC BIOMASS TO ISOPARAFFINIC KEROSENE AND LIGNIN CO-PRODUCTS

1) Introduction

1.1 Background and Motivation

The Northwest Advanced Renewables Alliance (NARA) is an alliance of public universities, government laboratories, NFO's, Indian Tribes, and private industry that provides technologies, resources and analyses for stakeholders interested in using forest residuals to create bio-based alternatives to petroleum-based products such as jet fuel. The Alliance was funded through a five-year grant provided by USDA National Institute of Food and Agriculture.

Led by Washington State University, NARA took a comprehensive approach to building a supply chain for aviation biofuel with the goal of increasing efficiency in everything from forestry operations to conversion processes. Using forest residuals from logging operations as feedstock, the project aims to create a sustainable industry to produce aviation biofuels and important co-products. The project includes a broad alliance throughout the Northwest.

The mission of the project is to provide stakeholders, interested in creating a forest residuals to bio-jet industry, with regional solutions that are economically viable, socially acceptable, and meet the high environmental standards of the Pacific Northwest (WA, OR, ID and MT).

The assessment of the extent that the conceived conversion facility and product(s) production meets the economically viable criteria is done via this Techno Economic Assessment (TEA).

1.2 Process Overview

The base case NARA process uses mild bisulfite pretreatment of softwood forest harvest residual feedstock to allow a biochemical conversion (fermentation) of the cellulosic portion of the feedstock to isobutanol (IBA) and this is then oligimerized to isoparaffinic kerosene (IPK), a bio-based jet fuel. The portions of the feedstock not converted to IPK (largely lignin) are converted to co-products; lignosulfonates (LS) from the pretreatment liquor and activated carbon (AC) from the fermentation residual solids. An overview of the process is shown in Figure TEA-1.1.

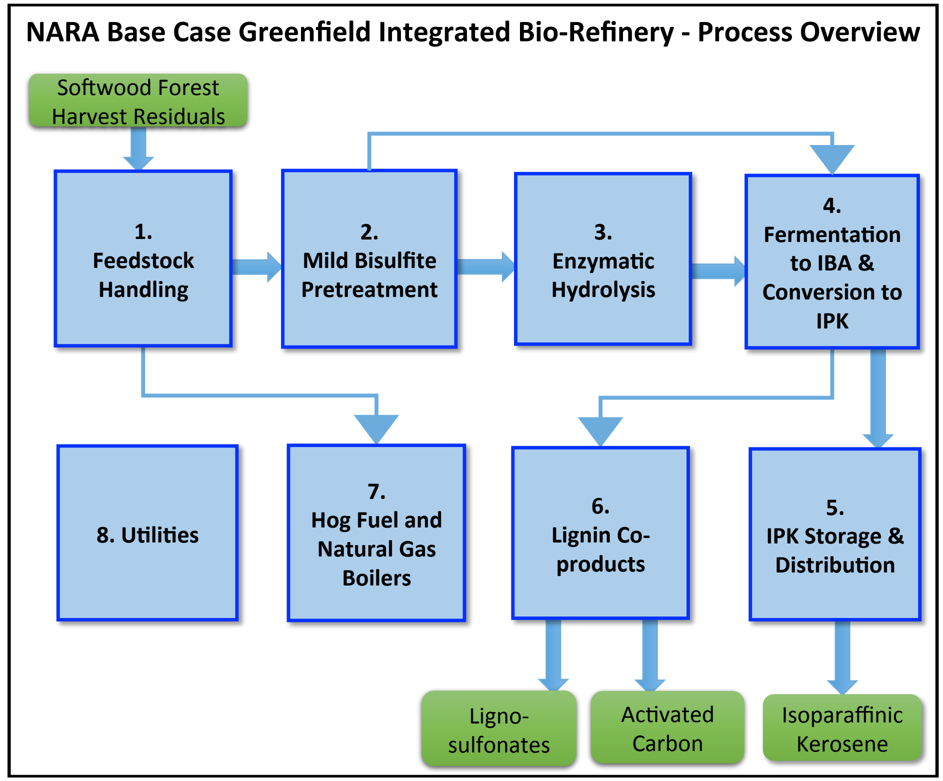

Figure TEA-1.1. Overview of the NARA process for production of isoparaffinic kerosene (IPK), lignosulfonate (LS), and activated carbon (AC) from softwood forest harvest residues (FHR).

1.2.1 Process Departments and Brief Descriptions

Department 1: ***Feedstock Handling:***
This department receives the bio refinery primary feedstock—softwood forest harvest residuals (FHR)—by truck and stores them in circular outstock/reclaim pile systems. To assure continued supply for 24/7 operation of the biorefinery during equipment and weather-related outages the average pile inventory is 21 days of feedstock to conversion. This department also receives, stores, and delivers "hog fuel"—mixed wood and bark residues from wood products manufacturing operations—for energy production in the hog fuel boiler. This department also screens

out oversize particles of FHR and resizes them, and screens out about 9% of the feedstock as fines, which are sent to the hog fuel system for energy production.

Department 2: ***Pretreatment:***
This department uses a mild bisulfite “pulping” process to prepare the recalcitrant softwood feedstock for subsequent enzymatic hydrolysis and fermentation of the cellulosic sugars. A single large continuous digester processes ~2,200 BDST per day of FHR chips at about 40% moisture (wet basis), adds an acid cooking liquor and cooks at high temperature and pressure for about 4 hours, resulting in two streams: one mostly solids stream which is sent to enzymatic hydrolysis and one liquor output stream which is sent to fermentation.

Department 3: ***Enzymatic Hydrolysis:***
This department produces cellulase enzymes and then hydrolyzes the cellulosic portion of the pulp solids to sugar monomers that can be then fermented to isobutanol (IBA). Hemicellulase enzymes are purchased from the open market.

Department 4: ***Fermentation to IBA and Conversion to IPK:***
This department ferments the sugar monomers in the hydrolyzed solids and the dissolved sugars in the SSL to IBA, then converts the IBA through stages of dehydration, oligomerization, and hydrogenation to produce IPK.

Department 5: ***IPK Storage and Distribution:***
This department consists of tanks sufficient to store 30 days of IPK production and loading facilities for shipping IPK via tanker trucks and rail cars.

Department 6: ***Lignin Co-products:***
This department produces two co-products for sale to industrial markets: liquid calcium lignosulfonates (Ca-LS or simply LS) and activated carbon (AC). These two products are derived from the pretreatment product solids that are not fermented into IBA. The liquid Ca-LS (50% solids) is produced from the beer stillage of fermented spent sulfite liquor (SSL). AC is produced from the beer stillage of the cellulose fermented residual solids (FRS).

Department 7: ***Boilers:***
This department has two steam boilers. One is a multi-fuel boiler that uses either natural gas (for startup) or hog fuel (routinely) to generate much of the process steam needed. There is also a smaller boiler for the volatile gases produced from carbonizing the FRS at high temperature.

Department 8: ***Utilities:***
This “department” is a collection of all other units needed to operate the entire facility and is essentially a cost collection center for capital and operating expenses. It encompasses items like electrical power supply to the mill, gates, roads, fences, water and compressed air systems and waste disposal costs for external landfill.

1.3 Techno-Economic Analysis Approach

The approach used for the NARA TEA was to adopt as many of the complex TEA conventions, assumptions, and terminology as possible from the most extensive set of cellulosic biofuels TEAs that have been done in recent years. These are the NREL, INL, and PNNL TEA studies done on behalf of the U.S. Department of Energy (DOE) as part of the Bio-Technology Energy Office (BETO). The DOE has created and maintained a Multi-Year Program Plan (DOE, 2015) to track and plan for State of Technology (SOT) and projections into future SOT targets that help set research and policy focus for DOE and others. The detailed Excel spreadsheet for the most recent update of the most promising biochemical path—Corn Stover to Ethanol (Humbird et al, 2011)—was obtained directly from NREL staff. This allowed direct adoption of all relevant financial approach assumptions and facilitates eventual comparison of NARA results with literature reports, including alternate pathway projections (such as thermochemical routes like Fast Pyrolysis (Wright, Daugaard, and Hu, 2010). One key departure from the BETO / NREL TEA approach is that in addition to setting a cost-of-capital (aka, discount) rate of 10% and solving the DCF/ROR for a Minimum Selling Price (MSP), one form of the NARA TEA projected future product selling prices for all products generating revenue (including the biobased jet fuel) and then calculated a resulting IRR.

The TEA model and the underlying process and cost estimation data used at input were developed as an iterative process over the last four NARA project years. Early in the project life certain process and product conditions were tentative and needed refinement and improvement during the course of the project. As such, assumptions were made based upon available data early in the project, and these refined over the project life leading to the final model version reported here. The majority of those earlier TEA estimates will not be reported here in detail. Alignment of deliverable products with the task deliverables agreed upon are done via reference to Table TEA-10.2 in the Appendix section of this report, where the specific eleven task deliverables for this area (System Metrics – Techno-Economic Analysis, or “SM-TEA”) are listed.

As the TEA effort evolved over the course of the NARA project, various TEA versions were created and tracked according to a version numbering system. Significant version changes were due to many factors, including: scope of bio refinery; process changes; cost estimate updates; yield changes; etc. There were over 60 notably different TEA versions created over the project life (see Table TEA-10.3 for a full list). Six of these warrant specific mention here as they drove significant decision points in the NARA project (each was reported in detail in routine NARA cumulative reports as the project progressed). The summary information for these six is shown in Table TEA-1.1.

Table TEA-1.1. Results of key model versions over NARA project life.

NARA TEA Key Model Versions and Results							
Version Number	Model Description	Date of Analysis	Last Modified Date	IRR @ projected prices	MSP $/gal IPK @ 10% IRR	Total Capital Investment, $MM	Major Conclusion(s) from this version.
3.6	*V 3.6 - Burn lignin for power, no co-products.*		12-Sep-13	Negative	$6.93	$ 881	With IPK valued at $3.09/gal, IRR is negative with no lignin co-products.
6.43	*V 6.43 Produce IPK, LS, and AC using MBS*	5-Feb-15	5-Feb-15	12.3%	-	$ 1,118	Adding LS and AC co-products could make the biorefinery viable.
7.1	*V 7.1 Produce IPK and AC using WetOx Pretreatment*	17-Feb-14		8.9%	-	$ 1,060	Compared to MBS PT, Wet Ox less favorable (lose LS revenue).
13.1	*NARA V 13.1 DCF-ROI Techno-economics - Re-purpose case.xlsx*	13-Jul-15		1.2%	-	$ 1,121	Very little advantage to re-purposing a pulp mill - not enough equipment savings.
13.2	*V 13.2 Updated yields, products, values for 2015.*		25-Aug-13	0.9%	-	$ 1,440	Greatly reduced AC yield dropped revenue to make project non-viable.
13.42	*V 13.42 "Final" NARA Integrated Bio-refinery*	22-Jun-16	22-Jun-16	~3.7%	$7.28	~$1,100	MSP to get 10% IRR is considerably higher than projected revenue.
14.50	*V 13.50 "Final" NARA Integrated Bio-refinery*	5-Dec-16	9-Dec-16	~3.7%	$7.27	~$1,109	Relatively small error corrections to prior versions. No change in conclusions.

This report largely focuses on the "final" NARA TEA – the version refined with all the base-case parameters and assumptions at the end of the NARA project. A 3-day review and vetting session was conducted in January of 2016 with a host of NARA member participants (from all technical areas of the project). From this session identified improvements / corrections were incorporated into the final TEA, V 13.50. Earlier iterative detailed results (which were described in detailed NARA cumulative status reports over the project years) will be described here only when important findings set the direction of following work.

1.4 About n^{th}-Plant Assumptions

Just as for the NREL TEA analyses, the NARA TEA reported here uses what are known as "n^{th}-plant" economics. The key assumption implied by n^{th}-plant economics is that the analysis does not describe a "pioneer" plant; instead, several plants using the same technology have already been built and are operating. In other words, it reflects a mature future in which a successful industry of n plants has been established. Because the NREL TEA model is primarily a tool for studying new process technologies or integration schemes in order to comment on their long-term comparative economic impact, they feel it is prudent to ignore artificial inflation of project costs associated with risk financing, longer start-ups, equipment overdesign, and other costs associated with first-of-a-kind or pioneer plants, lest these overshadow the real economic impact of research advances in conversion or process integration. At the very least, these n^{th}-plant economics should help to provide justification and support for early technology adopters and pioneer plants.

The NARA TEA objective is similar to NREL assumptions – nth plant, since we want to estimate what will be the long-term economics. If and when those are attractive, consideration can be given to sources of financing willing to accept lower returns on a relatively lower return pioneer plant, in order to eventually achieve n^{th} plant returns.

The n^{th}-plant assumptions in the NARA model apply primarily to the factored cost model used to determine the total capital investment from the purchased equipment cost and to the choices made in plant financing. The n^{th}-plant assumption also applies to some operating parameters, such as process uptime of 96%. These assumptions were agreed upon by NREL and DOE for NREL TEAs, and the NARA values reflect our best estimates at the time of publication. It should be emphasized, however, that these assumptions carry a large uncertainty and are subject to refinement.

1.5 Review of Related Techno Economic Studies

A fairly exhaustive search was done for comparison biofuel TEA reports in order to both vet the NARA TEA model as well as to understand the relative results and look for opportunities for improvement by seeking sources of difference(s) between reported results. Constraining the search to those results reported since 2008, and for those using cellulosic feedstocks to liquid transportation fuels (ethanol, butanol, gasoline, diesel, jet fuel), over 30 articles were deemed relevant. Some of those compared multiple options for feedstocks and/or pathways and/or end products, resulting in over 50 comparison cases. The key values for these (Total Installed Capital, Minimum Selling Prices, etc.) were extracted to a database to allow comparison to the NARA TEA results.

The specifics of those comparisons will be reported later in this report following the summary NARA TEA results section. However, it should be noted that:

- Many published TEAs were somewhat outdated, in that considerable progress has been made in intervening years (e.g., on enzymatic pretreatment cost and effectiveness).
- Many did not address pathways relevant to NARA (e.g., in feedstocks, conversion, end products).
- Most of the "peer-reviewed" journal publications have insufficient data presented to investigate WHY the results are different in main elements.
- Many report on future targets, not actual projections of hypothesized plausible improvement paths.
- Virtually none of the reports have co-products from non-fuels residues (e.g., lignin), which contribute very significantly to capital and operating expenses as well as revenue in the NARA TEA.
- Importantly, only one report discussed the pathway of woody feedstock via biochemical pathway to hydrocarbon fuel, as NARA TEA does.

Thus despite many reported TEA results for biofuels, it is very difficult to find useful direct comparisons to the NARA process. Again, details of comparisons that were made are found in a latter section in this report (section 7 titled "Comparison of Results to Related Technoeconomic Analyses").

1.6 About the NARA ASPEN Model

After a preliminary TEA model was constructed using the NREL CSTE model (Humbird et al., 2011) as a template in the first years of the TEA effort, adapted to NARA conditions using experiential values for capital and operating costs, these were later refined via construction of an ASPEN model. That model, as with the NREL efforts, provided an integrated and internally consistent set of mass flows and energy balances from which improved capital and operating costs could be derived. The ASPEN model for NARA is fully documented in a separate NARA Final Report (Chen et al., 2016), so will not be further discussed here.

2) Design Basis and Conventions

2.1 Plant Size

Feedstock supply curves were developed that show the expected change in average softwood Forest Harvest Residuals (FHR) feedstock cost to the gate of a single facility, as the facility scale changes. These too were done in several iterations over the course of the project, each with finer detail, data, and therefore reliability.

For the initial choice of plant size, done early in the project life, feedstock sourcing curves were derived from the same data source as used for the "Billion Ton Study" (U.S. Department of Energy [DOE], 2011)—that is the county-level FHR availability estimates from the USDA Forest Service Timber Products Output (TPO) system (U.S. Department of Agriculture [USDA], 2012).

From these county-level estimates of sustainable annual FHR production contiguous blocks of adjacent counties in WA, OR, and MT/ID were selected in which each block had over 1 million BDST FHR available annually. The presumption was that given typical county sizes in the NARA region, a biofuels conversion facility located somewhat centrally in these adjacent count blocks would have hauling distances which were plausible given prior work (say, under 100 miles one-way haul). Table TEA-2.1 shows the FHR availability data for the selected counties in WA and OR, with those in adjacent blocks meeting the total availability criteria are highlight. Note that when converted to a unit area basis (BDST/total county acre) the values vary highly between counties. Figure TEA-2.1 shows the geographic location of these adjacent highest-biomass feedstock areas—roughly the Longview area in WA and the Springfield area in OR. Not surprisingly there is a long history of a strong forest products industry present in these areas, making them likely candidates for available infrastructure for biofuels manufacturing operations.

Table TEA-2.2 shows MT/ID highest-county areas for comparison. Because there tend to be larger counties in MT, with large non-forested areas, the average BDST/county acre is much lower than WA or OR highest values, and in fact this initial estimate did not find over 1 MM BDST/yr available in adjacent county blocks. Since normally the most plausible cellulosic biofuels economics are supported by highest density of feedstock, we chose to use the WA and OR feedstock density as basis for choosing target facility scale.

Table TEA-2.1. Results of key model versions over NARA project life.

Residuals per County acre for top 3 or 4 tonnage adjacent counties to get past 1 MM BDT/yr residuals in each of OR and WA						*Biomass 2008 NI*
NARA_ZONE	NAME	STATE_NAME	SQMI	Total County Acres	Forest_Residuals_BDT	BDT/yr Residuals per Total Co Acre
W_OR	Douglas	Oregon	5,070	3,244,736	423,101	0.13
W_OR	Lane	Oregon	4,618	2,955,264	412,483	0.14
W_OR	Coos	Oregon	1,610	1,030,208	351,356	0.34
		OR 3 counties	**OR top 3**	**7,230,208**	1,186,940	**0.1642**
W_W	Grays_Harbor	Washington	1,929	1,234,688	414,609	0.34
W_W	Lewis	Washington	2,436	1,559,168	383,204	0.25
W_W	Pacific	Washington	960	614,592	218,857	0.36
W_W	Cowlitz	Washington	1,166	746,368	193,157	0.26
		WA 4 counties	**WA top 4**	**4,154,816**	1,209,827	**0.2912**
		OR-WA Average				**0.2105**

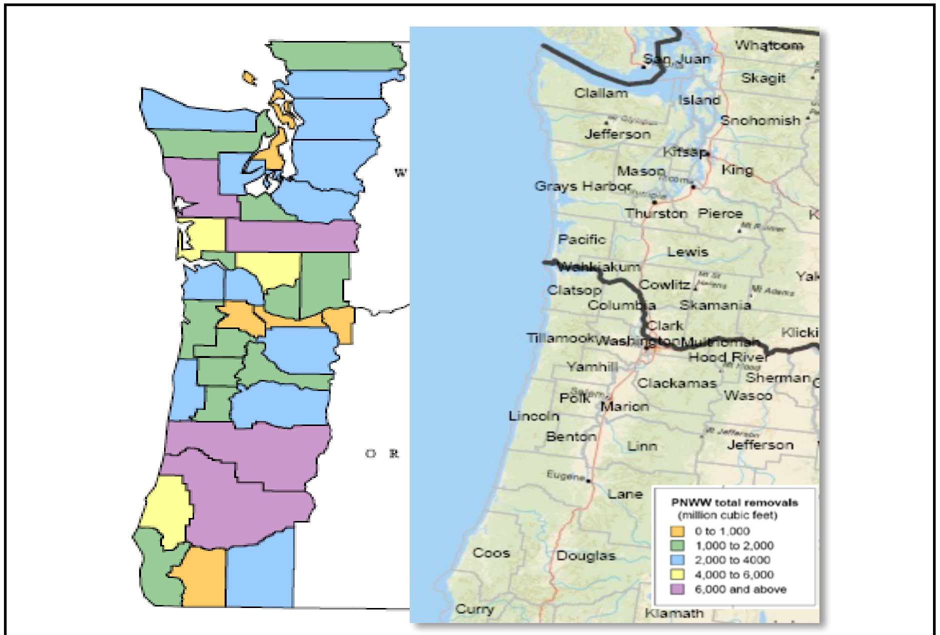

Figure TEA-2.1. Timber harvest by county in western WA and OR in 2005, from which forest harvest residuals are derived, showing general geographic zones of highest feedstock density. Adapted from Projections of timber harvest in western Oregon and Washington by county, owner, forest type, and age class, (17), by Zhou, X., Haynes, R.W. & Barbour, J. (2005). Portland, OR: U.S Department of Agriculture Forest Service.

Table TEA-2.2. Forest harvest residuals availability in highest-productivity adjacent county blocks in MT and ID. (Data from USDA (2012))

Residuals per County acre for top 3 or 4 tonnage adjacent counties to get past 1 MM BDT/yr residuals in MT-ID Since there are relatively few users for Primary Mill Residuals, add both Forest and Primary mill to county availble.						
NARA_ZONE	NAME	STATE_NAME	SQMI	Total County Acres	Forest_Residuals_BDT	BDT/yr Residuals per Total Co Acre
RM	Lincoln	Montana	3,675	2,352,064	103,332	0.04
RM	Sanders	Montana	2,790	1,785,600	69,189	0.04
RM	Shoshone	Idaho	2,636	1,686,720	124,641	0.07
RM	Bonner	Idaho	1,920	1,228,544	-	0.00
RM	Kootenai	Idaho	1,316	842,048	61,275	0.07
MT-ID Zone Total					358,437	
MT-ID Ave.						0.05

Using the WA & OR county level averages of unit feedstock availability (0.210 BDST/county acre/year) we constructed delivered cost estimates for varying quantities to a single-point refinery using cost components of a) stumpage to owner, b) FHR gathering costs, c) loading and grinding costs and d) truck transport to bio refinery. For this initial estimate the stumpage was estimated to be $7/BDST, based upon experience of NARA team members working with current operations in WA and OR. The loading and grinding costs were estimated to be $13/BDST. Of the remaining cost elements, there were three assumed cost levels of FHR availability on each site for collection costs. FHR material was assumed to be either: 1) piled, 2) within reach of landing, or 3) spread across harvest site. The hauling costs were broken into four hauling distance zones of 55, 75, 95, and 115 miles one-way haul. These combinations gave 12 feedstock cost levels, which could be accumulated in order of delivered cost to supply differing amounts of feedstock to a central site at various total costs. Table TEA-2.3 shows the specific values assumed for each component and the resulting 12 incremental cost categories.

The quantities in each of these cost categories was accumulated by delivered cost, with the results shown in Figures TEA-2.2 and TEA-2.3, referred to as a sourcing curve. The individual incremental cost values for supplies up to 900,000 BDST/yr were smoothed via linear curve fit, and then converted to average delivered cost as the total delivered per year (facility scale) changes.

Table TEA-2.3. Accumulation of delivered feedstock costs for varying sources and hauling distances in WA and OR highest feedstock density counties.

				Location on harvesting site		
				% Landing	% Close By	% Gathered
				40%	30%	30%
		Harvesting Cost, $/BDT		$ 16.00	$ 26.00	$ 38.00
				Harv + Haul Costs, $/BDT		
	Haul Miles	Haul Cost, $/BDT		On Landing	Close by Landing	Gather from Site
Zone 1	55	$ 18.57	Zone 1	$ 34.57	$ 44.57	$ 56.57
Zone 2	75	$ 23.61	Zone 2	$ 39.61	$ 49.61	$ 61.61
Zone 3	95	$ 28.65	Zone 3	$ 44.65	$ 54.65	$ 66.65
Zone 4	115	$ 33.69	Zone 4	$ 49.69	$ 59.69	$ 71.69
			Plus $20 for Stumpage & Comminution			
				Total Delivered Increment Costs to gate		
				On Landing	Close by Landing	Gather from Site
			Zone 1	$ 54.57	$ 64.57	$ 76.57
			Zone 2	$ 59.61	$ 69.61	$ 81.61
			Zone 3	$ 64.65	$ 74.65	$ 86.65
			Zone 4	$ 69.69	$ 79.69	$ 91.69

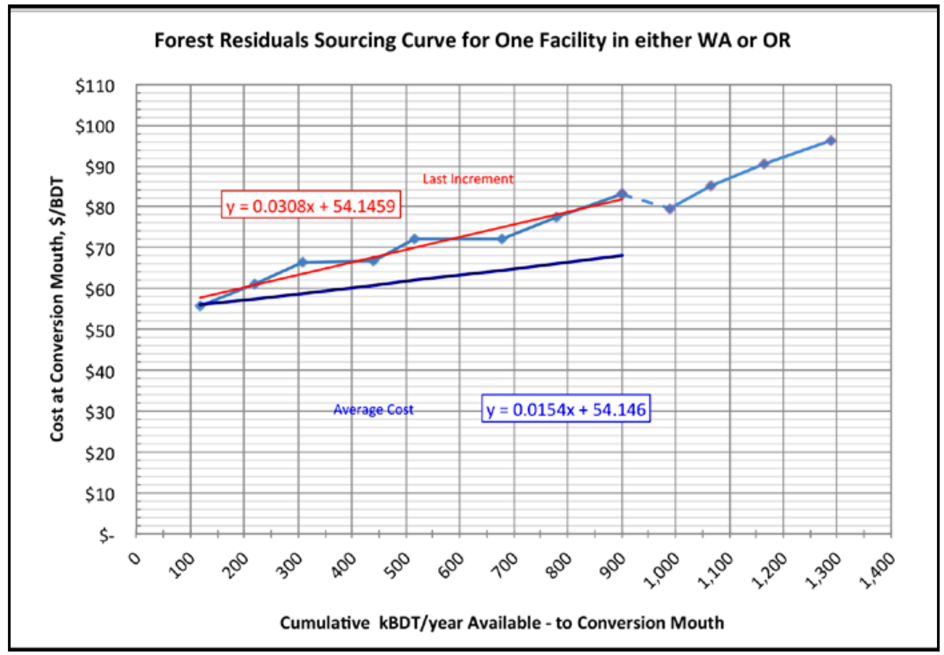

Figure TEA-2.2. Incremental and average delivered FHR feedstock curves for western WA or OR highest-feedstock county blocks.

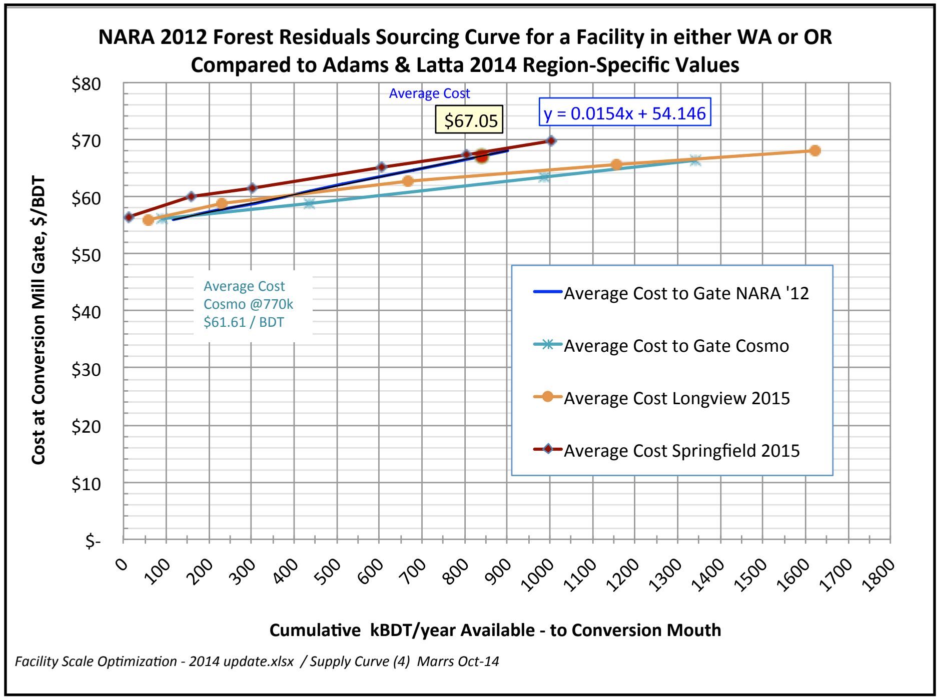

Figure TEA-2.3. Forest harvest residuals sourcing curves for various regions and demand levels.

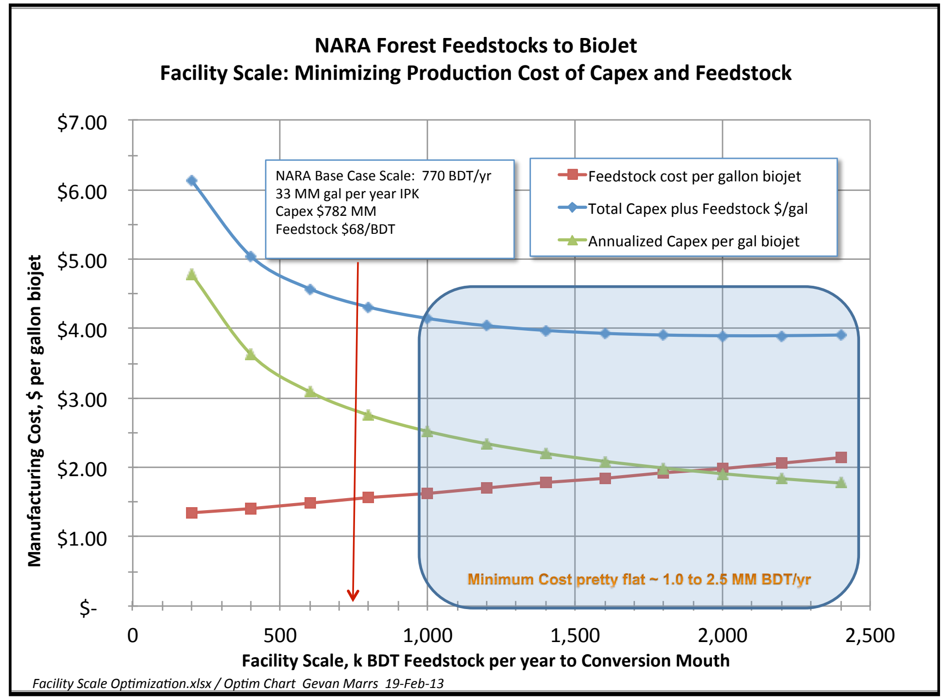

Figure TEA-2.4. Tradeoff of economy of scale for annualized capital investment against rising feedstock cost as scale of facility changes.

In this early stage, the NARA Base Case was assumed to be (like NREL TEAs (Humbird, 2011)) 2,000 BDMT/operating day, or 2,205 BDST/day, (which equates to 770,000 BDST / year) to conversion mouth. The initial capital (TIC) estimate for a facility without co-products was $782 MM total installed capital. Using a 0.6 exponent for the scaling factor and a 42.7 gal IPK/BDST feedstock yield, both the feedstock and capital (after annualizing the TCI assuming a 11.8% annual capital recovery factory) were expressed on a $/gal IPK. The sum of these two gives the tradeoff of declining annualized TCI per fuel gallon against increasing operating cost (just feedstock) is as shown in Figure TEA-2.4. Note that these costs are not the total manufacturing costs as there are many other operating costs.

What this analysis shows is that a true optimum (inflection point where rising feedstock costs exceed rate of gain in economy of scale for larger facility) is not reached even at 2.5 MM BDST per year facility scale. Since most newer scale pulp mills (similar feedstock and plant complexity) are around 1 MM BDST/yr, and NREL BETO uses 770 k BDST/yr, we chose to be comparable to NREL rather than strictly optimized. At this scale the majority of the economy of scale effect has been achieved and there is relatively small gain in much larger scale. There is, however, a very significant dis-economy of scale, without significant gain in reduced feedstock costs, to be much lower than 770 k BDST/yr. Thus this has been the NARA Base Case IBR facility scale for the duration of the project.

Over the course of the NARA project, both the TIC and feedstock cost estimates were refined, with TIC in particular rising considerably as capital for added lignin co-products manufacturing was added. However, since the same economy of scale exponent is assumed (0.6), the shape of the annualized TCI curve shown in Figure TEA-2.4 does not change—only the position. For feedstock cost, considerably increasing the complexity and specificity of the analysis (e.g., considering actual regional mill location, road network and timber harvest sites distances to mill, competitive pressures from existing forest products facilities, etc.) did not have a large impact on the rate of change of average feedstock with scale. For example, the final NARA IBR TEA assumes a siting in the Longview, WA area. Figure TEA-2.5 shows the final feedstock sourcing curve (the "LURA" model curve with added $9/BDST stumpage cost), specifically for Longview. Note that this model indicates a non-linear increase in cost at the low end of the sourcing curve. This means that there is additional favorable feedstock cost gain on the low scale of the facility size. If extended out past the total shown, it is likely that there is an accelerated increase in average cost on the high end of the supply curve (although this data was not estimated).

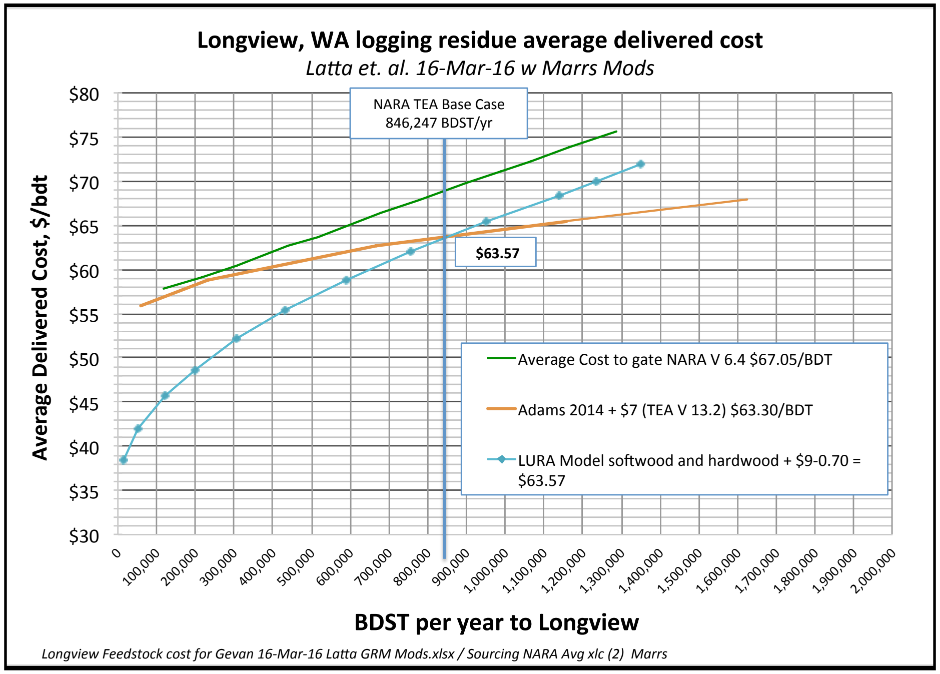

Figure TEA-2.5. March 2016 sourcing curve for NARA TEA using Longview region and LURA model.

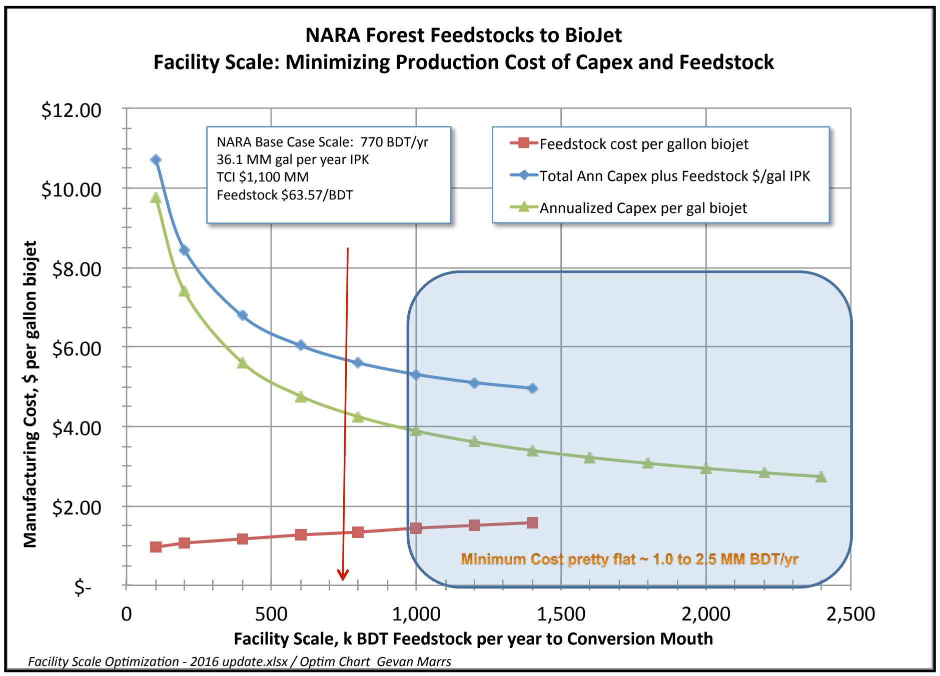

Figure TEA-2.6. Facility scale optimization with March 2016 data.

The facility scale optimization curves were recalculated with this non-linear supply curve data for Longview (March 2016), as well as updated 2016 values for; TIC ($1,100 MM); CRF (14%), and IPK yield (46.4 gal IPK/BDST feedstock). This updated optimization is shown in Figure TEA-2.6.

Again, it is worth noting that the annualized capital cost per gallon of IPK shown in Figure TEA-2.6 includes all capital for co-products as well as IPK, all shown allocated against IPK production, thus it does not portray IPK manufacturing costs—just the relative facility capital cost contribution compared to feedstock, thus the sum still correctly portrays the rate of change with facility scale. We conclude that there is not enough change in optimum facility scale with these new data to warrant changing the base case facility size from that commonly used in the biofuels TEA literature: 2,200 BDST/day or 770k BDST feedstock/yr.

2.2 Feedstock Composition

A range of feedstock types and sources with the spectrum of softwood forest residuals from the PNW were sampled and characterized, and based upon demonstrated suitability for conversion, as well as availability. A feedstock designated at FS-10 was selected as the material to use for the bulk of the laboratory conversion work, which forms the underpinnings of the yield assumptions, which largely influence economics.

The source of FS-10 was a private industrial timberlands tract being managed for softwood timber production (specifically, Douglas-fir) in Lane County, OR. The feedstock prepared for the NARA project was the residual materials left on the site following the commercial timber harvest. The key feedstock characteristics for FS-10 are shown in Tables TEA-2.4 through to Table TEA-2.9.

Table TEA-2.4. Accumulation of delivered feedstock costs for varying sources and hauling distances in WA and OR highest feedstock density counties.

Black Clawson gyratory screen FS-10			
First Screening As-received			
Accepts lbs	Overs + 1 3/4" lbs	Fines -1/8" lbs	Total Wt. lbs
14,630	1,743	1,339	17712
82.6%	9.8%	7.56%	100.0%
Re-screening of re-sized Oversize			
Resized overs/gyratory screen			
Accepts lbs	Overs + 1 3/4" lbs	Fines -1/8" lbs	Total Wt. lbs
1,431	4	252	1687
84.8%	0.2%	14.9%	100.0%
Combined Results			
Accepts	Overs + 1 3/4"	Fines -1/8"	Total Wt.
16,061	4	1,591	17,652
91.0%	0.0%	9.0%	100.0%

Table TEA-2.5. Laboratory moisture content, particle size classification and bark content of gyratory screen accepts.

FS-10	Moisture Content, wet basis	Classification Percentages, Dry Weight Basis									Bark Content
Sample	% MC	64mm	32mm	16mm	8mm	4mm	+2mm	+1mm	+0.50mm	-0.50mm	% Bark
1	44.0%	0.0%	4.1%	26.3%	33.3%	27.4%	6.6%	2.1%	0.09%	0.15%	3.39%
2	43.3%	0.0%	5.9%	24.2%	36.9%	25.7%	5.7%	1.4%	0.15%	0.15%	3.08%
3	44.3%	0.0%	2.9%	22.4%	35.1%	29.5%	7.4%	2.3%	0.17%	0.11%	3.37%
4	43.4%	0.0%	0.0%	27.5%	36.4%	27.6%	6.3%	1.8%	0.21%	0.15%	3.65%
5	44.4%	0.5%	1.2%	17.4%	35.1%	31.8%	10.9%	2.8%	0.18%	0.20%	4.13%
6	44.4%	0.5%	1.5%	16.5%	38.6%	30.6%	9.3%	2.6%	0.18%	0.20%	2.56%
7	43.4%	0.6%	3.7%	18.6%	36.1%	27.9%	9.9%	2.7%	0.25%	0.18%	3.85%
8	43.7%	0.0%	2.2%	20.5%	34.2%	30.2%	9.8%	2.7%	0.20%	0.22%	3.22%
Average	**43.9%**	**0.2%**	**2.7%**	**21.7%**	**35.7%**	**28.8%**	**8.2%**	**2.3%**	**0.2%**	**0.2%**	**3.4%**
Std Dev	***0.5%***	***0.3%***	***1.9%***	***4.1%***	***1.7%***	***2.0%***	***2.0%***	***0.5%***	***0.0%***	***0.0%***	***0.5%***

Table TEA-2.6. Chemical composition of Accepts and screen Fines – sugar polymers.

Report

NARA - FS-10

Sugar Analysis-Polymers

Client ID:	Lab ID:	PERCENT ARABINAN	PERCENT GALACTAN	PERCENT GLUCAN	PERCENT XYLAN	PERCENT MANNAN	TOTAL
FS-10 Accepts #1	13-0255-001	1.15	2.84	39.6	5.15	11.2	59.94
FS-10 Accepts #2	13-0255-002	1.15	2.84	39.8	5.14	11.3	60.23
FS-10 Accepts #3	13-0255-003	1.17	2.85	39.6	5.29	11.2	60.11
Average		**1.16**	**2.84**	**39.67**	**5.19**	**11.23**	**60.09**
FS-10 Fines #1	13-0255-004	1.41	2.83	33.6	4.23	9.09	51.16
FS-10 Fines #2	13-0255-005	1.46	2.83	32.6	4.18	8.89	49.96
FS-10 Fines #3	13-0255-006	1.45	2.85	32.9	4.25	9.24	50.69
Average		**1.44**	**2.84**	**33.03**	**4.22**	**9.07**	**50.60**

Table TEA-2.7. Chemical composition of Accepts and screen Fines – extractives and lignin.

Weyerhaeuser Analytical and Testing Services
32901 Weyerhaeuser Way South
Federal Way, Washington 98003

Service Request 13-0255

Report

NARA - FS-10

Sample Designation	Analytical Lab Code	Alcohol Extractives (Wt %)	Alcohol-Benzene Extractives (Wt %)	Klason Lignin (Wt %)	Acid-Soluble Lignin (Wt %)	H_2O Extractives (Wt %)
FS-10 Accepts #1	001	2.14	1.80	27.4	0.45	3.75
FS-10 Accepts #2	002	2.17	1.82	27.7	0.44	3.04
FS-10 Accepts #3	003	2.12	1.82	27.5	0.42	3.31
Average		**2.14**	**1.81**	**27.53**	**0.44**	**3.37**
FS-10 Fines #1	004	4.36	3.74	32.2	0.57	4.32
FS-10 Fines #2	005	4.32	3.90	32.3	0.56	4.06
FS-10 Fines #3	006	4.30	3.75	32.2	0.55	4.64
Average		**4.33**	**3.80**	**32.23**	**0.56**	**4.34**
	Date Analyzed:	3/6/13	2/27/13	3/1/13	3/7/13	3/11/13
	Analyst:	KH	KH	KH	KH	KH
	Method used:	AM-T 204	AM-T 204	AM T-222M	AM W-1301-5	calculation

Results reported on O.D. unextracted basis.

Table TEA-2.8. Chemical composition of Accepts and screen Fines – ash content.

Weyerhaeuser Analytical & Testing Services
32901 Weyerhaeuser Way South
Federal Way, WA 98001

Service Request 13-0255

Report

NARA - FS-10

Client ID	Lab ID	600° C Ash % O.D. Basis
FS-10 Accepts #1	001	0.44
FS-10 Accepts #2	002	0.44
FS-10 Accepts #3	003	0.44
Average		**0.44**
FS-10 Fines #1	004	1.91
FS-10 Fines #2	005	2.00
FS-10 Fines #3	006	2.01
Average		**1.97**

Table TEA-2.9. Species identification (from microscopic fiber analysis)

Microstructure test method MM I-9184M

SR# 13-0255

NARA – FS-10

weight %

	Douglas fir	Hemlock	Cedar	Pine	Spruce	Balsam fir	Hardwood
001 FS-10 Accepts #1	64	15	1	1 lodgepole/ ponderosa	3	1	15 maple

Notable items in the feedstock characterization are:

- Mill simulated screening of Fines downgrades about 9% of an FHR feedstock like FS-10 to energy content value (assumed to be $45/BDST), however this is likely warranted because Fines have:
    - Lower polysaccharides to contribute to IPK production
    - Higher ash content, likely to be some issue in production
- This feedstock (FS-10) had considerable hardwood (15%), which is probably typical in softwood timber stand harvest residuals and was not an issue in conversion to IPK.
- The bark content of 3.5% was no issue in biofuels conversion steps.

Note that the acceptability of both hardwood and bark in this feedstock, both of which are likely very unacceptable in softwood-based pulp and paper operations, is why FHR are a cost-effective feedstock at scale for biofuels—they do not compete as a pulp and paper feedstock (except as a relatively lower value energy source).

2.3 Design Report Conventions

2.3.1 Units

In the present report, certain quantities (e.g., yields and costs) are computed and reported in terms of "tons." To avoid ambiguity, tonne will denote a metric tonne (1,000 kg) and ton will denote a short or U.S. ton (2,000 lb). In general, the U.S. ton is the standard for this document. For feedstock, frequently expressed on a dry weight basis, the units will be "Bone Dry Short Tons", or BDST.

3) Process Design and Cost Estimation Details

Design and cost details are provided below for each department. The capital costs ("Capex") for equipment were taken from vendor quotes where possible, or other TEA efforts.

3.1 Major Operating Costs and Sources

A summary of the operating costs common to many departments are based upon prices for a few key items. These are listed in Tables TEA-3.1 through TEA-3.3.

Table TEA-3.1. Key operating cost values used in various departments.

Cost Item	Value Used and Units	Source
FHR Feedstock	$61.55/BDST delivered[2]	Longview, WA area - *Latta and Marrs 2016 Longview: Latta, G. & Marrs, G. Personal communication, June16, 2016: Longview FHR cost for Gevan - update 13-Jun-16.xlsx / Jun-16 Update*
Hog Fuel	$45/BDST delivered	Western Washington 2008-2010 Forest Residuals Biomass Delivered Prices - *Wood Resources International LLC* (TEA-1.8). http://woodprices.com/wp-content/uploads/2015/01/NAWFR-SAMPLE.pdf
Electricity	$43.2 / MWhr	Washington average 2014 Industrial, http://www.eia.gov/electricity/sales_revenue_price/pdf/table5_c.pdf
Natural Gas	$8.3/ MM Btu	US EIA, Washington Industrial Nat Gas rates, 2012-2016: https://www.eia.gov/dnav/ng/hist/n3035wa3m.htm
Highway Diesel Fuel	$3.54/gal	EIA Projections of highway diesel price for 2016 through 2040: http://www.eia.gov/beta/aeo/#/?id=3-AEO2015&region=1-0&cases=ref2015&start=2012&end=2040&f=A&linechart=~3-AEO2015.29.~~3-
Off-Road Diesel Fuel	$2.92/gal	Off-road obtained by subtracting average of WA and OR highway fuel surcharge: EIA Federal and State Fuel (gasoline and diesel) surcharges https://www.eia.gov/petroleum/gasdiesel/

[2] See Feedstock operating cost update later in this report Section 3.3.3. A Dec-2016 update revised the "final" FHR cost to $61.55/BDST.

Table TEA-3.2. Bulk chemicals price assumptions.

Bulk Chemicals		Historical bulk prices from ICIS, using rounded values slightly lower than the low end of ranges shown assuming our large quantities would enable favorable prices: http://www.icis.com/chemicals/channel-info-chemicals-a-z/
Calcium Carbonate $CaCO_3$	$50/short ton	$CaCO_3$ $60 - $66 / short ton
Sulfur	$200/short ton	Sulfur $224 - $403 / short ton
Caustic (Sodium Hydroxide) NaOH	$500/short ton	Caustic Soda $495 - $822 / short ton
Lime (CaOH)	$180/short ton	Hydrated Lime, bulk $65 - $74 / short ton
Ammonia	$0.40/lb ($800 / short ton)	f.o.b. New Orleans $386 - $772 / short ton
Sulfur Dioxide (SO_2)	$0.10/lb ($200 / short ton)	$230 / short ton

Table TEA-3.3. Enzyme production nutrients price assumptions

Corn Steep Liquor (CSL)	$0.10/lb ($200 / short ton)	(Anderson, 2009)
Glucose (dry weight basis)	$0.3394/lb dry wt glucose, or $678.8/ short ton	USDA Economic Research Service Sugar and Sweeteners Yearbook Tables, Table 07, wholesale glucose syrup dry weight basis to West Coast in rail cars, 2015 average. http://www.ers.usda.gov/data-products/sugar-and-sweeteners-yearbook-tables.aspx

3.2 Operating Cost Assumptions Details

3.2.1 Forest Harvest Residuals Feedstock

The cost details for feedstock have been given previously in this report in the facility scale optimization section.

3.2.2 Hog Fuel

Figure TEA-3.1 shows example trends of delivered prices for "forest woody biomass" (our FHR) for 2008-2010 period, with an approximate average of $45/BDST. As "mill residues" are already being consumed, our assumption is that new large supplies would come at the higher incremental cost of forest biomass, i.e., about $45/BDST delivered (or competition would drive up cost of mill residues to that alternative level).

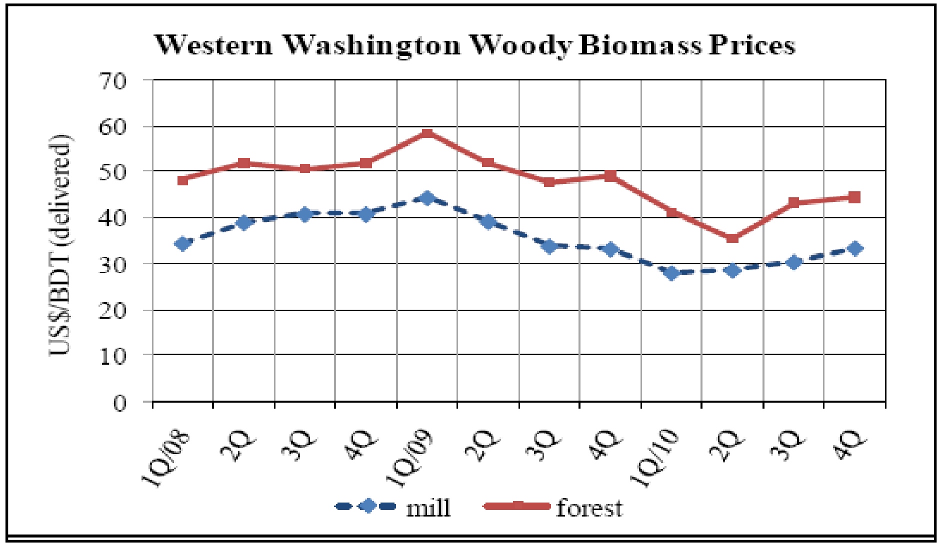

Figure TEA-3.1. Historical hog fuel prices for mill residues and forest harvest residuals. Reprinted from North American Wood Fiber Review (p. 23) by Wood Resources International LLC. (2011). Retrieved from http://woodprices.com/wp-content/uploads/2015/01/NAWFR-SAMPLE.pdf

3.2.3 Electricity

The rate used is from EIA for Washington Industrial rate for 2014, and is 4.32 cents/kWh, or $43.2/MWh. Future commercial electrical rate projections are for no significant increase or decrease (Figure TEA-3.2), thus this recent historical value is used for the entire 30-year project life.

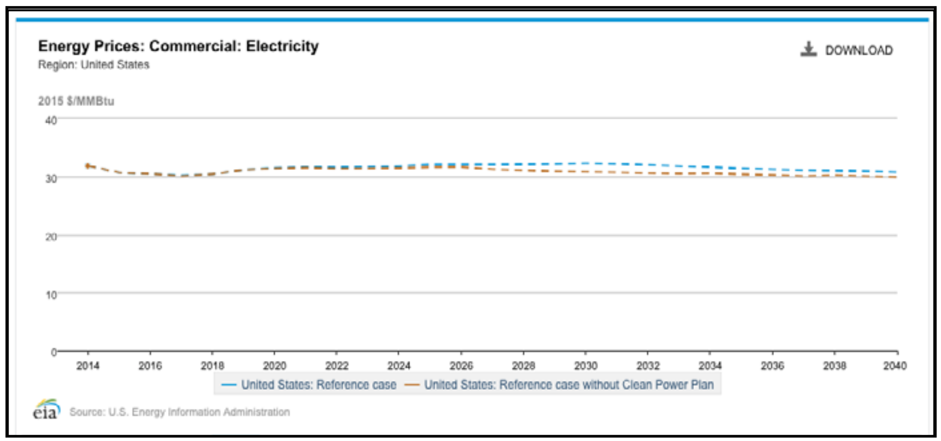

Figure TEA-3.2. Commercial energy prices in the U.S (source EIA). Retrieved from http://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2016&region=1-0&cases=ref2016~ref_no_cpp&start=2013&end=2040&f=A&linechart=~~~~~~ref2016-d032416a.13-3-AEO2016.1-0~ref_no_cpp-d032316a.13-3-AEO2016.1-0&map=ref_no_cpp-d032316a.3-3-AEO2016.1-0&sourcekey=1 8-Dec-16.

3.2.4 Natural Gas

Historical data Washington state industrial natural gas rates ($/thousand cubic feet) for Jan-2012 through Mar-2016 was taken from EIA data (Figure TEA-3.3).

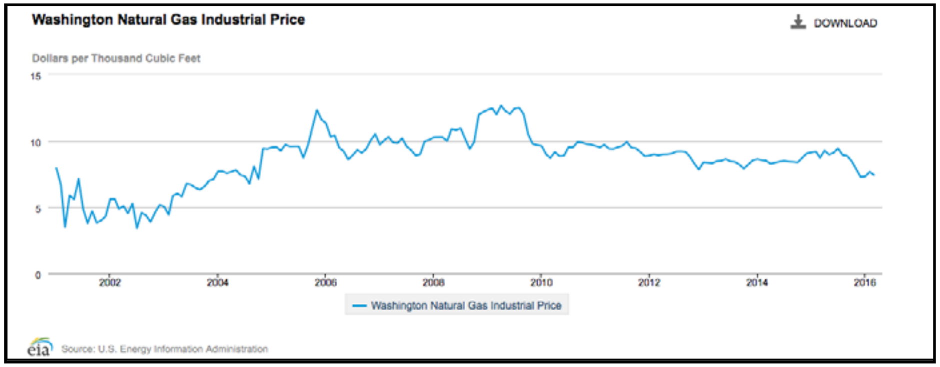

Figure TEA-3.3. Historical industrial natural gas prices in Washington. The average of the time period of Jan-2012 to Mar-2016 was used ($8.56 / MM Btu). Data retrieved from https://www.eia.gov/dnav/ng/hist/n3035wa3m.htm

The EIA projections for future industrial natural gas prices were relatively constant (Figure TEA-3.4) so constant values were assumed based upon recent history.

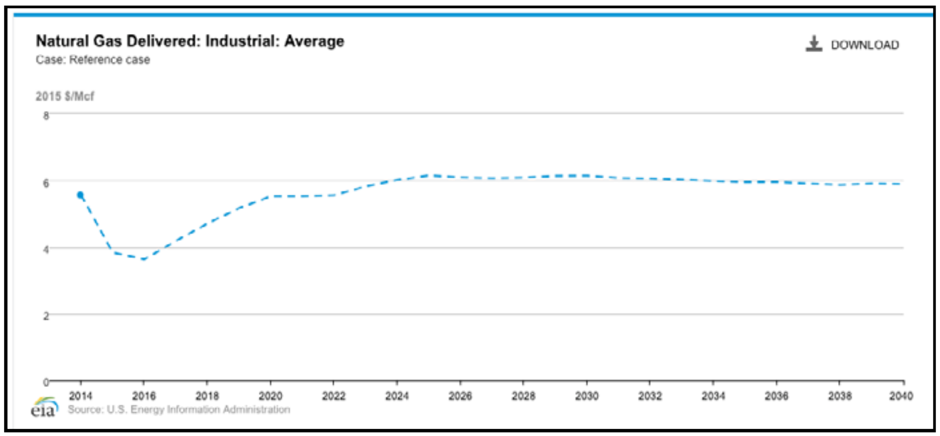

Figure TEA-3.4. Projected US industrial prices for natural gas (source EIA) http://www.eia.gov/outlooks/aeo/data/browser/#/?id=78-AEO2016&region=0-0&cases=ref2016~ref_no_cpp&start=2013&end=2040&f=A&linechart=~~~~~~ref2016-d032416a.24-78-AEO2016&ctype=linechart&sourcekey=1

The WA prices shown in Figure TEA-3.3 in $/Mcf were converted per EIA formula (obtained at https://www.eia.gov/tools/faqs/faq.cfm?id=45&t=8): $ 8.56 per Mcf divided by 1.032 = $ per MMBtu. The resulting natural gas price used was $8.3/MMBtu.

3.2.5 Diesel Fuel

Diesel fuel is used primarily in transporting ground FHR from woods sites to the IBR by tractor-trailer rigs. The assumed price for highway diesel used in the TEA was based upon the 2016 to 2040 EIA price projections, which were linearly extrapolated to 2047 to achieve the 30-year project life. This escalating 30-year value was then equated to a single present value (PV) with a 10% discount rate (same as assumed in the DCF-ROI calculations). This results in a value for highway diesel of $3.54/gal.

Considerable diesel fuel is also used in the accumulation, loading, and grinding of FHR in the woods. This diesel does not have the highway surcharges added, which have both a Federal and varying state value. EIA data for total state and federal surcharge for WA and OR was averaged and this value ($0.62/gal diesel) was subtracted from the highway diesel price to get a price of $2.92/gal off-road diesel.

Note that these diesel fuel costs are built into the FHR delivered cost as the harvesting operations occur outside the IBR gate and are passed along to the IBR in feedstock cost.

3.3 Department 1: Feedstock Receipt, Storage and Handling and Preparation

3.3.1 Overview

All feedstocks to the NARA base case are assumed to be forest harvest residuals that are ground to "chips" in the forest, loaded into chip vans, conveyed to the conversion mill site and stored there in outdoor piles to give a supply buffer to the continuous conversion process. Some on-site feedstock preparation occurs by sizing the feedstock, and there is a small short-term storage of prepared feedstock to buffer the conversion digester against screen room or chip reclaim outages. In the NARA base case (Greenfield IBR) there are no other softwood feedstocks considered (for example, construction and demolition waste), and no other chip delivery methods used (like rail or barge), and other than size, no other adjustments to the feedstock (no moisture adjustment, etc.). While any of these could possibly occur in specific facility situations, for the broad general base case they are excluded from consideration and only the "most likely" situation is evaluated. Figure TEA-3.5 gives an overview of the process flow and some key measures / capacities / rates.

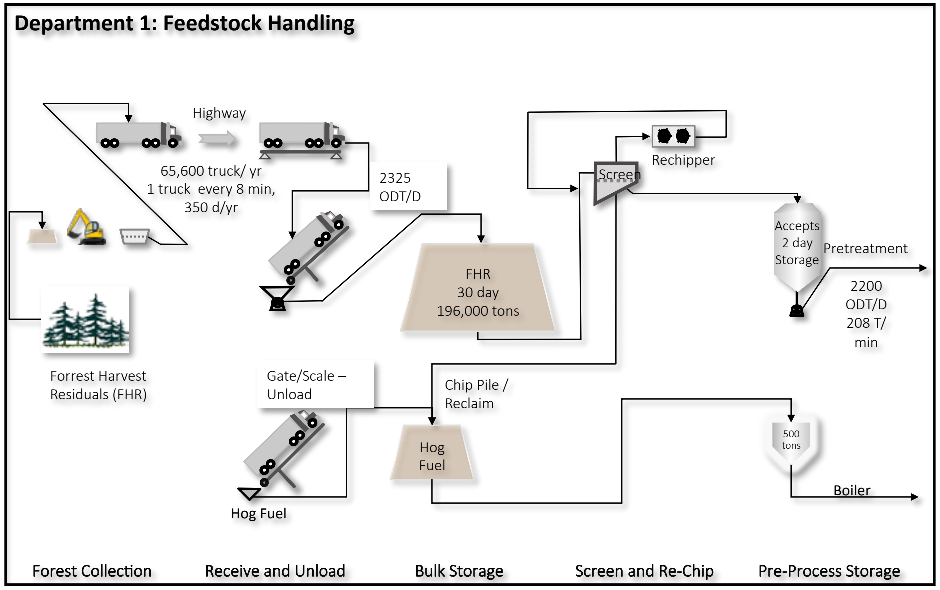

Figure TEA-3.5. Forest harvest residuals receipt, storage, preparation and delivery to conversion.

3.3.2 Design Basis

Department 1, Feedstock Handling, receives woods-ground forest harvest residual "chips". The material is ground at the woods residuals location in a horizontal drum grinder and loaded directly into chip vans (see Figure TEA-3.6). The vans are then transported by highway tractor-trailer chip vans to the conversion mill site. After passing over a truck scale at the mill site to obtain delivered weight, they are dumped on one of a number of tip-up truck dumps and conveyed to one of two circular outstock and reclaim chip storage piles (Figure TEA-3.7). After reclaim they pass through a chip size sorting (screening) process where the oversize material (retained on a screen with 1.75 inch round holes) is removed and sent to a hammer hog for re-sizing to smaller particles. This resized flow is then recycled again to the screens. The screen fines material—that is, material passing a 1/8-inch woven wire mesh—is transferred to the hog fuel system for later combustion in the biomass boiler. All remaining material—the screen accepts—are conveyed to a short-term storage surge bin ahead of the feed to the pretreatment digester.

3.3.3 Feedstock Handling Area Cost Estimation

Operating Expense (Opex)

The assumption used is that the feedstocks are prepared and delivered by third-party contractors who cover all costs to obtain and prepare and deliver the feedstock (as well as an operating profit in order to stay in business), with a single

Figure TEA-3.6. Typical PNW Forest Harvest Residuals woods grinding – western Oregon.

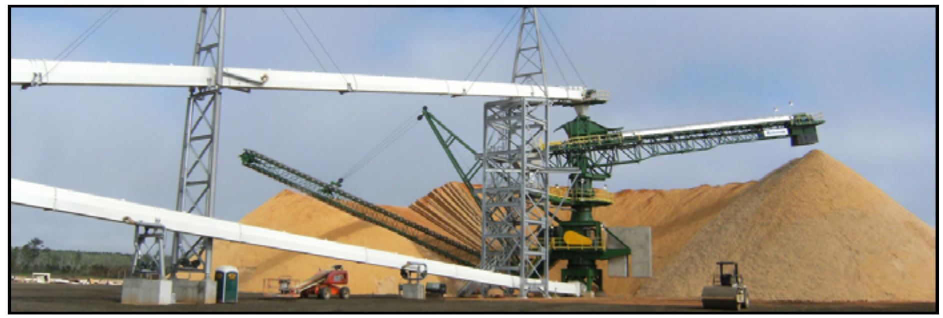

Figure TEA-3.7. Circular chip outstock and reclaim storage systems.

payment by the IBR per ton of delivered feedstock to cover those costs. Since there is not an existing FHR supply infrastructure existing at the scale needed for the NARA IBR, there is no market pricing data for delivered cost at that scale. Accordingly, the NARA project team members generated likely cost curves by building up component cost estimates from various sources. The delivered feedstock cost to the conversion mill gate for the NARA base case was originally estimated from available data at $68/BDST (Marrs, Mulderig, Davio, and Burt (2016). The assumed costs for specific elements in the delivered feedstock cost were provided by John Sessions (Oregon State University) and were matched up with estimated tonnages of FHR available in each of those harvesting categories based upon sourcing to the Longview, WA area with linear interpolation to our base case scale of 846,000 BDST/yr. In June of 2016 the sourcing detail was expanded to six zone types and the categories redefined to hit precisely our annual target (so that no interpolation was needed). The June 2016 update average cost components for delivery of 846,000 BDST/yr to the Longview WA region is estimated at $62.60 / BDST. In December 2016 some errors in the annualized stumpage values were identified and corrected.

NARA Stumpage Cost Assumption for FHR

"Stumpage" is the traditional term used in the forestry industry for the payment to the owner of a timber crop—that is the price paid for the tree "on the stump". Using similar terminology, the "stumpage" for FHR is the payment to the owner of the timberlands. (In INL, terminology is as "access cost".)

The information used for generating feedstock "sourcing curves"—tons of forest harvest residual material that could be delivered to various sites at differing costs provided by Latta et. al. in the NARA team do not have a return-to-landowner (or "stumpage") cost included, as they have no rationale for developing it. One with considerable experience in actual current operations (John Sessions) feels that $6 to $7 /BDT might be a reasonable estimate, but this is derived from unpublished, personal communications, and is not readily attributable to any particular source.

In order to develop a credible rationale for stumpage cost over the 30-year NARA IBR project life, we will use an approach similar to that for other important costs (like petroleum jet fuel price assumptions, diesel price assumptions, etc.) whereby a citable, (hopefully) credible published source makes projections about possible future price trends. If these are not constant values, then the 30-year pattern is to be "levelized" (at the 10% discount rate used in the DCF/ROI of the NARA TEA) such that we can speak of a single economically equivalent value for the project life.

The DOE BETO MYPP NREL TEAs have (virtually) all, for many years, used INL "Uniform Feedstock Supply" assumptions and values for feedstock costs. For example, the INL 2014 Uniform Feedstock for multiple pathways (Idaho National Laboratory, 2014) backs out what is now called an "access cost" (to distinguish from "grower payment" terminology used previously). This comes from subtracting INL chipping cost estimates from Billion Ton Study Update "farmgate" costs, which are the total of collection and chipping at roadside.

This INL report calculates a $26/BDT "access cost" for FHR. This seems way too high – maybe it includes "collection costs" too—it's not clear to me what the "farmgate" concept is for forest residuals harvesting. The other souce deemed generally credible is the "Billion Ton Study". Going back to BTS update (U.S Department of Energy (2011)). In that they state that:

"For privately owned timberland, stumpage price is assumed to begin at $4 per dry ton and increase to 90% of the pulpwood stumpage price when 100% of the available logging residue is used."

- The stumpage prices for pulpwood are based upon Timber Mart historical prices, and run about $20/BDT. Thus at high FHR demand the BTS assumes $18/BDT stumpage for FHR.
- We could use a ramped stumpage cost assumption over time, starting at $4 and increasing to $18 at the end of the 30-year project in the actual NARA TEA DCF/ROI spreadsheet.
- However, it is easier to lay out the ramped cost, discount it at 10% to a PV, calculate a level payment (PMT) for 30 years of equal annual payment to just use up that PV.
    - This is shown in Table TEA-3.4.
    - Note that due to the Excel PMT function convention, we use the version where the first payout is at the start of the first period, not the end.
    - This is because we don't need the PV until we are ready to make the first payment, not a year ahead of that.
    - This results in an "average" (PV of 30-year start-of-period ramped value discounted at 10%) TEA stumpage of $7.95 / BDST.

This levelized approach, in words, takes the stance to make annual feedstock payments in the middle of each project year for the entire year's feedstock (so that the capital carrying costs of feedstock seller's deliveries ahead of payment and the capital carrying cost of the buyer in the second half, ahead of receipt, are balanced). In practice, the payments are typically made at least monthly, if not bi-weekly, but for our analysis an annual basis will be sufficiently close. We don't need to commit (or borrow) the entire PV amount until the "day before" we need to make the first payment in the middle of year 1, then we make one payment at the middle of the remaining project life, finishing with the 30th payment in the middle of the last project year.

Table TEA-3.4 shows the details of the annual payments[3] with verification that either paying the ramped prices or the levelized prices just exactly consumes the initial amount after 30 years when the balance each year earns 10%.

[3] The labels in the spreadsheet describe a convention where the first annual payment is made at the end of the first year, rather than the middle, however, economically it is identical to the case described above where mid-year payments are made.

Table TEA-3.4. NARA levelized stumpage cost

NARA Levelized Stumpage Costs
Discounted ramped stumpage price.xlsx / by columns
24-Nov-16 Gevan Marrs

			Present Value EOY #1	$7.95	Check Ramped Payments	Check	
	$74.92		$ 82.4087	Start of year	Balance in account end of year	Level Payment	EOY Balance
	$/BDT	Check Increment	Discounted at 10%	$74.9170	$ 82.4087	$7.95	$82.41
1	$ 4.00		$ 4.00	$ 82.4087	$ 78.41	$7.95	$74.46
2	$ 4.48	$ 0.4828	$ 4.08	$ 78.4087	$ 81.77	$7.95	$73.96
3	$ 4.97	$ 0.4828	$ 4.10	$ 81.7669	$ 84.98	$7.95	$73.41
4	$ 5.45	$ 0.4828	$ 4.09	$ 84.9780	$ 88.03	$7.95	$72.80
5	$ 5.93	$ 0.4828	$ 4.05	$ 88.0276	$ 90.90	$7.95	$72.14
6	$ 6.41	$ 0.4828	$ 3.98	$ 90.8993	$ 93.58	$7.95	$71.40
7	$ 6.90	$ 0.4828	$ 3.89	$ 93.5754	$ 96.04	$7.95	$70.60
8	$ 7.38	$ 0.4828	$ 3.79	$ 96.0364	$ 98.26	$7.95	$69.71
9	$ 7.86	$ 0.4828	$ 3.67	$ 98.2607	$ 100.22	$7.95	$68.73
10	$ 8.34	$ 0.4828	$ 3.54	$100.2247	$ 101.90	$7.95	$67.66
11	$ 8.83	$ 0.4828	$ 3.40	$101.9024	$ 103.27	$7.95	$66.48
12	$ 9.31	$ 0.4828	$ 3.26	$103.2650	$ 104.28	$7.95	$65.18
13	$ 9.79	$ 0.4828	$ 3.12	$104.2812	$ 104.92	$7.95	$63.75
14	$ 10.28	$ 0.4828	$ 2.98	$104.9162	$ 105.13	$7.95	$62.18
15	$ 10.76	$ 0.4828	$ 2.83	$105.1320	$ 104.89	$7.95	$60.45
16	$ 11.24	$ 0.4828	$ 2.69	$104.8865	$ 104.13	$7.95	$58.54
17	$ 11.72	$ 0.4828	$ 2.55	$104.1338	$ 102.82	$7.95	$56.45
18	$ 12.21	$ 0.4828	$ 2.42	$102.8231	$ 100.90	$7.95	$54.15
19	$ 12.69	$ 0.4828	$ 2.28	$100.8985	$ 98.30	$7.95	$51.62
20	$ 13.17	$ 0.4828	$ 2.15	$ 98.2987	$ 94.96	$7.95	$48.83
21	$ 13.66	$ 0.4828	$ 2.03	$ 94.9561	$ 90.80	$7.95	$45.77
22	$ 14.14	$ 0.4828	$ 1.91	$ 90.7966	$ 85.74	$7.95	$42.40
23	$ 14.62	$ 0.4828	$ 1.80	$ 85.7383	$ 79.69	$7.95	$38.69
24	$ 15.10	$ 0.4828	$ 1.69	$ 79.6914	$ 72.56	$7.95	$34.61
25	$ 15.59	$ 0.4828	$ 1.58	$ 72.5571	$ 64.23	$7.95	$30.13
26	$ 16.07	$ 0.4828	$ 1.48	$ 64.2266	$ 54.58	$7.95	$25.19
27	$ 16.55	$ 0.4828	$ 1.39	$ 54.5803	$ 43.49	$7.95	$19.76
28	$ 17.03	$ 0.4828	$ 1.30	$ 43.4866	$ 30.80	$7.95	$13.79
29	$ 17.52	$ 0.4828	$ 1.21	$ 30.8008	$ 16.36	$7.95	$7.22
30	$ 18.00	$ 0.4828	$ 1.13	$ 16.3636	-$ 0.00	$7.95	$0.00

Total Delivered Feedstock Costs

Tables TEA-3.5-TEA-3.9 show the tons available, cost components and hauling distances for forest harvest residuals supplied to a Longview WA. Table TEA-3.10 shows the feedstock delivered cost components for the NARA Base Case 846,000 BDST/yr to Longview, WA (the calculations were done in Table TEA-3.5)

This FHR price is the final value used in TEA Version 13.50.

Table TEA-3.5. Softwood forest harvest residuals annual supply estimates for varying marginal cost categories and harvest site types.

Logging Residue Supply to Longview Tons — *Longview FHR cost for Gevan - update 13-Jun-16.xlsx / Jun-16 Update*

		Marginal Cost Category				
		$ 66.00	$ 66.16	$ 66.17	$ 66.20	$ 66.25
Logging Zone	Description	BDS tons per year				
G1	Ground System <150' from Landing	118,862	119,674	119,674	119,674	119,674
G2	Ground System 150 - 300' from Landing	85,585	88,852	88,852	88,852	88,852
G3	Ground System >300' from Landing	176,024	179,070	179,070	184,219	184,611
GL	Ground System at Landing	279,442	284,180	285,725	286,569	286,993
Cable	Cable System Swing Bin	94,557	96,908	96,908	96,908	97,780
CableL	Cable System no Rebin	68,744	69,882	69,882	70,127	70,127
Total		**823,214**	**838,565**	**840,109**	**846,348**	**848,036**

Table TEA-3.6. Average cost of residue to Longview WA at varying annual scales.

Average Total Cost of Logging Residue Supply to Longview Tons (without any stumpage)

		Marginal Cost category				
		$ 66.00	$ 66.16	$ 66.17	$ 66.20	$ 66.25
Logging Zone	Description	$/bdt				
G1	Ground System <150' from Landing	$ 53.17	$ 53.25	$ 53.25	$ 53.25	$ 53.25
G2	Ground System 150 - 300' from Landing	$ 56.32	$ 56.68	$ 56.68	$ 56.68	$ 56.68
G3	Ground System >300' from Landing	$ 58.18	$ 58.31	$ 58.31	$ 58.53	$ 58.55
GL	Ground System at Landing	$ 48.95	$ 49.24	$ 49.33	$ 49.38	$ 49.40
Cable	Cable System Swing Bin	$ 57.75	$ 57.95	$ 57.95	$ 57.95	$ 58.03
CableL	Cable System no Rebin	$ 48.23	$ 48.52	$ 48.52	$ 48.58	$ 48.58
Total		**$ 53.25**	**$ 53.49**	**$ 53.51**	**$ 53.60**	**$ 53.63**

Table TEA-3.7. Hauling distances, total miles from harvest to mill gate by tonnage harvest type.

Average Haul Distance of Logging Residue Supply to Longview Tons

		Marginal Cost				
		$ 66.00	$ 66.16	$ 66.17	$ 66.20	$ 66.25
Logging Zone	Description	miles				
G1	Ground System <150' from Landing	62.0	62.2	62.2	62.2	62.2
G2	Ground System 150 - 300' from Landing	49.8	50.9	50.9	50.9	50.9
G3	Ground System >300' from Landing	39.7	40.1	40.1	40.8	40.9
GL	Ground System at Landing	80.4	81.3	81.6	81.7	81.8
Cable	Cable System Swing Bin	46.5	47.1	47.1	47.1	47.4
CableL	Cable System no Rebin	77.7	78.6	78.6	78.8	78.8
Weighted Ave		**61.7**	**62.4**	**62.5**	**62.6**	**62.7**

Table TEA-3.8. Average hauling costs for varying annual tonnages to Longview, WA.

Average Haul Cost of Logging Residue Supply to Longview Tons

		Marginal Cost				
		$ 66.00	$ 66.16	$ 66.17	$ 66.20	$ 66.25
Logging Zone	Description	$/bdt				
G1	Ground System <150' from Landing	$ 19.37	$ 19.45	$ 19.45	$ 19.45	$ 19.45
G2	Ground System 150 - 300' from Landing	$ 15.52	$ 15.88	$ 15.88	$ 15.88	$ 15.88
G3	Ground System >300' from Landing	$ 12.38	$ 12.51	$ 12.51	$ 12.73	$ 12.75
GL	Ground System at Landing	$ 25.15	$ 25.44	$ 25.53	$ 25.58	$ 25.60
Cable	Cable System Swing Bin	$ 14.45	$ 14.65	$ 14.65	$ 14.65	$ 14.73
CableL	Cable System no Rebin	$ 24.43	$ 24.72	$ 24.72	$ 24.78	$ 24.78
Total		**$ 19.29**	**$ 19.51**	**$ 19.55**	**$ 19.58**	**$ 19.60**

Table TEA-3.9. Harvesting cost components for woods harvesting steps – 846,000 BDST/yr to Longview, WA.

Cost and Zone Description Table - for 846,348 BDST/yr

			Cost Components				
		Piled	Move-in	Collection	Grind	Truck Wait	Total
Logging Zone with Description		--- % ---	$/bdt				
G1	Ground System <150' from Landing	67.2	$1.50	$ 10.00	$18.80	$ 3.50	$ 33.80
G2	Ground System 150 - 300' from Landing	67.2	$1.50	$ 17.00	$18.80	$ 3.50	$ 40.80
G3	Ground System >300' from Landing	67.2	$1.50	$ 22.00	$18.80	$ 3.50	$ 45.80
GL	Ground System at Landing	67.2	$1.50	$ -	$18.80	$ 3.50	$ 23.80
Cable	Cable System Swing Bin	46.5	$1.50	$ 19.50	$18.80	$ 3.50	$ 43.30
CableL	Cable System no Rebin	46.5	$1.50	$ -	$18.80	$ 3.50	$ 23.80
Weighted Average			$1.50	$ 10.22	$18.80	$ 3.50	$ 34.02

Table TEA-3.10. Feedstock delivered cost components for NARA Base Case 846,000 BDST/yr to Longview, WA. (December 2016 update.)

Average Feedstock Cost Components	
Longview Region at 846,000 BDT/yr	
	$/BDST
30-yr Average stumpage	$ 7.95
Average Move-in cost	$ 1.50
Average collection cost	$ 10.22
Average Grinding cost	$ 18.80
Average Truck Wait cost	$ 3.50
Average Hauling cost (63 mile average haul)	$ 19.58
Total Delivered Average cost	**$ 61.55**

In addition to the FHR feedstock for biofuel and lignin co-products, additional biomass is needed for energy production. This energy biomass ("hog fuel"), as noted in the Operating Costs section, was assumed to be $45/BDST hog fuel. Fines screened out in the sizing process are sent to the hog fuel system. As such they displace purchased hog fuel at the $45/BDST price.

There are some additional minor miscellaneous operating costs inside the plant associated with receipt, storage, reclaim and preparation as shown in Table TEA-3.11

Table TEA-3.11. Feedstock handling operating costs inside plant gate.

Department 1	Description of Cost	Per hour	units	per year	Cost/unit ($)	Cost/year ($MM)
Feedstock						
	Hog Fuel	30	bdt	252,000	$ 45.00	$ 11.34
	Feedstock	100.72	bdt	846,059	$ 62.60	$ 52.96
	Electricity	3.2	MWhr	26,880	$ 43.20	$ 1.16
	Miscellaneous (hyd oil, gloves, diesel, etc)	15.27	$/hr	8,400	n/a	$ 0.13
Feedstock	Department Total					$ 65.59

Capital Expense (Capex)

Feedstock Handling Capex Background

In 2012 when the effort began to construct a TEA for NARA, the NREL corn stover to ethanol model (Humbird et al., 2011) was readily available and was a good starting basis for the bulk of the model structure. The NREL model, however, assumed off-site preparation of corn stover (drying, sizing, storage) and on-demand delivery to the conversion site, thus they had virtually no feedstock handling Capex (just small scale receipt and short-term storage). The NARA greenfield conversion facility would have forest residuals harvested in the woods and delivered directly, so it will need considerable infrastructure to receive, store, reclaim, and prepare feedstocks for conversion. Sufficient on-site storage is required to buffer the 24/7/350 conversion operation from potential supply issues due to weather or other unavoidable interruptions to woods production or transport.

A search of publicly disclosed feedstock handling design and cost estimates was performed, but no detailed systems estimates were found. It was known that NARA member company Catchlight Energy (CLE) had commissioned a feedstock handling design from parent Weyerhaeuser Company (WY), specifically for a forest residual chips feedstock handling for a bio-fuels conversion facility. Since the estimates were all based upon vendor quotes for standard equipment, the equipment cost details were released to NARA for use in the TEA.

CLE / WY feedstock handling Design Criteria

CLE used NREL existing models for biofuels conversion estimates—which were scaled to 100 metric tons (MT) per hour, or 2,400 MT/day. This is 20% larger than the NARA base case consumption of 2,000 MT/day (2,204 BDST/day). However, since roughly 10% of the feedstock through the gate for the forest residuals is screened out as fines and sent to hog fuel, the NARA rate through the gate is only about 10% less than NREL, so no adjustments for scale were initially made, as the resolution of these estimates was considered far better than many other areas in the model, and this was a relatively small portion of the overall Capex. Accordingly the total CLE / WY Capex estimate was used at the scale as provided. Now that individual equipment costs have been disclosed, adjustments for scale have been included in the final NARA TEA model. The general feedstock handling layout and elements assumed for the CLE feedstock handling is shown in Figure TEA-3.8.

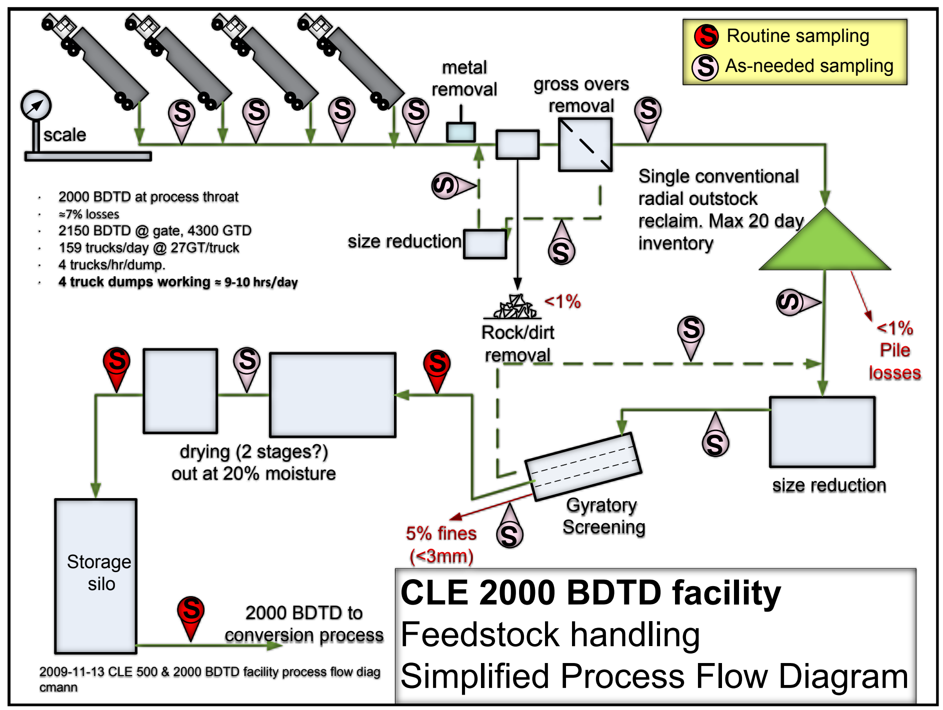

Figure TEA-3.8. Generalized feedstock handling system layout for CLE feedstock handling. Note that NARA system does not require feedstock drying, as did some other conversion types under consideration.

Table TEA-3.12 shows the specific design criteria used for the CLE / WY feedstock handling cost estimate. It is worthwhile noting that a key assumption driving overall feedstock handling design will be the assumptions about number of hours per week feedstock can be delivered and days of buffer inventory required on-site to avoid running out of feedstock during weather-related production outages. Since forest residuals are normally delivered “hot” upon production in the woods, and this is normally only done during daylight hours and often only 5 or 6 days per week, the rate during woods production hours has to be much greater than the 24/7 uniform reactor feed rate. Additionally, one must plan on weather-related outages where access to many or most of the forest sites is restricted – so inventory back-up and “catch-up” production rate factors are needed in the design.

Using either recent WY actual feedstock handling construction data or newly-acquired vendor quotes, a cost estimate was constructed for a system meeting the design criteria shown in Table TEA-3.11. Table TEA-3.13 shows the individual elements cost assumptions and installed total costs for each element and the overall system. This total installed feedstock handling system cost of $41.73 million in 2010 $ was increased by 5.25% to escalate into 2012 $. This final installed equipment cost value used in the NARA base case TEA was then **$56.52 MM**.

Note that the overwhelming capital cost element of feedstock handling is the 3 circular outstock/reclaim systems (O/R)—comprising $36.1 MM of the $56.52 MM total. The WY 2010 cost basis for this item was checked by verifying with BRUKS Rockwood staff (personal E-mail communication with Smith, D., 5/13/ 2015) for recent budget prices and was confirmed to be reasonable.

Table TEA-3.12. CLE feedstock handling for 2,400 bone dry metric ton per day design criteria adjusted to NARA 2,200 BDST/day capacity.

Catchlight Energy - Weyerhaeuser 2010 Woodyard Design Criteria			NARA 2000 BDMTPD (2200 BDSTPD) Wood Yard Design Criteria	
		WY	NARA (Gevan Marrs)	7-May-15
Item	**Units**	Linked Values	**Units**	**Values**
Average Pretreatment Consumption	BDMTPD	2400	BDSTPD	2,200
Moisture Content as Received	%	50%	%	45%
Production	DPY	350	DPY	350
	HPD	24	HPD	24
Plant available		96%		96%
Process Utilization	%	93%	%	93%
Overall utilization		89%	%	89%
Design increase		10%	%	10%
Design Supply to reactor	GMTPD	5,933	GSTPD	4,944
In feed conveyor	GMTPH	247	GSTPH	206
Chip Storage - Max Capacity	Days	21	Days	21
Tons in pile(s)	GMT	124,584	GST	103,820
Green lbs in piles	G#	274,583,730	G lbs	207,640,449
OD tons in piles, max				57,101
Bulk Density, Dry, in the pile		12.5	OD lbs/cu ft	11.0
Bulk Density, wet, in the pile	#/cu ft	25	G lbs/cu ft	20.00
Volume in pile	cu ft	10,983,349	cubic feet	10,382,022
Stacker reclaimer capacity, each	cu ft/unit	6,000,000	cu ft/unit	6,000,000
Number required	units	1.8	units	1.7
Receiving/Offloading	HPD	16	Hours per Day	16
	DPW	6	Days per Week	6
	HPW	96	Hours per week	96
Consumption:Receiving hours factor		1.75	mill hrs/dump hours	1.75
Inventory build capacity factor, assumed		1.5	build rate / avg rate	1.5
Peak day capacity factor, assumed		1.8	max hourly rate / avg rate	1.8
Avg usage	GMTPH	200	Average GSTPH	167
Factored Max rate dump usage	GMTPH	945	Max dump rate, GSTPH	788
Truck Deliveries				
Bulk Density in chip van	green #/cu ft	20	G lbs / cu ft	19.1
Chip Van capacity, size 2900 Cu Ft	MT	24.21	GST	25.47
Minutes/turn @ dump assumed	Min/truck	10		10
Dumper capacity - takeaway	MTPH	145.1	GST	159.9
Design offload capacity	% availability	95%	% available	95%
Dumper factored capacity	MTPH	137.8	Capacity per dump, GTPH	151.9
Van dumpers required	units	6.86		5.18
	say	7	Van dumpers needed	6
Hog Fuel System				
Annual Usage			BDST/yr	327,600
Screen fines to hog fuel			BDST/yr	76,400
Fines annual compared to chip usage			BDST HF / BDST FHR	9.1%
Total Hog Fuel compared to chip usage				38.6%
Pro-rated dumpers			Dumpers	0.47
Truck dumpers			Integer dumpers	1
Outstock / Reclaim system				
BDT/year			BDT/yr	327,000
BDT/day			BDT/day	934
Inventory Days, maximun capacity			Days	10
Inventory capacity, max BDT			BDT	9,343
Cubic foot volume at FHR density			Cu Feet	1,698,701
One circular Outstock / Reclaim			One @ 2 MM cu ft	1
Conveyors - trivial				
		Marrs 2015		Marrs 2015

3.4 Department 2: MBS Pretreatment of Softwood Biomass

3.4.1 Overview

Versions of the NARA TEA with different pretreatment options were prepared and used, along with other criteria, to select the Mild Bisulfite process (MBS – developed by NARA members Catchlight Energy and USDA Forest Products Lab and described in Anderson and Gao (2016)) as the softwood pretreatment for NARA. In essence

Table TEA-3.13. CLE/WY feedstock handling capital estimates for 2400 BDMTPD (2,650 BDSTPD) adjusted to NARA scale in 2014$.

CLE /WY Woodyard Capital Cost Estimates for NARA @ 2,200 BDTPD							
2-Jun-15							
Area Name	**Notes**	K$ /unit	Year	Units	Install Factor	Installed Cost, $MM 2010	Installed cost, 2014 $MM
							1.046
Receiving & Storage							
Weigh Scale (includes building)		$ 434	*2010*	2	2	$ 1.736	$ 1.82
Truck Dumps - Forest Residual Chips	50 ton units	$ 550	2010	6	2.4	$ 7.920	$ 8.28
Truck Dump - Hog Fuel	50 ton units	$ 550	2010	1	2.4	$ 1.320	$ 1.38
Truck Dump Collection Conveyor (#1)	600 TPH/line	$ 1	2010	120	2.4	$ 0.288	$ 0.30
Tramp Metal Magnet System	Travelling magnet	$ 32	*2010*	2	2.4	$ 0.152	$ 0.16
Incline Conveyor to Sizer (#2)		$ 1	2010	200	2.4	$ 0.480	$ 0.50
Tramp Metal Detector	with chute, containment	$ 20	2010	2	2.4	$ 0.096	$ 0.10
Chip Screen - gyratory	3/4" cut, 300 TPH ea	$ 100	2010	4	2.4	$ 0.960	$ 1.00
Preliminary Chip Sizing System - Hammermill	~1" out	$ 275	2010	0.72	2.4	$ 0.475	$ 0.50
Cross Conveyor from Sizer (#3)		$ 1	2010	50	2.4	$ 0.120	$ 0.13
Stacker and Reclaim System							$ -
Stacker Infeed Conveyor (# 4 & 6)	350' but incl w Stacker/Reclaim	$ -	2010	700	2.4	$ -	$ -
Stacker Reclaimer	6 MM Cu FT ea	$5,800	2010	2	2.25	$ 26.100	$ 27.30
Stacker Outfeed Conveyor (#5 & 7)	230' but incl w Stacker/Reclaim	$ -	2010	460	2.4	$ -	$ -
							$ -
Circular Outstock / Reclaim for Hog Fuel	2 MM Cu Ft ea	$3,737	2010	1	2.25	$ 8.409	$ 8.80
Front End Loader	CAT 966	$ 456	*2010*	1	1.1	$ 0.502	$ 0.52
Stacker/Reclaim Collection Conveyor (#8)	650' total	$ 1	2010	650	2.4	$ 1.560	$ 1.63
Receiving & Storage Subtotals						**$ 50.118**	**$ 52.42**
					2.4		
Preconversion short-term Storage							
Silo Supply Conveyor (#16)		1.0	2010	400	2.4	$ 0.960	$ 1.00
Chip Storage Silo	8 hrs = 2 @ 40' dia x 80' ht	416.7	2010	2	2.4	$ 2.000	$ 2.09
Mill Supply Conveyor (#17)		1.0	2010	400	2.4	$ 0.960	$ 1.00
Storage Subtotals						**$ 3.920**	**$ 4.10**
Biomass Handling: Total Cost =						**$ 54.04**	**$ 56.52**
Woodyard Cost Estimates - Lovas - Jun-10 GRM Mods - non-conf BioChem to NARA Aprr-15 a.xlsx							

MBS is much like a mild sulfite pulping cook, but carried out to a much lower degree of lignin dissolution ("higher pulp yield"), such that roughly 75% of the feedstock emerges as solids from the digester.

3.4.2 Design Basis

Process Overview

The Mild Bisulfite pretreatment process uses calcium bisulfite (Ca(HSO3)2) to pretreat softwood residuals at 145° C with a residence time of 4 hours. The pretreated softwood is then run through a disk refiner, followed by a countercurrent wash process. This results in two streams being produced. The first stream contains the pulp solids and proceeds to the enzymatic hydrolysis department. The second stream—Spent Sulfite Liquor or SSL—contains primarily soluble sugars, extractives, and lignosulfonates. The SSL proceeds directly to fermentation. The process flow is shown in Figure TEA-3.9.

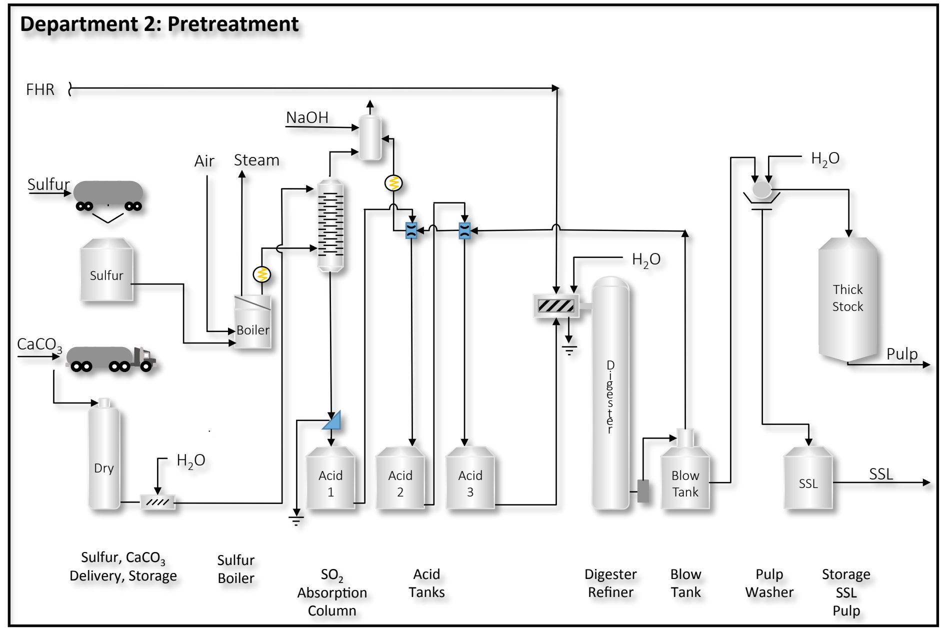

Figure TEA-3.9. NARA Mild Bisulfite pretreatment process flow.

Process Steps

A detailed mass balance can be found on the ASPEN NARA Final Report (Chin et al, 2016). The process steps are:

Chemical Production

1. Liquid sulfur is purchased from Pacific Northwest oil refineries and transported in specially insulated trucks. A steam heated liquid sulfur tank and steam heated lines are required.

2. Liquid sulfur is burned to SO_2 under controlled conditions to minimize sulfite and sulfate formation. Sulfur is burned at a 10:1 air to sulfur ratio at 1300 ºC to form SO_2.

3. A sulfur boiler generates steam (42,600 lbs/hr) from the cooling of the SO_2 followed by a cooling tower to further cool and condition the SO_2 for entry into the calcium bisulfite acid preparation absorption column.

4. Granular calcium carbonate is sourced from mines in the PNW and delivered to plant site by truck, rail, or barge.

5. Granular calcium carbonate is mixed with water and combined with SO_2 in the acid preparation absorption column. Calcium carbonate is pumped to the top of the column and SO_2 enters at the bottom below the first ab-

sorption plate. A liquid settling tank is used to settle the acid solids and the cleaned acid is then pumped to the cold acid tank. Carbon dioxide and combustion exhaust gases are vented from the top of the acid absorption column.

6. The calcium bisulfite solution is the cooking acid that will be used in pretreatment.

Pretreatment & Washing

1. The cold cooking acid goes through a preheating system where flash vapors (SO_2, steam, and volatiles) from the continuous digester are condensed in a 2-stage heat. It is estimated that 50% of the flash energy can be recovered and recycled directly back to the continuous digester by heating the cold acid. The remaining digester vapor energy is directed to an internal plant hot water recovery system and on to the pretreatment vent scrubbing system.

2. The heated cooking acid then enters the digester alongside the softwood residual chips.

3. The continuous reactor holds the forest residual chips for 4 hours at 145 ^{o}C.

4. The forest residual chips exit the reactor through a disk refiner and into a flash tank.

5. The flash vapors are used for heat recovery as described in item 1 above.

6. The solids from the digester flash tank are recovered and pumped to a multi stage countercurrent washer.

7. The countercurrent washer removes 95% of soluble solids, and these soluble solids are sent directly to fermentation. The soluble solids stream consists primarily of sugar, extractives, and lignosulfonate.

8. The insoluble solids, termed pulp, is sent to a high-density pulp storage tank and then pumped to the enzymatic hydrolysis department.

3.4.3 Cost Estimation

Operating Cost

The various operating costs for the Pretreatment department are shown in Table TEA-3.14, leading to an annual operating cost for pretreatment at $13.98 MM/yr.

Table TEA-3.14. Operating costs for pretreatment.

Department	Description of Cost	Per hour	units	per year	Cost/unit ($)	Cost/year ($MM)
Pretreatment						
	Steam	116	klb/hr	974,400	n/a **	n/a**
	Eletricity	18.017	MWhr	151,343	$ 43.2	$ 6.54
	CaCO3	3.25	Ton	27,300	$ 50.0	$ 1.37
	Sulfur	3.3	Ton	27,720	$ 200.0	$ 5.54
	Process Water	321	Ton	269,640	n/a **	n/a**
	NaOH	0.125	Ton	1,050	$ 500.0	$ 0.53
Pretreatment	Department Total					$ 13.98

Capital Cost

Capital cost estimates for a major portion of the pretreatment department—the digester and much associated equipment (feeders, washers, etc.) for a mild-bisulfite pretreatment process of the scale and conditions specific to the NARA Base case were obtained from Andritz Pulp and Paper (personal communication with Cort, B. by Spink, T., 01/15/2016). Costs for several equipment items not included in the Andritz quote, (Acid plant and blow gas system), were estimated by Thomas Spink Inc. (TSI) and added to the cost estimate. The resulting pretreatment department total IEC is $105.0MM (Table TEA-3.15).

Table TEA-3.15. Installed equipment costs for pretreatment area.

	NARA w/ Andritz ($MM)	
Unit operations		
Acid plant		$ 9.35
Digester		$ 59.60
Chip feed system		
	Chip feed bins	
	Chip washers	
	Chip pump sumps	
	Hydra screens	
	Chip inclined dewatering s	
	Wash Water Tank	
	Junk screws	
	Chip feed bins (**)	
	MSD Impressifners (2)	
	Filtrate thickening drums	
	Steam mixing conveyors	
Digester	Digester	
	Outlet device	
Refiner		
		$ 5.00
Blow gas System		$ 12.00
Brown stock washer		$ 15.00
High Density Storage		$ 4.00
Total		**$ 105.0**

3.4.4 Achieving the Pre-treatment Design Case

The NARA TEA mild bisulfite pretreatment conditions were based upon laboratory treatments of FS-10 by CLE and FPL. Cook conditions, times, temperatures, and chemistry all were used to define equipment metallurgy, sizes, and types. The lab results also defined mass flows and yields for the various components. These full details are reported in a separate NARA Final Report (Anderson and Gao, 2016), so will not be documented here. The basic NARA MBS pretreatment process is so similar to sulfite pulping, which has been practiced at scale for well over 100 years, that the implementation risk is considered to be quite small.

3.5 Department 3: Enzymatic Hydrolysis

3.5.1 Process Overview

The enzymatic hydrolysis process uses cellulase and hemicellulase enzymes to break down polysaccharides contained in the pretreated pulp into monomeric sugars. The cellulase enzymes are produced on-site via an appropriate fungal strain—which is purchased from a commercial enzyme company through a royalty agreement. Glucose and other required components are purchased and utilized in the production of cellulase enzymes. Hemicellulase enzymes are purchased. The hydrolysis takes place over 72 hours and the released sugars are sent forward for fermentation into isobutanol (Figure TEA-3.10).

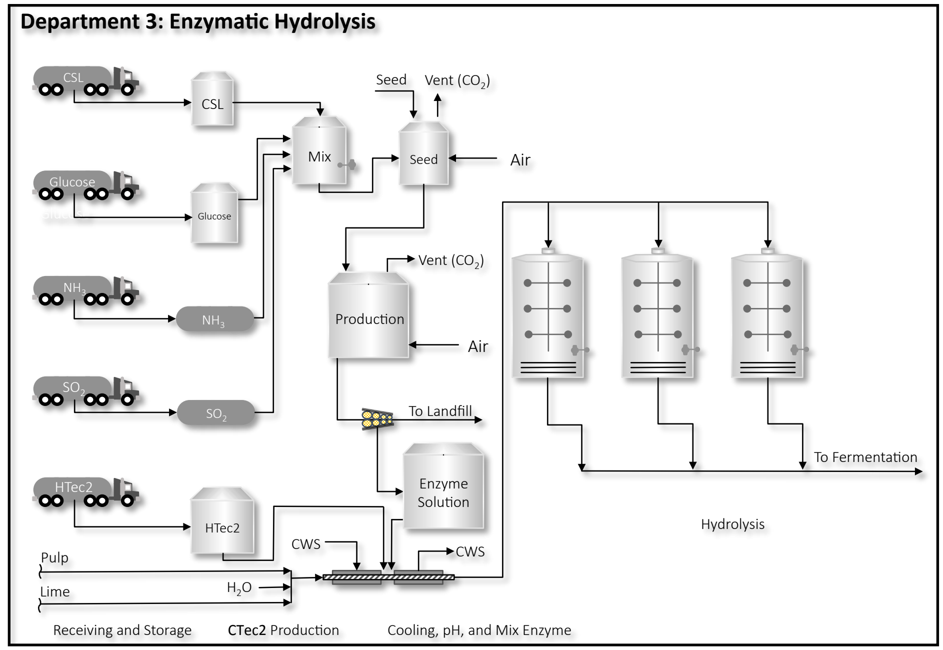

Figure TEA-3.10. Enzymatic hydrolysis (including enzyme production).

3.5.2 Enzymatic Hydrolysis (EH) Design Basis

Process Steps:

Enzyme Production:

1. Under a license from a commercial enzyme company, glucose, SO_2, corn steep liquor, ammonia, and water are used in an enzyme fermenter seed train to produce a dense culture of Trichoderma reesei (or other fungal strain capable of producing enzymes) for the production of cellulase enzymes.

2. Hemicellulase enzymes for saccharification of hemicellulose will be purchased from a commercial enzyme company.

3. The fungal strain producing the enzyme produces a large quantity of carbon dioxide, which is vented to the atmosphere.

4. The seed fungal culture is inoculated into a larger enzyme production reactor and is induced with sophorose, which begins enzyme production.

5. The produced enzyme broth is filtered to remove fungal biomass and used directly in large batch saccharification. Produced enzyme is stored in a tank for use in enzymatic saccharification.

6. The produced enzyme is separated from fungal biomass through a filtration step. The fungal biomass is discarded.

7. The enzyme production plant is required to be sterile to maintain the quality and dependability of the enzyme production process.

Enzymatic Hydrolysis:

1. The pulp stream from pretreatment (80ºC, 1.8 pH and 15% consistency) is cooled to 50° C and pH is adjusted by lime to a pH of 5.0. This cooling and pH adjustment is accomplished in an indirect cooled paddle or auger contactor. The cooling water system (CWS) is utilized as the coolant.

2. The enzymes are mixed with the pulp in the later stages of the paddle cooler indicated in item 1 and sent to a set of eight saccharification reactors. The saccharification is performed in batch mode.

3. The exothermic reaction in saccharification aids in maintaining the reactor temperature. According to the exothermic reaction, a small amount of cooling is required to maintain the reactor temperature at 50° C.

4. The hydrolyzed pulp is sent directly to fermentation. The hydrolyzed pulp contains approximately 10% (w/w) monomeric sugars, with significant residual fibers (up to 6% w/w), and the consistency of the solution is similar to a slurry.

5. The saccharified solution is stored in a large storage tank prior capable of twelve hours of storage prior to fermentation.

3.5.3 Capital Cost

The majority of the equipment costs in the EH department were obtained from ASPEN, with the single largest item (8 million-gallon hydrolysis tanks) from a current budgetary quote from Paul Mueller Co. (personal communication from Vance, C. to Spink, T. on 12/21/2015). Specific items are shown in Table TEA-3.16.

Table TEA-3.16. Installed equipment cost estimates for enzymatic hydrolysis department.

Enzymatic Hydrolysis			
From:	*03_Capital Expenditure - EnzymeHydrolysis_20150505.docx*		
	Process Step	**Description**	**IEC, $MM**
1	Chemical receiving, storage, mixing	SO2, NH3, CSL, Glucose, purchased enzyme unload, store, control room	$ 1.19
2	Seed Fermentor and storage tank	Fermentor, compressed air	$ 2.21
3	Enzyme growth tank	Growth tanks, CO2 vents, heat(?), compressed air	$ 8.48
4	Enzyme filtration	Rotary vacuum filter, sludge storage and loading to landfill truck	$ 0.51
5	Finished Enzyme storage tank	24 hour storage capacity	$ 0.15
6	Pumps	Miscellaneous	$ 0.44
			$ -
	Total Installed Cost of Enzyme Production		$ -
7	Chemical receiving, storage	Slaked lime receive store, water mix	$ -
8	Pulp cooling, pH adjust, enzyme mi	Jacketed paddle cooler mixers	$ 0.35
9	Enzymatic Hydrolysis reactors	8 jacketed agitated tanks, discharge pumps,	$ 12.30
10	Hydrolyzed storage tank	24 hour storage	$ 0.37
11	Pumps	Miscellaneous	$ 1.70
			$ -
		Total Installed Cost	**$ 27.68**

The EH department total IEC is **$27.68 MM**.

3.5.4 Operating Cost

The operating cost detail for the EH department is shown in Table TEA-3.17, totaling $27.66 MM/year.

Table TEA-3.17. Enzymatic hydrolysis department operating costs.

Department 3	**Description of Cost**	**Per hour**	**units**	**per year**	**Cost/unit ($)**	**Cost/year ($MM)**
Enzymatic Hydrolysis	Corn Steep Liquor	433	lb	3,637,200	$ 0.1	$ 0.36
	Glucose syrup (on dry weight basis)	3.1875	ton	26,775	$ 678.8	$ 18.17
	Lime for pH adjustment	0.51	ton	4,368	$ 180.0	$ 0.78
	Ammonia	303	lb	2,545,200	$ 0.4	$ 0.91
	SO2	42.2	lb	354,480	$ 0.1	$ 0.04
	Enzyme royalty	n/a	n/a	1	$ 1,000,000.0	$ 1.00
	Htec Enzyme	0.29	ton	2,436	$ 3,000.0	$ 7.31
	Steam	0.98	klb	8,232	n/a**	n/a**
	Electricity	2.32	MWhr	19,488	$ 43.2	$ 0.84
	Cooling water				n/a**	n/a**
Enzymatic Hydrolysis	Department Total					$ 29.41

3.5.5 Achieving the Design Case

The science and business practices of enzymatic hydrolysis (EH) continue to change rapidly and thus the State of Technology (SOT) has been changing over the life of the NARA project. Both the scale and technology of the NARA enzymatic hydrolysis department are at the leading edge of technology. Also, at the inception of NARA, there were no commercial enzyme cost estimates available to NARA. Initial estimates based upon NARA member confidential sources indicated that the enzyme costs would be similar to feedstock costs, one of the single largest costs in the NARA process. After much discussion within NARA, it was decided that NARA team members would estimate a material and energy balance and from those enzyme production costs.[4] This enzyme cost would then be used to estimate the total cost of enzymatic hydrolysis. This is also the technique that NREL used (Humbird et al., 2011).

The enzymatic hydrolysis department includes cost estimates for enzyme production and enzymatic hydrolysis. To be as reasonable as possible in the business case for an onsite enzyme production, a $1.0MM/yr. royalty is included to procure expert or patent protected technology to produce enzymes onsite. Thus, the enzymatic hydrolysis department cost estimate of NARA is based on underlying material balance principles, raw material prices, and a $1MM per year royalty for cellulose hydrolysis. Hemicellulase enzymes are priced at an estimated price from open market data.

Whether or not an actual NARA IBR would produce their own enzymes or contract "over-the-fence" could only be determined by actual supplier offerings and negotiations at the time of project initiation and could not be reliably compared at this stage.

3.6 Department 4: Fermentation, Separation, and Alcohol-to-Jet (F,S&ATJ)

The NARA member with the expertise and intellectual property in the area of fermentation of cellulosic sugars to isobutanol (IBA), then the separation of IBA, utilizes the proprietary Gevo GIFT system. The IBA is then converted to IPK via a proprietary process. The specific details could not be divulged without compromising Gevo intellectual property, so the combined area totals for Capex and Opex were provided to NARA.

3.6.1 Overview

The Gevo process consists of three major processes: 1) fermentation of softwood-derived sugar monomers into isobutanol; 2) separation and purification of the isobutanol; and 3) dehydration, oligomerization, and hydrogenation of isobutanol into isoparafinnic kerosene (IPK) via the alcohol-to-jet (ATJ) process (Figure TEA- 3.11). IPK is a mixture of C_{12} and C_{16} alkane hydrocarbons. The unit operations in these processes were designed by Gevo, using input provided by the upstream models of pretreatment and enzymatic hydrolysis, which were designed by the WSU ASPEN team. In order to maintain confidentiality of the Gevo technology, process details will not be stated in this report. A general process description is provided along with the overall mass and energy balance of the Gevo operation in the ASPEN Model NARA Final Report (Chen et al., 2016).

[4] Many thanks are is due to Dr. Shulin Chen, Dr. Allan Gao and Dr. Liang Yu of the WSU Biological Systems Engineering Department for the basic understanding and economics of enzyme production and enzymatic hydrolysis.

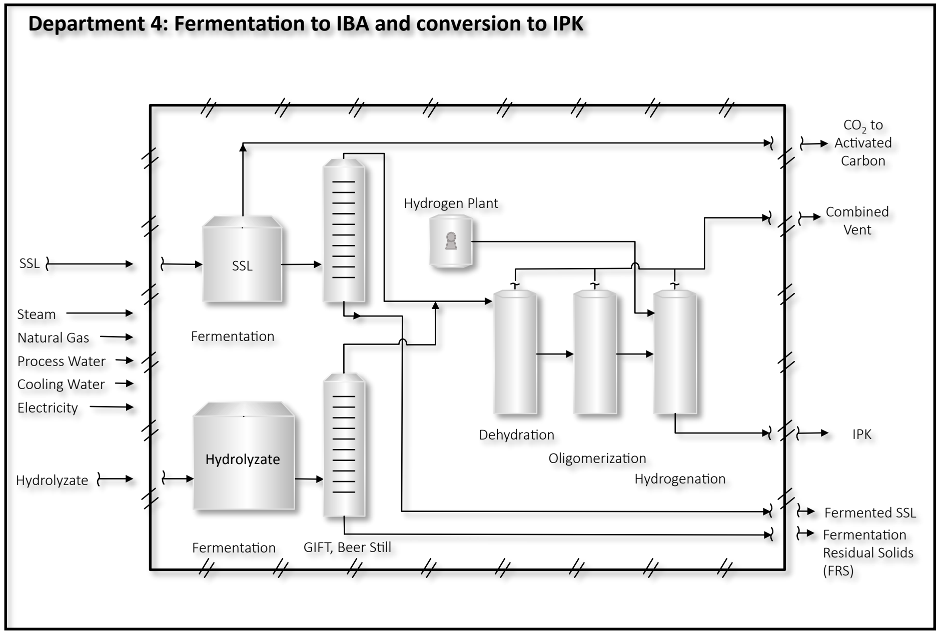

Figure TEA-3.11. Fermentation to IBA, separation and ATJ conversion to IPK.

3.6.2 Design Basis

Process Steps

1. The saccharified pulp biomass, containing C6 and C5 sugars, residual unreacted cellulose fibers and non-sulfonated lignin is fermented by a Gevo proprietary yeast to produce isobutanol. (The saccharified pulp biomass is produced by the enzymatic hydrolysis department.) The fermentation produces CO_2 which is then utilized in Activated Carbon production.

2. The Spent Sulfite Liquor (SSL) biomass stream, containing C5 and C6 sugars is also used in fermentation by a Gevo proprietary yeast to produce isobutanol. (The spent sulfite liquor is produced by the pretreatment department.) The SSL sugars are fermented by the Gevo yeast to isobutanol separately from the pulp saccharified sugars.

3. The fermentation process requires up to 48 hours. Both the SSL sugar stream and the pulp saccharified sugar stream are cooled by indirect cooling from 80° C and 50° C respectively to 34° C. The SSL sugars are adjusted in pH with lime.

4. The separation and purification of the isobutanol from the SSL solution and the pulp biomass stream is done according to Gevo patented processes.

5. The SSL stillage and pulp biomass fermentation residual stillage is transferred to the co-products department at 100° C and 7% and 9% solids respectively.

6. The separated and purified isobutanol is dehydrated, oligomerized, hydrogenated and IPK purified according to the Gevo demonstrated alcohol-to-jet (ATJ) processes.

7. The information supplied by Gevo estimates a production of 35.7 million gallons of IPK per year. The produced IPK is sent to the distribution department.

3.6.3 Cost Estimation

Capital Cost

The F,S&ATJ department total IEC for the combined department was $146 MM (Personal communication with Johnson, G. (Gevo) and Spink, T. and Marrs, G. on 05/05/2016) as a single number without disclosure of the details (considered proprietary).

Operating Cost

The F,S&ATJ department total IEC for the combined department was comprised of operating elements from the provided mass flows and a miscellaneous category (Table TEA-3.18). The total is $28.20 MM/yr.

Table TEA-3.18. Operating costs for fermentation, separation and alcohol-to-jet department.

Department	Description of Cost	Per hour	units	per year	Cost/unit ($)	Cost/year ($MM)
Gevo F, S & ATJ	Process Water	n/a**	n/a**			n/a**
	Steam	135	ton	1,134,000	n/a**	n/a**
	Natural Gas	56.5	MM BTU	474,254	$ 8.3	$ 3.93
	Electricity	22	MWhr	184,800	$ 43.2	$ 7.98
	Miscellaneous (From Gevo)	4310	Gal IPK	36,200,000	$ 0.5	$ 16.29
	Cooling Water	81,000	GPM	116MGD	n/a**	n/a**
Gevo F, S & ATJ	Department Total					$ 28.20

3.6.4 Achieving the Design Case – F,S&ATJ

NARA member company, Gevo, has been operating a commercial plant in Luverne, MN producing isobutanol (IBA) from corn starch using its patented biocatalysts and separation technology, which are the processes assumed in the NARA TEA base case. Gevo currently operates the plant in "side-by-side" mode producing both fuel grade denatured ethanol and fuel grade isobutanol. With the one production train running on isobutanol, Gevo has the annual capacity of 1.5 million gallons of fuel grade isobutanol. Gevo, since 2011, has been operating a demonstration scale unit in Silsbee, TX, converting the renewable isobutanol into jet fuel (IPK) and other hydrocarbons such as isooctane and isooctene. The facility has produced over 150,000 gallons of hydrocarbons, which have been used to fly multiple flights with the US Department of Defense (DOD), US Navy, US Army, US Airforce. It has also completed extensive testing and is now included in the ASTM D7566 Annex 5 specification for synthetic jet fuel. Recently the fuel has flown in commercial service aboard a Boeing 737-800, powered by CFM56-7B Turbofan Engines for Alaska Airlines. Accordingly, the demonstrated ability to produce marketable bio-jet (IPK) at scale considerably greater than lab scale has been demonstrated when the feedstock is corn starch.

To build confidence about scalability for the softwood lingo-cellulosic feedstocks in NARA, a project effort was conducted whereby about 1,000 gallons of IPK was produced from softwood lignocellulosic feedstocks from the PNW (Wooley et al., 2016).

3.7 Department 5: IPK Storage and Distribution

3.7.1 Overview

The distribution operation stores and distributes the isoparaffinic kerosene (IPK) produced by the NARA biorefinery (Figure TEA-3.12). The co-products storage and handling is detailed in the co-products department.

The distribution department was not modeled in ASPEN Plus. Instead, a list of equipment was provided by Thomas Spink Inc (TSI).

The products are distributed through both rail and truck, with an estimated 75% of product leaving by truck and 25% leaving by rail due to the relatively small volume of product being produced.

The IPK product would likely be delivered to an existing petroleum depot where pipeline access to conventional jet fuel and tanks allowing blending to the desired mix ratio, and then pipeline transport to the airline supplies at the airport(s).

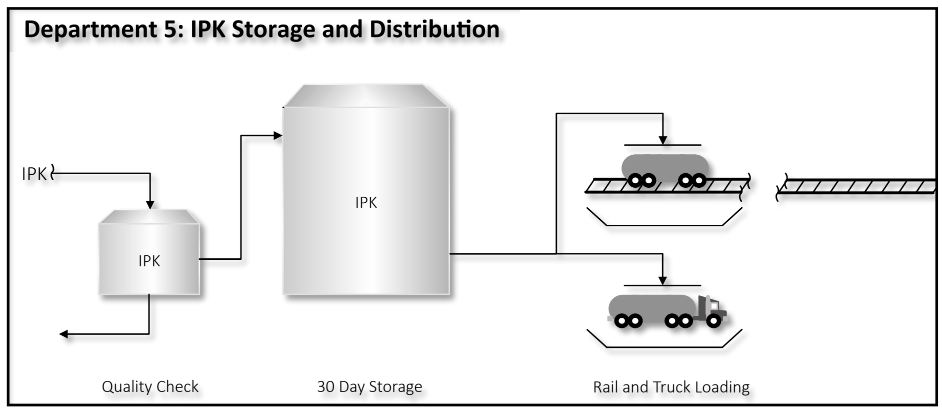

Figure TEA-3.12. IPK storage and distribution department

3.7.2 Design Basis
The storage and loading facilities are relatively simple – a storage tank for 30-days supply and truck and rail loading facilities. Smaller day production tanks are intended to allow quality checks of IPK prior to pumping to the large single tank.

3.7.3 Cost Estimation
The costs for the relatively simple components in this department were estimated by Thomas Spink Inc (TSI) based upon similar equipment at a sulfite pulp mill.

Table TEA-3.19. Storage and Distribution department IEC.

		Liquid Distribution Cost Estimate			
Item	Process Description	Unit Description	Detailed description	Cost Estimate	Reference
1	IPK Product Storage, 30 days	Two 2.00MM Gallon Tanks	Poly coated Iron and system pipes to from plant and racks, heated	$ 6,000,000	TSI
2	IPK/IBA Rail loading system	System for single car and unit trains	Scales and automated loading	$ 2,500,000	TSI
3	IPK/IBA Truck loading system	Multiple Loading stations	Automated loading and billing	$ 1,500,000	TSI
	Total			$ 10,000,000	

Capital Cost
Total installed equipment cost was estimated at $10 MM (Table TEA-3.19)

Table TEA-3.20. Storage and Distribution department operating costs.

Department	Description of Cost	Per hour	units	per year	Cost/unit ($)	Cost/year ($MM)
IPK Distribution	Electricity	0.13	MWhr	1,126	$ 43.2	$ 0.05
IPK Distribution	Department Total					$ 0.05

Operating Cost
Operating costs for the department are just electricity, and total $0.05 MM/yr (Table TEA-3.20).

3.8 Department 6: Co-Products
3.8.1 Overview
The co-products department consists of two primary processes: 1) Lignosulfonates (LS), and 2) Activated carbon (AC) production (Figure TEA-3.13).

The lignosulfonate process takes fermented spent sulfite liquor obtained from the bottom of the beer still (stillage) after the fermentation and uses vapor recompression evaporators to remove water until the spent sulfite liquor is 50% solids. The pH is adjusted to 6.5 and the 50% SSL is then sold as calcium lignosulfonate (Ca-LS).

The activated carbon process uses fermentation residual solids (FRS) obtained from the bottom of the beer still (fermentation residual solids) after the fermentation. The solids are first run through a belt press or solid bowl centrifuge to remove excess water, followed by dryer to remove residual water prior to pyrolysis.

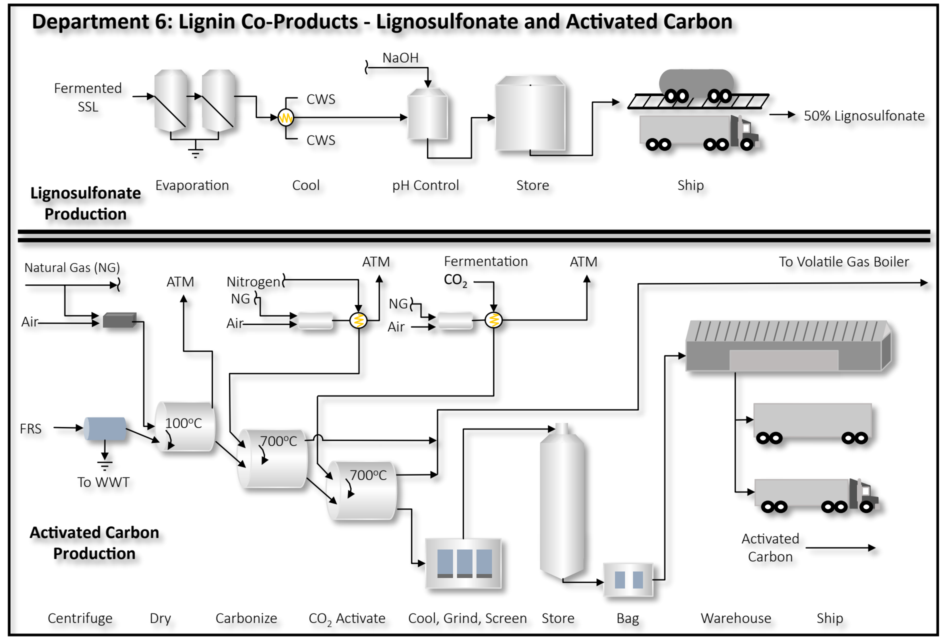

Figure TEA-3.13. Lignin co-products – lignosulfonate and activate carbon

The FRS is then used in slow pyrolysis to produce a biochar, which is then activated through carbon dioxide activation.

3.8.2 Design Basis
Lignosulfonate

1. The fermented spent sulfite liquor, obtained from the base of the fermented SSL beer still, is pumped in to the vapor recompression evaporators (VRE).

2. The VRE units evaporate the SSL until it reaches 50% solids.

3. The evaporator condensate is discharged directly to wastewater treatment.

4. The pH of the SSL is adjusted to 6.5.

The 50% SSL solution is intended for sale as a concrete additive.

Activated Carbon

1. Fermentation residual solids are obtained from the fermentation department beer still and excess water is initially removed through a belt press or solid bowl centrifuge.

2. The excess water is directly discharged to wastewater treatment and contains small amounts of sugar as well as organic acids and furfural.

3. Residual water in the FRS is removed through a dryer.

4. The dry FRS is placed into a rotary kiln reactor for pyrolysis at 700 °C for 1 hour. The reactor is fed with a nitrogen carrier gas at a 1:1 nitrogen to solid mass ratio.

5. The generated pyrolysis vapors are burned in a multi-fuel boiler to generate heat and steam for the process.

6. The pyrolysis reaction gives a yield of 40% (w/w) biochar. The remaining 60% becomes pyrolysis vapor and is combusted.

7. The biochar is subjected to an activation process in which excess CO_2 is reacted with the biochar at 700 °C for one hour.

8. The activation reaction generates a yield of about 55%, which results in 22.5% (w/w) yield of activated carbon based on input FRS.

9. The activated carbon is cooled and placed in Supersaks for sale.

3.8.3 Cost Estimation

Capital Cost – Lignosulfonates

Capital costs for LS production were taken from individual unit equipment costs in ASPEN, then accumulated to two main process groups as shown in Table TEA-3.21.

Table TEA-3.21. Capital cost for lignosulfonate production.

Lignosulfonates Evaporator components	Installed Equipment Cost, IEC
Vapor Recompression Evaporator	$ 12,777,700
Ancilliary pumps and heat exchangers	$ 490,000
Total	**$ 13,267,700**

The individual equipment is fairly common and the total cost is relatively small so the estimates are considered adequate for this department. Total LS IEC is $13.27 MM.

Table TEA-3.22. Operating costs for lignosulfonate production.

Department	Description of Cost	Per hour	units	per year	Cost/unit ($)	Cost/year ($MM)
Co Products	LS					
	Electricity	10.94	MWhr	91,896	$ 43.2	$ 3.97
	Lime (Calcium Hydroxide)	1	ton	8,400	$ 180.0	$ 1.51
	Total for LS					$ 5.48

Operating costs – Lignosulfonate Production

Operating costs for 50% liquid Ca-LS production are minimal—a total of $5.48 MM/yr (Table TEA-3.22).

Capital Costs – Activated Carbon

Table TEA-3.23. Activated carbon production capital costs.

As reported in ASPEN doc:
03_Capital Expenditure - Coproducts_20150507.docx
Table 1 – CAPEX of activated carbon process (WY)

Unit Operation	Purchased Equip Cost	Installed Equip Cost
Residual dryer	$181,451	
Carbonization/activation	$40,500,000	
Wash/rinse	$1,411,320	
Screw press	$200,000	
Activated carbon dryer	$220,588	
Crusher	$1,500,000	
Screener	$245,000	
Total Capital	**$44,258,359**	**$110,645,897**

Capital costs for an activated carbon production facility were taken from a NARA Final Report (Gao and Neogi, 2016). The unit operations equipment purchase cost and total installed equipment cost for AC production is $110.65 MM (Table TEA-3.23).

Operating Costs – Activated Carbon Production

Operating costs in the AC production area are mostly for nitrogen gas to blanket the slow pyrolysis of the FRS, with some natural gas and bags for sacking the product

Table TEA-3.24. Operating costs for activated carbon production.

Department 6b	Description of Cost	Per hour	units	per year	Cost/unit ($)	Cost/year ($MM)
	Activated Carbon					
	Steam	34.2	MMBTU	287,280	n/a**	n/a**
	Electricity	0.112	MWhr	941	$ 43.2	$ 0.04
	Natural Gas	58.4	MMBTU	490,560	$ 8.3	$ 4.06
	N2	24	ton	201,600	$ 54.0	$ 10.88
	CO2	6	ton	50,400	$ 160.0	$ 0.25
	Bags for AC					$ 4.09
	Total for AC					$ 19.32

for shipping. Total operating costs for AC production are $19.32 MM/yr (Table TEA-3.24).

3.9 Department 7: Boilers

3.9.1 Overview

The boilers provide steam and heat for the entire biorefinery (Figure TEA-3.14). Based on the earlier process models, a minimum of 415,000 lbs/hr of steam is required to power the entire biorefinery. Hog fuel (35-50% moisture) has an average heating value of 6,000 BTU/lb, equivalent to 12 MMBTU per short ton. This requires the consumption of 35 to 40 tons per hour of hog fuel, depending on the quality of

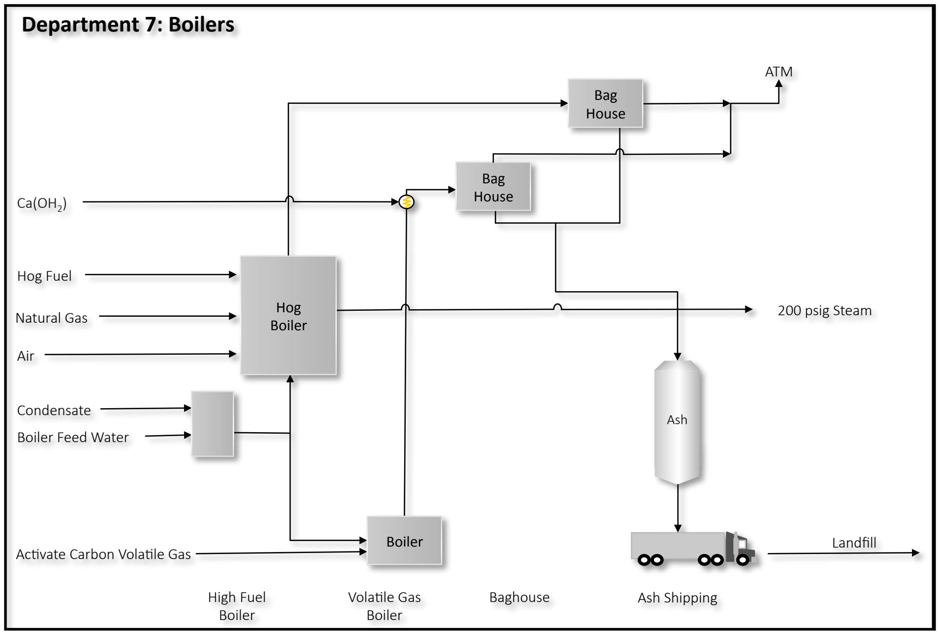

Figure TEA-3.14. Hog fuel and volatile gas boilers.

the input fuel. The boiler department consists of additional processes related to the boilers, including preheating, condensate return system, and water treatment. These unit operations were taken into account in the capital and operating expense.

3.9.2 Design Basis

There are two sources of fuel for the hog fuel boiler: 1) fines, which were screened out in the feedstock handling department (8.3 TPH) and 2) directly purchased hog fuel (29.7 TPH). Hog fuel is described as a wet mix of coarse chips of bark and wood, which is of too poor quality to process as wood pulp. The fines are forest residual chips that pass through the lower screen in the feedstock handling department, and are too small to be used for pretreatment.

In addition to the hog fuel boiler, a mixed fuel boiler (aka volatile gas boiler) is used to handle pyrolysis vapors from the activated carbon process. The mixed fuel boiler receives the vapors at 700 °C and is co-located near the co-products process unit operations. A special note should be made that the piping to handle these vapors needs to be specialized in order to prevent corrosion as well as condensation of the pyrolysis vapors on the pipes.

3.9.3 Cost Estimation

Capital Cost – boilers

Table TEA-3.25. Boilers capital expense.

03_Capital Expenditure - Boiler_20150416.docx		
Item	**Reference**	**Estimated Installed Capital ($MM)**
Condensate System	TSI, Inc.	$ 2.00
Boiler Feed Water System	NREL 2013 Report, APEA, Icarus	$ 2.35
Hog Fuel Supply System	APEA, Icarus	$ 0.36
Hog Fuel Boiler	Towler, Sinnott (2013)	$ 23.94
Baghouse, Hog Fuel Boiler	EPA (Turner, 1998)	$ 3.94
Multifuel Boiler	Towler, Sinnott (2013)	$ 6.11
Baghouse, Multifuel Boiler	EPA (Turner, 1998)	$ 1.22
Baghouse Ash Collection, etc.	TSI, Inc.	$ 2.00
Clean Exhaust Stack, Etc.	APEA, Icarus	$ 1.25
	Total Installed Capital	**$ 43.17**

Capital costs for boiler department were taken from various literature sources (Turner, McKenna, Mycock, Nunn and Vatavuk, 1998; Davis et al., 2013; Towler and Sinnott, 2013). The boilers department total installed capital cost was $43.17 MM

Table TEA-3.26. Operating cost for hog fuel and volatile gas boilers.

Department 7	Description of Cost	Per hour	units	per year	Cost/unit ($)	Cost/year ($MM)
Boilers	Hog Fuel Boiler					
	Ca(OH)2	1.68	ton	14,111	$ 45.0	$ 0.63
	Feedwater Chemicals	415,000	$/klb steam	3,486,000	$ 0.2	$ 0.52
	Condensate Treatment	415,000	$/klb steam	3,486,000	$ 0.0	$ 0.10
	Electricity	2.68	MWhr	22,512	$ 43.2	$ 0.97
	Bags	1.2	bags	10,080	$ 50.0	$ 0.50
	Natural Gas	n/a	mmbtu	19,920	$ 8.0	$ 0.16
	Total for Hog Boiler					$ 2.90
	Multifuel Volatile Gas Boiler					
	Electricity	0.67	MWhr	5,628	$ 43.2	$ 0.24
	Boiler Feed Water	n/a	n/a	n/a	n/a	n/a
	Condensate Treatment	n/a	n/a	n/a	n/a	n/a
	Bags	n/a	bags	200	$ 50.0	$ 0.01
	Ca(OH)2	0.208	ton	1,747	$ 45.0	$ 0.08
	Process water	n/a	n/a	n/a	n/a	n/a
	Total for Volatile gas boiler					$ 0.33
Boilers	Department Total					$ 3.23

(Table TEA-3.25).

Operating Cost – boilers

The operating costs for the boilers department consists of a variety of relatively small cost items (Table TEA-3.26), which total $3.23 MM/yr.

3.10 Department 8: Utilities

3.10.1 Overview

The utilities department contains the following operations (Figure TEA-3.15):

1. Electrical Substation
2. Gates, roads, fence, rail, security
3. Cooling tower
4. Potable water and sanitary waste
5. Mill compressed air
6. Mill control and data system
7. Wastewater treatment
8. Landfill
9. Process water supply and fire suppression system
10. Administration and human needs building

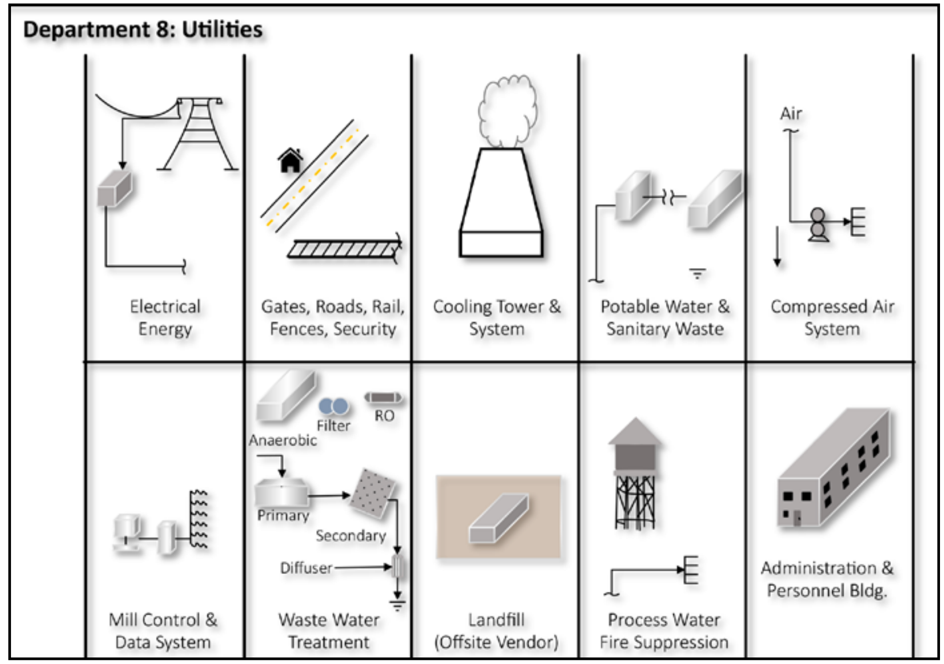

Figure TEA-3.15. Elements of Utilities "department". These are needed infrastructure elements, which generally serve the entire IBR.

3.10.2 Design Basis - Utilities

Electrical Substation

The NARA biorefinery does not produce electricity. As a result, the refinery needs to be connected to the local power grid to obtain electricity to run the plant. The electrical substation transforms and distributes power from the local grid to the plant.

Gates, Roads, Fence, Security

The plant site requires gates, roads into and out of the site, fencing, and security.

Cooling Tower

The cooling tower handles heat removal for various process water streams, including water from pretreatment, upgrading of isobutanol to IPK, and cooling of evaporator condensate prior to wastewater treatment.

Potable Water and Sanitary Waste

The people working at the plant site require potable water and disposal of sanitary waste generated at the site.

Mill Compressed Air

Compressed air is required for pneumatic actuators and other process equipment.

Administration and Human Needs Building

This building at the plant site houses the engineers and administrative staff that manage the refinery.

Mill Control & Data System

The mill control and data system manages equipment settings, material flow rates through processes, and monitors the unit operations at the site. Essentially, this is a process control system.

Flare Stack System

This unit burns the light ends from the F,S&ATJ process distillation.

Wastewater Treatment

Wastewater treatment uses aerobic treatment, anaerobic treatment, and reverse osmosis to clean process wastewater. Wastewater comes from many sources. Two of the largest sources are evaporator condensate and FRS filtrate from the activated carbon department. Clean water is recycled to the plant for re-use. There is a high probability of excess treated wastewater above the process requirements. This makes it likely that a wastewater discharge to receiving waters would be required. Due to the high uncertainty of this item, the capital expense of a discharge pipeline, diffuser, and permits is not included in this cost estimate.

Process Water Supply & Fire Suppression

The process water supply system pumps fresh municipal water and treated water from the wastewater treatment process back to the various operations that require it. The fire suppression system includes a fire suppression water storage area and pumps for the fire suppression system.

Enzymatic and Fermentation CO2 Scrubbing System

This system scrubs odiferous and volatile compounds from the CO_2 produced by the enzyme production facility and the fermentation plant. Since these two plant's CO_2 discharges are in separate departments, a single scrubbing system is placed in the utilities department. The scrubbed CO_2 is discharged to the atmosphere. CO_2 utilized in co-products for activation is removed prior to this scrubber.

3.10.3 Cost Estimation

Capital Cost

Capital cost estimates for elements of the utilities department were largely estimated based upon professional engineers with experience in this area (Thomas Spink Inc. (TSI)) (Table TEA-3.27).

Table TEA-3.27. Capital costs for utilities department.

Capital Expenditure (CAPEX) – Utilities
Source: *03_Capital Expenditure_utilities_20150507.docx*

Item	Unit Operations	Description	More detail descriptiion	Total Installed Capital (TIC)
1	Electrical Sub Station; transformers and distribution	Transmission voltage reduced to mill distribution voltage and disrtributed to department	Prep site and mill distribution to 440V department voltage with large moters at 4160V	15,000,000
2	Gates, Roads, Fence, Rail, security manpower	Build from Greenfield	Unit train (100 cars) required	20,000,000
3	Cooling Tower	100,000 gpd	Cooling tower and Cooling Water System (CWS) distribution	5,000,000
4	Potable Water, and Sanitary waste treatment	20,000 gpd water well and chlorination; primary/secondary/Discharge	Water well; primary, secondary, and discharge to stream. Possibility of City service (?)	2,000,000
5	Mill Compressed Air	250 Hp 150psi and distribution system		1,500,000
6	Admin and Human Needs Bldg	Offfices for staff, showers, lockers etc for all employess	$250/ft at 10,000 sq ft	2,500,000
7	Mill Control and Data system	Workstation connectivity and real time mill data/control	Software and licenses for ERP and mill control	7,500,000
8	Flare Stack System	Burn light ends from GEVO IPK process and discharge exhaust	Includes environmental monitoring	1,500,000
9	Waste water treatment	Primary, Secondary, RO, Anearobic, recycle (50%)	NREL model plus, recycle piping, and sewers	62,680,000
10	Process Water Supply and Fire suppresion system	Three water wells at 5mgd total with filtration, & independent fire system	Water to department boundary; Fire water to department and then by code	5,000,000
11	Enzyme, Saccarification, and Fermentation Scrubbing	Scrub CO2 and miscellaneous vents	Scrubber and all connecting piping	2,000,000
Total				124,680,000

Wastewater Treatment

A very large portion of the utilities capital cost is for wastewater treatment. Because the main uncertainties addressed in the NARA project were related to adding information about the considerable uncertainties and technical feasibility of producing biojet and lignin coproducts from softwoods, there was no empirical investigation of wastewater flows or mass balances in the NARA project effort. Accordingly, the assumptions for the TEA effort were based upon professional experience of Thomas Spink (TSI) at a WA state sulfite pulp mill and the equipment cost assumptions used in the 2013 NREL Biofuel TEA for hydrocarbons from corn stover (Davis et. al 2013).

The NARA wastewater treatment system (WWT) assumes that conventional processing of wastewater (as is typically done in pulp mills) is utilized with the additional steps of ultrafiltration and reverse osmosis to allow significant process water recycle. The NARA WWT process assumes the following process steps:

1) Primary settling (must include sludge thickening and primary sludge disposal to landfill)

2) Biological aeration in basins (often referred to as Aerated Stabilization Basin, ASB)

3) Clarification of ABS waste water discharge with partial sludge recycle

4) Anaerobic treatment of ASB settled sludge

5) Dewatering of anaerobic treatment sludge with centrifuges

6) Disposal of anaerobic sludge to landfill (or burning[5] of anaerobic sludge)

7) ASB clarified water Purification - A system of ultrafiltration (UF) and reverse osmosis (RO) is employed on the aerobic basin settling supernatant to attain at least a 50% process water recycle return to the NARA process.

8) Disposal of salts and unreacted organic compounds are to be discharged to landfill from the UF/RO plant.

Although the WWT flows internal to the WWT system were not modeled in the NARA ASPEN model (due to limited time, complexity, and minor contribution to technical uncertainty), it is estimated that the water balance potentially requires that excess wastewater be discharged to receiving waters. There is no provision in the cost estimate for discharge to receiving waters as this is beyond the NARA TEA scope (it would depend upon siting specifics of a facility—state regulations, etc.). Additionally, the salts and organics to be discharged from RO/UF are to be landfilled.

Wastewater Treatment System Flows

The flow to the WWT is composed several streams. The three most prominent are:

1. The ATJ waste water discharge from the F,S&ATJ process
2. The evaporator condensate form the Spent Sulfite Liquor (SSL) evaporators in the pretreatment process
3. The filtrate from the Fermentation Residual Solids (FRS) (solid bowl centrifuge)

These three streams comprise a majority of the water flow (2,707 gpm, or 3.9 MM gallons per day) and the predominant quantity of BOD, COD, dissolved solids and total solids.

[5] The NREL report (Davis 2013) says burn or landfill the sludge. Due to small heat recovery from very wet sludge, and uncertainty about the technical feasibility of dewatering this specific sludge, we chose to simply assume it will be landfilled.

Additional (relatively minor flow) streams to WWT from each department include:

4. Feedstock Handling department: hydraulic cooling and rainfall on the total site
5. Pretreatment department: SO2 gas interstage cooling and PT scrubber caustic water
6. Enzymatic Production and Hydrolysis department: Water caustic scrubber
7. F,S&ATJ step: Fermentation CO2 caustic scrubber
8. Co Products department: Non condensate vent scrubber and FRS dryer gas scrubber
9. Boiler Department: Boiler Feed water ion exchange backwash and Boiler blowdown
10. Utilities department: Cooling Tower Blowdown and RO/UF wash cycle discharge

The minor flows total 879 gpm. Table TEA-3.28 shows the specific total flow values for each of these streams. The total WWT hydraulic loading is thus estimated at 3,085 gpm, or 4.442 MM gallons per day.

Table TEA-3.28. Flow rates of streams going to wastewater treatment system.

Waste Water feed to NARA Wastewater Tratment Plant Original Flow estimates			
Department	**Description of Source**	**Flow**	
		Gallons per Minute	MM gallons per day
Feedstock Handling	Hydraulic oil cooling coils	10	0.0144
	Rainwater from total site 50ac	54	0.0776
Pretreatment	Cooling SO_2 gas from boiler temp to absorber	10	0.0144
	S combustion, CO_2 RX, Blow residual gas	25	0.0360
Enzyme Prod & Hydol	Water Caustic Scrubber	25	0.0360
Fermentation, Separation and ATJ			
ATJ	Wastewater	270	0.3888
Fermenter	CO2 Scrubber	25	0.0360
Distribution		0	0.0000
Co Products			
Lignosulfonate Production	Evaporator Condensate	840	1.2096
	Non Condensible Vent Scrubber	25	0.0360
Activated Carbon	Centrifuge/Press Filtrate	1597	2.2997
	Dryer Gaseous scrubber	25	0.0360
Boiler	BFW Ion exchange back wash	25	0.0360
	Boiler Blowdown	44	0.0633
Utilities			
Cooling Tower (100,000gpm)	Cooling Tower Blow Down	100	0.1440
RO wash system	Washing cycle in RO of WWT	10	0.0144
Total		**3085**	**4.4422**

Wastewater Treatment Capital Estimate

Since the basic individual components of the NARA WWT process and the NREL process are similar the Capex for NARA was estimated by scaling the NREL cost estimates for individual equipment based on liquid flow to that equipment (Davis 2013 reports 1.6 MM gpd). Since the NARA WWT system places anaerobic treatment after aerobic, the NARA flow rate and anaerobic reactor needs are much smaller, thus the total NARA system is only slightly more that NREL despite much higher total input flow. Table TEA-3.29 shows the equipment list, the Davis 2013 NREL costs, scaling for NARA, and total installed capital costs used for NARA. The NARA installed capital cost estimate is $62.68 MM. The total utilities installed equipment cost IEC is $124.68 MM.

Table TEA-3.29. Wastewater treatment system cost estimate.

Equipment	$MM USD, installed cost ($2011) - NREL	Scaling Factor	$MM USD, installed cost ($2011) - NARA
Evaporator System	$ 5.90	1.83	$ 10.70
Membrane Bioreactor	$ 4.80	1.83	$ 8.70
Reverse Osmosis System	$ 2.60	1.83	$ 4.70
Centrifuge	$ 2.00	1.83	$ 3.60
Anaerobic Digester	$ 30.90	0.31	$ 9.58
Aeration Basin	$ 12.00	1.83	$ 21.80
Other (pump, conveyer, etc.)	$ 2.00	1.83	$ 3.60
Total	$ 60.20		$ 62.68
Wastewater Treatment Capex per Allan.xlsx			

Wastewater Treatment Environmental Comments (Air, Water, and Solid Waste)

The air discharges from the WWT system include the air discharged from the aeration basins. These are characterized by; 1) residual organic and biological odors from sulfur and fermentation processes, 2) waste gases (sanitary sewer smell) from anaerobic treatment and anaerobic sludge thickening, and 3) odor issues in RO and UO waste sludge.

Water discharge is to be considered similar to an oil refinery in that the primary NARA final product is IPK, is not miscible with water. IPK is an oil and therefore produces a sheen on receiving waters when accidentally discharged in minute quantities. Therefore, it is necessary for the collection and treatment of surface waters as well as precautions on those pieces of equipment that use water cooling in close proximity IPK.

Sludge discharge from WWT is estimated to be two streams; a) anaerobic sludge (centrifuge discharge) and b) concentrates from UF/RO. The estimated anaerobic sludge is 1.3 bone dry tons per hour at a solids content of somewhere between 8% and 20%, depending upon how difficult it is to dewater this (untested) sludge. It is beyond the scope of the NARA effort to determine whether the anaerobic sludge could be dewatered sufficiently to be burned, hence we simply assumed it is landfilled.

The UF/RO sludge is the salt and unreacted organics that are concentrated and discharged from the UF/RO process. This sludge quantity is a result of the lignin loses in the SSL evaporators, the FRS filters, and various salts in the wastewater. Since lignosulfonates and native lignins are minimally consumed by anaerobic treatment, these materials much be discharged from the UO/RO process. Estimation of the UF/RO organic and salt discharge is beyond the scope of the NARA WWT design, as no empirical data was generated during the project effort. There is a potential for significant increase in the NARA WWT Capex and Opex when considering the impact required to operate a modern WWT plant, but these are likely site-specific and are not addressed here.

Operating Cost – Utilities

The utilities operating costs have large contributors for electricity (mostly for motors for aerators in the wastewater treatment system) and landfill tipping fees for sludge disposal and total $13.52 MM/yr (TEA-3.30).

Table TEA-3.30. Utilities operating costs.

Department 8	Description of Cost	Per hour	units	per year	Cost/unit ($)	Cost/year ($MM)
Utilities	Electrical Distribution					$ 0.10
	Gate, road, security					$ 0.01
	Cooling Tower					$ 0.70
	Potable Water					$ 0.01
	Sanitary Waste System					$ 0.18
	Mill Compressed Air					$ 0.21
	Administration Building					$ 0.03
	Mill Data/Control					$ 0.50
	Flare Gas System					$ 0.02
	Waste Water Treattment					
	Electricity	13.4	MWhr	112,560	$ 43.2	$ 4.86
	Liime for pH adjustment					$ 0.63
	Reverse Osmosis Tubes					$ 0.10
	Flocculants					$ 0.15
	Filter Additives					$ 0.10
	landfill					$ 5.49
	Process Water (Make up beyond 50% recycle)					$ 0.44
Utilities	Department Total					$ 13.52

3.11 Fixed Operating Costs

There are categories of operating costs considered fixed that apply across all departments. The categories, values used and data sources are shown in Table TEA-3.31.

Table TEA-3.31. Fixed operating costs.

Category	Rate	Annual $ MM	Source
Labor		$15.94	TSI Labor Table
Maintenance	5% of IEC	$31.85	Perry 1963
Insurance	~0.5% of IEC	$5.00	Perry 1963
Property Tax	1.5% of TCI	$16.50	Perry 1963
Total Fixed Costs		**$69.29**	

3.11.1 Labor Cost Details

The labor costs were developed by NARA member Thomas Spink Inc. (TSI), and are based upon experience in a similarly complex industrial field (pulp and paper operations). The organization charts for the IBR are show in Figures TEA-3.16 and TEA 3.17. Based on numbers of staff in each position and salary and loading rates from similar positions in pulp and paper, the annual labor cost details are estimated as shown in Table TEA-3.32.

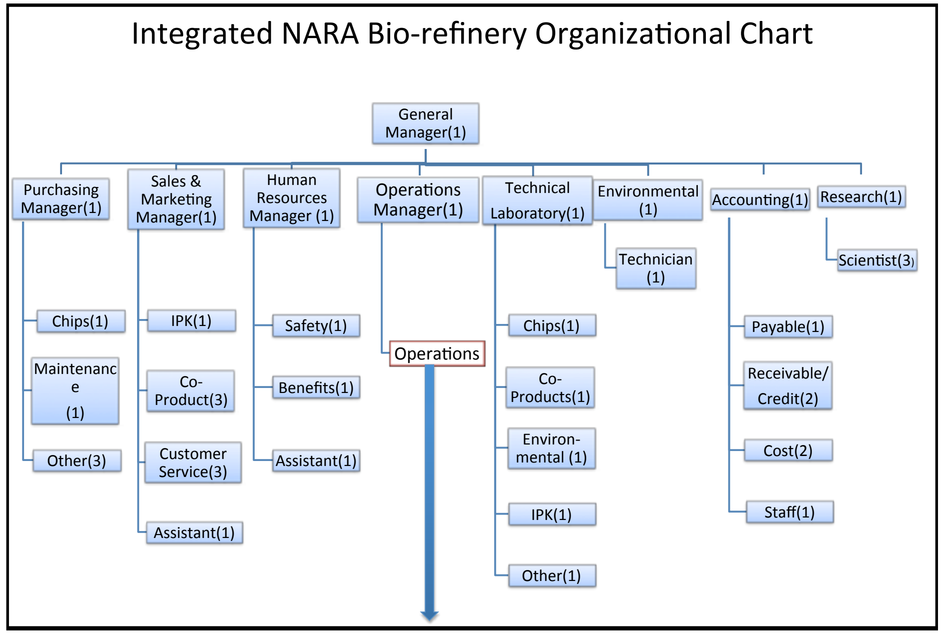

Figure TEA-3.16. First level organization chart for NARA IBR staffing and labor cost estimate.

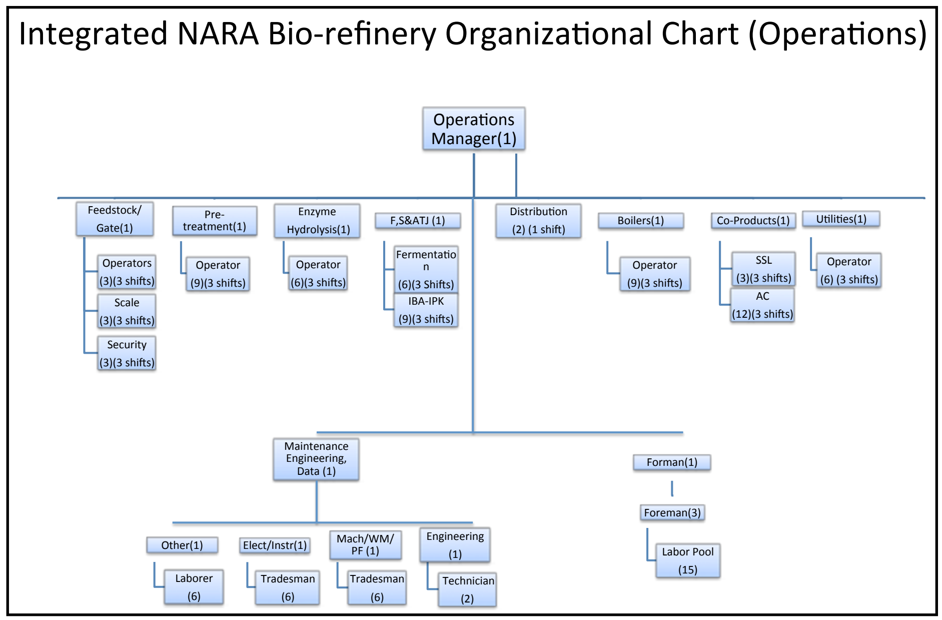

Figure TEA-3.17. Operations organization chart for NARA IBR.

Table TEA-3.32. Annual labor cost assumptions for NARA IBR.

Annual Operating Labor costs for IBR											
TSI Inc 14-Feb-16											
Operating Sections	General Manager		Department Managers		Adminsitrative staff		Operation superisors		Operators and Trades		Totals
	Headcount	Salary	Headcount	Salaries	Headcount	Salaries	Headcount	Salaries	Headcount	Salaries	
Administration											
General Mgr	1	$ 300,000									
Purchasing			1	$ 125,000	3	$ 195,000					
Sales, marketing, customer service			1	$ 150,000	8	$ 660,000					
Human Resources			1	$ 100,000	3	$ 180,000					
Technical and Laboratory			1	$ 125,000	5	$ 425,000					
Environmental			1	$ 100,000	1	$ 65,000					
Accounting			1	$ 125,000	6	$ 390,000					
Research			1	$ 100,000	3	$ 255,000					
Operations											
Operations manager			1	$ 200,000							
Maintenance, Engineering, Data							1	$ 150,000	20	$ 1,500,000	
Feedstock Handling							1	$ 110,000			
Operations									4	$ 260,000	
Truck gate and security									6	$ 390,000	
Pretreatment							1	$ 110,000	12	$ 780,000	
Enzymatic Production and Hydrolysis							1	$ 110,000	8	$ 520,000	
GEVO											
Fermention and GIFT							1	$ 110,000	8	$ 520,000	
IBA Purification thru IPK							1	$ 110,000	12	$ 780,000	
Distribution									2	$ 130,000	
Boilers							1	$ 110,000	12	$ 780,000	
Co Products							1	$ 110,000	20	$ 1,300,000	
Utilities							1	$ 110,000	8	$ 520,000	
Shift Foreman							4	$ 400,000			
Labor Pool									10	$ 500,000	
Total Headcount	**1**		**8**		**29**		**13**		**122**		**173**
Totall Salaries		$ 300,000		$ 1,025,000				$ 1,430,000		$ 7,980,000	$ 10,735,000
Total Benefits		$ 105,000		$ 358,750				$ 500,500		$ 3,591,000	$ 4,555,250
Total Labor Costs											**$ 15,290,250**
Note: Operations based on 12 hour shifts											

3.12 Summary of Operating and Capital Cost Estimates

The summary of costs for all departments is shown in Table TEA-3.33. Note that capital costs are one-time, while operating costs are annual, so the two cannot be directly compared.

Table TEA-3.33. Summary of capital and operating cost elements by department.

Department / Area	Installed Equipment Capital Costs, million $	Annual Operating Costs, million $
1. Feedstock handling	$56.5	$66.4
2. Pretreatment	$105.0	$14.0
3. Enzymatic Hydrolysis	$27.7	$27.7
4. Fermentation, Separation & Alcohol-to-Jet	$146.0	$28.2
5. Lignin Co-products	$123.9	$24.8
6. IPK Product Storage and Distribution	$10.0	$0.05
7. Multi-fuel Boiler	$43.2	$3.2
8. Utilities	$124.7	$13.5
Fixed Costs	-	$69.3
Total Cost	**$636.91**	**$247.15**

4) Process Economics

The purpose for developing a relatively detailed process design, simulation model, and cost estimate is to determine the economics of bio-based jet fuel production and to assess the merit for co-products from the lignin-rich residues. This information can be used either as an absolute cost to assess bio-jet fuel economic potential in the marketplace or as a relative cost that can be used to guide research by examining the change in production cost associated with a process modification or other core research activity.

Following the well-established approach used in the NREL BETO TEA models (NREL, 2016), the total capital investment (TCI) is first computed from the total installed equipment cost. Next, variable and fixed operating costs are determined. With these costs, a discounted cash flow analysis is used to determine the IPK minimum selling price (MSP) required to obtain a zero net present value (NPV) with a specified internal rate of return (IRR). This section describes the assumptions made in completing the discounted cash flow analysis.

The initial analysis does not take into account any policy factors such as subsidies, mandates, or carbon credits because none of the comparative published TEAs include such "bio-fuel premiums". Once that MSP for IPK is calculated, an assessment is made of how likely it will be that the market would bear such a cost, and how much certain kinds of bio-fuel premiums (RINs valuation) might impact the IRR of such a project. In other words, how close to economically viable does this process currently seem?

4.1 About Cost-Year Indices

The final TEA cost-year basis was chosen to be 2014. Equipment costs quoted in different years were adjusted according to the Chemical Engineering Plant Cost Index (CEPCI). Operating costs were determined for values as close to 2014 as possible.

4.2 Total Capital Investment (TCI)

A factored capital cost (like NREL) cost approach is used, where the starting basis is cost-year adjusted, scaled purchased equipment cost (PEC) estimates. These are multiplied by installation factors (IF) to account for costs of foundations, piping, electrical, etc., to give installed equipment costs (IEC). The equipment directly related to manufacturing the saleable products is designated as inside the battery limits (ISBL). This total is factored for additional items outside the battery limit (OSBL)—warehouse, site development, etc., to give the total direct cost (TDC). This TDC is then multiplied by indirect cost (IC) factor(s) for items like engineering and management for the plant construction to give fixed capital investment (FCI). The FCI is the depreciable portion of the capital investment. To this FCI then is added factored non-depreciable capital items like land purchase and working capital, yielding the total capital investment (TCI) for the project. Comparisons to other TEA values for capital are commonly done based on TCI.

Note that since every element of TCI is factored (that is, multiplicative) the order of calculation and nesting of cost buildup is irrelevant, and it is virtually all based upon purchase equipment cost estimates specific to the NARA process and factored against factors commonly used in other (NREL) TEAs.

4.3 Variable Operating Costs

Variable operating costs, which include raw materials, waste handling charges, and by-product credits, are incurred only when the process is operating. Quantities of raw materials used and wastes produced were determined using the ASPEN material balance. Tables TEA-3.1, TEA-3.2, and TEA-3.3, shown previously, document the costs and sources of power, chemicals and gases used in the process.

4.4 Fixed Operating Costs

Fixed operating costs are generally incurred in full whether or not the plant is producing at full capacity. These costs include labor and various overhead items. Fixed costs and sources have been shown in Table TEA-3.31.

4.5 Revenue Assumptions

Virtually all biofuels TEAs published have a single revenue product—the biofuel. Therefore, no assumption about future selling prices of the resulting biofuel are needed because the analysis stance is to assume a given return on investment (commonly 10%) and then solving for a minimum selling price (MSP) of the fuel in order to achieve that return. For NARA, however, there are three physical commodities being produced for sale—IPK, LS, and AC. There is uncertainty about future selling prices for each of these products, and one cannot solve simultaneously for MSP for three items. Accordingly in the NARA TEA in order to solve for an MSP for the bio-fuel alone (IPK) the assumed selling price for LS and AC is set and then held constant, allowing a solution for an IPK MSP. Following the discussion of results of the analysis comments are given on the plausibility of achieving the calculated IPK MSP.

4.5.1 Lignosulfonates (LS) Revenue

Lignosulfonates are an industrial chemical class of currently marketed products based upon the spent sulfite liquor (SSL) from existing sulfite pulp mills. Depending upon the chemical basis for the sulfite process and the wood species, and additional processing the material may have received (such as fermenting the solubilized sugar monomers), the uses and market value for various LS varies widely, and contractual prices are closely held.

NARA LS is specifically from (mostly) softwoods and is calcium-based sulfite chemistry. Thus, NARA LS is technically a Ca-LS. Furthermore, NARA SSL is then fermented to convert sugars into IBA, whereby the sugars are removed from the SSL to leave “fermented SSL”. The resulting Ca-LS, technically a “fermented softwood Ca-LS”, has a particular market niche as a concrete additive.

A NARA member, Thomas Spink Inc (TSI)., has through confidential market analyses, assessed the likely value of this material when concentrated to 50%, as $200 per dry Ca-LS ton. With the ~200,000 dry tons available to sell per year, this generates nearly $40 MM/year revenue for the project. Since the alternative is to burn the Ca-LS for its fuel value, (only about $9 MM/yr value) and given the small capital required to concentrate the Ca-LS, it is clearly an economic advantage to produce and sell Ca-LS.

4.5.2 Activated Carbon (AC) Revenue

Considerable effort was expended in the NARA project developing technology to manufacture AC from the fermentation residual solids (FRS) remaining after enzymatic hydrolysis, fermentation and beer still distillation of the pulp stream. Market value estimates for activated carbon were from two sources. One study (Stavropoulos and Zabaniotou, 2009) lists various assumed selling prices for AC of varying key property (BET surface area) depending upon starting material. For the listed material most similar to our NARA FRS (wood), they list an assumed $2009 value of $1.54 USD per kg product. Updating to 2014 $ and short tons the resulting value is approximately $1,500/short ton. Discussions with attendees at the 34th International Activated Carbon Conference (Fox, 2013) supported the pricing of about $1,500/ton AC, which is the market price used for the NARA IBR TEA.

Given the estimated 66,000 dry tons of AC per year produced, this price brings about $99 MM/year revenue to the project, a very significant income source assumption. Like the fuel value of LS, the alternative of burning the fermentation residuals solids (FRS) for power instead is very clearly a poorer economic option.

4.5.3 Isoparaffinic Kerosene (IPK) Revenue

IPK is not currently marketed as bio-jet fuel in any notable scale, thus there is no history of customer willingness-to-pay. A project boundary assumption has been that the airlines (the final customer) will not pay a bio-fuel premium for the renewability aspect of the IPK. While this may be an option for further discussion as a way to facilitate industry start-up, the available data is on petroleum-based jet fuel as the alternative pricing basis for the IPK. Following the MSP discussion the likely petro-jet pricing assumptions will be addressed when calculating a project IRR.

4.5.4 Renewable Identification Numbers (RINs) Revenue

The definition of, and an explanation of how the system works and could generate revenue for a cellulosic “advanced” bio-fuels producer is very complex and beyond the scope of explaining here. Interested readers can examine a report from Christensen, Searle and Malins (2014) for a thorough explanation of RINs and how revenue could be extracted. In essence, the RINs have a marketable value that can be converted to revenue for every gallon of IPK produced in the NARA process.

While the future of RINs per se is uncertain, they can be taken as indicative of the "carbon credit" value that might be placed on cellulosic biofuels by society. The specifics of how large that might be will be discussed in the later analysis section of this report—but suffice it to say here that the magnitude could be as large as the basic petro-jet fuel equivalent price value for IPK, so it is by no means trivial.

5) Discounted Cash Flow Analysis and the Minimum Selling Price of IPK

Once the total capital investment, variable operating costs, and fixed operating costs have been determined a discounted cash flow rate of return (DCFROR) analysis can be used to determine the minimum selling price per gallon of IPK produced. The discounted cash flow analysis is calculated by holding revenue assumed from LS and AC fixed, and then iterating the revenue from IPK until the net present value of the project is zero. Financially, this means that the project owners are receiving exactly the assumed discount rate (aka cost of capital) for the project life. In other words, they would be economically indifferent to this project compared to an alternative project returning exactly the same assumed cost of capital. This analysis requires that the discount rate, depreciation method, income tax rates, plant life, and construction start-up duration be specified.

5.1 Discount Rate and Plant Life

For this analysis, the discount rate (which is also the internal rate of return [IRR] in this analysis) was set to 10% and the plant lifetime was set to 30 years. This is the discount rate used in NREL BETO TEA design reports (NREL, 2016) and was based on the recommendation from Short, Packey and Holt (1995) on how to perform economic evaluations of renewable energy technologies for DOE. Their view (Short et al., 1995) was that, *"In the absence of statistical data on discount rates used by industrial, transportation and commercial investors for investments with risks similar to those of conservation and renewable energy investments, it is recommended that an after tax discount rate of 10%…be used."*

5.2 Equity Financing

The NREL model has capability to alter the proportion of debt and equity funding, and if debt funding is used, the loan terms must be specified. Because specifics about what loans (amounts and rates) might be available, and under what favorable conditions to foster biofuels industry startup is highly uncertain and speculative, we chose to avoid using debt funding. Therefore our base case IBR is 100% equity-financed (although the NARA TEA retains the capability to specify debt funding if desired).

5.3 Depreciation

The NARA TEA uses the same depreciation used in the NREL BETO TEA models (NREL, 2016). They determine the capital depreciation amount for the calculation of federal taxes to be paid using the IRS Modified Accelerated Cost Recovery System (MACRS). Within the MACRS system is the General Depreciation System (GDS), which allows both the 200% and 150% declining balance (DB) methods of depreciation. This offers the shortest recovery period and the largest tax deductions. According to IRS publication 946 (U.S. Department of Treasury, 2015) a cellulosic ethanol plant (and we assume the same would be true for a biorefinery producing IPK) would fall under Asset Class 49.5, "Waste Reduction and Resource Recovery Plants." This class uses a 7-year recovery period, not including the steam plant equipment (boilers department), which has a 20-year recovery period (Asset Class 49.13).

5.4 Taxes

5.4.1 Federal Income Tax

The federal corporate tax rate used in our analysis is 35%. The amount of income tax to be paid varies annually due to changes in the allowable depreciation deduction. In fact, no income tax is paid in the first eight years of operation because the depreciation is greater than the net income (net losses for income taxes are carried forward).

5.4.2 State Taxes

For our base case, with a location in the state of Washington, we include a Business and Occupation (B&O) Tax and property taxes, which together are assumed to be 1.5% of the Total Capital Investment.

5.5 Construction Time

The NARA TEA uses the same assumptions as the NREL BETO TEA (Humbird et al., 2011) for construction time:

"The construction time is important to the cash flow analysis because no income is earned during construction, but huge sums of money are being expended. Perry and Green [83] indicate that small projects (less than $10 million investment) can be constructed in fewer than 18 months and that larger projects can take up to 42 months. An overview of petroleum refining economics indicates that large refineries (on the order of $1.5 billion investment) can be constructed in 24 months [84]. Certainly this NARA IBR process is much smaller than a petroleum refinery, so using a construction time of 24 months fits within these references, although an important difference between this type of facility and a refinery is the large number of field-erected vessels. These are constructed on-site and have a longer construction time than if the tanks were delivered finished. Table 32 summarizes the schedule for construction and the cash flow during that time. Twelve months are added before construction for planning and engineering."

Table 32 described in the above quote is replicated in Table TEA-5.1:

Table TEA-5.1. Construction period activities used by NREL and adopted by NARA TEA. Retrieved from Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol Dilute-Acid Pretreatment and Enzymatic Hydrolysis of Corn Stover (p. 57), by Humbird et al. 2011: NREL.

Project Start Month	Project End Month	Activity Description	% of Project Cost
0	12	Project plan and schedule established; conceptual and basic design engineering, permitting completed. Major equipment bid packages issued, engineering started on selected sub-packages, P&IDs complete, preliminary plant and equipment arrangements complete.	8%
12	24	All detailed engineering including foundations, structure, piping, electrical, site, etc. complete; all equipment and instrument components purchased and delivered; all site grading, drainage, sewers, rail, fire pond, foundation, and major structural installation complete; 80% of all major process equipment set (all except longest-lead items), all field fabricated tanks built, and the majority of piping and electrical materials procured.	60%
24	36	Complete process equipment setting, piping, and instrumentation installation complete; all electrical wiring complete; all building finishing and plumbing complete; all landscaping complete; pre- commissioning complete; and commissioning, start-up, and initial performance test complete.	32%
		TOTAL	100%

Note: The above assumes no utility or process equipment orders placed prior to month seven. Expenditures based on typical 60 MMgal/yr grain-to-ethanol facility.

5.6 Start-Up Time

The startup time assumptions used in NREL CSTE TEA (Humbird et al., 2011), they state:

"Perry and Green (1997) indicates that for a moderately complex plant, start-up should be about 25% of the construction time, or 6 months in this case. Delta-T's experience (described in Aden et al., 2002) with start-up indicated that a large grain-to-ethanol plant could be started up in less than 6 months. Considering that this design is for the n^{th} operating plant, we assumed a start- up time of 3 months. The start-up period is not completely wasted, however. We expect that an average of 50% production could be achieved during that period while incurring 75% of variable expenses and 100% of fixed expenses."

For the NARA TEA, the complexity of altering the first year formulas for revenue, costs, depreciation, taxes, etc. from a full year to the more complex distinction listed above for NREL was considered insignificant, so there is no explicit startup period in the NARA TEA.

5.7 Working Capital

From Humbird et al. (2011): *"Peters and Timmerhaus 2003 define working capital as money available to cover (1) raw materials and supplies in inventory, (2) finished product in storage, (3) accounts receivable, (4) cash on hand for monthly payments such as wages and maintenance supplies, (5) accounts payable, and (6) taxes payable. They indicate that working capital is usually 10%–20% of the fixed capital investment. This flow of money is required over the life of the plant, beginning in the start-up phase to make product that generates revenue to use in purchasing more materials and supplies."* We used the same as Humbird et al. (2011), that is, 5% of the fixed capital investment, which amounts to $52 MM for the NARA IBR.

5.8 Land Cost

Humbird et al. (2011) used $1.8 MM for land cost in the NREL CSTE TEA. The NARA IBR is a considerably more complex facility with the co-products production and two boilers, as well as a very large feedstock outstock / reclaim area for pile storage (Humbird (2011) assumes all corn stover feedstock stored at suppliers and delivered on-demand with no on-site storage). Based upon this, and some cursory investigations into land values for industrial land in WA and OR (which were highly variable), we increased the land cost to $8.2 MM. This was based upon assuming 200 acres total needed, based upon comparison to an operating sulfite pulp mill in WA state, and the county assessed land value (for taxation) of $41,000 per acre for land alone. If expressed as a factored approach this equates to 1.25% of the TDC. Note that land costs are not depreciated and are returned at the end of the project life as salvage value.

5.9 Summary Financial Parameters

Table TEA-5.2 summarizes the parameters used in the discounted cash flow analysis. Using these parameters, plus the cost information above, the resulting IPK minimum selling price (MSP) from Version 13.50 is $7.27/gal IPK (2014$).

Table TEA-10.1 shows the full 30-year DCF/ROR analysis table. Table TEA-5.3 shows the overall summary of the key analysis inputs and results.

Table TEA-5.2. Discounted cash flow analysis parameters

Plant life	30 years
Discount rate	10%
General plant depreciation	200% declining balance (DB)
General plant recovery period	7 years
Steam plant (boilers) depreciation	150% DB
Steam plant recovery period	20 years
Federal tax rate	35%
Financing	100% equity
Loan terms	NA
Construction period	3 years
First 12 months' expenditures	8%
Next 12 months' expenditures	60%
Last 12 months' expenditures	32%
Working capital	5% of fixed capital investment
Start-up time	0 months
Revenues during start-up	50%
Variable costs incurred during start-up	75%
Fixed costs incurred during start-up	100%

Table TEA-5.3. Summary results for NARA final TEA. MSP for IPK is $7.27/gal IPK.

NARA PNW Forest Feedstocks to Bio Jet Fuel - Techno-Economics

Revised 29-Nov-16 Case: **13.50**

Authors Gevan Marrs & Tom Spink

PNW Softwood to renewable IPK, LS, AC

Feedstock: OR Douglas-fir Forest Residuals (like FS-10)

Mild Bisulfite Pretreatment

Case 13.50 MSP - Integrated Facility producing IPK, Lignosulfonates, and Activated Carbon

Annual Revenue

Product	Annual Product	Units	Revenue $/Unit	Total Annual Revenue, $MM	MSP **$/gal IPK**
Iso-Paraffinic Kerosene - IPK	35.7	MM gallons	$ 2.56	$ 91.49	**$ 2.56**
BioFuel Premium(s) / gal IPK	35.7	MM RINS	$ 4.71	$ 168.31	**$ 4.71**
		MSP $/gal IPK	***$ 7.27***		**$ 7.27**
Lignosulfonates	196,224	Dry tons	$ 200	$ 39.24	
Activated Carbon	66,192	Dry tons	$ 1,500	$ 99.29	
Total Annual Revenue (million $ per year)				**$ 398.34**	

Feedstock Supply to Mill Gate	846	Thousand BDT/yr
Feedstock to Conversion	770	Thousand BDT/yr
IPK BioJet Production	**35.7**	**million gallons per year**
IPK Yield	46.4	gal / dry U.S. ton feedstock
Feedstock Cost to Mill Gate	$61.55	/dry U.S. ton
Equity Percent of Total Investment	100%	
Internal Rate of Return (After-Tax)	**10.00%**	

Capital Costs, million $

Feedstock handling	$56.5
Pretreatment	$105.0
Enzymatic Hydrolysis	$27.7
Fermentation, Separation & Alcohol-to-Jet	$146.0
Lignin Co-products	$123.9
IPK Product Storage and Distribution	$10.0
Multi-fuel Boiler	$43.2
Utilities	$124.7
Total Installed Equipment Cost	**$636.91**
Added Direct + Indirect Costs	$472
(% of TCI)	43%
Total Capital Investment (TCI)	**$1,109.1**

Manufacturing Costs (million $ per year)

Feedstock + Handling	$64.7
Pretreatment Opex	$14.0
Enzymatic Hydrolysis	$29.4
Fermentation, Separation & Alcohol-to-Jet	$28.2
IPK Product Storage and Distribution	$0.05
Power Boiler	$3.2
Lignin Co-products	$24.8
Utilities	$13.5
Fixed Costs (Labor, Prop Tax, Insurance, Maint.)	$67.6
Total Manufacturing Costs	**$245.51**
Annual "Average" Income Tax	**$26.7**
Average Annual Cash Flow After-tax	**$126.0**

Note that in the final version summary shown in Table TEA-5.3 (V 13.50), we assume that the basic selling price for the IPK itself stays at the projected market price of $2.56/gal. This market price for the IPK, just like the revenue for LS and AC, is then assumed to hold and only the price received for the biofuel premium for IPK is solved for a total IPK revenue per gallon to return 10%, giving $4.71/gal IPK biofuel premium. But the total needed for IPK in all forms of revenue is the sum of the two, thus $7.27/gal IPK.

6) Analysis and Discussion

In the early NARA project years, the TEA analysis first looked at the economics of producing only bio-fuel and using the various lignin-rich residual materials for energy production within the facility. These analyses (Marrs and Spink, 2013) showed that an IPK-only facility would need to generate about $9.04/gal IPK revenue to return 10% IRR (or cost of capital). This is considerably above the then-average pricing of petroleum-based jet fuel ($3.09/gal jet fuel) which would be displaced in using IPK. Accordingly, the investigations within NARA for higher-value co-products and uses for the lignin-rich residuals were intensified.

The second major iteration of the TEA had the addition of all capital, operating costs, and revenue from identified co-products: LS and AC. These updated economics (along with a large number of refinements of other cost elements, yields, etc. from the intervening NARA teams' work) led to results reported for TEA V 6.41 (Spink, Marrs and Gao, 2014) where very favorable economic contributions from AC (in particular) led to estimates, that when including RINs valuation, the overall project would have an internal rate of return (IRR) over 12% when assuming a petro-jet fuel equivalence price of $3.09/gal for the IPK. Since the IRR exceeded the 10% cost of capital, solving for IPK MSP was somewhat irrelevant since it would only show that it was less than the $3.09/gal petro-jet pricing.

In NARA project Year 4, the yields and costs were continually refined. One important change was clarifying in the lab a much lower yield of AC from FRS than originally assumed (20% instead of 40%). This, plus increases for capital in other areas (notably pretreatment digester and F,S,&ATJ departments), caused the project IRR to drop to near-zero (when assuming $3.09/gal IPK and $2.12/gal IPK RINs revenue). This result was reported at the 4th NARA Annual meeting (Spink and Marrs, 2015).

A major effort in NARA project Year 5 was review and vetting of the TEA by a group of NARA members. This included comparisons to published TEAs as a way to identify any possible errors, improvements, or to understand fundamental similarities or differences in economic prospects compared to other feedstock sources, conversion pathways, and end bio-fuel products (Marrs and Spink, 2015). Changes identified and made in preparation for, and as follow-up to that review session, lead us to the NARA 5th project year Final TEA – Version 13.50 with results as shown in Table TEA-5.3. The remaining discussion will be based upon the Final TEA model results and implications for economic viability of the process.

In November of 2016, two (relatively minor) calculation errors were found and corrected, resulting in the Final TEA Version 13.50. In that version for solving for an IPK MSP there is also a small reporting convention shift—the market price for IPK is held constant, and ALL needed revenue for IPK to reach 10% IRR is attributed to some "biofuel premium". This would be some mechanism, of unspecified nature, that would result in sufficient revenue for each gallon IPK sold to achieve the 10% IRR. Note that this only shifts IPK revenue listing from one category to another without changing total revenue for IPK.

6.1 Market price of IPK, bio-fuels premiums, and IRR

With a Final TEA model MSP of $7.27/gal IPK we can examine information about the likelihood of achieving that price.

6.1.1 Petro-jet pricing

From the outset, one of the NARA TEA boundary assumptions was that the final bio-jet fuel customer would not pay a premium for bio-jet, meaning that the revenue assumption for the IPK from, say, airlines, would be equal to the price of petroleum-based jet fuel ("petro-jet"). For most of the early NARA project years, we used in the TEA an average of $3.09/gal petro-jet, based upon January, 2012 value—a then-current value in a relatively stable period (Figure TEA-6.1). There was, however, subsequently quite a dramatic drop in petroleum prices in the 2012-2016 time period (Figure TEA-6.2), making the use of historical values somewhat questionable. For a 30-year project, the relevant question is future price projections, not historical data.

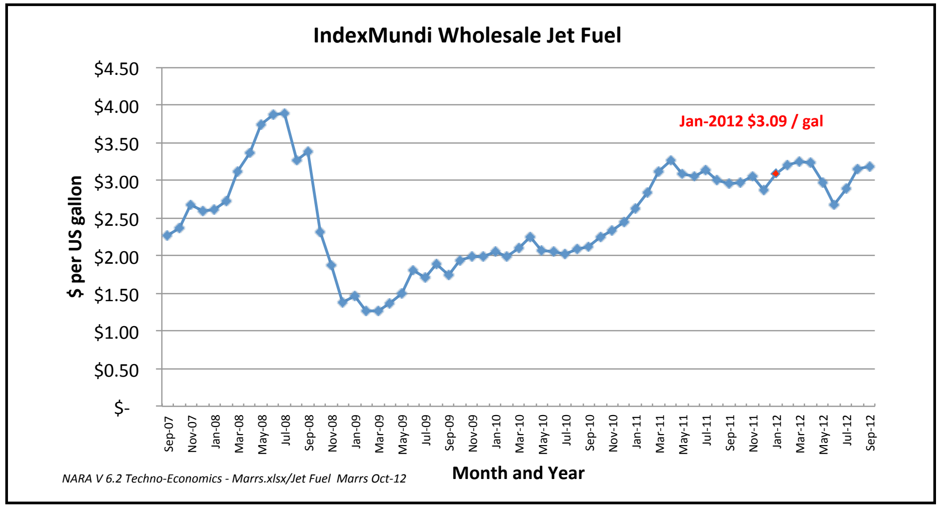

Figure TEA-6.1. Jet Fuel monthly price basis for early-year jet fuel prices. Price data from IndexMundi and retrieved from http://www.indexmundi.com/commodities/?commodity=jet-fuel&months=120

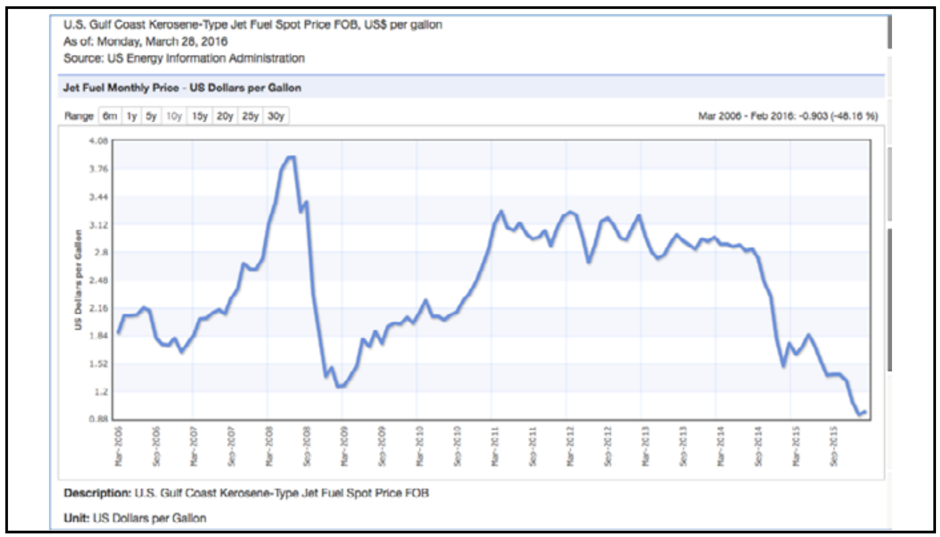

Figure TEA-6.2. Jet fuel pricing dropped dramatically in 2014-2015.

Shifting emphasis from historical values to future projections, the U.S. Energy Information Agency (EIA) was chosen as the logical source for reasonable future pricing projections. Their projections for key liquid transportation fuels are shown in Figure TEA-6.3.

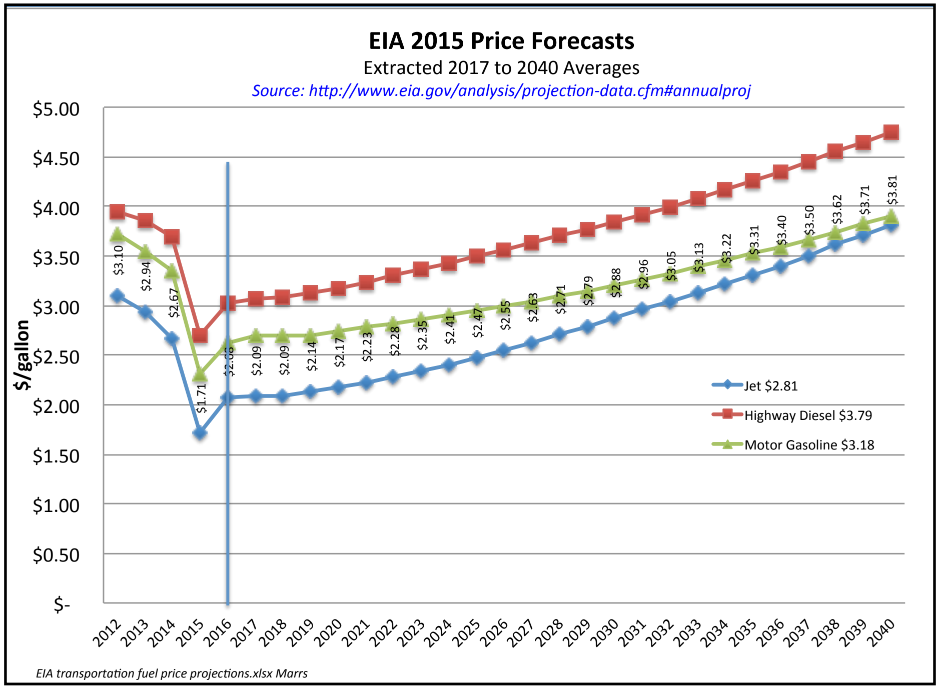

Figure TEA-6.3. US EIA price forecasts for key liquid transportation fuels.

A simple average of 2017 through 2040 price forecast for jet, the EIA value would be $2.81/gal jet. But of course taking the simple average value for the entire project life is not the economic equivalent of a time-series starting lower and ending higher.

To eliminate the 2102 through 2016 (highly variable) information, as "water under the bridge", and to extend the projections for 30 years total for the project life, the data from 2017 to 2040 was fit with a simple linear regression, then the jet values extrapolated to 2047 (a 30-year NARA IBR project life starting in 2017), see Figure TEA-6.3.

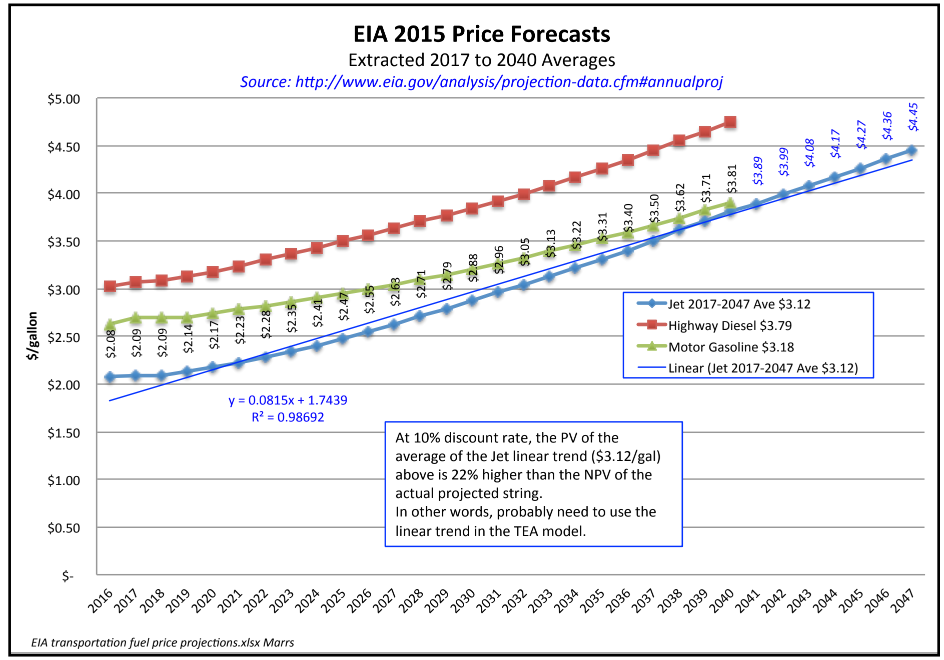

Figure TEA-6.4. Projection of EIA jet fuel forecasts for 2017 out through 30-year project life (2047).

Empirically comparing the present value (PV) of a level $3.12/gal for 30 years at 10% cost of capital with the PV of the linearly increasing price trend shown above, the PV of the level value is 22% higher than the trending value. Clearly, using the simple average overestimates the time-weighted price.

However, using even a simplified linear trend as shown in the regression above adds complexity to the model, and additionally eliminates a simple answer to the important contextual question "What is your assumed IPK selling price?", as it would vary over time. Additionally, if we index the rate of change of diesel to the same rate of change as jet, we also have varying diesel costs, which impact feed-stock delivered prices, which then do not hold constant and thus we also cannot easily answer "What is your assumed feedstock cost?".

For these reasons an alternative approach was used. One can empirically solve for a level fixed jet fuel (or IPK) price projection that gives a PV equal to the PV of the varying trend shown in Figure TEA-6.4. The result is $2.56/gal jet. That is, get-ting a constant $2.56/gal jet for all project years gives the same PV as the ramped linear values starting at about $1.80 and ending at about $4.40 as shown in Figure TEA-6.2.

The "parity" price of petro-jet is clearly well below the MSP needed for IPK in the NARA IBR—in other words to return even 10% there needs to be additional revenue from IPK, and a bio-fuel premium of some type is needed.

6.1.2 RINs – D3 RINs valuation

The US Renewable Fuel Standard (RFS) is an existing, nationwide act, which currently provides a framework for setting a marketable value for biofuels—in the NARA case cellulosic biofuels. This is done via the Renewable Identification Numbers (RINs) procedure, which applies a unique identifying number to each gallon of qualifying biofuel. This number can at some point be separated from the fuel and has a marketable value (ultimately) to obligated parties. Thus RINs can be sold by a biofuels producer either as a premium on the IPK gallons, or later to a broker, or ultimately to an obligated party. The most comprehensible, relatively simple explanation of how this would work is given in the Christensen et al. (2014) briefing and will not be repeated here.

Suffice it to say that estimating RINs value for the 30-year project life is akin to IPK pricing assumptions – we have a history of RINs prices, but it is highly variable and has been driven by forces not likely to re-occur for the next 30 years (see Figure TEA-6.5), so is not a good basis for price projections.

Figure 1: Prices of D4 (biomass-based diesel), D5 (advanced) and D6 (renewable) RINs from the beginning of the RFS2 program to the present (where data was available).

Figure TEA-6.5. Price history of D4, D5 and D6 RINs. Reprinted from A Conversational Guide to… Renewable Identification Numbers (RINs) in the U.S. Renewable Fuel Standard (p.7), by Christensen, A., Searle, S. & Malins, C. (2014, May). The International Council of Clean Transportation [ICCT). Retrieved from http://www.theicct.org/sites/default/files/publications/ICCTbriefing_RINs_20140508.pdf

The method we use to estimate value of RINs for a cellulosic biofuel (D3 RINs, which have essentially not been traded because (virtually) none have been produced and thus marketed), as stated by (Christensen et al., 2014), is as follows:

"In years that EPA reduces the cellulosic mandate (every year of the RFS2 so far) the agency must also offer "cellulosic waiver credits" (CWCs). In the case that obligated parties are unable to obtain cellulosic RINs (D3) they can purchase CWCs and retire them alongside an identical number of D5 or D4 advanced RINs, to fulfill their cellulosic obligation for the year.

The CWC price, combined with the price of D5 or D4 RINs, sets an effective cap on the price that an obligated party is likely to be willing to pay for any D3 or D7 cellulosic RINs that are actually available."

While it seems likely that future legislation will curtail or change the RFS requirements and associated RINs system and thus market price, our project assumption is that there will be some societal demand for greenhouse gas reduction and thus a method for giving a renewable biofuel a premium to assist in achieving that goal. While RINs may not be a 30-year enduring system to capture this, we use it as a currently existing method that serves as an indicator of the level of valuation that might be expected for a bio-fuel premium.

Thus the task becomes to project out 30 years what D3 RINs value might be, and we use the D5+CWC (Cellulosic Waiver Credit) method to estimate this, meaning we need projections of CWC and D5 RINs.

Cellulosic Waiver Credit Value Projection

Cellulosic Waiver Credit valuation is again like IPK and RINs valuation – we have historical values (Figure TEA-6.6) but they vary widely and are of little use for projecting 30 years into the future. Note that the CWC has historically been similar in magnitude to the underlying value we projected previously for IPK alone ($2.56/gal IPK), so CWC valuation is quite significant in projecting future total value for IPK as a renewable biofuel.

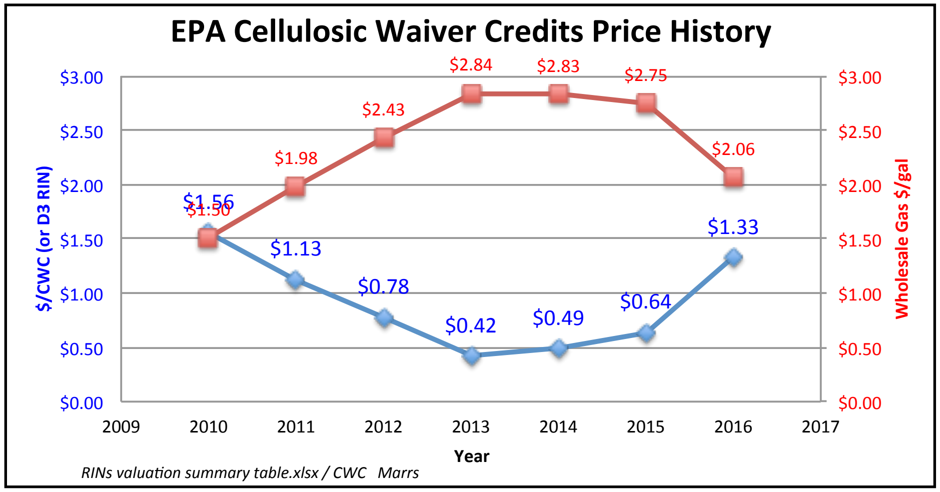

Figure TEA-6.6. Historical CWC prices as set by EPA. CWC values are indexed (inversely) against wholesale gasoline price, which has been highly volatile. Source data for CWC: (EPA, 2015). Source data for wholesale gasoline prices: (U.S. Energy Information Administration (EIA), 2016).

To project a future value of CWC we can examine the underlying formula relating it to wholesale gasoline, and use EIA projections for gasoline (like we did for petro-jet) for the 30-year project life. Since the EPA CWC formula uses wholesale gasoline prices rather than retail, as shown in EIA projections, we use federal and state gasoline tax values to reduce the EIA retail prices to wholesale. From this wholesale price we can calculate a CWC. The gasoline projections and resulting CWC are shown in Figure TEA-6.7. By formula, the CWC drops as the projected wholesale gasoline price increases, eventually reaching the $0.25/gal floor for CWC.

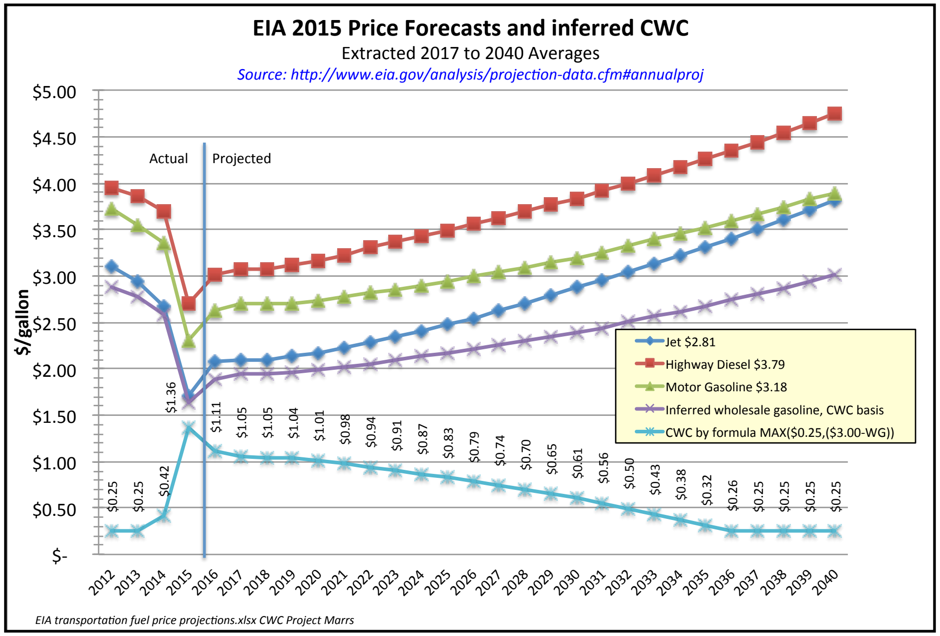

Figure TEA-6.7. EIA history and projections of retail gasoline, diesel and jet fuel. Source: Inferred wholesale gasoline (EIA, 2016). Source for federal and state taxes (American Petroleum Institute (API), 2016). CWC calculation based upon EPA formula. Source: (Biofuels Digest, 2015).

When the 2016-2040 CWC projection in Figure TEA-6.7 is set as a 30-year string (projected to 2046) and discounted at 10%, the PV-averaged value is $0.34 per CWC.

D5 RIN value projection

To project the valuation of the D5 RIN component of the D5+CWC valuation, a modeled prediction of future D5 RINs prices, as found in Christensen and Siddiqui (2015), can be used. Their projections (under two scenarios) are shown in Figure TEA-6.8.

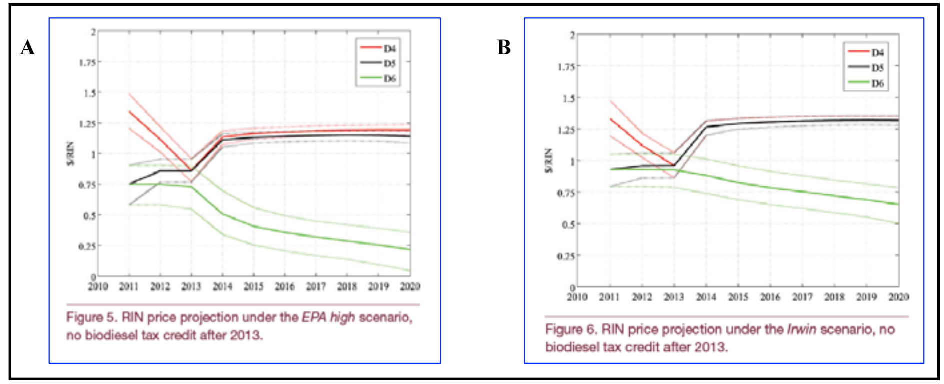

Figure TEA-6.8. Projections of D5 RINs bounded by the "high (A)" and "low (B)" biofuels production cases. Steady-state values go to ~$1.12 to $1.25/D5 RIN. Adapted from Christensen, A. & Siddiqui, S. (2015). A mixed complementarity model for the US biofuel market with federal policy interventions. Biofuels, Bio-prod. Bioref., 9: 397–411. doi:10.1002/bbb.1545

The average RIN price from Figure TEA-6.8 is about $1.20/D5 RIN.

D3 RIN (Cellulosic Biofuel) Value Projection

The D5 RIN value plus the PV-averaged CWC value of $0.34 gives a total of $1.54/D3 RIN. Since the EV of IPK is 1.6, the resulting IPK RIN value is $2.46/gal IPK.

This value projection is nearly equal to the underlying equivalence value of IPK against petro-jet, so is highly significant.

6.1.3 Internal Rate of Return

If the total value to the producer for IPK is taken as the equivalent petro-jet value (projected as $2.56/gal IPK), plus the bio-fuel premium as estimated by D3 RINs as a surrogate using $2.46/gal IPK, one can enter these as revenue values for the IPK and calculate an overall project IRR (rather than assuming 10% and calculating an MSP). Obviously, since the sum of value to IPK ($5.02/gal IPK) is less than the previously shown MSP to achieve 10% return, the IRR will be less than 10%. When these revenue assumptions for IPK are entered into the DCF/ROI model, the resulting IRR is about 3.7%. This would suggest that additional improvements or bio-fuel premiums would have to be achieved before a process like the NARA IBR would be financially attractive to many investors. A NARA TEA summary that reflects the economic impact of $5.02/gal IPK price is presented in Table TEA-6.1.

Table TEA-6.1. NARA TEA summary results if 30-year IPK pricing is at EIA projected petro-jet price ($2.56/gal IPK) and RINs projected value is $2.46 / gal IPK. TEA V 13.50.

NARA PNW Forest Feedstocks to Bio Jet Fuel - Techno-Economics

Revised	29-Nov-16	Case:	13.50
Authors	Gevan Marrs & Tom Spink		NARA $
	PNW Softwood to renewable IPK, LS, AC		
	Feedstock: OR Douglas-fir Forest Residuals (like FS-10)		
	Mild Bisulfite Pretreatment		

Case 13.50 MKT - Integrated Facility producing IPK, Lignosulfonates, and Activated Carbon

Annual Revenue

Product	Annual Product	Units	Revenue $/Unit	Total Annual Revenue, $MM	MKT $/gal IPK
Iso-Paraffinic Kerosene - IPK	35.7	MM gallons	$ 2.56	$ 91.49	**$ 2.56**
BioFuel Premium(s) / gal IPK	35.7	MM RINS	$ 2.46	$ 87.92	**$ 2.46**
		MKT $/gal IPK	***$ 5.02***		**$ 5.02**
Lignosulfonates	196,224	Dry tons	$ 200	$ 39.24	
Activated Carbon	66,192	Dry tons	$ 1,500	$ 99.29	
Total Annual Revenue (million $ per year)				**$ 317.94**	

Feedstock Supply to Mill Gate	846	Thousand BDT/yr
Feedstock to Conversion	770	Thousand BDT/yr
IPK BioJet Production	**35.7**	**million gallons per year**
IPK Yield	46.4	gal / dry U.S. ton feedstock
Feedstock Cost to Mill Gate	$61.55	/dry U.S. ton
Equity Percent of Total Investment	100%	
Internal Rate of Return (After-Tax)	**3.73%**	

Capital Costs, million $	
Feedstock handling	$56.5
Pretreatment	$105.0
Enzymatic Hydrolysis	$27.7
Fermentation, Separation & Alcohol-to-Jet	$146.0
Lignin Co-products	$123.9
IPK Product Storage and Distribution	$10.0
Multi-fuel Boiler	$43.2
Utilities	$124.7
Total Installed Equipment Cost	**$636.91**
Added Direct + Indirect Costs	$472
(% of TCI)	43%
Total Capital Investment (TCI)	**$1,109.1**

Manufacturing Costs (million $ per year)	
Feedstock + Handling	$64.7
Pretreatment Opex	$14.0
Enzymatic Hydrolysis	$29.4
Fermentation, Separation & Alcohol-to-Jet	$28.2
IPK Product Storage and Distribution	$0.05
Power Boiler	$3.2
Lignin Co-products	$24.8
Utilities	$13.5
Fixed Costs (Labor, Prop Tax, Insurance, Maint.)	$67.6
Total Manufacturing Costs	**$245.51**
Annual "Average" Income Tax	**$5.2**
Average Annual Cash Flow After-tax	**$67.1**

6.2 Carbon and Energy Balance

A full Life-Cycle Assessment (LCA) was done by a NARA team and is reported in the NARA Final Reports collection (NARA, 2016). Suffice it to say here that the greenhouse gas reduction level was sufficient to qualify for D3 cellulosic biofuels RINs, making the projections of biofuel premium made earlier technically plausible.

6.3 Water Balance

The NARA IBR process produces about 5MM gallons per day to the wastewater treatment system. It does not seem plausible to recycle wastewater internally to get to a near zero-discharge facility. We therefore carry significant capital and operating costs in the wastewater treatment facility. Due to uncertainty about specific mill siting location and associated permitting, there is no capital included for equipment discharge to receiving waters.

6.4 Cost Sensitivity Analysis[6]

6.4.1 Base Case

Extensive efforts were undertaken to develop sensitivity analyses based upon V 13.42, the "near Final" TEA in mid-2016. For the very small net changes made in V 13.43 and Dec-2016 to get to V 13.50 (less than 0.5% relative change in Capex, Opex, MSP, etc.) it was deemed not cost effective to update all the previous sensitivity curves since 1) there are many sources of cost and revenue assumption that almost certainly have much larger uncertainty that 0.5%, and 2) the portrayed curves probably move less than the width of the lines on the graphs. Accordingly, for this sensitivity analysis section we retain the use of V 13.42, where IRR is 3.6% and MSP is $7.31/gal IPK.

The NARA Final Base Case greenfield full-scale integrated biorefinery, assumed to be located in the Longview, WA area with IPK and RINs assumptions as discussed previously has an V 13.42 **IRR of 3.6%**. Sensitivity charts (for IRR change against Feedstock Costs, Capex, Opex, and Revenue. etc.) have been created to help assess how much IRR would be changed by varying individual key factors. Additionally, one "biofuel premium" IPK pricing strategy—based upon a blend pricing scenario—is quantified.

Note that the range of input values tested are not generally based upon probability estimates of likely future changes in that value, but instead are scaled to show how much change would be required to achieve a significant shift in IRR.

6.4.2 Feedstock Cost Sensitivity

Average delivered feedstock cost base case for V 13.42 was $62.60/BDST. Figure TEA-6.9 shows the impact of very large theoretical changes in feedstock cost alone. Even very large reductions in feedstock cost, by themselves, do not improve the IRR very much.

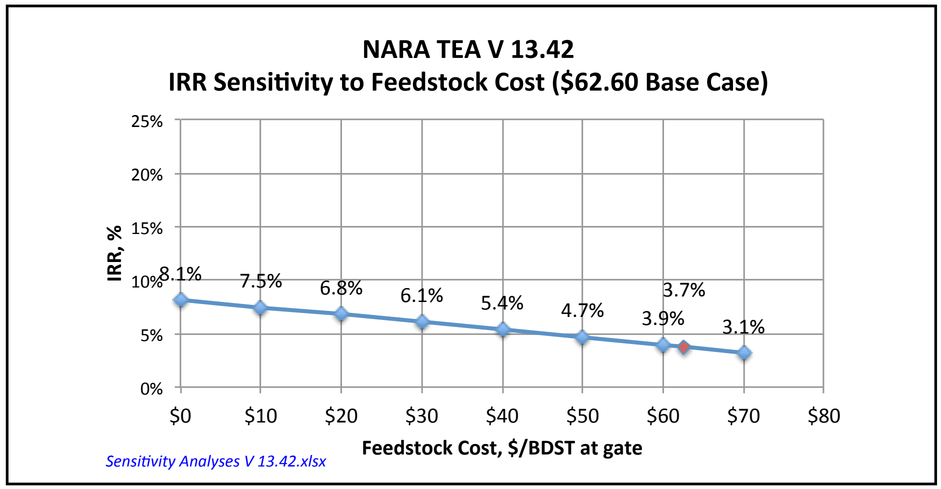

Figure TEA-6.9. NARA TEA IRR sensitivity to delivered feedstock cost.

[6] Most of the sensitivity analyses were done against the "near-final" Version 13.42. The absolutely final 13.43 is only very slightly different so the sensitivity values were not changed—they correct within the resolution of the graphs shown.

6.4.3 Capital Costs Sensitivity

The base case Total Capital Investment (TCI) in V 13.42 is $1,100 MM. The Fixed Capital Investment (TCI minus land cost and working capital) is $1,040 MM. Sensitivity to theoretical reductions in FCI (the depreciated portion of TCI) is shown in Figure TEA-6.10.

While very large reductions in “Capex” would improve the IRR considerably, we have no concepts for achieving even moderate reductions while holding everything else (capacity, products, etc.) the same. Even estimates of re-purposing existing facilities to reduce capital have shown only about a 10% reduction, which doesn’t improve IRR that much.

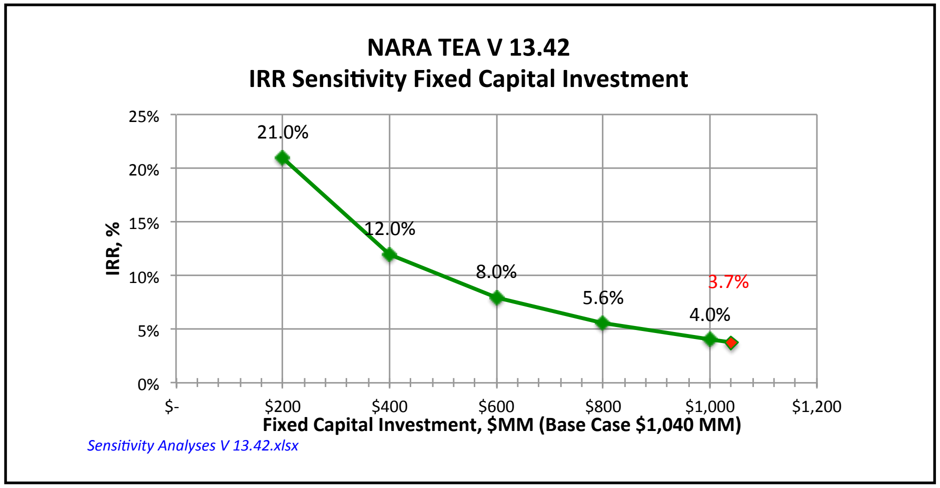

Figure TEA-6.10. NARA TEA IRR sensitivity to Fixed Capital Investment.

6.4.4 Total Annual Operating Costs

The NARA TEA base case V 13.43 annual operating expenses (Opex) are $246 MM/yr. Figure TEA-6.11 shows the impact on IRR of theoretical changes in Opex. The base case IRR is quite sensitive to changes in annual operating costs, however again we identified no concepts for achieving huge reductions in operating costs while maintaining the same facility size, products, etc.

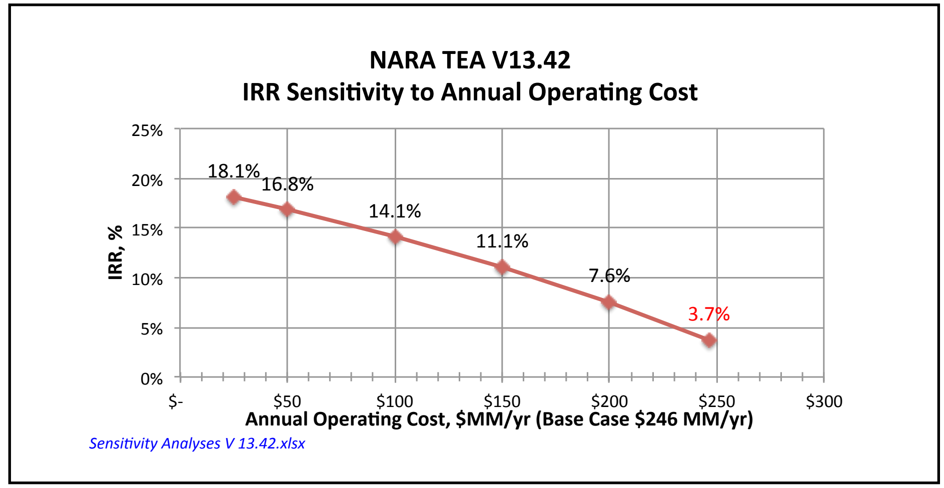

Figure TEA-6.11. NARA TEA IRR sensitivity to total annual operating costs.

6.4.5 Annual Operating Cost elements

Within the annual operating costs there are several components that could warrant a sensitivity analysis. Only those that comprise a significant portion of annual cost and have enough relative variation (either spatially, temporally, etc.) warrant further analysis. Candidates are electrical, natural gas, and labor rates. When these are examined compared to total annual costs (Table TEA-6.2) it can be seen that only electrical rates are a large enough portion of annual costs (and they have known large geographic variations) to examine for sensitivity analysis.

Table TEA-6.2. Major components of annual operating costs

Total OPEX	$	246.33	% of total
Total Electrical	$	24.91	10%
Total Labor	$	15.94	6%
Total natural gas	$	8.15	3%

6.4.6 Electrical Rate Sensitivity

One operating cost that varies widely within the US is electrical rate. Our base case assumes western WA siting, which has one of the lowest electrical rates in the country (we are using $43.5 / MWhr). Data from EIA for state average 2015 rates (https://www.eia.gov/electricity/data/state/) shows a range from $43.5 (WA) to a high for the contiguous US of $137.6 / MWhr in New England (RI), with a US average of $69.1 / MWhr. Using these as boundaries of possible rates, the effect on V 13.42 IRR is shown in Figure TEA-6.12. It can be seen that even the lowest feasible electrical rates, while economically helpful, are not sufficient to dramatically raise the IRR. On the other side, even US average electrical rates diminish IRR pretty significantly (~2.2%) and the higher US rates actually take IRR to less than zero.

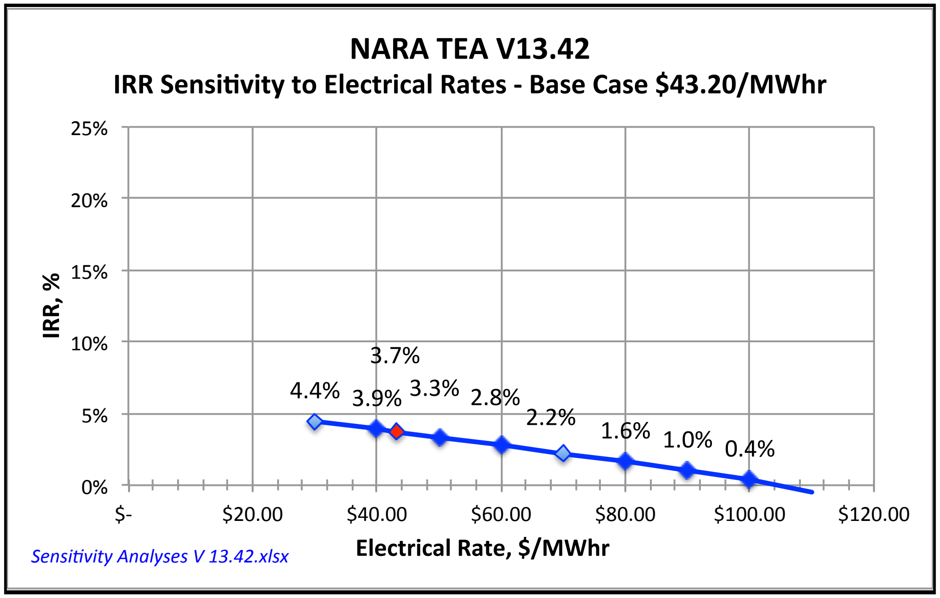

Figure TEA-6.12. IRR sensitivity to electrical rates

6.4.7 Revenue Sensitivity

IPK Revenue Sensitivity

Total annual revenue in V 13.43 with projected IPK selling price and D3 RINs value is $318 MM/yr. Of that total 12% ($39 MM/yr) is from lignosulfonates (LS) and 31% ($99 MM/yr) is from activated carbon (AC) sales. Of the remaining revenue, ~29% ($91 MM/yr) comes from IPK sales at jet pricing assumptions ($2.56/gal base case), with an added 28% ($88 MM/yr) for the RINs generated from renewable IPK. Thus all told the renewable IPK is responsible for 55% of the project revenue. For the revenue sensitivity analysis we held LS and AC fixed at the values above, and only varied the revenue per gallon of the IPK. Figure TEA-6.13 shows sensitivity to IPK pricing.

Clearly, increasing revenue, and specifically from increased selling price for the IPK, is quite powerful for increasing IRR. The main reason for the potential improvement here is that unlike costs of Capex and Opex, which are very hard to reduce by even 10% much less by half, the theoretical pricing for a volatile product like IPK (based on petro-jet equivalence pricing and historical volatility) could rather easily double over the assumed base case of $2.56. Additionally, biofuel premiums are hard to estimate and depend more on societal values than technology.

Note that the reference line for a minimum selling price (MSP) for IPK to achieve 10% IRR is shown ($7.31/gal IPK total revenue is needed, which could be $4.80/gal IPK with an added $2.46/gal RINs for a renewability premium.)

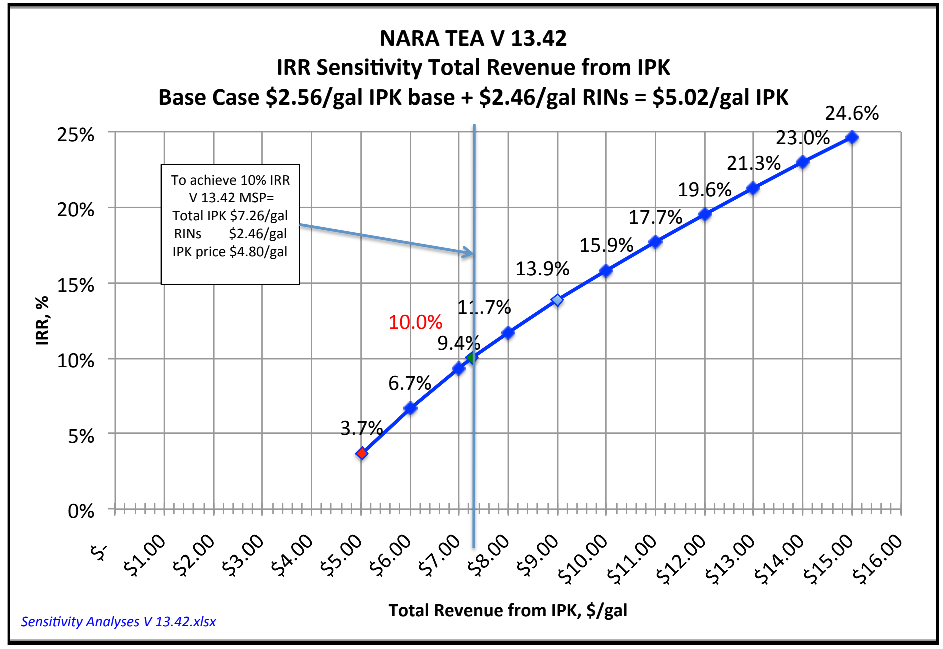

Figure TEA-6.13. NARA TEA IRR sensitivity to revenue from selling price of IPK.

Bio-Fuel Premium Blend Pricing Strategy

An example of how this unit selling price biofuel premium for IPK might be achieved is called here a “blend pricing strategy”. The premise is that bio-jet end users (e.g., the airlines) are willing to pay a relatively small price increase for the overall blend of jet fuel and IPK in order to have a partially-renewable fuel stream. The biofuel premium paid on the basis of a small increase for the overall blend would then accrue solely to the IPK component, which gave the renewable component. If the blend percentages are relatively small, then even a small increase in the overall blend price gives quite a significant lift to the renewable component. There are of course an infinite number of possible blend premiums and IPK blend percentages, and these give a very wide array of potential IPK prices and thus IRR values for the NARA IBR. Table TEA-6.3 shows values of selected combinations and Figure TEA-6.14 shows some of the plausible ranges of blend bio-premiums and IPK blend percent-ages, and the IRR result to NARA V 13.43

Table TEA-6.3. Scenarios for a "bio-premium" adder to total fuel blend price varying IPK blend percentages and all premium accruing to the renewable fuel portion (IPK).

Jet Price	$2.56			
	Bio-premium, $/gal blended fuel			
	$ 0.05	$ 0.10	$ 0.15	$ 0.20
	Selling price of IPK portion, $/gal IPK			
	Net price to buyer per gal blended fuel			
Blend % IPK	*$ 2.61*	*$ 2.66*	*$ 2.71*	*$ 2.76*
1%	$ 7.56	$ 12.56	$ 17.56	$ 22.56
2%	$ 5.06	$ 7.56	$ 10.06	$ 12.56
3%	$ 4.23	$ 5.89	$ 7.56	$ 9.23
4%	$ 3.81	$ 5.06	$ 6.31	$ 7.56
5%	$ 3.56	$ 4.56	$ 5.56	$ 6.56
10%	$ 3.06	$ 3.56	$ 4.06	$ 4.56
25%	$ 2.76	$ 2.96	$ 3.16	$ 3.36

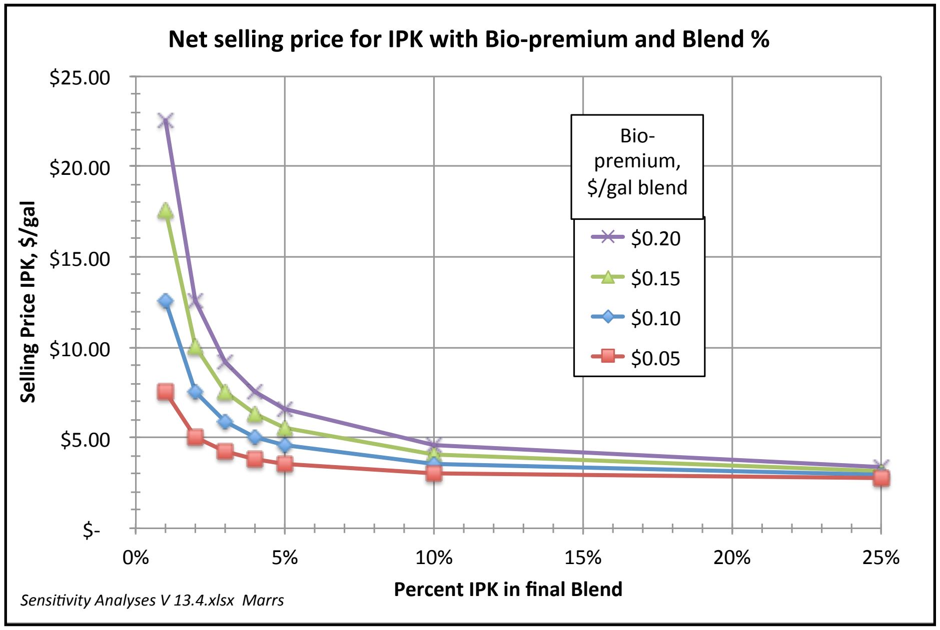

Figure TEA-6.14. Selling price for IPK portion of blends with bio-premium on the blend.

A specific example may help better understand the mechanics of the strategy. Assume that an airline would be willing to pay an additional $0.20 / gal of blended fuel containing renewable jet (IPK). Assume they would be comfortable with only 1% of the blend consisting of IPK. The $0.20/gal jet blend accrues entirely to the IPK portion, yielding $22.56/gal IPK (the highest point on Figure TEA-6.13).

From the perspective of the biorefinery, the IRR is only dependent (with this change alone) on the selling price of the IPK. Figure TEA-6.12 showed previously the IRR with various IPK selling prices. Because IRR is determined by changes in IPK selling price, one can functionally fit the curve in Figure TEA-6.12 and then translate the Y-axis of Figure TEA-6.14 to IRR instead of selling price. Although not exactly linear, that is a close enough approximation, yielding"

IRR % = - 0.0303 + 0.0224*(IPK Price, $/gal) $r^2 = 0.990$

Transforming the price to an IRR gives the relationships shown in Figure 6.15.

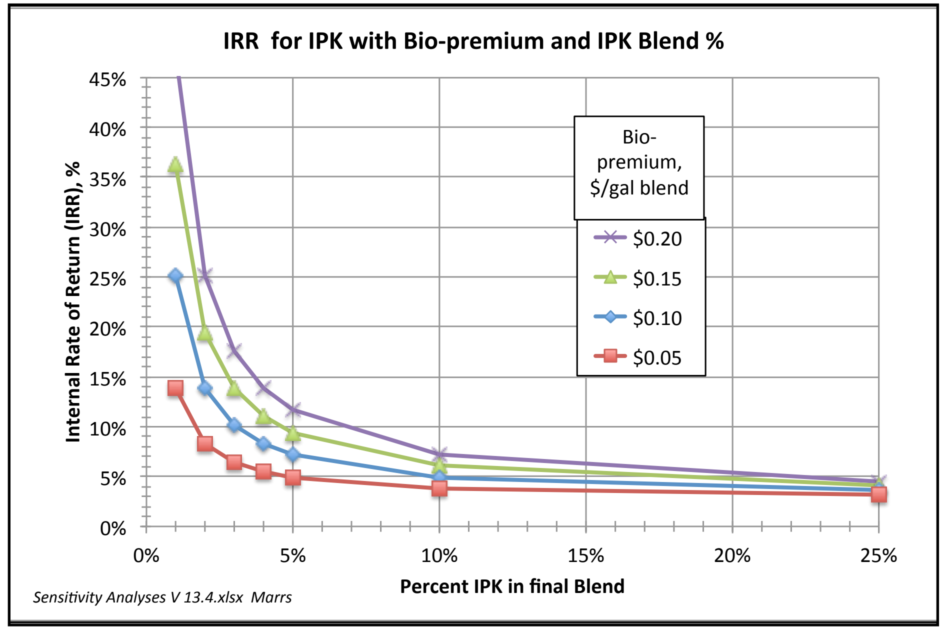

Figure TEA-6.15. Alternatives for blend percent and bio-premium for the blend – impact on IRR.

To use the data in Figure TEA-6.15, one can:

1. Choose a needed IRR for the project. Let's say for illustration it is the NREL / BETO standard 10% comparison case.

2. Negotiate with an IPK purchaser for a 30-year contract for IPK with a price for IPK sufficient to yield that IRR (e.g., $5.63/gal IPK), where they do this by:

    a. Only paying a relatively small premium per total blended gallon of petro-jet + IPK, and

b. Only blending in a relatively small percentage of IPK in order to hold the blend total to the target.

c. This can be done by any combination along an IRR line in TEA-6.14. For 10% IRR (or equivalently $5.63 per gal IPK in Figure 6.13), they could:

   i. Add about 2.3% IPK with only a $0.05/gal blend premium

   ii. Add about 3% IPK with a $0.10/gal blend premium

   iii. Add about 5% IPK with a $0.15/gal blend premium

   iv. Add about 7% IPK with a $0.20/gal premium

   v. and so on…

Note that the refinery would need to have a 30-year contract at the net IPK price in order to achieve the stated IRR for the project life. The choice(s) about blend bio-premium and blend % are really the airlines business decision, not a technical decision of the biorefinery. Also note that the NARA TEA is an Nth plant assumption—everything goes correctly in purchasing, construction, startup, operation and it is a full-scale facility. A startup facility having both pioneer plant economics, and being smaller for less cost risk in a first facility (less economy of scale) would require significantly higher MSP values for IPK in order to achieve a given return on a first facility. Estimates of these conditions (pioneer plant and reduced scale) have not been estimated for NARA but could be inferred from published literature.

6.4.8 Lignin Residue Co-products Revenue Sensitivity

While we examined IPK revenue sensitivity in section 6.4.7, any change in total project revenue, whatever the source, has the same impact. While the LS market is relatively established and defined, the AC market (particularly for renewable, wood-based AC) is not well-known and has an unpredictable future. Both LS and AC contribute considerable portions to the revenue assumptions in the NARA version V 13.43, so improvement options are worth considering as well.

6.4.9 Total Revenue Sensitivity

The overall impact of total revenue, regardless of source, was shown previously in Figure TEA-6.13.

6.4.10 Summary of Sensitivity Analysis

Getting the NARA process IRR up to the benchmark 10% is simply not plausible with feasible cost reductions in either Capex or Opex. The only viable route with significant (theoretical) upside potential is a significant increase in revenue.

7) Comparison of Results to Related Techno-economic Analyses[7]

A literature survey was done in early 2016, resulting in about 25 articles, of which we have determined that about 16 have both relevance and sufficient detail disclosed to allow us to gather and compare key metrics, including among the most important:

- Total installed capital
- Feedstock scale, type, and cost
- Conversion path (biochemical, thermochemical)
- End biofuel product (ethanol, hydrocarbons, etc.)
- Yield of biofuel on feedstock (gallons fuel per ton feedstock)
- Operating costs
- Overall IRR, or alternatively Minimum Selling Price of fuel to achieve set return (usually 10%).
- Other important factors ($year for cost estimates, State of Technology Year assumptions, etc.)
- Inclusion of *all* project elements needed to be "realistic".

The relevant data was extracted, converted to our units, and compiled in a database. While this effort has been considerable (for example, $Year costs, $ units, scale differences, liters, all required adjustment to make a useful comparison database). Since some articles compared multiple options, there were a total of about 50 separate reported options to compare our results against.

Published information relating to biofuels production economics can broadly be divided into two categories. One type of information is what could be called "entrepreneurial disclosures". These are typically press releases or mentions of high level information, such as scale of a facility purportedly going to be constructed, dollars that will be invested, usually feedstock type and biofuels output type and quantity described. Rarely, if ever, do such disclosures have sufficient detail available to allow determination of whether the "money to be invested" is the same as our installed equipment cost, or total fixed costs, or total capital investment, etc. Virtually never is the data presented that cites the underlying information about unit operations costs, much less individual equipment costs, scaling, etc. For these reasons (essentially, they are not TEAs, they are limited economic disclosures) such articles are of limited use for our TEA literature review and comparison.

[7] Most of the literature comparison was done against the "near-final" Version 13.50. The absolutely final 13.43 is only very slightly different so the literature comparison values were not changed—they are correct within a few cents per gallon.

The second category of literature publications are true Techno-Economic Analyses (TEAs). These invariably disclose all the higher summary level details of importance, however, these types of publications can be further split into two categories:

1. "Detailed TEAs" – these are like the typical TEAs done by NREL, INL, and PNNL, usually under the auspices of the U.S. Department of Energy Bio-Technologies Energy Office Multi-Year Program Plan (DOE BETO MYPP). These are characterized by a nearly uniform methodology, assumptions, analytical approach, results formats, and disclosure of extensive detail (these reports are usually 150-200 pages long.)
2. "Summary Published Results" – these are distilled reports, published in journals, and contain the final key results but not the underlying details, like flow diagrams, mass and energy flows, equipment lists and costs, etc. They are, however, frequently summaries pulled from the very long and detailed TEAs listed above, thus many can be set aside if the associated detailed article is included in our review database.

These latter publication types—actual TEAs—are the basis of the subsequent detailed review and comparison. It should be noted that because many technology assumptions change over time, TEA articles prior to about 2009 were (generally) not included. Secondly, many of the process-product combinations are those selected as most promising routes by BETO, many of the reports are revisions / modifications / adaptions of prior reports using most of the same methodology and many of the same numbers. For example, the NREL Corn Stover-to-Ethanol via biochemical route has been reported 4 or 5 times during this last decade. We have tended to focus primarily on the just the most recent report for a given pathway[8], on the assumption that the latest report has the most up-to-date view of technical details and economics.

It must be emphasized here that the objective of the comparison review is to gain insight and understanding in whether and how this report's final results differ from published information, and by this review help identify any significant calculation errors, assumptions to be re-considered, or process constraints inherent in the boundary conditions set in the NARA project, that is: softwood feedstock converted via biochemical path (specifically Gevo GIFT and ATJ process) to hydrocarbon – IPK with lignin-rich residue co-products.

[8] A "pathway" here is used to describe a combination of feedstock, conversion method, and end biofuel product(s).

7.1 MSP results comparison

The key result of MSP is extracted from published TEAs and compared to NARA TEA V13.42 MSP of \$7.26/ gal IPK biofuel. The results are as shown in Figure TEA-7.1. The NARA process has a measurably higher MSP than the reported literature TEAs. We have chosen to array the literature values by publication year, on the assumption that the more recent are more likely to be the view based upon most recent technology assumptions.

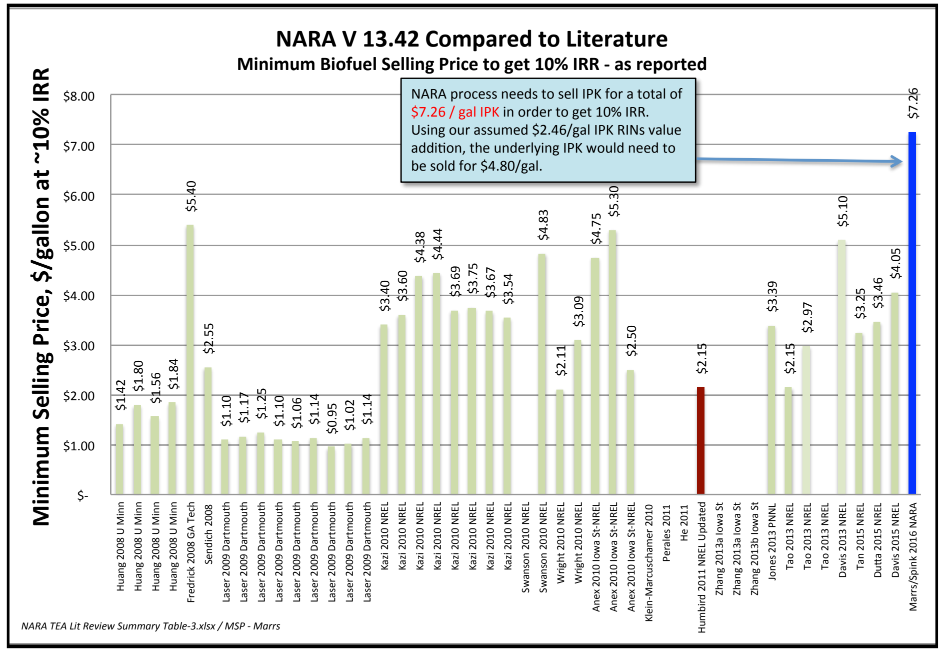

Figure TEA-7.1. NARA IPK revenue needed to give 10% IRR (MSP), compared to literature TEA reports. (There are a number of reports from which we cannot extract an MSP). TEA reports are listed in the Reference section of this report.

It is clear that compared to results reported in the last five years, that NARA MSP is roughly twice what is being reported elsewhere. Since selling prices of the biofuels do not impact calculated MSP values, one must conclude that the combination of Operating Costs (Opex) and Capital costs (Capex) must be greater for NARA. The underlying causes of the difference are investigated below.

7.2 Capital Costs Comparison Overview Results

7.2.1 Total Capital Investment

There are a number of specific types of "Capex", or capital costs normally discussed in a TEA – purchased equipment costs (PEC), installed equipment costs (IEC), fixed capital costs (FCI), and total capital investment (TCI). The comparison below rolls the Capex up to the highest level—TCI. All comparison numbers have here been adjusted to \$2014 basis, and wherever needed the scale of facility adjusted to the very common 2,000 mt /day feedstock, or 2,200 BDST/day, just as used in NARA (although most were published at that same capacity basis).

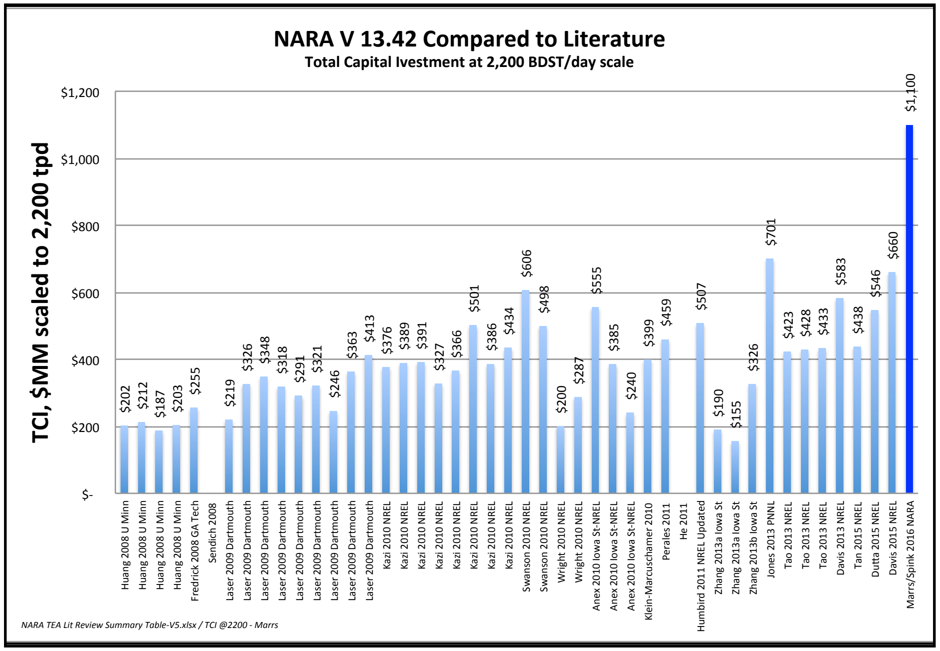

Figure TEA-7.2. Total capital investment, TCI, in $2014 for 2,200 BDST scale. Reports are listed in the reference section of this report.

The first comparison is to look at TCI for all studies on facility basis, shown in Figure TEA-7.2. The NARA TCI compared to other reports is notably higher. One reason for this is that none of the reported biofuels TEAs had lignin-residue co-products being sold. They were instead used for energy generation inside the conversion facility (at times generating excess electrical power for sale to reduce net operating costs). Of course the additional processing equipment needed to partially dry the LS for shipping and production of AC adds capital that other reported pathways do not have. It is very difficult to account for capital for these co-products since if instead they were burned for energy, there would be some offsetting additional expenses in that operation. As reported previously, the addition of lignin-residue co-products to the NARA process is clearly economically favorable over simply burning them for energy, so no attempt was made here to rigorously identify and remove "extra" capital for co-products. Suffice it to say that a main reason NARA process has more capital is that the process is more complex than reported biofuels TEAs.

7.2.2 Capital Investment per Gallon Biofuel Product

It is common to also express this TCI on a unit biofuel basis for output fuel to normalize between either different facility scales, and/or different conversion process pathway yields. Since all values have been to the same feedstock scale, comparing on a per gallon biofuel basis shows differences from yield impacts. Figure TEA-7.3 shows the comparison of TCI on a per-annual gallon biofuel capacity basis, which shows that on a unit basis, NARA is even more different (more like 3 times higher) than the literature values than simply on a TCI basis.

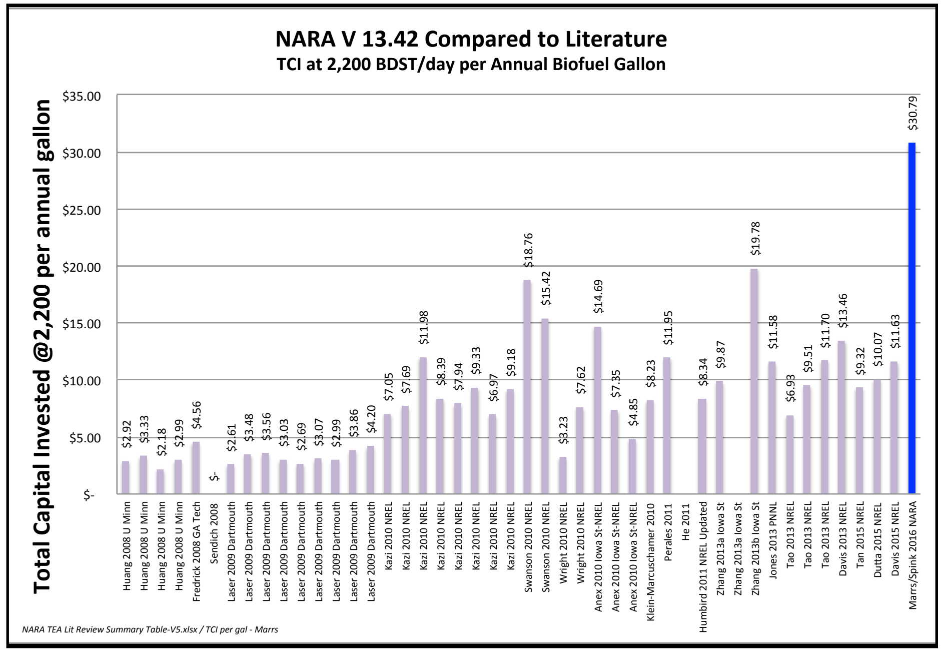

Figure TEA-7.3. Total Capital Investment on a per-gallon biofuel annual capacity basis. Reports are listed in the reference section of this report.

Since we have shown previously that the TCI was higher, and attribute much of that to additional complexity for co-products, it is not surprising that spreading all the capital over just one product (the IPK) gives a higher unit cost for the biofuel component. Additionally, however, if the yield of biofuel per ton of feedstock is measurably different (that is, lower) then unit capital costs would be higher even if TCI was the same.

Investigating TCI$/annual gallon differences

Obviously, TCI is often loosely related to the feedstock scale, and since we have adjusted all to the same scale, then TCI/annual biofuel gallon is strongly impacted by yield of biofuel per ton of feedstock. Figure TEA-7.4 shows the biofuel yields for NARA compared to the selected TEAs. Two particular observations might be made. The first is that there seems to be some unrealistic optimism for very high yields in the earlier works, as it does not seem that as the technology improves over the years that the yields should generally decline. Also, some of the more recent work with quite low relative yields (~20-25 gal/BDST) is due to using part of the feedstock to generate hydrogen for hydro-treating bio-oils in thermo-chemical pathways.

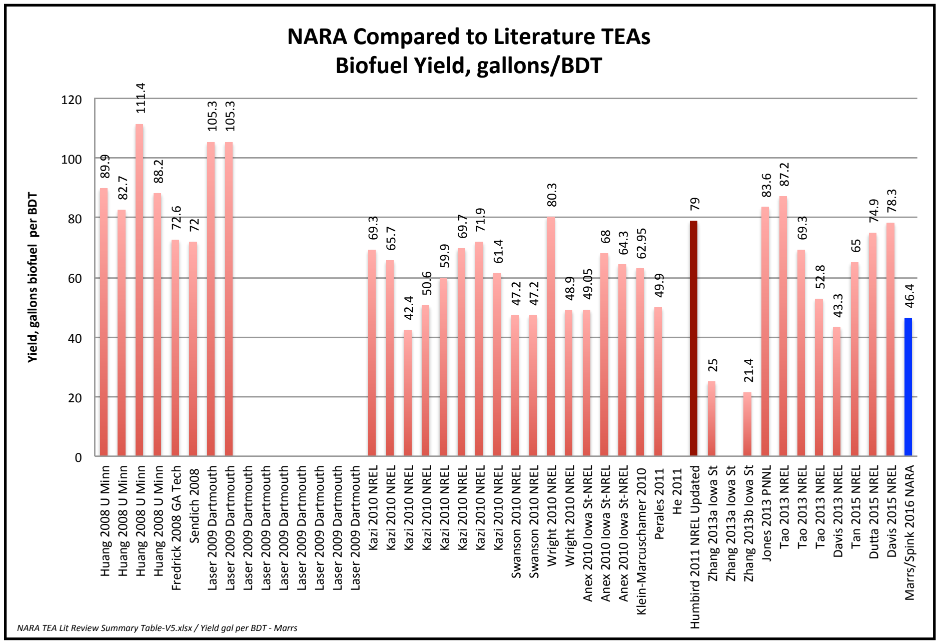

Figure TEA-7.4. Yields of biofuels, on a gallon gasoline equivalence, per dry ton of feedstock. Reports are listed in the reference section of this report.

Due to the complexity of comparing NARA to specific underlying details at the next level of detail, we have chosen to focus on one key TEA—the NREL CSTE (Humbird et al., 2011). This the most recent NREL detailed report on the biochemical conversion pathway. As a biochemical pathway, this is the most like the NARA process up to the production of an alcohol fuel (NARA then adds ATJ and co-products).

The fundamental reason for the lower NARA yield on feedstock (46 gal/BDST) compared to NREL CSTE (Humbird et al., 2011) (69 gal/BDST) can be viewed in two ways. One is that, compared to an ethanol fuel product, NARA takes an alcohol (IBA) on to hydrocarbon fuel, at a yield reduction in gallons of hydrocarbon biofuel. For comparison, our IBA production assumption in the TEA is about 65 gal IBA/BDST. If compared on the basis of hydrocarbon output product, the thermochemical route converts much of both polysaccharides and lignin to biofuels, whereas biochemical route only uses the 60% or so of the feedstocks that are polysaccharides. Where NARA process only uses polysaccharides toward the biofuel, and the final product is hydrocarbons, the total yield is less.

There are also a few other key high level differences in the NARA IBR and TEA that cause significant differences in TCI$/annual gallon. We are the only TEA for a process starting with softwood, conversion via biochemical (fermentation) to a hydrocarbon, with significant co-products expense expressed against biofuel only. The approximate contribution of these differences is examined below.

Impact of NARA lignin co-products on TCI

Not one of the comparison TEAs reviewed has a lignin co-product, but our TEA does have significant capital associated with both LS and AC co-products production. This makes a comparison of total capital for all products, spread over just the biofuel component, a different basis that all other reported literature. While perhaps not all LS Capex can be removed (as something must be done to prepare the lignin for a logical alternative, like energy production for the IBR), still we can make a ballpark estimate of the impact of this process difference compared to literature reports. Removing the ~$214 MM TCI in the NARA TEA for lignin co-products drops the TCI$/annual gal IPK to about **$19**.

Impact of pretreatment difficulty of softwood on TCI

It is widely known that softwoods have “recalcitrant” lignin, which makes effective enzymatic hydrolysis difficult without relatively complex pretreatment compared to hardwoods or herbaceous lignocellulosic feedstocks when using a biochemical conversion process. As an example of this, the pretreatment time in the digester for NARA softwood by MBS is 240 minutes. The NREL corn stover pretreatment time is only 2 minutes—less than 1% as long (Humbird et al., 2011). The residence time has a direct implication for the volume of the reactor/digester, and thus the cost. This explains the absence of TEAs for softwoods via biochemical path in the BETO MYPP scenarios (NREL, 2016). The two main routes focus on herbaceous (corn stover or switchgrass) to ethanol via biochemical (fermentation), and thermochemical route when softwoods are a potential feedstock. If we conceptually reduced the pretreatment difficulties of our softwood, having $105 MM installed equipment cost, (IEC) with the NREL corn stover pretreatment of only $29MM IEC, the reduction in NARA TCI is about $122MM, which combined with the reduction above would further reduce the TCI$/annual gallon to about $16 TCI$/annual gallon.

Alcohol vs. Hydrocarbon end product

The yield difference between going to IPK hydrocarbon fuel compared to stopping at the fermentation alcohol IBA, (~46 vs 65 gal/BDST respectively) would increase total plant output from ~36 MM gal/yr IPK to ~50MM gal/yr. That alone, with the same TCI, gives a further reduction in TCI$/annual gal fuel to about $12 TCI$/annual gal. Of course if one does not make IPK, the Capex for ATJ block can be removed. The breakout of fermentation, separation and alcohol-to-jet (FS&ATJ) Capex was not disclosed to NARA, however removal of ATJ capital would further reduce Capex$/annual gallon. These values compare quite favorably with the NREL CSTE (Humbird et al., 2011) reported costs per gallon biofuel (~$8/annual gallon ethanol). While stopping at IBA production might be an option to investigate, the boundary conditions of the NARA Greenfield IBR TEA from the project outset have included producing jet biofuel, not other biofuel or chemical products. Quantifying other options is outside the scope of this report.

Cumulative effect of Capex (TCI) differences

It should be noted that this comparison is not intended to suggest than NARA should have used corn stover as a feedstock (softwoods are the renewable lignocellulosic feedstock in the PNW), it only helps to understand whether there are underlying reasons for higher apparent TCI, or if the difference lies in different assumptions about equipment costs, installation costs, indirect cost factors, etc.

A summary of the accumulated differences decribed above is shown in Figure TEA-7.5, where it can be seen that with these key differences much of the comparison difference to key recent literature values disappears.

Note that this discussion and portrayal of differences does not mean we are suggesting that making these changes is a way to achieve NREL CSTE (Humbird et al., 2011) returns of 10%. We have been bounded in this project to use softwoods, and to use the Gevo processes for IBA and IPK and end up with biojet as a product, and to add lignin co-products that are highly favorable to the economics.

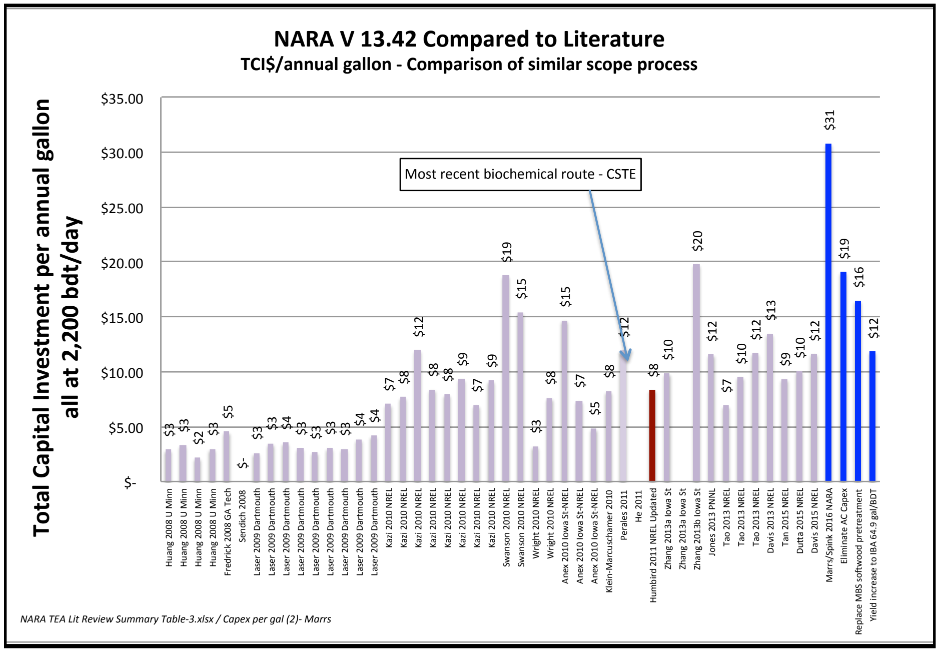

Figure TEA-7.5. Cumulative effect of major process and feedstock differences for NARA compared most recent NREL TEAs, and CSTE in particular. Reports are listed in the reference section of this report.

Comparison to hydrocarbon biofuels pathways

Since the NARA end product is a hydrocarbon biofuel instead of ethanol, despite conversion process differences we can compare overall capital per gallon of biofuel. The two most current BETO MYPP routes with hydrocarbon end products (gasoline, diesel) are (Dutta, 2015) and (Davis, 2015), both NREL TEAs for BETO MYPP. These are highlighted in Figure TEA-7.6. The NARA capital/annual gallon is considerably higher than either NREL route to hydrocarbons, both due to lower yield per gallon feedstock, and higher capital for a 2,200 tpd feedstock facility.

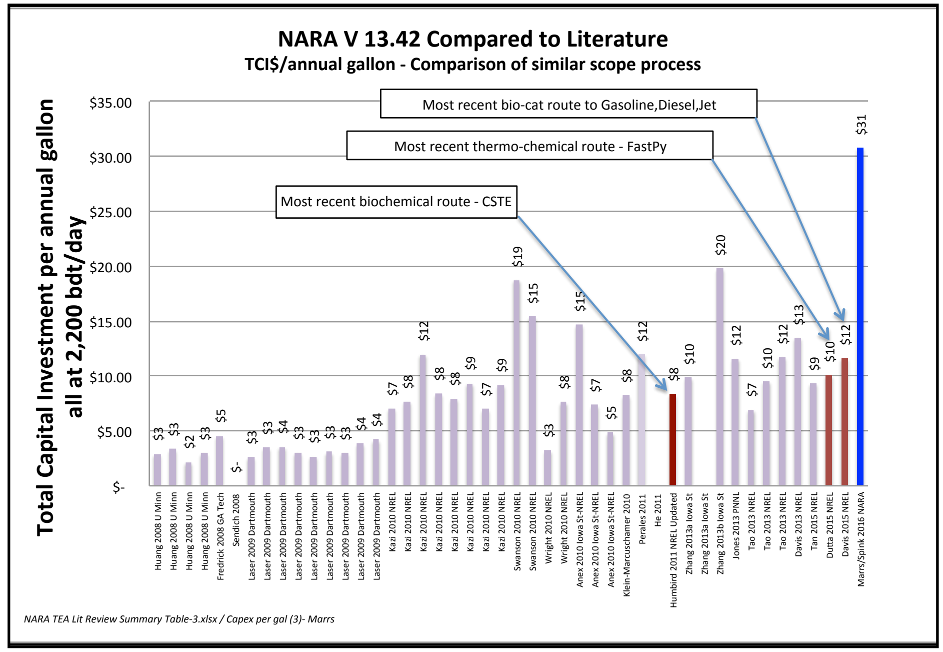

Figure TEA-7.6. NARA capital per annual gallon compared to most recent NREL hydrocarbon TEA routes. Reports are listed in the reference section of this report.

This comparison, however, is not entirely valid since the NREL BETO TEAs report target values for the future, not current State of Technology.

7.2.3 State of Technology

While one might assume that over this ~7-year time frame, shown earlier in Figure TEA-7.1, we might expect TCI and TCI/annual gallon to be declining as technology gains are made. In fact, if anything, there is a slight trend toward increasing reported TCI and TCI/gallon estimates as time goes by (even for the same pathway) and further information is gained. One report describes this as a typical pattern often seen – an optimism in early stages that diminishes as better cost estimates become more inclusive of all needed elements. This is mentioned because, as we will see, NARA TEA staff have attempted to realistically include all needed elements to actually build and operate such a facility in the very near term, whereas many of the reported TEAs are actually hopeful projections of either what might be achieved in the future, or even less comparable, estimates based on needed results (targets) in order to be successful, whether those are supported by hypothesized paths to achievement or not. This is not to say these comparison TEAs are invalid—just critical to understand that their main purpose was/is actually to identify needed technology focus areas in order to achieve economic viability. Accordingly the BETO State of Technology (SOT), year assumptions must be carefully examined for reported values to understand whether and how to compare results.

A significant example of this can be shown by examining data from one recent NREL TEA—that for Fast Pyrolysis (Dutta et al., 2015). While the summary page shows—as plotted above—a TCI$/annual gallon of $10.07, reading the body of the report notes that this is based upon a 2022 SOT target from the MYPP. Going to BETO MYPP report for Mar-15 shows the $TCI/annual gallon project changes for this one pathway, shown in Figure TEA-7.4. The view of current SOT (2014) TCI$/annual gallon is nearly twice the target for 2022, but the 2022 target is what is reported in the 2015 TEA. That is, the purpose of the report is to assess the feasibility (or needed improvements) to achieve a particular cost target by a future date. As shown in Figure TEA-7.3, this can be very different from assessment of current SOT. Since the NARA process elements have largely been demonstrated at considerable scale, the SOT for NARA is clearly already at a 2015 level, and to correctly compare to literature we should use 2014 or 2015 SOT values, not future targets.

Comparing the NARA IBR TCI to the 3 most recent BETO hydrocarbon pathways[9] that convert cellulosic to hydrocarbon fuels (Table TEA-7.1), Figure TEA-7.7 shows the change from the future target values compared to extracted 2014 SOT levels in the MYPP for that pathway.

Table TEA-7.1. Comparing the NARA IBR TCI to the 3 most recent BETO hydrocarbon pathways that convert cellulosic to hydrocarbon fuels. Reports are listed in the reference section of this report.

Name Used	Feedstock	Conversion	End BioFuel	Source
Davis 2013 NREL '14 SOT	corn stover and switchgrass	Hybrid biochem to sugars, thermochem to hydrocarbons	gasoline and diesel	Davis et al. 2013
Dutta 2015 NREL '14 SOT	Hardwood and Softwood	Fast Pyrolysis	Gasoline and Diesel	Dutta et al. 2015
Davis 2015 '14 SOT	corn stover and switchgrass	Hybrid biochem to sugars, thermochem to hydrocarbons	diesel and naptha	Davis et al. 2015

[9] Because the Humbird et al. (2011) NREL CSTE report was considered concluded, no further BETO investigations into advances have been reported since 2011, so that information is somewhat dated. Furthermore, the significant differences in feedstock and end product, and lack of co-products, makes TCI comparison to NARA relatively un-useful, so this route is not compared further here.

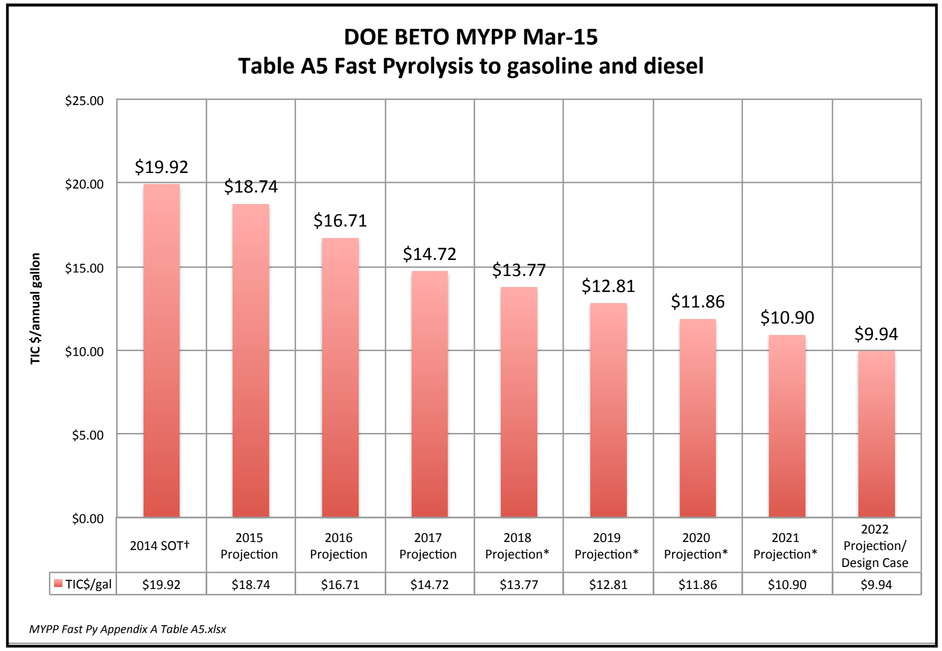

Figure TEA-7.7. Impact of State of Technology (SOT) assumption on fast pyrolysis capital costs.

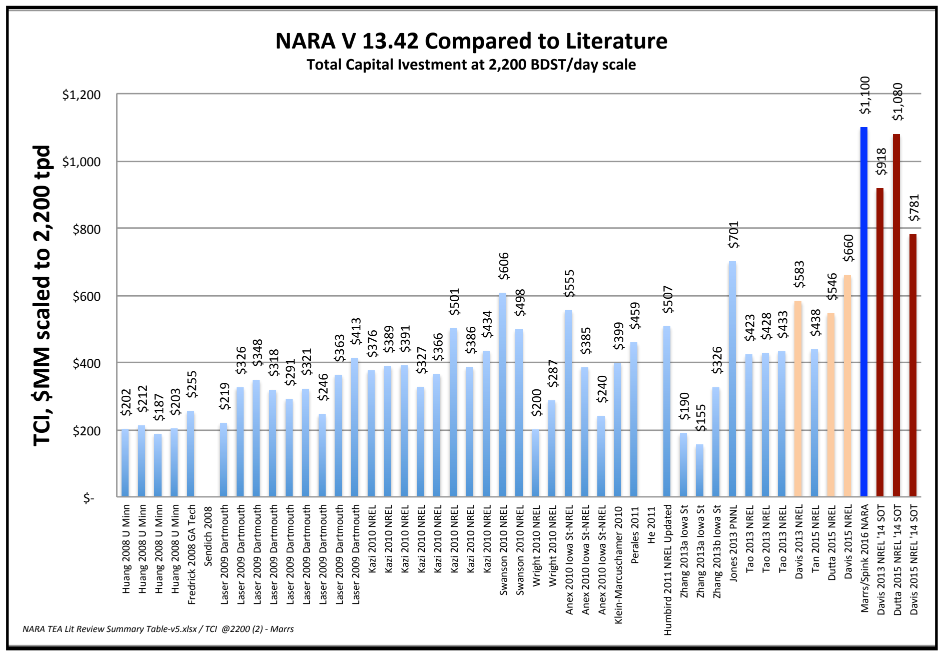

Figure TEA-7.8. Total Capital Investment for current (2014) SOT for 3 recent BETO MYPP pathways to hydrocarbons. Reports are listed in the reference section of this report.

It can be seen that when current SOT TCI estimates are used for BETO pathways to hydrocarbons, the NARA process is only slightly higher in TCI (Figure TEA-7.8). Given that we do have co-products and none of the BETO pathways do, this is surprisingly similar in TCI.

7.3 Capital Cost Elements Investigation

Regardless of the analysis described in section 7.2 of this report, which explains that a pathway choice is driving much of the current Capex per gallon, there still remains, for the most relevant conversion pathway comparison case (NREL CSTE), a somewhat higher TCI estimate. Since TCI is a factored cost that begins with vendor quotes for individual equipment, sized by scaling factors, then factored up to installed equipment costs (IEC), then these factored up to TCI by using indirect costs components factors, any of these elements (starting costs, scaling factors, installation factors, indirect costs factors) can be a part of ultimate differences. Only by digging down to this level of detail on the elements of capital costs can we understand the reason(s) for the remaining Capex differences, after we have "explained" the process basis differences.

Each of the components of the factored TCI were investigated by examining comparative sources from NREL BETO reports (mostly using the NREL report that was the starting basis for the NARA TEA: Humbird et al. 2011 NREL CSTE. Summary findings about each of these investigations are described below.

7.3.1 Indirect Costs Factor(s)

Fortunately, since the NARA TEA was actually based upon, and actually built upon the exact underlying TEA Excel spreadsheet used for the Humbird et al. 2011 NREL CSTE, and we attempted to adopt virtually all NREL assumptions and calculations as a beginning point, there are actually very few differences in the Indirect cost factors. The factored items included in the NARA TEA are shown in Table TEA-7.2, where the installed equipment costs (IEC) have added to them other direct costs (warehouse, site development) to give total direct costs (TDC) which is then factored up to fixed capital investment (FCI), to which factored land costs and working capital are added to get to Total Capital Invested, TCI.

Suffice it to say here that nowhere in this string of factors does NARA assumptions vary significantly from NREL, hence this is not a significant contributor to resulting TCI differences.

Table TEA-7.2. NARA indirect costs as a percentage of Total Direct Costs (TDC) are derived from Humbird et al., 2011 NREL CTSE data.

Prorateable expenses	10% of TDC
Field expenses	10% of TDC
Home office & construction fee	20% of TDC
Project contingency	10% of TDC
Other costs (start-up, permits, etc.)	10% of TDC
Total Indirect Costs % of TDC	**60%**

7.3.2 Equipment Installation Factors

Since total purchase equipment cost (PEC) estimates get factored by a significant installation factor, differences in this assumption could be a component in explaining final differences in TCI. For the NREL detailed TEAs, it appears that a considerable variation in assumptions has occurred and still occurs between pathways. This is despite the commonality of source for the underlying purchased and installed equipment cost estimates (all done by Harris Group). The NREL CSTE (Humbird et al., 2011) uses the following simplified values shown in Table TEA-7.3.

Table TEA-7.3. NREL CSTE equipment installation cost factors. Reprinted from Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol Dilute-Acid Pretreatment and Enzymatic Hydrolysis of Corn Stover (p. 59), by Humbird, D., Davis, R., Tao, L., Kinchin, C., Hsu, D., Aden, A., Schoen, P... & Dudgeon, D., 2011: Golden CO, NREL.

Table 25. Installation Factors

Equipment	Multiplier[a]
Agitators, carbon steel	1.6
Agitators, stainless steel	1.5
Boiler	1.8
Compressors, motor driven	1.6
Cooling tower	1.5
Distillation columns, stainless steel	2.4
Heat exchangers, shell & tube, stainless steel	2.2
Heat exchangers, plate & frame, stainless steel	1.8
Heat exchangers, air-cooled	2.8
Inline mixers	1.0
Skidded equipment	1.8
Solids handling equipment (incl. filters)	1.7
Pressure vessels, carbon steel	3.1
Pressure vessels, stainless steel	2.0
Pretreatment reactor system	1.5
Pumps, stainless steel	2.3
Pumps, carbon steel	3.1
Tanks, field-erected, carbon steel	1.7
Tanks, field-erected, stainless steel	1.5
Tanks, storage, plastic	3.0
Tanks, storage, carbon steel	2.6
Tanks, storage, stainless steel	1.8
Turbogenerator	1.8

[a] Installed cost = (purchased equipment cost) x (multiplier).

When these installation factors (IF) are used in the NREL CSTE TEA (Humbird et al., 2011), for example in the feedstock handling section, every piece of equipment is given the same IF for “solids handling equipment” shown above, that is, 1.7. However this is not true in every unit block done by Harris in the CSTE TEA, nor is it true in other TEAs like the NREL FastPy (Dutta et al., 2015). Table TEA-7.4 shows the NREL CSTE Harris Eng. IEC data, where every item has a 1.7 IF. This is in significant contrast to the NREL Fast Py TEA (Dutta et al., 2015) where a baled corn stover feedstock handling system has uniformly 3.02 IF for all equipment (Table TEA-7.5). Compare these to IFs used in the NARA TEA, where the feedstock handling IEC numbers were supplied by Weyerhaeuser Engineering (in a study for Catchlight Energy, a NARA member). These are shown in Table TEA-7.5. For the most part (and for the vast bulk of the equipment expense) the IF is 2.4 (Table TEA-7.6), that is, intermediate compared to NREL CSTE (Humbird et al., 2011) or NREL FastPy (Dutta et al., 2015).

These factors are different enough that it probably warrants some investigation, however in the big picture feedstock handling alone is not a major Capex difference in the overall process. Suffice it to say that so far there is not evidence of NARA IF values being consistently higher than literature, so are not likely a source of a higher TCI.

Table TEA.7.4. NREL CSTE TEA feedstock handling installed equipment costs. Installation factor is 1.7 for all equipment. Reprinted form Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol Dilute-Acid Pretreatment and Enzymatic Hydrolysis of Corn Stover (p. 97), by Humbird, D., Davis, R., Tao, L., Kinchin, C., Hsu, D., Aden, A., Schoen, P... & Dudgeon, D., 2011: Golden CO, NREL.

EQPT NO	EQUIPMENT TITLE	VENDOR	HP	MATERIAL	NUM REQD	$	Year of Quote	Scaling Variable	Scaling Val	Units	Scaling Exp	Inst Factor	New Val	Size Ratio	Scaled Purch Cost	Purch Cost in Proj year	Inst Cost in Proj year
C- 101	Transfer Conveyor	Dearborn Midwest	20 hp ea.	CS	2	$5,397,000	2009	STRM.101	94697	kg/hr	0.60	1.7	104167	1.10	$5,714,628	$5,752,952	$9,780,018
C- 102	High Angle Transfer Conveyor	Dearborn Midwest	50 hp ea.	CS	2	INCLUDED											
C- 103	Reversing Load-in Conveyor	Dearborn Midwest	20 hp	CS	1	INCLUDED											
C- 104	Dome Reclaim System	Cambelt	45 kw ea.	CS	2	$3,046,000	2009	STRM.101	94697	kg/hr	0.60	1.7	104167	1.10	$3,225,265	$3,246,895	$5,519,721
C- 105	Reclaim Conveyor	Dearborn Midwest	10 hp ea.	CS	2	INCLUDED											
C- 106	High Angle Transfer Conveyor	Dearborn Midwest	20 hp	CS	1	INCLUDED											
C- 107	Elevated Transfer Conveyor	Dearborn Midwest	10 hp	CS	1	INCLUDED											
C- 108	Process Feed Conveyor	Dearborn Midwest	5 hp ea.	CS	1	INCLUDED											
M- 101	Truck Scale	St. Louis Scale		CONCRETE	2	$110,000	2009	STRM.101	94697	kg/hr	0.60	1.7	104167	1.10	$116,474	$117,255	$199,333
M- 102	Truck Dumper	Jeffrey Rader	2 x 50 hp ea.	CS	2	$484,000	2009	STRM.101	94697	kg/hr	0.60	1.7	104167	1.10	$512,485	$515,922	$877,067
M- 103	Truck Dumper Hopper	Jeffrey Rader	50 hp ea.	CS	2	$502,000	2009	STRM.101	94697	kg/hr	0.60	1.7	104167	1.10	$531,544	$535,109	$909,685
M- 104	Concrete Feedstock Storage Dome	Domtec		CONCRETE	2	$3,500,000	2009	STRM.101	94697	kg/hr	0.60	1.7	104167	1.10	$3,705,984	$3,730,838	$6,342,424
M- 105	Belt Scale	Tecweigh		CS	2	$10,790	2009	STRM.101	94697	kg/hr	0.60	1.7	104167	1.10	$11,425	$11,502	$19,553
M- 106	Dust Collection System	Sly	25 hp ea.	CS	6	$279,900	2009	STRM.101	94697	kg/hr	0.60	1.7	104167	1.10	$296,373	$298,360	$507,213
														Area 100 Totals	$14,114,178	$14,208,831	**$24,155,013**

Table TEA-7.5. NREL Fast Py TEA feedstock handling installed equipment costs. Installation factor is 3.02 for all equipment. Data from Techno-economic analysis of biomass fast pyrolysis to transportation fuels (pp. 28-30) by Wright, M.M., Daugaard, D.E. & Hu, G, (2010). Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy11osti/46586.pdf

NREL Fast Pyrolysis Corn Stover								
Equipment Name	**Equipment Type**	**Equipment Cost**	**Number Required**	**Total Equipment Cost (with spares)**	Installation Factor (backcalc)	**Installed Cost**	Installed Cost, $2013K
Truck Scales	C	$45,000	1	$45,000	3.0200	$135,900	$ 136
Truck Unloading Forklift	C	$24,000	4	$96,000	3.0200	$289,920	$ 290
Magnetic Separator	C	$19,000	1	$19,000	3.0200	$57,380	$ 57
Concrete Storage Slab	C	$600,000	1	$600,000	3.0200	$1,812,000	$ 1,812
Bale Moving Forklift	C	$24,000	4	$96,000	3.0200	$289,920	$ 290
Bale Transport Conveyor	C	$533,000	2	$1,066,000	3.0200	$3,219,320	$ 3,219
Bale Unwrapping Conveyor	C	$200,000	2	$400,000	3.0200	$1,208,000	$ 1,208
Belt Press	C	$133,000	1	$133,000	3.0200	$401,660	$ 402
Chopper	ECR HAMMER MED	$302,200	1	$302,200	3.0200	$912,644	$ 913
Grinding Hammer Mill	ECR HAMMER MED	$302,200	1	$302,200	3.0200	$912,644	$ 913
Discharge Conveyor	C	$67,000	1	$67,000	3.0200	$202,340	$ 202
Biomass Grinding Screen	EVS ONE DECK	$23,000	1	$23,000	3.0200	$69,460	$ 69
Biomass Chopping Screen	EVS ONE DECK	$22,500	1	$22,500	3.0200	$67,950	$ 68
Rotary Dryer	ERD DIRECT	$681,400	4	$2,725,600	3.0200	$8,231,312	$ 8,231
Steam Blower	EFN CENTRIF	$803,300	1	$803,300	3.0200	$2,425,966	$ 2,426
							$ 20,236

Table TEA-7.6. NARA TEA woodyard handling installed equipment costs. Installation factor for most items is 2.4, but varies based upon Weyerhaeuser engineering experience.

Weyerhaeuser 2010 Woodyard	Notes	Equip Purch cost ea, $2010k	Number Required	Total Eq Cost	Install Factor	Installed Cost MM $2010	Installed Cost $2014MM
Receiving & Storage							
Weigh Scale (includes building)		$ 434	2	$ 868	2	$ 1.736	$ 1.82
Truck Dumps - Forest Residual Chips	50 ton units	$ 550	6	$ 3,300	2.4	$ 7.920	$ 8.28
Truck Dump - Hog Fuel	50 ton units	$ 550	1	$ 550	2.4	$ 1.320	$ 1.38
Truck Dump Collection Conveyor (#1)	600 TPH/line	$ 1	120	$ 120	2.4	$ 0.288	$ 0.30
Tramp Metal Magnet System	Travelling magnet	$ 32	2	$ 63	2.4	$ 0.152	$ 0.16
Tramp Metal Detector	with chute, containmer	$ 20	2	$ 40	2.4	$ 0.096	$ 0.10
Stacker Infeed Conveyor (# 4 & 6)	350' but incl w Stacker/I	$ -	700	$ -	2.4	$ -	$ -
Stacker Reclaimer	6 MM Cu FT ea	$ 5,800	2	$ 11,600	2.25	$ 26.100	$ 27.30
Stacker Outfeed Conveyor (#5 & 7)	230' but incl w Stacker/I	$ -	460	$ -	2.4	$ -	$ -
Stacker/Reclaim Collection Conveyor (#8)	650' total	$ 1	650	$ 650	2.4	$ 1.560	$ 1.63
Incline Conveyor to Sizer (#2)		$ 1	200	$ 200	2.4	$ 0.480	$ 0.50
Preliminary Chip Sizing System - Hammermill	~1" out	$ 275	0.72	$ 198	2.4	$ 0.475	$ 0.50
Cross Conveyor from Sizer (#3)		$ 1	50	$ 50	2.4	$ 0.120	$ 0.13
Chip Screen - gyratory	3/4" cut, 300 TPH ea	$ 100	4	$ 400	2.4	$ 0.960	$ 1.00
				$ -			$ -
Front End Loader	CAT 966	$ 456	1	$ 456	1.1	$ 0.502	$ 0.52
Receiving & Storage Subtotals						**$ 41.709**	**$ 43.62**

7.3.3 Purchased Equipment Cost Estimates

The bulk of the major equipment items PEC was obtained from relatively recent vendor quotes or actual purchases. Table TEA-7.7 lists by department the major cost element items and sources for recent PEC information.

Table TEA-7.7. Purchased equipment cost estimate sources for major cost items. Source information provided in reference section of this report.

Department	Main Equipment Cost Items	Source(s)
Feedstock Handling	Truck Dumpers, Circular pile outstock / reclaim systems	Bruks Rockwood 2015, Weyerhaeuser 2014
Pretreatment	Continuous digester system	Andritz 2016
Enzymatic Hydrolysis	1 MM gallon hydrolysis tanks	Mueller 2015
Fermentation, Separation	Gevo GIFT IBA fermentation and separation	Gevo 2016
Boilers	Hog Fuel boiler, volatile gas boiler	APEA, Icarus Towler and Sinnott (2013)
Lignin Co-products	Activated Carbon	Weyerhaeuser (based on vendor quotes)
Utilities	Wastewater Treatment	NREL CSTE (Humbird et al., 2011) scaled to NARA

Minor cost equipment was obtained from either NREL reports or ASPEN cost tables for standard equipment.

7.3.4 Installed Equipment Cost Estimates

Because the feedstock handling is one of the few areas in which we have identical or very similar equipment estimates (weigh scales, dumps, conveyors, storage and reclaim, etc.) to the NREL CSTE TEA, and because it was the first process step, we have performed additional comparison of the next level down in Capex – the purchased equipment unit costs and scaling to required number / size of units.

As a summary here, we found that there are not large vendor cost estimate differences for the same unit equipment pieces (after adjustment to same $year) – like truck dumps, weigh scales, conveyors, etc.. The main difference why NREL CSTE (Humbird et al., 2011) feedstock handling is estimated as $24 MM IEC, (however this was not used in the report) and NARA feedstock handling is $56.5 MM has to do with assumptions about needed scale of feedstock in inventory. Remember that both facilities operate about 350 days per year, and both use 2,200 BDST per operating day, so the quantity of feedstock per refinery operating hour is the same.

A main difference in corn stover as a feedstock is that it is harvested only during a short period in the fall, and it all goes to on-farm storage. These many, many relatively small storage piles do not carry any explicit storage cost—it is assumed that the farmers can and will set aside a bit of land on their property and cover baled stover with tarps and bear these relatively minor costs within the farmer portion of the payment for the stover. Furthermore when recovered for shipment to the biorefinery, it is assumed that all-weather access, 24 hours per day applies, and likely paved highway (relatively high-speed haul) to biorefinery. Accordingly the biorefinery supply assumptions are 24 hours per day for 6 days per week. Additionally, an overly simplistic assumption is that all deliveries arrive evenly spaced during that time, and that there is no need to build inventory catch-up capacity in dumps and conveyors (and that there are never maintenance down-time outages). Accordingly, NREL CSTE (Humbird et al., 2011) design assumes only 2 truck dumps are needed.

The WY/CLE feedstock handling design for forest residuals assumes that forest harvests are only done during mostly daylight hours 6 days a week, or 16/6. This makes the weekly delivery hours 96 hours instead of 144. Additionally, based on real-world experience, it is known that truck deliveries from FHR sites will NOT be uniformly spaced during the day. The dumps and conveyors to take away must be sized to accommodate a higher maximum rate to avoid long delays of loaded trucks at the dumps. Additionally, it is known that there will be weather periods where the remote woods unpaved roads become impassable, and these broad geographic incidents tend to affect all suppliers, not just one, putting continued IBR operation at risk due to running out of feedstock. Consider that the daily revenue for the NARA IBR is over $1 MM per day, and many costs continue even when no product is being manufactured to sell—the cost of shutting down the IBR because of lack of feedstock is something to be avoided. This weather outage risk drives both the assumed needed on-site inventory for NARA IBR, and then ripples to a needed supply catch-up rate capacity to build inventory back to target level after the weather outage is resolved. These nested capacity needs result in the WY/CLE feedstock handling to need 6 truck dumps.

This risk of outstock due to weather events leads to a need for far more inventory in the NARA model than in NREL CSTE (Humbird et al., 2011) . NARA currently uses 21 days max storage capacity in piles (far less than the 30 days some pulp mills use) but far greater than the 3 days that NREL assumes (basically enough to get through weekends). The high cost of two large circular pile outstock/reclaim systems for feedstock, and one moderate sized one for hog fuel is the main IEC cost difference for the NARA feedstock handling compared to NREL CSTE (Humbird et al., 2011) .

One not-so-obvious detail in the NREL CSTE TEA (Humbird et al., 2011) is that although they had Harris design and cost out a feedstock handling yard for corn stover, and that is reported in the DCF-ROR analysis they excluded all Capex for this area—they simply excluded all Capex, leaving zero for dealing with the incoming stover. A brief mention in the body text describes the rationale: that the stover will be prepared (ground, screened) in off-site depots as portrayed in Idaho National Lab concepts to the MYPP. Still, there has to be something at the biofuel production site to receive and unload even prepared corn stover, and there also must be at least a few hours of intermediate storage, and there has to be some way to get the stover from truck to storage and storage to pretreatment reactor. This seems to be an incorrectly simplified approach in the NREL CSTE model (Humbird et al., 2011), however, as will be later shown, even adding the feedstock cost area back in is not a huge contributor to overall costs, but it should be done to be comparable to NARA.

This approach on feedstock (shifting Capex and Opex for feedstock handling outside the refinery and then including all these costs in Opex of delivered feedstock) makes direct comparison of that important variable—feedstock cost—on a different basis between NARA and both the NREL CSTE (Humbird et al., 2011) and NREL FastPy TEA (Dutta et al., 2015), which also assumes off-site preparation and delivery on-demand. Eventually it was determined that feedstock costs were not large enough nor variable enough to significantly alter the TEA results, so we chose not to expend the considerable effort that would have been required to delve into the detail of the very large MYPP reports (typically ~200 pages) and the underlying INL detailed feedstocks reports upon which these are based—220 pages of details.

For our TCI comparison purposes, to make the process operations more similar we should add the designed feedstock yard Capex to the TCI for NREL CSTE (Humbird et al., 2011). The estimated $24 MM IEC for NREL feedstock, up-scaled with indirect costs added, adds $44 MM to the TCI, which translates to an added $0.72 TCI$/annual gal. shown in Figure TEA-7.6 previously. In a later comparison of delivered feedstock cost we will need to adjust the delivered feedstock cost for NREL downward from the reported value for NREL CSTE (Humbird et al., 2011) in order to shift the costs appropriately back into the refinery as Capex. This will be done empirically by solving for reduced feedstock cost that gives exactly zero NPV with the same assumed MSP for ethanol after Feedstock IEC has been added back into TCI.

Given the amount of time and effort it takes to dig into the details explaining TCI differences for any given process area, we concluded that we needed to focus and expend efforts on the big differences first. Figure TEA-7.9 shows, as best as we can, alignment of similar process block IEC[10] values for NARA compared to NREL CSTE (Humbird et al., 2011). The difference between the two is shown, and the units ordered by declining difference. Figure TEA-7.9 also shows that our attention should be focused on pretreatment and the combined FH&ATJ blocks, whereas feedstock handling, storage/distribution, enzyme production and boiler IEC are not large enough to explain big total differences.

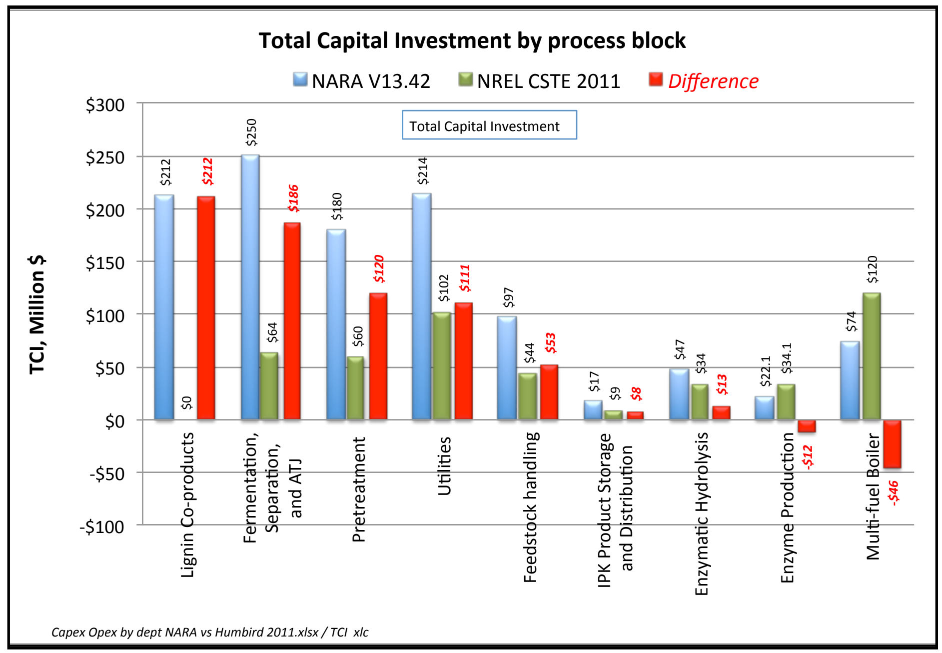

Figure TEA-7.9. Main installed equipment cost (IEC) differences by unit process for NARA compared to NREL CSTE, sorted by magnitude of difference.

[10] Since all IEC values have the same indirect costs loading factor applied to get to TCI, we can looks directly at IEC values to get relative comparisons.

These differences were used to guide further in-depth investigations into sources of differences to either understand why or correct them if errors were found. While far too detailed and lengthy to report here, the summary of importance is at four main changes were identified to improve V 13.43 economics over the prior V 13.2.

1. A current quote for continuous digester significantly reduced pretreatment IEC.
2. A current quote for hydrolysis tanks significantly reduced pretreatment IEC.
3. Electrical rates were reduced substantially from a US average to a WA state average.
4. CO_2 from fermentation was routed to AC production, reducing purchased CO_2.

7.3.5 Conclusions for Feedstock and Pretreatment Capital Cost differences

For the portions of the NARA process that are quite comparable to NREL CSTE (Humbird et al., 2011) (feedstock and pretreatment) the major differences in capital cost estimates arise from the NARA use of FHR. The dispersed, numerous woods locations where the feedstock originates, with unpaved roads limiting access in some weather conditions drives large storage inventory and thus large outstock / reclaim costs. The difficulty of pretreating the recalcitrant lignin in softwoods requires a long residence time and thus a relatively large continuous digester vessel. These two main cost differences are a direct result of using softwood FHR, yet this are still the most readily available feedstock available at scale in the PNW NARA region, so that boundary condition remains for the final TEA analysis.

7.4 Operating Costs Comparison

The total annual operating costs are more difficult to extract from literature TEAs on an equivalent basis to NARA (if reported at all) hence at this time we have far fewer observations to compare against (Figure TEA-7.10). The NARA Opex is notably higher than any of the other TEAs.

In order to delve into possible causes for Opex differences, we compared (as best we could align them) the NARA department Opex with NREL CSTE (Humbird et al., 2011) (Figure TEA-7.11). The largest difference is in Fixed Costs.

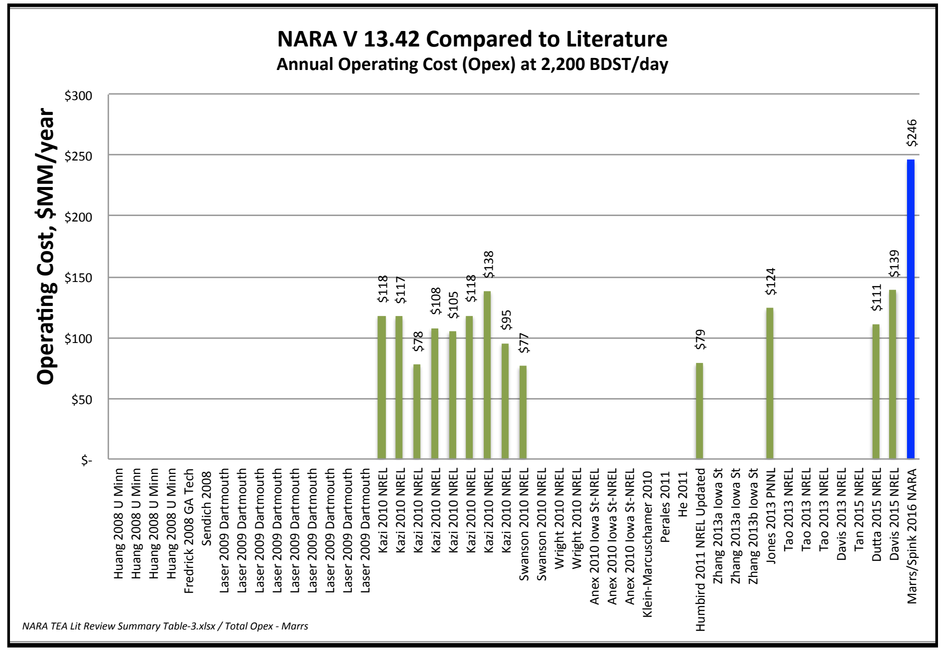

Figure TEA-7.10. Total annual operating costs for reported TEAs

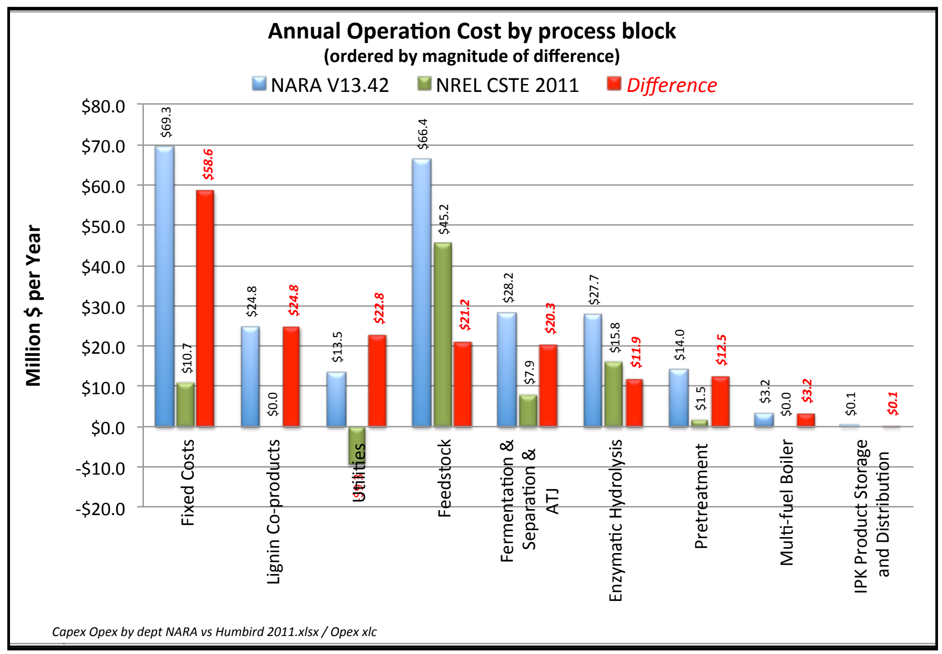

Figure TEA-7.11. Annual operating costs by process department.

7.4.1 Fixed Costs Differences

Figure TEA-7.12 examines the components of fixed costs and differences from NREL CSTE (Humbird et al., 2011). The majority of difference in fixed costs is the much higher maintenance costs. NARA has both a higher percentage (5%) of IEC compared to NREL (3% of ISBL), but IEC is also higher in NARA, and NREL omits OSBL. Reviewing our assumptions on common practices used in engineering such facilities (Perry, 1997) for a corrosive environment (MBS very acidic), we are confident our assumptions are realistic. Taxes (Property and Business and Occupation) for NREL may be correct for a nationwide case, but NARA values are specific to WA and OR values (1.5% of TCI). Labor for NARA is higher than NREL, mostly due to assumed salary rate differences, but somewhat due to larger assumed staffing for AC and LS production and sales, none of which NREL has. NARA labor rates are based upon recent, very similar existing roles in pulp and paper operations in the PNW.

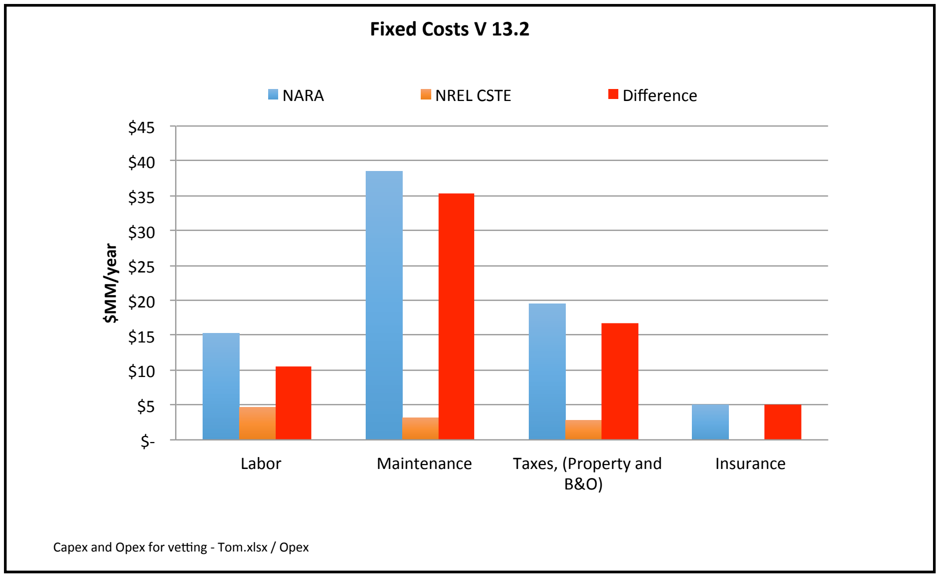

Figure TEA-7.12. Fixed costs components for NARA and NREL CSTE.

7.4.2 Lignin Co-products Operating Cost Differences

NREL CSTE has no lignin co-products, thus zero Opex. This is a case where the added complexity of manufacturing operations causes NARA to be higher.

7.4.3 Utilities Opex Differences

The main cause of utilities cost difference between NARA and NREL CSTE is that NARA uses the lignin residue for co-products, thus has to buy electricity off the grid. NREL not only uses the residue for power production, they generate more than they need and sell electricity back into the grid. This difference gives a large utilities cost difference, however the NARA route is still economically desired due to the revenue from lignin co-products being much higher than the energy value.

7.4.4 Fermentation, Separation, and ATJ Opex Differences

The bulk of the cost difference here arises from the added complexity in NARA of the ATJ process to produce a hydrocarbon fuel, whereas NREL stops at ethanol. The specific components comprising the F,S & ATJ department Opex are considered confidential to NARA member Gevo and were not disclosed.

7.4.5 Feedstock Cost

A common suspect for Opex differences is feedstock cost. The reported feedstock cost assumptions for the comparison TEAs is shown in Figure TEA-7.13. The NARA cost is not wildly out of line with other TEAs—that is, the main difference shown above is not likely due to either very high cost FHR, or unrealistically low costs assumed in comparison TEAs. Comparing to NREL values used in the last-five-years, the feedstock cost estimates are quite similar. The NREL CSTE (Humbird et al., 2011) is a bit lower, but as shown in Figure TEA-2.2 previously, this will not make a huge difference to our IRR. As stated before, if we reduce the feedstock cost to move the feedstock handling Capex back inside the refinery, this NREL feedstock cost will drop to about $41/BDST (solved empirically in the NREL model). And even if corn stover can be had for $41/BDT through the gate, that feedstock is out of scope for NARA as it now is framed. So that favorable feedstock cost assumption explains about $22 MM of the $167 MM difference from CSTE shown above.

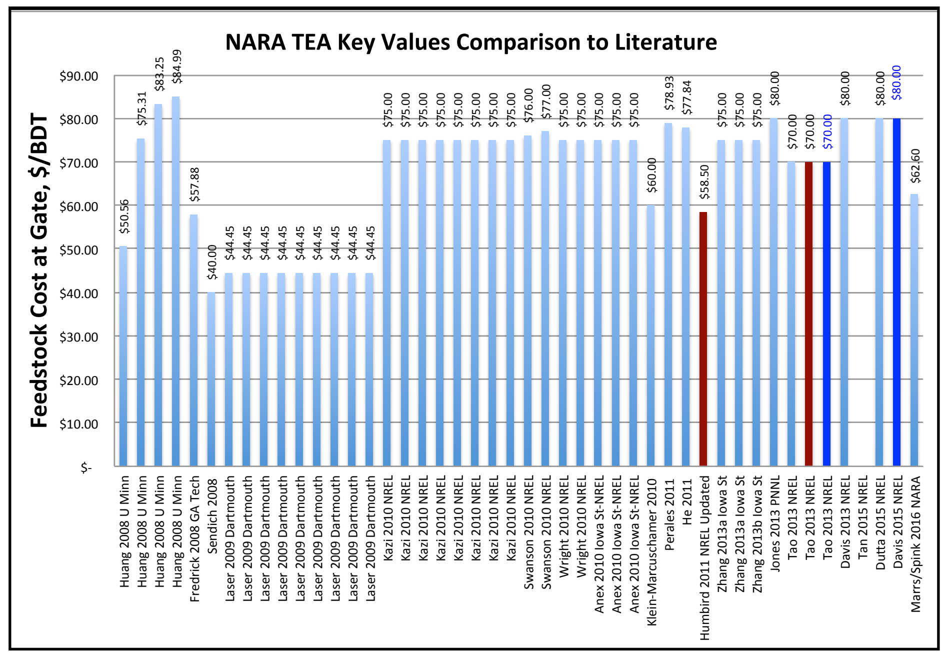

Figure TEA-7.13. Reported feedstock cost to gate.

7.4.6 Other Operating Cost Elements

Comparison with other elements to identify the reason for the difference is difficult as the categorization methods used by NARA and NREL differ significantly. No clearly identifiable element(s) of operating cost difference were identified in the literature comparison.

7.5 Revenue Comparison

There is little to say about revenue differences since virtually all literature TEAs have little if any revenue from sources other than the biofuel, and since they solve for MSP, no explicit revenue is shown. In contrast, the NARA TEA gets about 42% of its revenue from lignin co-products. Our relatively lower revenue from the biofuel side does not arise from lower price assumptions, but more from the smaller number of gallons sold, due to lower fuel yield per BDT feedstock. The previously shown Figure TEA-7.1 shows the literature values for MSP at 10%. Recall that our V 13.43 base case assumed $2.56 / gal for IPK, plus $2.46 for RINs, so our total revenue of $5.02 per gallon is actually quite a bit higher than literature MSP for future targets. In other words, we are not obtaining a low IRR due to “underpricing” our IPK. Our MSP of $7.31 / gal IPK cannot be compared to current (2014) SOT values from NREL TEAs since we do not have the detailed DCF/ROI models using prior SOT values—only the reported future targets.

7.6 Overall Capex, Opex, Revenue Comparison

The three elements that drive overall economics, at the highest level, are Revenue, Opex and Capex. Simply put, the annual before-tax income of (Revenue-Opex) must sufficiently cover the one-time Capex invested in order to get an adequate return on investment (after properly accounting for depreciation and taxes, of course). Figure TEA-7.14 shows the comparison of these metrics for NARA, NREL CSTE (Humbird et al., 2011), NREL FastPy (Dutta et al. 2015) and NREL Bio-Cat (Davis et al. 2015). One can basically see that for NARA that despite higher revenue (from co-products) with the higher Opex the relatively small annual net before income taxes cannot give a decent IRR against the comparatively very large NARA capital.

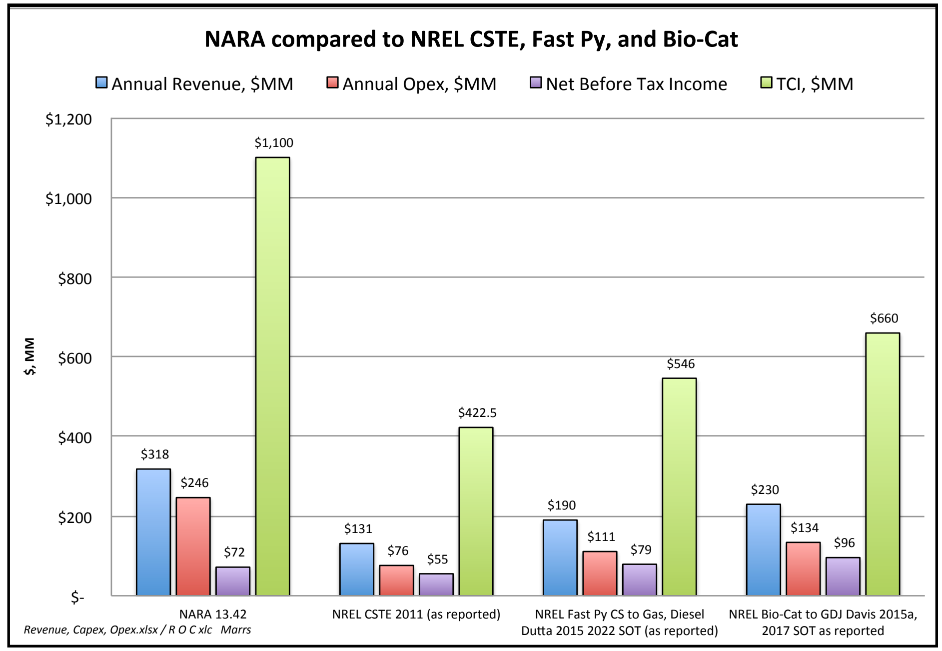

Figure TEA-7.14. Annual Revenue, Annual Operating Costs, and Total Capital Investment for NARA and NREL TEAs: NREL CSTE (Humbird et al., 2011), NREL FastPy (Dutta et al. 2015) and NREL Bio-Cat (Davis et al. 2015).

Of course the annual Revenue and Opex costs cannot be compared directly to the one-time capital investment, and due to the complicated nature of MACRS depreciation and the impact on income taxes (making both very non-uniform over the project life) it is difficult to “annualize” Capex. In order to approximate the effect (recognizing that this is only appropriate for a narrow range of IRR) we empirically solved the NREL CSTE (Humbird et al., 2011) for a $100 MM TCI reduction, holding selling price (MSP) constant, then increased Opex back up until the NPV was zero at the 10% IRR. This analysis showed that for this IRR level, the annualized net tradeoff in annual Opex for one-time Capex was about 14% of Capex. When this value is used to “annualize” the TCI (shown in Figure 7.14), the comparison changes to that shown in Figure TEA-7.15.

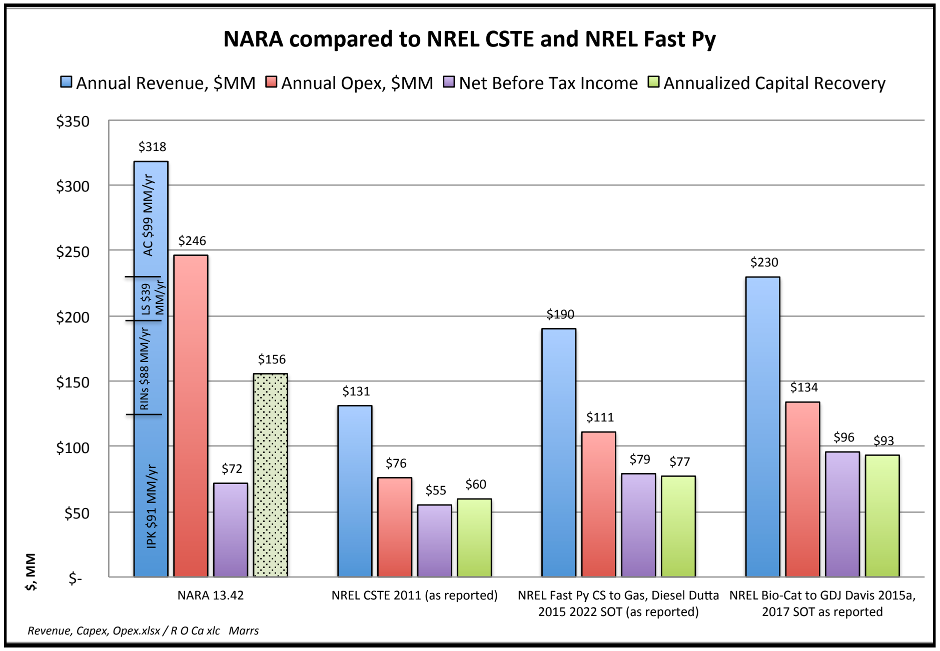

Figure TEA-7.15. Approximated annualized Capex compared to Revenue, Opex and Net Before Taxes. Comparisons made to NARA and NREL TEAs: NREL CSTE (Humbird et al., 2011), NREL FastPy (Dutta et al. 2015) and NREL Bio-Cat (Davis et al. 2015).

This portrayal of annualized Capex can be seen to be approximately correct by the fact that the Capex annualized at 10% IRR for the NREL TEAs just about balances net income before taxes for the two NREL cases. (They don't match exactly because of slight simplifications in minor sources of revenue, like selling excess electricity). The large gap in NARA annualized Capex (at a 10% IRR) over net before taxes, by this convention, shows that a) very substantial reductions in Capex alone will not get us to 10% IRR with the relatively low net income (as shown earlier in Figure TEA-6.10), and b) solving for NARA MSP to get to 10% requires selling IPK+RINs for $7.26/gal, which would raise the Revenue bar and the net shown in Figure TEA-7.15 and be quite close to the annualized capital cost estimate shown in Figure TEA-7.15.

These comparisons are, however, for the future technology states for NREL. When the 2014 SOT values for NREL are added both Capex and Opex are higher, and the NARA revenue is from the MSP version where IPK returns $7.26/gal IPK, as shown in Figure TEA-7.16.

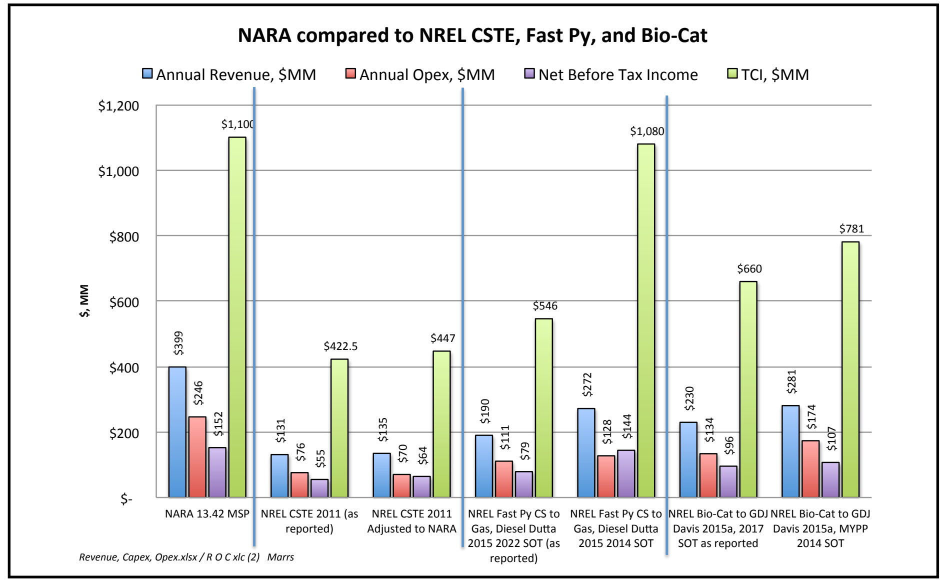

Figure TEA-7.16. Capex, Opex and Revenue for future and current SOT compared to NARA.

As shown previously, the capital costs for 2014 SOT in NREL hydrocarbon biofuels TEAs are closer to NARA capital. When annualized capital is shown rather than total capital (Figure TEA-7.17), one can see that the current (2014) SOT NREL routes to hydrocarbons (Dutta et al., 2015 and Davis et al., 2015) are actually quite similar to NARA when results are expressed as MSP values.

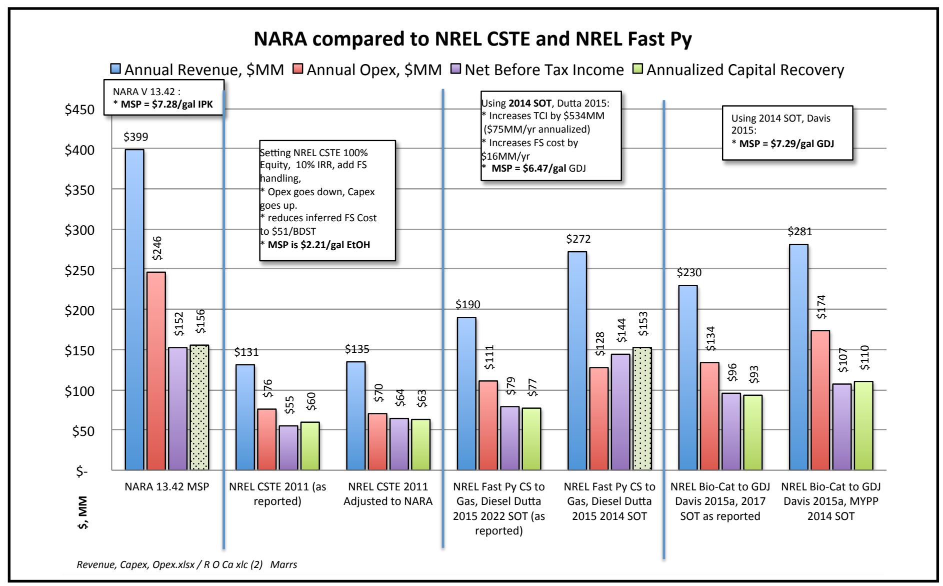

Figure TEA-7.17. For the MSP version of NARA TEA, the total revenue is higher due to co-products, thus it can cover the higher capital costs.

One recent TEA publication (de Jong et al., 2015) warrants particular discussion. Even though they do not disclose the level of detail as the BETO NREL TEAs (NREL. 2016), it is important as it is the only publication found that explicitly focuses on bio-based jet fuel as the end product, and includes among pathways compared a woody feedstock via biochemical conversion followed by ATJ (like the NARA process reported here).

The de Jong et al. (2015) publication focuses on European conditions, so many of the various costs reported are not comparable to the NARA process (e.g., feedstock cost, energy costs, jet fuel prices, income taxes, depreciation schedule, etc.). Thus, a detailed comparison of elements is not warranted, however they compare 16 pathways using consistent methodology, and one of those pathways is very similar to the NARA process (forest residues fermented to alcohol then renewable jet fuel (RJF) via an ATJ conversion) so that the relative results of this pathway compared to the others is useful to examine.

Their basic approach is to use published data for purchased equipment costs and yields, then use consistent factored cost adjustment (via an overall Lang Factor[11]) to get to total fixed costs (TFC) and then TCI. Their summary results for a nth plant for 11 pathways to RJF are shown in Figure TEA-7.18. They use the MSP @ 10% IRR approach (like BETO MYPP NREL TEAs) and most other aspects of the DCF/ROR are very comparable to both the NARA TEA as well as BETO TEAs.

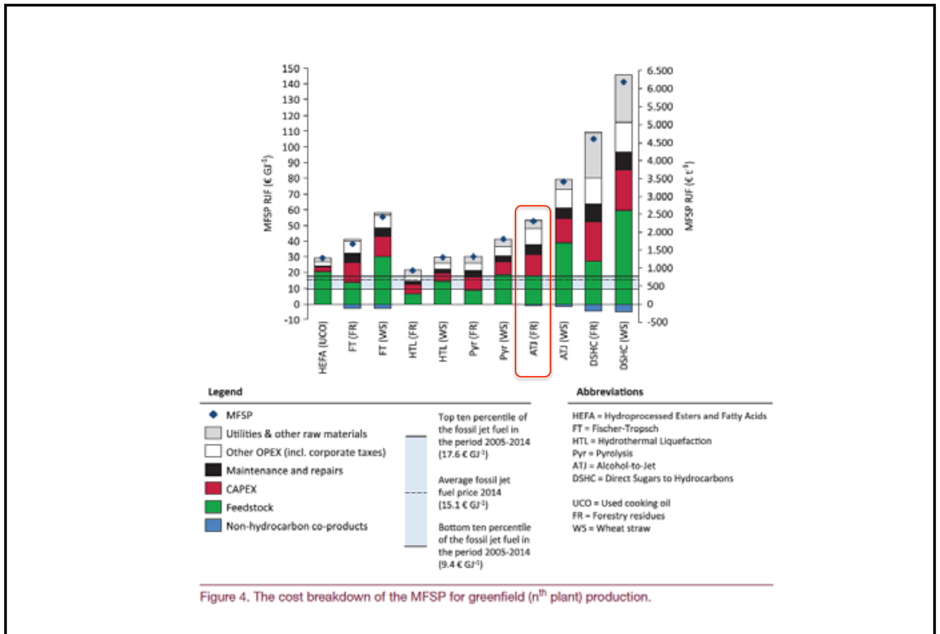

Figure TEA-7.18. Summary MSPs for 11 pathways. The pathway similar to NARA's is "ATJ (FR)". Adapted from "The feasibility of short-term production strategies for renewable jet fuels – a comprehensive techno-economic comparison" by de Jong S, Hoefnagels R, Faaig A, Slade R, Mawhood R, & Junginger M., 2015, Biofuel, *Bioprod. Bioref.*, 9, 778-800.

Two important observations can be made from their summary.

1. Producing RJF from FHR via biochemical route and ATJ ("ATJ (FR)") is "middle-of-the-pack) with respect to MSP required to get 10% IRR. This is consistent with our conclusion from BETO MYPP comparison—the NARA process economics are similar to the best alternative routes.

2. The MSP for ATJ (FR) is over twice the historical (2014) price of petroleum jet fuel, so like NARA and BETO MYPP paths would not be feasible at parity pricing to petroleum jet—their needs to be a biofuel premium even for mature, nth-plant industry.

8) Concluding Remarks

8.1 Summary

The NARA process described here—softwood FHR via MBS to Gevo GIFT and ATJ with LS and AC lignin co-products in an Nth plant—is relatively well-demonstrated, technically. This is evidenced by the production of ~1,000 gallons of IPK for a test flight on IPK blended with petro-jet fuel. In the current view the IPK would need to earn $7.27/gallon IPK total revenue, which is considerably above "parity" pricing projections for petro-jet fuel ($2.56/gal petro-jet). This minimum selling price for a biofuel is not much different from the current SOT for the best routes identified in the BETO MYPP for production of hydrocarbons, leading us to believe it is a "competitive" biofuels pathway compared to others under consideration. It is worth remembering that pioneer plants, and plants of smaller scale (demonstration, small commercial) would be expected to have considerably poorer economics than portrayed here for Nth plant.

8.2 Future Work

The authors believe there is relatively little room for technical process improvements of significance in the main process. Thus the main route for improved economics seems to be increasing revenue. While AC markets are not well defined, and there could be some higher revenue opportunities for activated carbon products, it seems that the most likely revenue increase option is to secure a "biofuel premium" for the IPK produced by the NARA process. Even the current method for quantifying biofuel premium (RINs) is projected to be too small ($2.46/gal IPK) to bring total IPK revenue to the MSP value. At least to get this process started some additional biofuel premium is needed.

[11] Lang Factor = (Total Fixed Cost) / (Purchased Equipment Cost)

9) List of References

Aden, A., Ruth, M., Ibsen, K., Jechura, J., Neeves, K., Sheehan, J. & Wallace, B. (2002). Lignocellulosic biomass to ethanol process design and economics utilizing co-current dilute acid prehydrolysis and enzymatic hydrolysis for corn stover (NREL/TP-510-32438). Golden, CO: NREL. Retrieved from http://www.nrel.gov/docs/fy02osti/32438.pdf

American Petroleum Institute (API) (2016) Gasoline Tax [Website] retrieved from http://www.api.org/oil-and-natural-gas/consumer-information/motor-fuel-taxes/gasoline-tax

Anderson, D. & Gao, J. (2016). Mild Bisulfite pretreatment of forest residuals (in NARA Final Reports). Pullman, WA. NARA. Retrieved from https://research.libraries.wsu.edu/xmlui/handle/2376/5310

Anderson, P.R. (2009) Conversion of renewables – Bioethanol markets & perspectives, Novozymes' Capital Markets Day presentation 09-Aug-2009, 32 pp. Accessed 15-Jun-16 at https://www.novozymes.com/en/-/media/Novozymes/en/investor/events-presentations/Documents/10_CMD_CoRE_PORA_FINAL.pdf

Andritz (2016). Personal communication with Cort, B. by Spink, T., (01/15/2016).

Anex, R.P., Aden, A., Kazi, F.K., Fortman, J., Swanson, R.M., Wright, M.M., Satrio, J.A.… Dutta, A. (2010). Techno-economic comparison of biomass-to-transportation fuels via pyrolysis, gasification, and biochemical pathways. Fuel, 89, S29-S35. doi.org/10.1016/j.fuel.2010.07.015

Biofuels Digest (2015, Mar. 25). EPA Issues 2014 and 2015 Cellulosic Waiver Credit prices [web page] Retrieved from http://www.biofuelsdigest.com/bdigest/2015/03/25/epa-issues-2014-and-2015-cellulosic-waiver-credit-prices/

Bruks Rockwood (2015). Personal communication via e-mail with Desmond Smith, 13-May-2015.

Chen, S., Spink, T., Gao, A., Bule, M., & Yu, L. (2016). ASPEN modeling of the NARA conversion processes (in NARA Final Reports). Pullman, WA. NARA. Retrieved from https://research.libraries.wsu.edu/xmlui/handle/2376/5310

Christensen, A., Searle, S. & Malins, C. (2014, May) A Conversational Guide to… Renewable Identification Numbers (RINs) in the U.S. Renewable Fuel Standard, ICCT Briefing. Retreived from http://www.theicct.org/sites/default/files/publications/ICCTbriefing_RINs_20140508.pdf

Christensen, A. & Siddiqui, S. (2015). A mixed complementarity model for the US biofuel market with federal policy interventions. *Biofuels, Bioprod. Bioref.*, 9: 397–411. doi:10.1002/bbb.1545

Davis, R., Tao, L., Scarlata, C., Tan, E.C.D., Ross, J., Lukas, J. & Sexton, D. (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). Golden, CO: NREL. Retrieved from http://www.nrel.gov/docs/fy15osti/62498.pdf

Davis, R., Tao, L., Tan, E.C.D., Biddy, M.J., Beckham, G.T., Scarlata, C., Jacobson, J…& Schoen, P. (2013). Process design and economics for the conversion of lignocellulose biomass to hydrocarbons: dilute –acid and enzymatic deconstruction of biomass to sugars and biological conversion of sugars to hydrocarbons (NREL/TP-5100-60223). Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy14osti/60223.pdf

de Jong S, Hoefnagels R, Faaig A, Slade R, Mawhood R, & Junginger M. (2015). The feasibility of short-term production strategies for renewable jet fuels – a comprehensive techno-economic comparison. *Biofuel, Bioprod. Bioref.*, 9, 778-800. doi:10.1002/bbb.1613

Dutta, A., Sahir, A., Tan, E., Humbird, D., Snowden-Swan, L.J., Meyer, P., Ross, J., … & Lukas, J. (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). Retrieved from http://www.nrel.gov/docs/fy15osti/62455.pdf

Fox, C. (2013). Personal conversations with attendees of: 34th International Activated Carbon Conference, PACS, Pittsburgh PA, 24-26-Sep-2013.

Frederick Jr, W.J., Lien, S.J., Courchene, C.E., DeMartini, N.A., Ragauskas, A.J. & Iisa, K. (2008). Production of ethanol from carbohydrates from loblolly pine: A technical and economic assessment, *Bioresource Technology*, 99, 5051-5057. doi.org/10.1016/j.biortech.2007.08.086

Gao, J. & Neogi, A. (2016). Clean sugar and lignin pretreatment (in NARA Final Reports). Pullman, WA. NARA. Retrieved from https://research.libraries.wsu.edu/xmlui/handle/2376/5310

Gevo (2016). Personal communication with Glenn Johnston via e-mail 05-May-2016.

He, J. & Zhang, W. (2011). Techno-economic evaluation of thermo-chemical biomass-to-ethanol. *Applied Energy*, 88(4), 1224-1232. doi.org/10.1016/j.apenergy.2010.10.022

Huang, H.J., Ramaswamy, S., Al-Dajani, W., Tschirner, U. & Cairncross, R. (2009) Effect of biomass species and plant size on cellulosic ethanol: A comparative process and economic analysis. Biomass & Bioenergy, 33(2), 234-246. doi:10.1016/j.biombioe.2008.05.007

Humbird, D., Davis, R., Tao, L., Kinchin, C., Hsu, D., Aden, A., Schoen, P., Lukas, J., Olthof, B., Worley, M., Sexton, D. & Dudgeon, D. (2011). Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol Dilute-Acid Pretreatment and Enzymatic Hydrolysis of Corn Stover (NREL/TP-5100-47764). Golden, CO.: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy11osti/47764.pdf

Jones, S., Meyer, P., Snowden-Swan, L., Padmaperuma, A., Tan, E., Dutta, A., Jacobson, J. & Cafferty, K. (2013). Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels Fast Pyrolysis and Hydrotreating Bio-oil Pathway (PNNL-23053; NREL/TP-5100-61178). Retrieved from http://www.nrel.gov/docs/fy14osti/61178.pdf

Kazi, F.K., Fortman, J., Anex, R., Kothandaraman, G., Hsu, D., Aden, A. & Dutta, A. (2010). Techno-Economic Analysis of Biochemical Scenarios for Production of Cellulosic Ethanol, NREL/TP-6A2-46588. Golden, CO: NREL

Klein-Marcuschamer, D., Oleskowicz-Popiel, P., Simmons, B.A. & Blanch, H.W. (2010). Technoeconomic analysis of biofuels: A wiki-based platform for lignocellulosic biorefineries. Biomass & Bioenergy, 34(12), 1914-1921. doi.org/10.1016/j.biombioe.2010.07.033

Idaho National Laboratory (INL) (2014). Biomass Feedstock Supply System Design and Analysis (Contract DE-AC07-05ID14517). Idaho National Laboratory Bioenergfy Program, Idaho Falls, ID. Retrieved from https://bioenergy.inl.gov/Reports/Feedstock%20Supply%20System%20Design%20and%20Analysis.pdf

Laser, M., Larson, E., Dale, B., Wang, M., Greene, N. & Lynd, L.R. (2009). Comparative analysis of efficiency, environmental impact, and process economics for mature biomass refining scenarios. *Biofuels Bioproducts & Biorefining*, 3(2), 247-270. doi:10.1002/bbb.136

Marrs, G., Mulderig, B., Davio, D. & Burt, M. (2016), Costs and Key Attributes of Candidate Feedstocks (in NARA Final Reports). Pullman, WA: NARA. Retrieved from https://research.libraries.wsu.edu/xmlui/handle/2376/5310

Marrs, G.R. & Spink, T. (2013) Softwood to Jet Fuel Techno-Economics, Presentation at NARA Annual Meeting, Corvallis, OR.

Marrs, G. & Spink, T. (2015). NARA TEA Review and Improvement Ideas. Working Session in Seattle, WA, January 20 & 21.

Mueller Co. (2015). Personal communication from Vance, C. to Spink, T. on 12/21/2015.

NARA (2016). NARA Final Reports [Website]. Retrieved from https://research.libraries.wsu.edu/xmlui/handle/2376/5310

NREL (2016). Biochemical Conversion Techno-Economic Analysis [Website]. Retrieved from http://www.nrel.gov/bioenergy/biochemical-conversion-techno-economic-analysis.html

Perales, A.L. Villanueva, Valle, C.R., Ollero, P. & Gómez-Barea, A. (2011) Technoeconomic assessment of ethanol production via thermochemical conversion of biomass by entrained flow gasification. *Energy*, 36(7), 4097-4108. doi.org/10.1016/j.energy.2011.04.037

Perry, R.H. & Green, D.W. (1997). Perry's Chemical Engineers' Handbook. 7th Ed., New York: McGraw-Hill.

Sendich, E., Laser, M., Kim, S., Alizadeh, H., Laureano-Perez, L., Dale, B. & Lynd, L. (2008). Recent process improvements for the ammonia fiber expansion (AFEX) process and resulting reductions in minimum ethanol selling price. *Bioresource Technology*, 99, 8429-8435. doi: 10.1016/j.biortech.2008.02.059

Short, W, Packey, D.J. & Holt, T. (1995) A Manual for the Economic Evaluation and Energy Efficiency and Renewable Energy Technologies. Report No. TP-462-5173. Golden, CO: National Renewable Energy Laboratory.

Spink, T. & Marrs, G. (2015) Softwood to Jet Fuel Techno-Economics for an Integrated Greenfield Biorefinery. Presentation at 2015 NARA Annual Meeting, Seattle, WA.

Spink, T., Marrs, G. & Gao, A. (2014). Slash to Fuel NARA 2014 Update. Presentation at 2014 NARA Annual Meeting, Seattle, WA, 15-Sep-14.

Stavropoulos, G.G. & Zabaniotou, A.A, (2009) Minimizing activated carbons production cost. *Fuel Processing Technology*, 90, 952-957. doi.org/10.1016/j.fuproc.2009.04.002

Swanson, R.M., Satrio, J.A. & Hu, G. (2010). Techno-economic analysis of biofuels production based on gasification (NREL/TP-6A20-46587). Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy11osti/46587.pdf

Tan, E.C.D., Talmadge, M., Dutta, A., Hensley, J., Snowden-Swan, L., Humbird, D., Schaidle, J. & Biddy, M. (2015). Conceptual process design and economics for the production of high-octane gasoline blendstock via indirect liquefaction of biomass through methanol/dimethyl ether intermediates. *Biofuels Bioproducts & Biorefining*, 10, 17-35. doi: 10.1002/bbb.1611

Tao, L., Tan, E.C.D., McCormick, R., Zhang, M., Aden, A., He, X. & Zigler, B.T. (2014). Techno-economic analysis and life-cycle assessment of cellulosic isobutanol and comparison with cellulosic ethanol and n-butanol. *Biofuels Bioproducts & Biorefining*, 8, 30-48. doi:10.1002/bbb.1431

Towler, G & Sinnott, R.K. (2013). Chemical Engineering Design - Principles, Practice and Economics of Plant and Process Design (2nd Edition). Elsevier. Online version available at: https://app.knovel.com/web/toc.v/cid:kpCEDPPEP4

Turner, J.H., McKenna, J.D., Mycock, J.C., Nunn, A.B. & Vatavuk, W.M. (1998). Baghouse and Filters (in Particulate Matter Controls; EPA/452/B-02-001). Retrieved from https://www3.epa.gov/ttncatc1/dir1/cs6ch1.pdf

U.S Energy Information Administration (EIA) (2016) PETROLEUM & OTHER LIQUIDS, U.S. Total Gasoline Bulk Sales Price by Refiners. [Website]. Retrieved from http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMA_EPM0_PBR_NUS_DPG&f=M

U.S Environmental Protection Agency (EPA) (2015). Fuels Registration, Reporting, and Compliance Help - Cellulosic waiver credits purchased annually [Website]. Retrieved from https://www.epa.gov/fuels-registration-reporting-and-compliance-help/cellulosic-waiver-credits-purchased-annually

U.S. Department of Agriculture, Forest Service. (2012). Timber Product Output (TPO) Reports. Knoxville, TN: U.S, department of Agriculture Forest Service, Southern Research Station. Retrieved from http://srsfia2.fs.fed.us/php/tpo_2009/tpo_rpa_int1.php

US. Department of Energy (2011), U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry (ORNL/TM-2011/224). Oak Ridge, TN: Oak Ridge National Laboratory. Retrieved from https://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf

U.S. Department of Energy. (2015). Bioenergy Technologies Office Multi-year Program Plan. Retrieved from http://www.energy.gov/sites/prod/files/2015/04/f22/mypp_beto_march2015.pdf

U.S. Department of the Treasury. Internal Revenue Service. (2015). Publication 946: How to depreciate property (Cat. No. 13081F). Retrieved from https://www.irs.gov/pub/irs-pdf/p946.pdf

Wooley, B. (2016). Thousand gallon bio-jet effort (in NARA Final Reports). Pullman, WA. NARA. Retrieved from https://research.libraries.wsu.edu/xmlui/handle/2376/5310

Wright, M.M., Daugaard, D.E. & Hu, G. (2010). Techno-economic analysis of biomass fast pyrolysis to transportation fuels (NREL/TP-6A20-46586). Golden, CO: National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy11osti/46586.pdf

Zhang, Y., Brown, T.R., Huc, G. & Brown, R.C. (2013a). Techno-economic analysis of two bio-oil upgrading pathways. *Chemical Engineering Journal*, 225, 895-904. doi.org/10.1016/j.cej.2013.01.030

Zhang, Y., Brown, T.R., Huc, G. & Brown, R.C. (2013b). Techno-economic analysis of monosaccharide production via fast pyrolysis of lignocellulose. *Bioresource Technology*, 127, 358-365. doi.org/10.1016/j.biortech.2012.09.070

10) Appendix

Table TEA-10.1. Discounted Cash Flow rate of return worksheet – V 13.43

Based on: Corn Stover Design Report Case: 2012 model DW1102A			1.00	
Case 13.42 Integrated Facility producing IPK, Lignosulfonates, and Activated Carbon				
Assumptions	**Value**		*Land Requirement*	
Fixed Capital Investment	$1,040.50		*132*	*Acres*
General Plant	$997.33		*$14,000*	*/acre*
Steam Plant	$43.17			
Equity	100%			
Loan Interest	8.0%			
Loan Term, years	10			
Annual Loan Payment	$0.00			
Periodic expenses		No. Bags	4320	
Baghouse Bags (5 yr life, Ryton MOC)	$0.45	Bag Cost	$ 80.00	
		Quote year	1998	
Working Capital (% of FCI)	5.00%			
Salvage Value				
General Plant	0	Not permitted since 2002		
Steam Plant	0	Not permitted since 2002		
Depreciation Period (Years)				
General Plant	7	IRS Pub 946		
Steam/Electricity System	20	IRS Pub 946		
Construction Period (Years)	3			
% Spent in Year -2	8%			
% Spent in Year -1	60%			
% Spent in Year 0	32%			
Start-up Time (Years)	0.00			
IPK production/Feedstock use (% of Normal)	50%			
Variable Costs (% of Normal)	75%			
Fixed Cost (% of Normal)	100%			
Discount Rate for Equity Capital	**10.00%**			
Income Tax Rate	35.00%			
IPK Production Rate (MMgal/yr)	35.739	Inputs tab		
Cost Year for Analysis	2014	IPK Selling price sensitivity		
IPK Market Selling Price ($/gal)	$4.79	$ -		
Net Present Value	**$0.0000**	**Targeted Value**		

Total Capital Investment, $MM			
Process Area		**Purchased Cost**	**Installed Cost, $MM**
Feedstock handling		$ 24	$ 56.52
Pretreatment		$ 48	$ 104.95
Enzymatic Hydrolysis		$ -	$ 27.68
Fermentation, Separation, Alcohol-to-Jet		$ -	$ 146.00
12:00:00 AM		$ -	$ -
12:00:00 AM		$ -	$ -
Lignin Co-products		$ 55	$ 123.91
12:00:00 AM		$ -	$ -
IPK Product Storage and Distribution		$ -	$ 10.00
Multi-fuel Boiler		$ -	$ 43.17
Utilities		$ -	$ 124.68
Totals		**$ 103**	**$ 637**
Warehouse	4.0%	of ISBL	$ 13.41
Site Development	9.0%	of ISBL	$ -
Additional Piping	4.5%	of ISBL	$ -
Total Direct Costs (TDC)			**$ 650.3**
Prorateable Expenses	10.0%	of TDC	$ 65.0
Field Expenses	10.0%	of TDC	$ 65.0
Home Office & Construction	20.0%	of TDC	$ 130.1
Project Contingency	10.0%	of TDC	$ 65.0
Other Costs (Start-Up, Perm	10.0%	of TDC	$ 65.0
Total Indirect Costs			**$ 390.2**
Fixed Capital Investment (FCI)			**$ 1,040.5**
Land			$ 7.8
Working Capital	5.0%	of FCI	$ 52.0
Total Capital Investment (TCI)			**$ 1,100.3**
Lang Factor (FCI/Purchased Equip Cost)			(44.9)
TCI per annual gallon			$30.79/gal
		Delta-T factor	6.75

Years 1-10:

DCFROR Worksheet - all $ MM														
Year	Annual Averages	-2	-1	0	1	2	3	4	5	6	7	8	9	10
Fixed Capital Investment		$83	$624	$333										
Land		$8												
Working Capital				$52										
Loan Payment					$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Loan Interest Payment		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Loan Outstanding Principal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
IPK Sales	$171.31				$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31
Cellulosic RINs	$88.06				$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06
12:00:00 AM	$0.00				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
12:00:00 AM	$0.00				$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lignosulfonates	$39.24				$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24
Activated Carbon	$99.29				$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29
Total Annual Sales	**$397.90**			**Total Annual Sales**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**
Annual Manufacturing Cost														
Feedstock					$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59
Baghouse Bags					$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
Other Variable Costs					$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45
Fixed Operating Costs					$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29
Total Product Cost	$246.42				**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**
Annual Depreciation														
General Plant Writedown					14%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%		
Depreciation Charge	*$33.2*			Depreciation Charge	$142.52	$244.25	$174.43	$124.57	$89.06	$88.96	$89.06	$44.48	$0	$0
Remaining Value					$855	$611	$436	$312	$223	$134	$44	$0		
Steam Plant Writedown					3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%
Depreciation Charge	*$1.44*				$1.62	$3.12	$2.88	$2.67	$2.47	$2.28	$2.11	$1.95	$1.93	$1.93
Remaining Value					$42	$38	$36	$33	$30	$28	$26	$24	$22	$20
Total Depreciation					$144.14	$247.36	$177.32	$127.23	$91.53	$91.24	$91.17	$46.43	$1.93	$1.93
Net Revenue	$116.80			Net Revenue	$7.35	($95.88)	($25.83)	$24.25	$59.96	$60.24	$60.31	$105.05	$149.56	$149.56
Losses Forward				Losses Forward		$0.00	($95.88)	($121.71)	($97.46)	($37.50)	$0.00	$0.00	$0.00	$0.00
Taxable Income	$105.05			Taxable Income	$7.35	($95.88)	($121.71)	($97.46)	($37.50)	$22.74	$60.31	$105.05	$149.56	$149.56
Income Tax	*$40.88*	10.27%		Income Tax	$2.57	$0.00	$0.00	$0.00	$0.00	$7.96	$21.11	$36.77	$52.35	$52.35
Annual Cash Income	$110.60	$ 91.04	$624	$385	$149	$151	$151	$151	$151	$144	$130	$115	$99	$99
Discount Factor	*10.000%*	*1.2100*	*1.1000*	*1.0000*	*0.9091*	*0.8264*	*0.7513*	*0.6830*	*0.6209*	*0.5645*	*0.5132*	*0.4665*	*0.4241*	*0.3855*
Annual Present Value	$1,178				$135	$125	$114	$103	$94	$81	$67	$54	$42	$38
Total Capital Investment + Interest		$110	$687	$385										
Net Present Worth				**$0.0000**										
Internal Rate of Return	**10.00%**	$ (91.04)	$ (624.30)	$ (384.99)	$ 148.91	$ 151.48	$ 151.48	$ 151.48	$ 151.48	$ 143.53	$ 130.38	$ 114.72	$ 99.14	$ 99.14

Years 11-30:

11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
																			($8)
																			($52)
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31	$171.31
$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06	$88.06
$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24	$39.24
$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29	$99.29
$397.90	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**	**$397.90**
$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59	$65.59
$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45	$111.45
$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29	$69.29
$246.42	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**	**$246.42**
$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	2.23%									
$1.93	$1.93	$1.93	$1.93	$1.93	$1.93	$1.93	$1.93	$1.93	$1.93	$0.96	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$18	$16	$14	$13	$11	$9	$7	$5	$3	$1	$0									
$1.93	$1.93	$1.93	$1.93	$1.93	$1.93	$1.93	$1.93	$1.93	$1.93	$0.96	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$149.56	$149.56	$149.56	$149.56	$149.56	$149.56	$149.56	$149.56	$149.56	$149.56	$150.52	$151.48	$151.48	$151.48	$151.48	$151.48	$151.48	$151.48	$151.48	$151.48
$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
$149.56	$149.56	$149.56	$149.56	$149.56	$149.56	$149.56	$149.56	$149.56	$149.56	$150.52	$151.48	$151.48	$151.48	$151.48	$151.48	$151.48	$151.48	$151.48	$151.48
$52.35	$52.35	$52.35	$52.35	$52.35	$52.35	$52.35	$52.35	$52.35	$52.35	$52.68	$53.02	$53.02	$53.02	$53.02	$53.02	$53.02	$53.02	$53.02	$53.02
$99	$99	$99	$99	$99	$99	$99	$99	$99	$99	$99	$98	$98	$98	$98	$98	$98	$98	$98	$98
0.3505	*0.3186*	*0.2897*	*0.2633*	*0.2394*	*0.2176*	*0.1978*	*0.1799*	*0.1635*	*0.1486*	*0.1351*	*0.1228*	*0.1117*	*0.1015*	*0.0923*	*0.0839*	*0.0763*	*0.0693*	*0.0630*	*0.0573*
$35	$32	$29	$26	$24	$22	$20	$18	$16	$15	$13	$12	$11	$10	$9	$8	$8	$7	$6	$6
																			($3)
$ 99.14	$ 99.14	$ 99.14	$ 99.14	$ 99.14	$ 99.14	$ 99.14	$ 99.14	$ 99.14	$ 99.14	$ 98.80	$ 98.47	$ 98.47	$ 98.47	$ 98.47	$ 98.47	$ 98.47	$ 98.47	$ 98.47	$158.3

Table TEA-10.2. NARA TEA task deliverables and reporting

SM-TEA-1. Techno-Economic Analysis Task Deliverables	Location in Report
Task SM-TEA-1.1. Build and populate first-cut NARA project TEA model framework	Sections 1.1 to 1.4
Task SM-TEA-1.2. Obtain and Assemble first-cut Capital Cost Estimates	Section 6, TEA Version 3.6
Task SM-TEA-1.3. Obtain and Assemble first-cut Process Flow and Operating Cost Estimate	Section 6 , TEA Version 3.6
Task SM-TEA-1.4. Construct first-cut pass at overall economics	Section 6 , TEA Version 3.6
Task SM-TEA-1.5. Summarize reporting elements and communicate with stakeholders	Section 6 TEA Version 3.4
Task SM-TEA-1.6. Evaluate the Pretreatment options on an equitable basis	Section 1.3, TEA Versions 6.43 and 7.1
Task SM-TEA-1.7. Solicit process improvements in key leverage areas and update economics	Section 1.3
Task SM-TEA-1.8. Refine and update model for process and siting specificity	Section 1.3
Task SM-TEA-1.9. Further refine and update model for process and siting specificity	Section 6, TEA V 1`3.42
Task SM-TEA-1.10. Further refine and update model to pro forma balance sheet level	Section 6, TEA V 1`3.42
Task SM-TEA-1.11. Evaluate retrofits of existing sulfite mills to the NARA MBS process	Section 1.3, TEA V 13.1

Table TEA-10.3. NARA TEA model versions listing

NARA TEA Archived Model Versions List								
Updated	05-Jul-16	Gevan Marrs						
Count	**Filename**	**Version Number**	**Date of Analysis**	**Last Modified Date**	**MSP or IRR?**	**MSP (w RINs), $/gal, or IRR, %**	**Total Capital Investment, $MM**	**Notes, Main Change from prior version**
1	*NARA Techno-Economics - Marrs - V1 old - pre-NREL don't use.xlsx*	1.0		4-Feb-13	NA			Intial structuring of spreadsheet for inputs, linkages.
2	*NARA Techno-Economics - Marrs V1.0 Purch Enzymes No Coproducts - hold.xlsx*	1.0		22-Feb-13	MSP			Used NREL Summary page, but pro-rated all elements, no DC-ROI
3	*NARA Techno-Economics - Marrs 2.xlsx*	2.0		19-Feb-13	MSP			Burn lignin, purchased enzymes
4	*NARA Techno-Economics - Marrs V2.0 Purch Enzymes No Coproducts.xlsx*	2.0		11-Mar-13	MSP	$ 8.47	$ 793	
5	*NARA Techno-Economics - Marrs V3.0 On-site Enzymes No Coproducts.xlsx*	3.0		28-Feb-13	MSP	$ 6.86	$ 811	On-site enzyme production
6	*NARA Techno-Economics - Marrs V3.1 On-site Licensed Enzymes No Coproducts.xlsx*	3.1		11-Mar-13	MSP	$ 6.78	$ 811	Iso-octane sales credit
7	*NARA Techno-Economics - Marrs V3.2 Iso-octane sales credit.xlsx*	3.2		11-Mar-13	MSP			
8	*NARA Techno-Economics - Marrs V3.3 FS-10 Higher Polysaccharides.xlsx*	3.3		12-Mar-13	MSP			
9	*NARA V3.3 Techno-Economics - Marrs - FS-10 Higher Polysaccharides.xlsx*	3.3		08-Apr-13	MSP			
10	*NARA V3.4 Techno-Economics - Marrs - FS-10 Burn Lignin for Power.xlsx*	3.4		30-Aug-13	MSP			
11	*NARA V3.5 Techno-Economics - Marrs - FS-10 Burn Lignin for Power.xlsx*	3.5		04-Sep-13	MSP	$ 6.66	$ 881	
12	*NARA V3.6 Techno-Economics DCFROR - Marrs - FS-10 Burn Lignin for Power.xlsx*	3.6		12-Sep-13	MSP or IRR	$6.93, IRR Negative	$ 881	NREL DCF-ROR added - Can set IPK to market price, calc IRR
13	*NARA V3.6.1 Techno-Economics DCFROR 40% Eq - Marrs - FS-10 Burn Lignin for Power.*	3.61		08-Jan-14	MSP or IRR			40% Equity funding instead of 100%
14	*NARA Techno-Economics - Marrs V4.0 No boiler sell lignin residue.xlsx*	4.0		05-Mar-13	MSP	$ 7.14	$ 734	Sell lignin residue over the fence, infer needed selling price.
15	*NARA Techno-Economics - Marrs V4.1 Nat Gas boiler sell lignin residue.xlsx*	4.1		16-Mar-13	MSP			Case 4.0 but re-allocate dept nat gas costs for steam back to nat gas steam boilers, add boiler capex.
16	*NARA Techno-Economics - Marrs V4.2 Nat Gas boiler sell lignin residue- dept energy co*	4.2		03-Apr-13	MSP			Reallocated Dept Energy Costs from Boiler to separate depts.
17	*NARA Techno-Economics - Marrs V4.3 Nat Gas boiler sell lignin residue- dept energy co*	4.3		03-Apr-13	MSP			Updated Direct costs as NREL percent of ISBL; boiler feedwater; land value, added Exec Summary sheet
18	*NARA V4.3 Techno-Economics - Marrs - Nat Gas boiler sell lignin residue- dept energy c*	4.3		08-Apr-13	MSP			
19	*NARA V4.3 Techno-Economics - Marrs - Nat Gas boiler sell lignin residue- dept energy c*	4.3		31-May-13	MSP			
20	*NARA V4.3.2 Techno-Economics - Marrs - Nat Gas boiler sell lignin residue- dept energy*	4.32		14-Jun-13	MSP			
21	*NARA V4.4 Techno-Economics - Marrs - Nat Gas boiler sell lignin residue- FS-10.xlsx*	4.4		26-Apr-13	MSP			Changed yield chain input chemistry to FS-10 composition
22	*NARA V4.4.2 Techno-Economics - Marrs - Nat Gas boiler sell lignin residue- FS-10.xlsx*	4.42		8-Aug-13	MSP			Removed After-tax profit from mfg costs - reduced gap to $83MM
23	*NARA V4.4.3 Techno-Economics - Marrs - Nat Gas boiler sell lignin residue- FS-10.xlsx*	4.43		21-Aug-13	MSP	$ 7.30	$ 861	Removed double-counting of RINs - gap is $145 MM
24	*NARA Techno-Economics - Marrs V5.0 Stop at IBA.xlsx*	5.0		11-Mar-13	MSP	$ 4.82	$ 684	Stop at IBA production, eliminate ATJ block
25	*NARA V5.0 Techno-Economics - Marrs - FS-10, Sugars Cost.xlsx*	5.0		21-May-13	MSP			Produce sugars - no ferm, ATJ
26	*NARA V5.1 Techno-Economics - Marrs - Stop at IBA.xlsx*	5.1		23-Aug-13	MSP			Produce IBA, elminate ATJ
27	*NARA V5.2 Techno-Economics - Marrs - Produce Ethanol.xlsx*	5.2		23-Aug-13	MSP			Produce ethanol instead of IBA
28	*NARA V 6.0 Techno-Economics - Marrs - Integrated IPK, LS, AC.xlsx*	6.0		21-Aug-13	MSP	$ 2.60	$ 1,083	Integrated multi-product case - but illogical as AC revenue offsets IPK MSP.
29	*NARA V 6.1 DCF-ROI Techno-Economics - Marrs - Integrated IPK, LS, AC.xlsx*	6.1		22-Aug-13	IRR	12.50%	$ 1,069	First incorporation of full NREL DCF-ROR sheet
30	*NARA V 6.2 DCF-ROI Techno-Economics - Marrs - Integrated IPK, LS, AC, 100% Eq.xlsx*	6.2		12-Sep-13	IRR			

NARA TEA Archived Model Versions List

Count	Filename	Version Number	Date of Analysis	Last Modified Date	MSP or IRR?	MSP (w RINs), $/gal, or IRR, %	Total Capital Investment, $MM	Notes, Main Change from prior version
Updated	05-Jul-16	Gevan Marrs						
31	*NARA V 6.2 DCF-ROI Techno-Economics - Marrs - Integrated IPK, LS, AC, Varying % Eq d*	6.2		12-Feb-14	IRR			
32	*NARA V 6.3 DCF-ROI Techno-Economics - Marrs - Integrated IPK, LS, AC, Mild BiSulfite F*	6.3		17-Feb-14	IRR			Direct linked updates for: Revenue from lignosulfonates and Activated Carbon Capex update on MBS to account for longer cook times
33	*NARA V 6.4 DCF-ROI Techno-Economics - Marrs - Integrated IPK, LS, AC, Mild BiSulfite F*	6.4		2-Apr-14	IRR			Removed double-counting of hog fuel credit.
34	*NARA V 6.41 DCF-ROI Techno-Economics - Marrs - Integrated IPK, LS, AC, Mild BiSulfite*	6.41		19-May-14	IRR			
35	*NARA V 6.41 DCF-ROI Techno-Economics - Marrs (2).xlsx*	6.41		25-Sep-14	IRR			Updated CLE MBS yield for FS-10
36	*NARA V6.41 DCF-ROI Techno-Economics - Marrs.xlsx*	6.41		6-Dec-14	IRR			
37	*NARA V 6.42 DCF-ROI Techno-economics - Marrs.xlsx*	6.42		1-Feb-15	IRR	12.8%		
38	*NARA V 6.43 DCF-ROI Techno-economics - Marrs.xlsx*	6.43	5-Feb-15	5-Feb-15	IRR	12.3%	$ 1,118	Fixed feedstock fines reject % error.
39	*NARA V 6.5 DCF-ROI Techno-Economics- **IBA** - Marrs.xlsx*	6.50	20-Nov-14	20-Nov-14	IRR	27.7%	$ 973	Stop at IBA production, eliminate ATJ block
40	*NARA V 7.0 DCF-ROI Techno-Economics - Marrs - Integrated IPK, LS, AC, Wet Ox PT.xlsx*	7.0		17-Feb-14	IRR			Use WetOx pretreatment instead of MBS
41	*NARA V 7.1 DCF-ROI Techno-Economics - Marrs - Integrated IPK, LS, AC, Wet Ox PT.xlsx*	7.1		22-Mar-14	IRR	9.0%	$ 1,061	Removed double-counting of hog fuel credit.
42	*NARA V 12.0 Techno-Economic Analysis - Sulfite Mill repurpose - Marrs.xlsx*	12.0	incomplete	26-Jun-14	IRR			Capex avoidance for existing assets, re-scale to Cosmo scale, Updated Opex
43	*NARA V 13.0 DCF-ROI Techno-economics - Marrs.xlsx*	13.0		27-Aug-15	IRR			Complete update with ASPEN-based mass flows, updated Opex, Capex
44	*NARA V 13.1 DCF-ROI Techno-economics - Re-purpose case.xlsx*	13.1		27-Aug-15	IRR	1.2%	$ 1,121	Repurposed pulp mill case
45	***NARA V 13.2 DCF-ROI Techno-economics - Marrs (2).xlsx***	13.2		25-Aug-13	IRR	0.9%	$ 1,440	Reference Base Case for 2015 Annual Meeting Presentation
46	*NARA V 13.3 DCF-ROI Techno-economics - Make IBA.xlsx*	13.3		20-Aug-15	IRR	8.4%	$ 1,310	Stop at IBA
47	*NARA V 13.31 DCF-ROI Techno-economics - Make IBA.xlsx*	13.31		17-Jan-16	IRR	10.6%	$ 1,047	Reduced digester and hydrolysis tanks per Jan-16 update capex
48	*NARA TEA V 13.4 DCF-ROI - Final YR5.xlsx*	13.4	10-Feb-16		IRR			Final NARA TEA - based upon V 13.2 with updates for Jan-16 and beyond
49	*NARA TEA V 14 DCF-ROI Techno-economics - pared.xlsx*	14.0		5-Jan-16	IRR	0.9%	$ 1,440	Exact replica of 13.2 except minimized input cells in Summary, Capex, Opex.
50	*NARA TEA V 15 DCF-ROI - NREL Fast Py (Version2).xlsx*	15.0	incomplete?	20-Nov-15	IRR			Replication of Davis 2015 Corn Stover to Hydrocarbons
51	*NARA TEA V 16 DCF-ROI - sugar syrup.xlsx*	16.0		16-Nov-15	IRR			Stop at sugar
52	*NARA TEA V 17 DCF-ROI - Woodyard only.xlsx*	17.0		30-Nov-15	IRR			Using NARA DCF-ROR to get Opex eqivalent to OTF woodyard
53	*NARA TEA V 18 Milled wood feedstock DCF-ROI .xlsx*	18.0		2-Dec-15	IRR			Beginning of requested Eastside Milled wood IBR
54	*NARA TEA V 19 DCF-ROI 40% Eq, MSP.xlsx*	19.0		16-Jan-16	MSP	$ 9.40	$ 1,440	V 13.2 changed to 40% Eq, MSP calc
55	*NARA TEA V 19.1 DCF-ROI 40% Eq, MSP.xlsx*	19.1		16-Jan-16	MSP	$ 8.16	$ 1,177	Reduced digester and hydrolysis tanks per Jan-16 update capex
56	*NARA TEA V 20 DCF-ROI Improved Case MSP.xlsx*	20.0		5-Jan-16	MSP	$ 7.39	$ 1,171	Hypothetical improved case with reduced cook time, increased yield.
57	*NARA TEA V 21 DCF-ROI - pared Use OCC.xlsx*	21.0	17-Jan-16	17-Jan-16	IRR	NA	$ 522	Use OCC (or linerboard pulp) as feedstock, send FRS back to pulp mill.
58	*NARA TEA V 13.41 DCF-ROI - Final YR5.xlsx*	13.41	27-Mar-16	16-Jun-16	IRR	2.5%	$ 1,100	Updated Feedstock cost, reduced F,S&ATJ IEC
59	*NARA TEA V 13.41 DCF-ROI - Final YR5 MSP $7.28.xlsx*	13.41 MSP	6-May-16	1-Jul-16	MSP	$ 7.28	$ 1,100	MSP version assuming 10% IRR
60	*NARA TEA V 13.42 DCF-ROI - Final YR5.xlsx*	13.42	22-Jun-16	1-Jul-16	IRR	3.7%	$ 1,100	Updated feedstock cost, used CO2 from ferment for AC production
61	*NARA TEA V 13.42 DCF-ROI - Final YR5 - MSP $7.26.xlsx*	13.42 MSP	22-Jun-16	1-Jul-16	MSP	$ 7.26	$ 1,100	MSP version assuming 10% IRR