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## **Thermochemical Research Pathways with *In Situ* and *Ex Situ* Upgrading of Fast Pyrolysis Vapors**

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*Harris Group Inc.*

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**Technical Report**  
NREL/TP-5100-62455  
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## Acronyms

ACCE	Aspen Capital Cost Estimator	LCA	life-cycle assessment
ANL	Argonne National Laboratory	LCI	U.S. Life Cycle Inventory
bbl	barrel	LHV	lower heating value
BETO	Bioenergy Technologies Office	LHSV	liquid hourly space velocity
BFW	boiler feed water	LP	low pressure
CE	<i>Chemical Engineering</i>	MACRS	IRS Modified Accelerated Cost Recovery System
CFB	circulating fluidized bed	MFSP	minimum fuel selling price
CFP	catalytic fast pyrolysis	MJ	megajoule
CH <sub>4</sub>	methane	MM	million (e.g., MMBtu or \$__MM)
CO	carbon monoxide	MOC	material of construction
CO <sub>2</sub>	carbon dioxide	NG	natural gas
COD	chemical oxygen demand	NO <sub>2</sub>	nitrogen dioxide
DCFROR	discounted cash flow rate of return	NREL	National Renewable Energy Laboratory
DOE	U.S. Department of Energy	OSBL	outside battery limits (of the plant)
EPA	U.S. Environmental Protection Agency	PFD	process flow diagram
EPC	engineering, procurement, and construction	PNNL	Pacific Northwest National Laboratory
FCC	fluid catalytic cracking	PSA	pressure swing adsorption
FCI	fixed capital investment	RO	reverse osmosis
FOB	freight on board	RTO	regenerative thermal oxidizer
FP	fast pyrolysis	scf	standard cubic feet
GGE	gallon gasoline equivalent	SMR	steam methane reformer
GHG	greenhouse gas	SO <sub>2</sub>	sulfur dioxide
GJ	gigajoule	TCI	total capital investment
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model	TDC	total direct cost
H <sub>2</sub> S	hydrogen sulfide	TIC	total installed cost
HDS	hydrodesulfurization	TEA	techno-economic analysis
HGF	hot gas filter	TPEC	total purchased equipment costs
HHV	higher heating value	VPU	vapor-phase upgrading
HP	high pressure	WGS	water gas shift
HT	hydrotreating	WHSV	weight hourly space velocity
INL	Idaho National Laboratory	WW	wastewater
IRR	internal rate of return	WWT	wastewater treatment
ISBL	inside battery limits (of the plant)	ZnO	zinc oxide
kWh	kilowatt hour		

## Executive Summary

This report was developed as part of the U.S. Department of Energy's Bioenergy Technologies Office's efforts to enable the development of technologies for the production of infrastructure-compatible, cost-competitive liquid hydrocarbon fuels from biomass. Specifically, this report details two conceptual designs based on *projected* product yields and quality improvements via catalyst development and process integration. It is expected that these research improvements will be made within the 2022 timeframe. The two conversion pathways detailed are (1) *in situ* and (2) *ex situ* upgrading of vapors produced from the fast pyrolysis of biomass. While the base case conceptual designs and underlying assumptions outline performance metrics for feasibility, it should be noted that these are only two of many other possibilities in this area of research. Other promising process design options emerging from the research will be considered for future techno-economic analysis.

Catalyst research and development, and the testing of catalysts in process-relevant equipment are the most important areas for the success of these two pathways. Some of the key objectives of catalyst development include the enabling of: (1) reduced coke and coke precursor formation, (2) reduced non-condensable species formation, (3) efficient hydrogen utilization, which ties into reduced aromatics in the product, reduced coke formation, and greater hydrodeoxygenation to allow higher carbon efficiency, (4) coupling (molecular combination) reactions to reduce the loss of smaller molecules to the gas phase and also enhance the formation of distillate range products, (5) attrition resistance of fluidizable catalysts, (6) catalyst maintenance and regeneration in fluidized and fixed bed configurations, and (7) catalyst longevity. It is expected that these developments will result in significant vapor quality improvements with reduced reactivity; upon condensation, the recovered organic phase can be hydroprocessed to fuel blendstocks at relatively less severe conditions compared to raw bio-oil from non-catalytic fast pyrolysis.

The conceptual process models for the two processes were developed using Aspen Plus. Based on the process models, n<sup>th</sup>-plant process economics (in 2011 dollars) projecting minimum fuel selling prices (MFSP) were developed in Microsoft Excel using discounted cash flow rate of return analysis. Economic assumptions include a 30-year plant life, 40% equity financing with a 10% discount rate (internal rate of return), and the remaining 60% debt financed at 8% interest paid back over 10 years. Impacts of deviations from these financial assumptions are captured through sensitivity studies. Capital cost estimates for some of the key equipment were provided by Harris Group through vendor quotes or previously developed mechanical design tools. The plant size was assumed to be 2,000 dry metric tonnes per day using woody biomass feedstock cost. The feedstock is delivered with 10 wt % moisture, low ash (<1%), and nominal size of 2 mm to the throat of the reactor for \$80/dry short ton per recent Idaho National Laboratory feedstock logistics design projections.

It should be noted that the base case processes assume a pressure of 120 psia (~8 bar), with hydrogen-enrichment of the fluidizing gases during fast pyrolysis and vapor upgrading. While this is assumed in the base cases, the ultimate decision about the operating pressure and fluidizing gas composition will be made based on their impacts on the economics. These impacts will be further quantified based on future experimental results. Table ES-1 shows key process conversion assumptions and metrics for both the *in situ* and *ex situ* upgrading cases, while the

following Table ES-2 and Table ES-3 outline the economic summaries for the *in situ* and *ex situ* cases, respectively.

Both the *in situ* and *ex situ* conceptual designs, *using the underlying assumptions*, project MFSPs of less than \$3.5/gallon gasoline equivalent (GGE) in 2022. The performance assumptions for the *ex situ* process were more aggressive with higher distillate (diesel-range) products. This was based on an assumption that more favorable reaction chemistry (such as hydrogenation, hydrodeoxygenation and coupling) can be made possible in a separate reactor where, unlike in an *in situ* upgrading reactor, one does not have to deal with catalyst mixing with biomass, char, and mineral matter/ash, which pose challenges to catalyst performance and maintenance. Natural gas was used for hydrogen production in the process model, but only when off-gases from the process were not sufficient to meet the needs; natural gas consumption is insignificant in both the *in situ* and *ex situ* 2022 base cases. Heat produced from the burning of char, coke, and off-gases is converted to electricity, with surplus electricity sold to the grid allowing a small reduction of less than 5¢/GGE in the MFSP.

There remain significant uncertainties in some of the assumptions which will be resolved with research progress and availability of more experimental data. Sensitivity analysis shows the impacts of many of the uncertainties on the projected costs, and opportunities for further cost reduction.

**Table ES-1. Key Process Metrics for the Proposed 2022 Target Cases**

	<i>In Situ</i>	<i>Ex Situ</i>
<b>Fast Pyrolysis Intermediate</b>		
Gas Species – CO, CO <sub>2</sub> , C <sub>1</sub> -C <sub>4</sub> (wt % of dry biomass)	N/A*	13
Organics (wt % of dry biomass)	N/A*	64
Water (wt % of dry biomass)	N/A*	11
Char (wt % of dry biomass)	N/A*	12
<b>Vapor Upgrading Product</b>		
Gas (wt % of dry biomass)	23	23
Aqueous Phase (wt % of dry biomass)	29	30
<i>Carbon Loss (% of C in biomass)</i>	2.1	1.3
Organic Phase (wt % of dry biomass)	28	27
<i>H/C Molar Ratio</i>	1.5	1.6
<i>Oxygen (wt % in organic phase)</i>	10.5	6.4
<i>Carbon Efficiency (%)</i>	44	44
Solid Losses, Char + Coke (wt % of dry biomass)	12 + 8	12 + 8
<b>Final Fuel Blendstock</b>		
Yield (% , w/w dry biomass)	24	25
Hydroprocessing Carbon Efficiency (% , not including light dissolved gases in feed and product; assumed efficiency scaling by O content in organic liquid feed—higher efficiency for lower O)	91	94
Overall Carbon Efficiency (% of C in biomass)	40.4	41.5
Overall Carbon Efficiency (% of C in biomass + NG)	40.4	41.5
Total Product (GGE/dry U.S. ton)	75	78
Gasoline-Range Product (gallons/dry U.S. ton)	56	36
Diesel-Range Product (gallons/dry U.S. ton)	18	39
Gasoline/Diesel-Range Product (% GGE basis)	73/27	45/55
Oxygen Content in Cumulative Product (wt %)	0.5	0.4
Minimum Fuel Selling Price (\$/GGE)	3.46	3.31
<b>Natural Gas<sup>†</sup> and Electricity</b>		
Natural Gas Energy Input (% of biomass, LHV basis)	0.1	0.2
Natural Gas Cost Contribution (¢/GGE)	0.1	0.2
Surplus Electricity Credit (¢/GGE)	4	3
<b>Fuel Blendstock Production Efficiencies (various bases)</b>		
Biomass Feedstock (% , LHV basis)	54	57
Biomass + Natural Gas <sup>†</sup> (% , LHV basis)	54	57
Biomass + Natural Gas <sup>†</sup> + Electricity (% , LHV basis, all electrical energy converted to heat)	56	57

\*Not applicable for *in situ* case. <sup>†</sup>Negligible natural gas used in process designs.



**Table ES-2. Economic Summary for *In Situ* Base Case (2022 Target)**

**Process Engineering Analysis for Hydrocarbon Fuel Production  
via *In Situ* Upgrading of Fast Pyrolysis Vapors**

Potential Research-Driven Pathway for Cost-Competitiveness by 2022

2,000 Dry Metric Tonnes Biomass per Day

All Values in 2011\$

**Minimum Fuel Selling Price (MFSP) \$3.37 /Gallon Gasoline Blendstock  
\$3.85 /Gallon Diesel Blendstock  
\$3.46 /Gallon Gasoline Equivalent (GGE)**

Gasoline Blendstock Production	40.4 MM Gal per Year	55.8 Gal per Dry US Ton Feedstock
Diesel Blendstock Production	13.4 MM Gal per Year	18.5 Gal per Dry US Ton Feedstock
Total Gasoline Equivalent Production	54.2 MM GGE per Year	74.9 GGE per Dry US Ton Feedstock
Delivered Feedstock Cost	\$80.00 per Dry U.S. Ton (Includes Capital Up to Throat of Pyrolyzer)	
Internal Rate of Return (After-Tax)	10.0%	
Equity Percent of Total Investment	40.0%	
On-Stream Factor	90.0%	

Capital Costs		Operating Costs (¢ / GGE Product)		
100: Feedstock (Additional Dryer & Blower Only)	\$500,000	Feedstock	106.9	
200: Fast Pyrolysis & Vapor Upgrading	\$92,480,000	Natural Gas	0.1	
300: Pyrolysis Vapor Quench	\$22,390,000	Catalysts	54.0	
400: Hydroprocessing & Separation	\$32,540,000	Sand	-	
500: Hydrogen Plant	\$70,640,000	Other Raw Materials	1.1	
600: Steam System & Power Generation	\$52,450,000	Waste Disposal	1.8	
700: Cooling Water & Other Utilities	\$9,450,000	Purchased Electricity	-	
800: Water Management	\$17,160,000	Fixed Costs	46.9	
Total Installed Equipment Cost (TIC)	\$297,610,000	Electricity Coproduct Credit	(4.4)	
Land (115 Acres at \$14000 per Acre)	\$1,600,000	Capital Depreciation	48.0	
Site Development	\$14,790,000	Average Income Tax	19.3	
(% of ISBL)	10.0%	Average Return on Investment	72.5	
Indirect Costs & Project Contingency	\$194,990,000			
(% of TIC)	65.5%	Operating Costs (\$ / Year)		
Fixed Capital Investment (FCI)	\$519,960,000	Feedstock	\$57,940,000	
Working Capital	\$26,000,000	Natural Gas	\$100,000	
Total Capital Investment (TCI)	\$545,960,000	Catalysts	\$29,290,000	
Loan Interest Rate	8.0%	Sand	\$0	
Loan Term (Years)	10	Other Raw Materials	\$610,000	
Total Installed Equipment Cost per Annual GGE	\$5.49	Waste Disposal	\$1,000,000	
Fixed Capital Investment per Annual GGE	\$9.59	Purchased Electricity	\$0	
Plant Operating Hours per Year	7884	Fixed Costs	\$25,410,000	
On-Stream Percentage	90.0%	Electricity Coproduct Credit	-\$2,360,000	
Efficiencies		Capital Depreciation	\$26,000,000	
Carbon Eff. to Organic Liquid after <i>In Situ</i> Upgrade	44%	Average Income Tax	\$10,480,000	
Carbon Eff. for Hydroprocessing of Organic Liquid	91%	Average Return on Investment	\$39,300,000	
Carbon Eff. for Overall Process (Biomass to Fuel)	40.4%	Total Plant Electricity Usage (kW)	43,173	
Overall Plant Efficiency - HHV %	54.1%	Electricity Produced on Site (kW)	48,291	
Overall Plant Efficiency - LHV %	54.3%	Electricity Purchased from Grid (kW)	0	
		Electricity Sold to Grid (kW)	5,117	
		Plant Electricity Use (kWh /GGE)	6.28	
		Specific Operating Conditions		
Version: PyVPU-v218 IS - 2022		Feed Rate	Dry Tonnes / Day	2,000
			Dry Tons / Day	2,205
		Feedstock Cost	\$/Dry Ton	\$80.00
			\$/Moisture+Ash Free Ton	\$80.74

**Table ES-3. Economic Summary for Ex Situ Base Case (2022 Target)**

**Process Engineering Analysis for Hydrocarbon Fuel Production  
via Ex Situ Upgrading of Fast Pyrolysis Vapors**

Potential Research-Driven Pathway for Cost-Competitiveness by 2022

2,000 Dry Metric Tonnes Biomass per Day

All Values in 2011\$

**Minimum Fuel Selling Price (MFSP) \$3.26 /Gallon Gasoline Blendstock  
\$3.68 /Gallon Diesel Blendstock  
\$3.31 /Gallon Gasoline Equivalent (GGE)**

Gasoline Blendstock Production	25.9 MM Gal per Year	35.7 Gal per Dry US Ton Feedstock
Diesel Blendstock Production	27.9 MM Gal per Year	38.6 Gal per Dry US Ton Feedstock
Total Gasoline Equivalent Production	56.5 MM GGE per Year	78.0 GGE per Dry US Ton Feedstock
Delivered Feedstock Cost	\$80.00 per Dry U.S. Ton (Includes Capital Up to Throat of Pyrolyzer)	
Internal Rate of Return (After-Tax)	10.0%	
Equity Percent of Total Investment	40.0%	
On-Stream Factor	90.0%	

Capital Costs		Operating Costs (¢ / GGE Product)	
100: Feedstock (Additional Dryer & Blower Only)	\$430,000	Feedstock	102.6
200: Fast Pyrolysis & Vapor Upgrading	\$126,940,000	Natural Gas	0.2
300: Pyrolysis Vapor Quench	\$24,220,000	Catalysts	36.2
400: Hydroprocessing & Separation	\$29,110,000	Sand	0.5
500: Hydrogen Plant	\$66,760,000	Other Raw Materials	1.1
600: Steam System & Power Generation	\$47,900,000	Waste Disposal	1.7
700: Cooling Water & Other Utilities	\$9,280,000	Purchased Electricity	-
800: Water Management	\$12,910,000	Fixed Costs	47.7
Total Installed Equipment Cost (TIC)	\$317,540,000	Electricity Coproduct Credit	(2.6)
Land (115 Acres at \$14000 per Acre)	\$1,600,000	Capital Depreciation	49.7
Site Development	\$18,070,000	Average Income Tax	19.8
(% of ISBL)	10.0%	Average Return on Investment	74.6
Indirect Costs & Project Contingency	\$210,580,000		
(% of TIC)	66.3%	Operating Costs (\$ / Year)	
Fixed Capital Investment (FCI)	\$561,550,000	Feedstock	\$57,940,000
Working Capital	\$28,080,000	Natural Gas	\$100,000
Total Capital Investment (TCI)	\$589,630,000	Catalysts	\$20,430,000
Loan Interest Rate	8.0%	Sand	\$300,000
Loan Term (Years)	10	Other Raw Materials	\$610,000
Total Installed Equipment Cost per Annual GGE	\$5.62	Waste Disposal	\$930,000
Fixed Capital Investment per Annual GGE	\$9.94	Purchased Electricity	\$0
Plant Operating Hours per Year	7884	Fixed Costs	\$26,950,000
On-Stream Percentage	90.0%	Electricity Coproduct Credit	-\$1,480,000
Efficiencies		Capital Depreciation	\$28,080,000
Carbon Eff. to Organic Liquid after Ex Situ Upgrade	44%	Average Income Tax	\$11,200,000
Carbon Eff. for Hydroprocessing of Organic Liquid	94%	Average Return on Investment	\$42,150,000
Carbon Eff. for Overall Process (Biomass to Fuel)	41.5%	Total Plant Electricity Usage (kW)	41,046
Overall Plant Efficiency - HHV %	56.4%	Electricity Produced on Site (kW)	44,247
Overall Plant Efficiency - LHV %	56.6%	Electricity Purchased from Grid (kW)	0
		Electricity Sold to Grid (kW)	3,201
		Plant Electricity Use (kWh /GGE)	5.73
		Specific Operating Conditions	
		Feed Rate	Dry Tonnes / Day 2,000
			Dry Tons / Day 2,205
		Feedstock Cost	\$/Dry Ton \$80.00
			\$/Moisture+Ash Free Ton \$80.74

Version: PyVPU-v218 ES - 2022

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# 1 Introduction

## 1.1 Motivation and Background

Fast pyrolysis-based biomass conversion processes have the potential to offer high efficiencies for the production of liquid transportation fuels such as gasoline and diesel blendstocks, or petroleum refinery compatible intermediates for conversion to liquid fuels. The process involves rapid heating of biomass particles in the absence of air at approximately 500°C with the production of permanent gases, vapors including water, and solids including mineral matter and char. The liquid product fraction collected after the condensation of the vapors is also known as bio-oil or pyrolysis oil [1]. The attractiveness of such conversion lies in the yield of a significant proportion of products directly in the liquid phase.

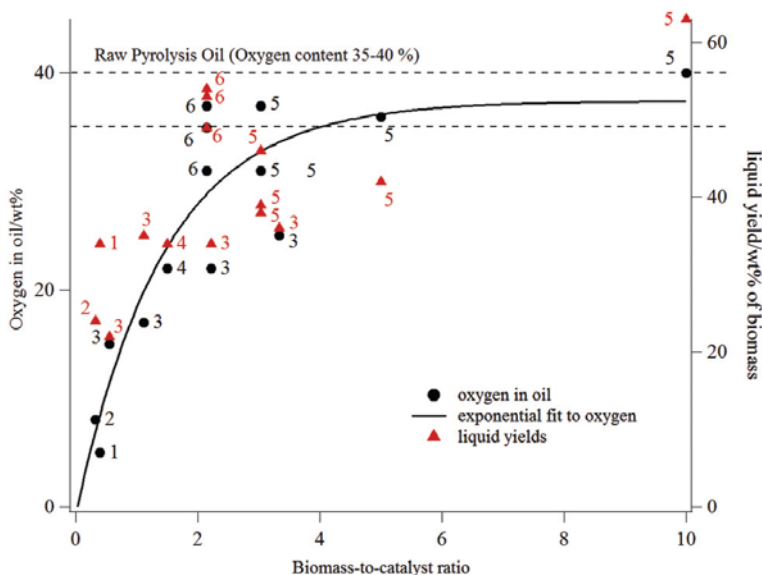
However, challenges lie in the modification of the quality of the liquid product to make it compatible with the current transportation fuels infrastructure and end use vehicles, which are predominantly operated with liquid hydrocarbon fuels. The source of this challenge is inherent to biomass feedstocks which usually contain substantial quantities of oxygen (~40 wt % in wood). Fast pyrolysis of such feedstocks yields oxygenated compounds that can react easily, posing a variety of processing challenges. Catalytically reducing the oxygen content, during or immediately after fast pyrolysis *while the products are still in the vapor phase*, can ease downstream processing challenges and provide many of the benefits outlined in this design report.

Included in this report are descriptions of process models and assumptions for two related conversion pathways: (1) *in situ* (also referred to elsewhere as catalytic fast pyrolysis), where catalytic vapor upgrading happens within the fast pyrolysis reactor, and (2) *ex situ* (also referred to elsewhere as vapor phase upgrading), where catalytic vapor upgrading happens in a separate reactor following the fast pyrolysis reactor. An *in situ* system includes catalytic upgrading within the circulating fluidized bed fast pyrolysis reactor system. This has the potential to reduce capital costs by precluding the use of additional vapor phase upgrading reactors and potentially a hot gas filter (HGF) in an *ex situ* configuration. However, the catalyst needs to survive in a considerably more challenging environment in an *in situ* reactor because of mixing with other solids including inhibitory mineral matter, char, and biomass. These other solids impose challenges for maintaining physical and chemical integrity required for a functional catalyst. In an *ex situ* configuration the elimination of such detriments can allow more focus on the achievable chemistry rather than on the mitigation of impacts of other solids. It is to be noted that a hybrid of an *in situ* configuration using relatively inexpensive catalyst followed by *ex situ* upgrading reactors may also be economically justifiable.

The *in situ* and *ex situ* catalytic fast pyrolysis vapor upgrading processes were identified by the U.S. Department of Energy's (DOE) Bioenergy Technologies Office (BETO) as research pathways for enabling the production of cost-competitive liquid transportation fuels from biomass [2, 3]. It should be noted that although circulating catalyst in fluidized beds were used as the basis for the conceptual designs, research and development will also consider other catalysts, including those with noble metals, suitable for use in *ex situ* fixed bed systems. Such design variations will be captured in future techno-economic analysis (TEA) and will leverage experimental data as they become available. Overall, this report captures envisioned process performances to be achieved for cost-competitiveness by 2022. Intermediate research targets

leading up to 2022 were developed subsequently for publication in BETO's Multi-Year Program Plan, using key assumptions in this report as the foundation; those metrics will be updated annually with research realities, and necessary deviations from the current design basis.

Numerous experimental studies have been conducted in the area of fast pyrolysis vapor upgrading, particularly with zeolite catalysts, and most commonly with HZSM-5 [4, 5, 6, 7]. Figure 1 illustrates how better quality, reflected by lower oxygen content, follows an inverse trend with liquid product yield. Lower biomass to catalyst ratios, corresponding to higher catalyst activity, result in better product quality at the expense of yield; potential organic liquid yield is lost to gas phase products, water, and coke. Since both improved bio-oil quality and high yields are necessary for economic viability, significant catalyst improvements will be necessary to break out of the performance mold demonstrated by current catalysts. In this regard it should be noted that performance in continuous systems with regeneration may be significantly better than in batch systems [8]. Some discussion of catalysts and associated references are provided in Section 3.2.1.6.



**Figure 1. Literature results for yields and oxygen content in bio-oil after catalytic upgrading of fast pyrolysis vapors using HZSM-5 as a function of biomass-to-catalyst ratio.** (Reproduced with permission from Mukarakate et al. [4].)

In this respect, modified zeolites and other families of catalysts [9] will need to be developed. Some of the key objectives of catalyst development include the enabling of: (1) reduced coke and coke precursor formation, (2) reduced non-condensable species formation, (3) efficient hydrogen utilization, which ties into reduced aromatics in the product, reduced coke formation, and greater hydrodeoxygenation to allow higher carbon efficiency, (4) coupling (molecular combination) reactions to reduce the loss of smaller molecules to the gas phase and also enhance the formation of distillate range products, (5) attrition resistance of fluidizable catalysts, (6) catalyst maintenance and regeneration in fluidized and fixed bed configurations, and (7) catalyst longevity. It is expected that these developments will result in significant vapor quality improvements with reduced reactivity; upon condensation the recovered organic phase can be



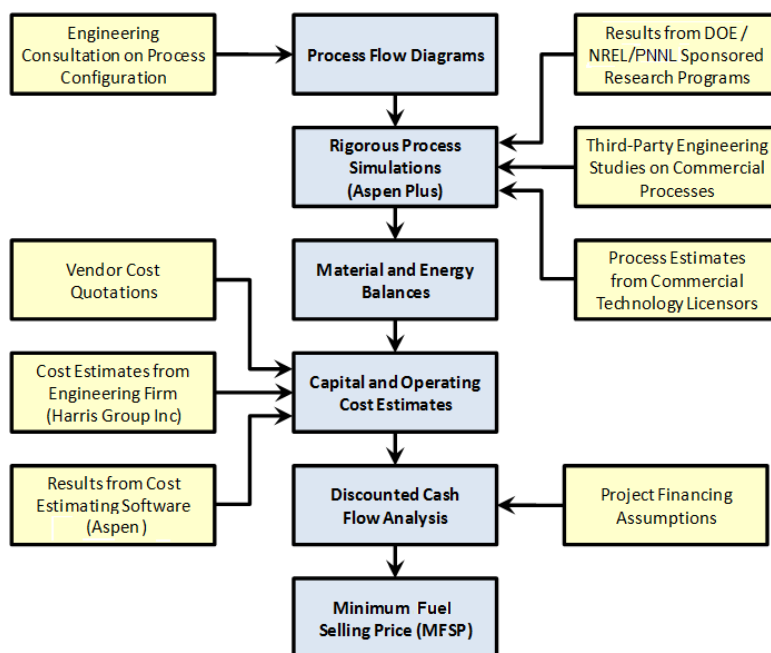
hydroprocessed to fuel blendstocks at relatively less severe conditions compared to raw bio-oil from non-catalytic fast pyrolysis. Note that quality is a function of not only the oxygen content, but also the types of remaining oxygenated species and functional groups in the oil, e.g. acids are more detrimental than phenol.

Some hydrogen reactivity during vapor upgrading will be necessary for higher organic liquid yields; hydrogen reactivity will need to be facilitated by the inclusion of metals within catalyst formulations. In order to help hydrogen reactivity in the vapor phase, the proposed designs for both *in situ* and *ex situ* configurations operate at slightly elevated pressures and include hydrogen in the fluidizing gas, with the aim of maintaining a nominal hydrogen partial pressure of 72–95 psia (5–6.6 bar) at the various reactor inlets (fast pyrolysis, *in situ* catalytic fast pyrolysis, and *ex situ* vapor phase upgrading). This process design decision does not require significant modifications to the vessel thicknesses of refractory-lined fluidized reactors operated at near ambient pressures. This inference was based on a design-study by Worley and Yale [10] who concluded that the minimum vessel wall thicknesses necessary to maintain mechanical integrity during fabrication and handling would be consistent with wall thicknesses of vessels designed for 150 psia. That study is the basis for the cost of fluidized reactors in this report. It is important to distinguish this process from conventionally known biomass hydrolysis processes operated at significantly higher pressures of 300–525 psia (20–35 bar) and a temperature range of 350°C–480°C [11].

The conceptual designs in this report assume stand-alone plants for the production of gasoline- and diesel-range blendstocks. It may be possible to produce sufficiently upgraded intermediates acceptable to petroleum refiners for further processing immediately after pyrolysis vapor upgrading. In such cases, it may be possible to further reduce or eliminate the on-site hydroprocessing facilities assumed in this report. However, such configurations will only be feasible after careful scrutiny of product quality and buy-in from refiners regarding compatibility with refinery unit operations [12].

## 1.2 Techno-Economic Analysis Approach

The general approach used in the process design, process model, and economic analysis is depicted in Figure 2. This design report includes information from previously published reports including those by the National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory (PNNL), reviews of commercially available technologies, process modeling using Aspen Plus software, equipment cost estimation through vendor quotes and Aspen Capital Cost Estimator (ACCE) software, and discounted cash flow analysis. The techno-economic analysis ultimately provides a minimum fuel selling price (MFSP) based on the financial assumptions in Table 1.



**Figure 2. Approach for *in situ* and *ex situ* fast pyrolysis vapor upgrading process design and analysis**

Aspen Plus Version 7.2 was used to develop mass and energy balances for the process. The plant operations are separated into eight major process areas:

- Area 100: Feed handling and drying
- Area 200: Fast pyrolysis and vapor upgrading
- Area 300: Pyrolysis vapor quench and product recovery
- Area 400: Hydroprocessing and product separation
- Area 500: Hydrogen plant
- Area 600: Steam system and power generation
- Area 700: Cooling water and other utilities
- Area 800: Wastewater management and recycle.

### 1.3 Definition of $n^{\text{th}}$ -Plant Economics

The techno-economic analysis reported here uses  $n^{\text{th}}$ -plant economics. The key assumption associated with  $n^{\text{th}}$ -plant economics is that several plants using the same technology have already been built and are operating. In other words, the assumption reflects a future in which a successful industry has been established with many operating plants. Because the techno-economic model is a tool used primarily for (1) studying new process technologies or (2) comparing integrated processes in order to comment on their relative economic impact, it is prudent to ignore artificial inflation of project costs associated with risk financing, longer start-

ups, equipment overdesign, and other costs associated with pioneer plants, as these overshadow the real economic impact of advances in conversion science or process engineering research. At the very least, n<sup>th</sup>-plant economics should help to provide justification and support for early technology adopters and pioneer plants about longer-term prospects.

Because equipment costs in this design report have been estimated explicitly, the n<sup>th</sup>-plant assumptions apply primarily to the factored cost model used to determine the total capital investment from the purchased equipment cost and to the assumptions applied for plant financing. The n<sup>th</sup>-plant assumption also applies to operating parameters, such as process uptime and start-up time. A summary of the n<sup>th</sup>-plant assumptions applied in this report are listed in Table 1. These financial assumptions are consistent with assumptions used for other economic analyses done for DOE’s Bioenergy Technologies Office, with some deviations to reflect the uniqueness of the current processes.

**Table 1. Summary of n<sup>th</sup>-Plant Assumptions for Techno-Economic Analysis**

<b>Description of Assumption</b>	<b>Assumed Value</b>
Internal rate of return (IRR)	10%
Plant financing by equity/debt	40%/60% of total capital investment
Plant life	30 years
Income tax rate	35%
Interest rate for debt financing	8.0% annually
Term for debt financing	10 years
Working capital cost	5.0% of fixed capital investment (excluding land purchase cost)
Depreciation schedule	7-year MACRS schedule [13]
Steam plant depreciation	20-year MACRS schedule [13]
Construction period (spending schedule)	3 years (8% Y1, 60% Y2, 32% Y3)
Plant salvage value	No value
Start-up time	6 months
Revenue and costs during startup	Revenue = 50% of normal Variable costs = 75% of normal Fixed costs = 100% of normal
On-stream percentage after startup	90% (7,884 operating hours per year)

## 1.4 Estimation of Capital Costs

Capital costs were estimated using a variety of resources. For sub-processes that utilize well-developed technologies and can be purchased as modular packages (e.g., steam reforming unit and refrigeration), an overall package cost was used instead of the sum of costs for individual pieces of equipment. Costs for common process equipment (e.g., tanks, drums, pumps, and simple heat exchangers) were estimated using ACCE costing software. Fluidized bed equipment (e.g., fast pyrolysis and *in situ* and *ex situ* reactors) specific to this process was estimated by

Harris Group using a mechanical design spreadsheet tool previously developed for gasifier costs [10]; design parameters were modified based on flow rates from the Aspen Plus process simulations and additional process inferences from mature fluid catalytic cracking (FCC) systems available in literature [14]. Hydroprocessing reactor costs were developed using ACCE, with some vendor quotes obtained by Harris Group used as supporting information. Some other major equipment costs, such as for the hydrogen compressors, were also obtained from vendors. Further details of equipment cost assumptions are provided under individual process areas in Section 3.

The original (base) purchased equipment costs reflect the base case for equipment size and cost year. Equipment sizes required for the process may vary from the original base case, requiring adjustment of the equipment costs. Instead of re-pricing equipment after minor changes in size, exponential scaling is applied to adjust the purchased equipment costs using Equation 1:

$$\text{Scale-Up Equipment Cost} = \text{Base Equipment Cost} \left( \frac{\text{Scale-Up Capacity}}{\text{Base Capacity}} \right)^n \quad (\text{Eq. 1})$$

The characteristic scaling exponent,  $n$ , is typically in the range of 0.6 to 0.7 for process equipment. The sizing parameters are based on a characteristic of the equipment related to production capacity, such as inlet flow for a process vessel or heat transfer duty for a heat exchanger. Equation 1 assumes that all other process parameters (pressure, temperature, etc.) remain constant relative to the base case. Scaling exponents were determined from the following sources:

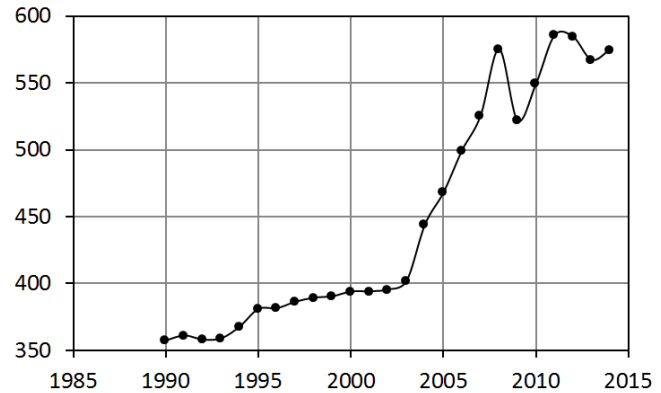
- Vendors' estimates of scaling exponent or inference from vendor quotes when multiple quotes were available for equipment of various processing capacities
- Development of correlations by multiple estimates from the ACCE software
- Standard reference from published sources such as Garrett [15], Peters, Timmerhaus, and West [16], and Perry et al. [17].

When cost data were not available in 2011 dollars, costs were adjusted with *Chemical Engineering's* (CE) Plant Cost Index [18] using Equation 2:

$$\text{Corrected Equipment Cost} = \text{Base Equipment Cost} \left( \frac{\text{2011 Cost Index Value}}{\text{Base Year Cost Index Value}} \right) \quad (\text{Eq. 2})$$

The CE indices used in this study are listed and plotted in Figure 3. The index data show a sharp increase after 2003 due to increases in global steel demand and a dip in 2009 due to the global recession. An intermediate 2014 index was used for 2014 corresponding to roughly the time when most of the recent cost quotes were obtained.

Year	Index	Year	Index
1990	357.6	2003	402.0
1991	361.3	2004	444.2
1992	358.2	2005	468.2
1993	359.2	2006	499.6
1994	368.1	2007	525.4
1995	381.1	2008	575.4
1996	381.7	2009	521.9
1997	386.5	2010	550.8
1998	389.5	2011	585.7
1999	390.6	2012	584.6
2000	394.1	2013	567.3
2001	394.3	2014	573.9
2002	395.6	(Mid-Year)	



**Figure 3. Chemical Engineering's Plant Cost Index data**

Once the total purchased equipment costs (TPEC) were determined, scaled, and time-corrected, an equipment installation factor was applied to estimate the total installed cost (TIC) for the equipment or process unit including associated piping, instrumentation and controls, electrical systems, buildings, yard improvements, and direct labor per Equation 3, where  $f_{Installation}$  is the installation factor:

$$Total\ Installed\ Cost\ (TIC) = f_{Installation} * Total\ Purchased\ Equipment\ Cost\ (TPEC) \quad (Eq. 3)$$

Where possible, specific installation factors from vendor quotes, ACCE, or published data [19] were applied to equipment or process units to estimate the TIC. Details for TPEC, installation factors, and TIC values for each process area are presented in Section 3.

Once the scaled TICs were determined, overhead and contingency factors were applied to determine a total capital investment (TCI) cost. The TCI, along with plant operating expenses, serves as the basis for the discounted cash flow analysis. The discounted cash flow analysis then yields the MFSP on a gallon gasoline equivalent (GGE) basis, a metric by which this conceptual process performance can be compared to alternate fuel production designs.

## 2 Plant Design Basis

### 2.1 Feedstock and Plant Size

The dry basis elemental composition of the feedstock, shown in Table 2, is identical to previous NREL and PNNL design reports [20, 21]. The composition was originally assumed to come from pulpwood. Recent feedstock logistics work at the Idaho National Laboratory (INL) suggests that the use of blended material may be required to meet a cost target of \$80/dry U.S. ton while still meeting these specifications [22]. For the purpose of this report, it is assumed that any blended material provided to meet this feedstock elemental composition will not adversely affect fast pyrolysis conversion efficiencies. Ongoing studies being conducted jointly by INL, NREL, and PNNL will provide experimental evidence of the impact of blended feedstocks on fast pyrolysis and gasification processes. Future TEA will be modified to reflect conversion impacts inferred from such studies.

**Table 2. Ultimate Analysis of Woody Biomass Feedstock**

<b>Component</b>	<b>Weight % (Dry Basis [20, 21])</b>
Carbon	50.94
Hydrogen	6.04
Nitrogen	0.17
Sulfur	0.03
Oxygen	41.90
Ash	0.92
Heating value <sup>a</sup> (Btu/lb)	8,601 HHV 7,996 LHV

<sup>a</sup> Calculated using the Aspen Plus Boie correlation.

The current feedstock moisture specification is 10 wt %, unlike the previous studies [20, 21] where a moisture content of 30 wt % was assumed at the plant gate. The cost of the material provided to the fast pyrolysis reactor (for *ex situ*) or catalytic fast pyrolysis reactor (for *in situ*) is \$80/dry U.S. ton [22]. This includes all feedstock logistics including the delivery of a nominal particle size of 2 mm into the reactors.

The design capacity for this study is 2,000 dry metric tonnes per day (2,205 dry tons per day), which matches that of previous design reports. With an expected 7,884 operating hours per year (90% on-stream factor/availability), the annual feedstock requirement is approximately 657,000 dry metric tonnes per year (724,000 dry tons per year). The assumed on-stream factor allows approximately 36 days of planned and unplanned downtime per year.

The delivered feedstock cost was estimated using INL's model. This cost of \$80 per dry ton includes all capital costs, operating costs, and dry matter losses associated with feed delivery, drying, and handling as determined by INL. The only additional equipment included with the plant costs is a cross-flow dryer, which was included for warming up the feedstock using flue gas and allowing for drying contingency during the wet weather.

It should be noted that the term mineral matter is used throughout the text to refer to the inorganic content in the feedstock, while the term ash is used to refer to the residual inorganic product after the combustion of biomass.

## 2.2 Process Overview

A block flow diagram of the current design is shown in Figure 4. A high level description of the conversion steps and their main purposes are presented below, with further details in Section 3.

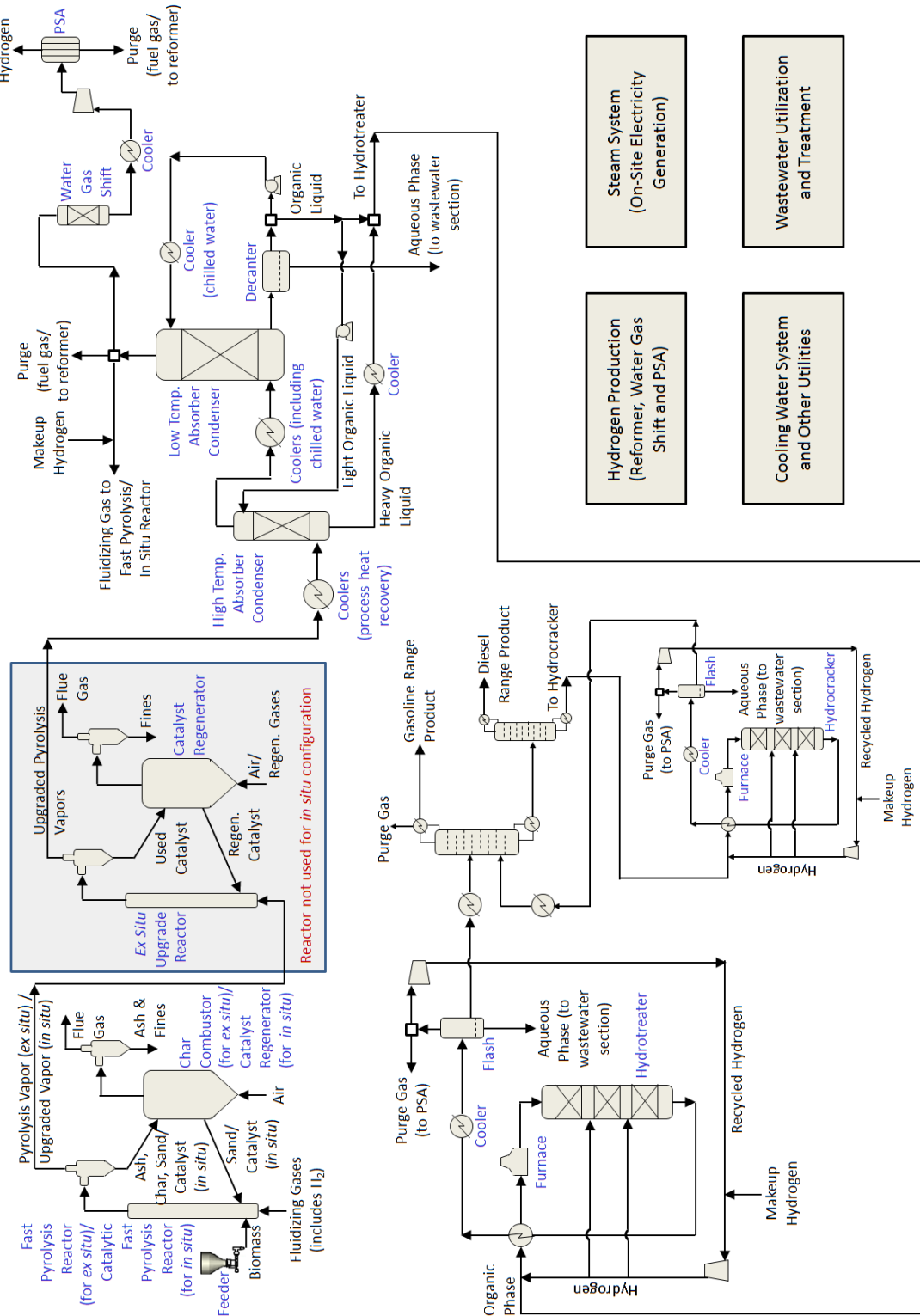


Figure 4. Simplified flow diagram for the conversion processes

- *Feed handling and preparation.* The modeled biomass feedstock has an ultimate analysis shown in Table 2. The assumed moisture content is 10 wt %, with an ash content of <1% and nominally sized to 2 mm for the fast pyrolysis reactor. A cross-flow dryer is included in the system to allow warming up of the feed prior to feeding in to the reactor, using process waste heat. This also allows for contingencies during wet weather when additional feed drying may be necessary. The feedstock is delivered at \$80/dry U.S. ton.
- *Fast pyrolysis with in situ or ex situ vapor upgrading.* The *in situ* configuration combines fast pyrolysis and catalytic vapor upgrading within the same reactor, while the *ex situ* configuration has a front end non-catalytic fast pyrolysis reactor followed by a separate *ex situ* catalytic vapor upgrading reactor system. The *ex situ* reactor is not exposed to biomass associated solids (biomass, char, and mineral matter) beyond the unintended entrainment of fine material such as attrited solids and some mineral matter/ash, making it a more benign environment for catalyst performance and maintenance. It is also possible for the *ex situ* reactor to have a fixed bed configuration. In this report, all three reactors, (1) non-catalytic fast pyrolysis, (2) catalytic fast pyrolysis or *in situ* upgrading, and (3) separate vapor phase upgrading or *ex situ* reactors, are dual circulating fluidized bed (CFB) systems. Each has an entrained flow reactor and a second fluidized bed combustor for char/coke combustion, similar to FCC reactors. In the *in situ* and *ex situ* catalytic systems the combustor also serves as a catalyst regenerator by burning off coke deposits. In the conceptual designs presented, all three reactors operate at 500°C (932°F) reactor outlet temperatures, with short residence times (<2 s), under approximately 72–95 psia (5–6.6 bar) of hydrogen partial pressure, and 120 psia (~8 bar) total pressure. The catalytic vapor upgrading step is designed to help reduce oxygen content in the produced bio-oil organic liquid fraction, making it less reactive and amenable to hydroprocessing under less severe conditions into fuel blendstocks. It should be noted that the above parameters are for one possible design, which are used for our base cases. The fluidizing gas composition and pressure assumed for the base case may be altered as benefits are analyzed with further catalyst development and experiments. Other design variations may include hot gas filters, fixed bed vapor phase upgrading reactor systems, and catalysts other than zeolites. Such changes can alter process conditions, including operating temperatures and catalyst regeneration protocols.
- *Pyrolysis vapor quench.* Upgraded vapors from both *in situ* and *ex situ* systems are quenched to separate vapors from non-condensable gases. The base case assumes that there will remain concerns about fouling of indirect heat exchange equipment during the condensation of the heavy fraction of the organic vapors. A first absorber/condenser is thus used to recover the heavy organic fraction after vapors are cooled to the stream's predicted dew point. The absorber/condenser is followed by indirect heat exchange to cool down the remaining vapor. This stream then enters a second absorber/condenser where a light organic phase and an aqueous phase are condensed from non-condensable gases. The organic fraction is sent for hydroprocessing, while the aqueous fraction is sent to wastewater treatment. The majority of the non-condensable gases are recycled to the fast pyrolysis reactor for fluidization. The remaining gas is used for hydrogen production via sour water gas shift and pressure swing adsorption (PSA). Economic impacts of the inability to use any indirect heat exchange for energy recovery from the hot upgraded



vapors are discussed later in Section 5 as part of sensitivity analysis; equipment configuration modifications for such scenarios were not modeled in this study.

- *Hydroprocessing and product separation.* The organic liquid fraction is sent to a hydrotreater for deoxygenation and saturation of a portion of the products to reduce aromatic content. Note that the separation of the aqueous phase after the condensation of upgraded vapors reduces the liquid flow to the hydrotreater significantly. The hydrotreater is modeled with a specified inlet temperature of 375°C (707°F), and inlet pressures of 1,845 psia and 1,545 psia for the *in situ* and *ex situ* cases, respectively. The products are fractionated into gasoline and diesel boiling ranges. The heavier product is sent to a hydrocracking reactor with a specified inlet temperature of 392°C (738°F) and inlet pressure of 1,945 psia. Products from hydrocracking are also sent for fractionation to produce gasoline and diesel boiling range products.
- *Hydrogen production.* A fixed-bed steam methane reformer (SMR) package was used for hydrogen production. Natural gas was used only as a supplement for hydrogen production; in the base cases there is sufficient fuel gas available in the process to provide all the duty necessary to operate the reformer at high temperatures as well as produce required quantities of hydrogen. In the base cases negligible amounts of supplemental natural gas was used for both the *in situ* and *ex situ* cases (as shown in Table 13). The natural gas demand increases for sensitivity cases where higher liquid fuel product yields are assumed. The process design and costs [21] include sulfur removal from the fuel gases fed to the reformer, a water gas shift reactor for the enhancement of hydrogen production, and a subsequent PSA for hydrogen purification.
- *Heat and power.* A conventional steam cycle uses process heat to produce electricity. There is a significant amount of heat available in the process that needs to be managed efficiently to positively impact the economics. The significant sources of heat are the char and coke combustors, hot upgraded pyrolysis vapors (including fluidization gases), steam reformer flue gas, and reformed gas quench. In both the *in situ* and *ex situ* designs, excess electricity is available after consumption in the plant. This electricity is sold to the grid, and the credit reduces the MFSP.
- *Cooling water.* A cooling water system is included in the Aspen Plus model to determine the requirements of each cooling water heat exchanger within the biomass conversion process.
- *Wastewater management.* Wastewater from the vapor condensation section is sent to a reboiler system to generate steam for process use (sour water gas shift and steam reforming). However, to avoid fouling in the reboiler, not all the wastewater is evaporated. The carbon in the remaining wastewater after partial evaporation is approximately 25 wt %. This wastewater is sent to an aqueous regenerative thermal oxidizer (RTO) to eliminate the varied carbon species that may be present. The Aspen Plus process model predicts that the aqueous RTO is self-sustaining with some extra heat available from the combustion of the carbon remaining in the aqueous phase. The remaining wastewater is sent for conventional treatment. However, there remain significant opportunities to recover valuable products from the wastewater using processes such as aqueous phase reforming and biological upgrading; such processes are

not considered in this design in order to focus on the core technology of *in situ* and *ex situ* fast pyrolysis vapor upgrading.

### 2.3 Aspen Plus Model

An Aspen Plus Version 7.2 simulation was used as the basis for this report. Since the products in pyrolysis are numerous and varied, only selected model compounds were used to represent the product slate. Additional hydrocarbon species were added to represent hydroprocessing products. Many of the desired molecular species in the desired boiling ranges for light and heavy fractions did not exist in Aspen Plus databanks and physical property parameters needed to be estimated. The biomass feedstock, ash, char, and coke were modeled as non-conventional components. Appendix F provides information about compounds selected to represent the process. The Peng-Robinson with Boston-Mathias modifications (PR-BM) equation of state was used throughout most of the process simulation. The ASME 1967 steam table correlations (STEAM-TA) were used for the steam cycle calculations.

## 3 Process Design and Cost Estimation

The process design broadly consists of the following areas:

- Area 100: Feed handling and drying
- Area 200: Fast pyrolysis and vapor upgrading
- Area 300: Pyrolysis vapor quench and product recovery
- Area 400: Hydroprocessing and product separation
- Area 500: Hydrogen plant
- Area 600: Steam system and power generation
- Area 700: Cooling water and other utilities
- Area 800: Wastewater management and recycle.

The following sections present process overviews, design bases, and installed equipment cost estimations for each process area of the plant. Heat balance and pinch analysis are discussed separately in Section 3.10. Note that additional details of equipment costs and economics are provided in Appendices B and C. Detailed process flow diagrams and stream summaries are presented in Appendix G. Note that appendix name suffixes “-1” and “-2” are used when there are separate sets of information presented for the *in situ* and *ex situ* cases, respectively.

### 3.1 Area 100: Feed Handling and Drying

Feed handling and drying, as well as all other off-site logistics are described in detail in a recent INL report [22]. As mentioned in Section 2, INL’s cost model for the material uses blended material. The blend constituents include pulpwood (45%), woody residues (32%), switchgrass (3%), and construction and demolition waste (20%). Further details are provided in the INL report [22]. The dry basis ultimate analysis of this blended material is similar to pulpwood. It is assumed that the biomass feedstock modeled will be provided at \$80/dry U.S. ton to the throat of the reactor and will have similar conversion performance to pulpwood for the processes under consideration in this report. It *remains to be experimentally determined* whether this assumption is correct; INL, NREL, and PNNL are jointly working on this aspect. Table 2 shows the feedstock ultimate analysis used in this design. This ultimate analysis is used in the simulation for atomic balance closure. The moisture content of the material is 10 wt %, with a nominal particle size of 2 mm. The conceptual plant is modeled to consume 2,000 dry metric tonnes of biomass feedstock per day.

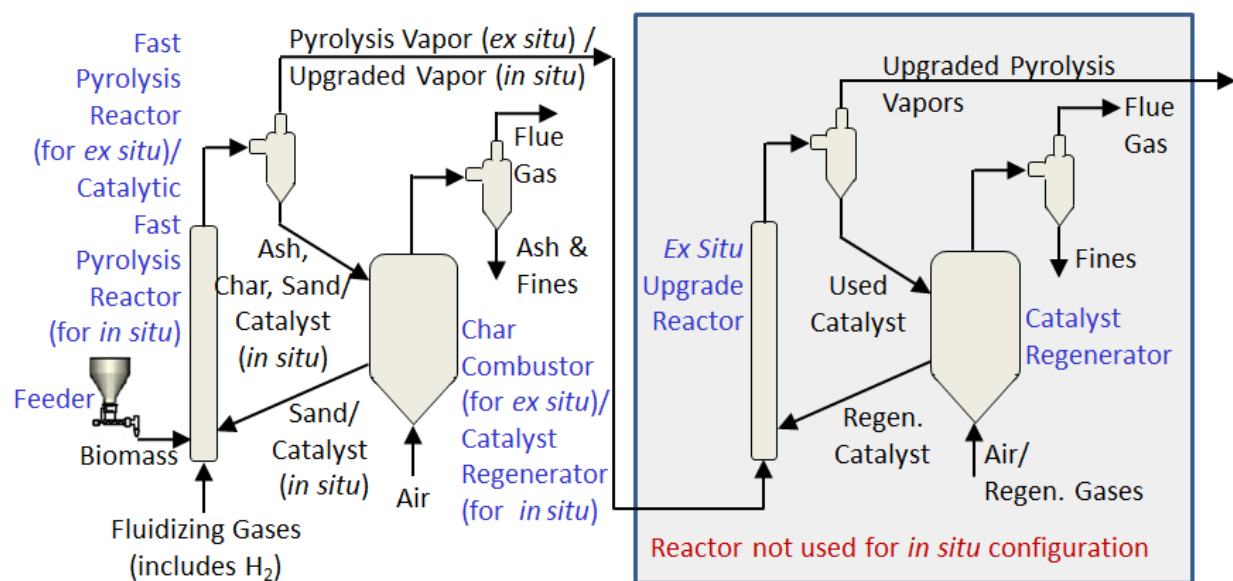
While all feedstock logistics including capital and energy requirements for drying and size reduction are included in the feedstock cost, an additional cross-flow dryer and a flue gas blower was added to the plant equipment list (the small power consumption for feed handling and drying shown in Table 15 and Table 16 are from these additional operations). The capital costs and installation factors are shown in Appendix B. This dryer was added to help warm up the biomass feedstock prior to feeding into the reactor. It will also help to control feedstock moisture content during wet weather. In both the *in situ* and *ex situ* process models the feedstock is warmed in the cross-flow dryer from 15.6°C (60°F) to 103.3°C (218°F) using flue gases from the combustors in the process.

## 3.2 Area 200: Fast Pyrolysis and Vapor Upgrading

The following section presents an overview, basis for design, and cost estimates for construction of the fast pyrolysis, *in situ* catalytic fast pyrolysis, and *ex situ* vapor upgrading facilities.

### 3.2.1 Area 200 Overview

Figure 5 shows a simplified flow diagram for the fast pyrolysis and catalytic vapor upgrading equipment.



**Figure 5. Simplified process flow diagram for fast pyrolysis and catalytic vapor upgrading**

The *in situ* configuration combines fast pyrolysis and catalytic vapor upgrading within the same reactor, while the *ex situ* configuration has a front end non-catalytic fast pyrolysis reactor followed by a separate *ex situ* catalytic vapor phase upgrading reactor system. The *ex situ* reactor is not exposed to biomass associated solids (biomass, char, and mineral matter/ash) beyond unintended entrainment of fine material such as attrited solids and some mineral matter/ash mixed with char. It should be noted that much of the mineral matter/ash is mixed with the char that is removed by the cyclones after the non-catalytic fast pyrolysis reactor. This makes the *ex situ* configuration a more benign environment for catalyst performance and maintenance; some of the superior performance assumptions in this design for *ex situ* over *in situ* are based on this advantage. It is also possible for the *ex situ* reactor to have a fixed bed configuration, with a hot gas filter to remove fine solid material before the vapors from the fast pyrolysis reactor enter the *ex situ* upgrading reactor. In this report, all three reactors, (1) non-catalytic fast pyrolysis for the *ex situ* case, (2) catalytic fast pyrolysis or *in situ*, and (3) separate vapor phase upgrading or *ex situ* reactors, are CFB systems. A hot gas filter may also be an option for ensuring that all remaining entrained mineral matter/ash (even after two cyclones in the fast pyrolysis system) is eliminated prior to the *ex situ* CFB reactor; this is not considered in the base case, and any future inclusion will be based on benefits to catalyst maintenance assessed from experimental results. Each of the CFB systems has an entrained flow reactor and a second fluidized bed combustor for

char/coke combustion, similar to FCC reactors. In the *in situ* and *ex situ* catalytic systems the combustor also serves as a catalyst regenerator by burning off coke deposits. The following paragraph focuses on the non-catalytic fast pyrolysis reactor and discusses some of the basis for the Aspen Plus model implementation, and equipment costs that needed to be taken into consideration [10]. Some of the key operating parameters and assumptions in our design are noted. Following this description of the non-catalytic system, variations introduced for the *in situ* and *ex situ* upgrading reactors are pointed out.

### 3.2.1.1 Fast Pyrolysis System

The non-catalytic fast pyrolysis reactor outlet temperature is maintained at approximately 500°C. The reactor is operated at approximately 120 psia (~8 bar) with a hydrogen partial pressure of approximately 72–95 psia (5–6.6 bar) in the inlet fluidizing gas. The riser reactor is sized for a residence time of less than 2 seconds, and velocity of 30 ft/s for design purposes. Hot sand returned from the combustor bed provides the heat necessary for the endothermic pyrolysis reactions. The reaction products include char and mineral matter in the solid phase along with vapors including water, as well as non-condensable light gases dominated by carbon monoxide (CO) and carbon dioxide (CO<sub>2</sub>). Upon exiting the riser reactor, the solids consisting of sand and mineral matter mixed with char are separated from the vapors in two cyclones in series. These solids are returned to the combustor. The vapor products are sent to an *ex situ* upgrading reactor. The combustor is operated at nearly the same pressure as the reactor; 20% excess air is supplied to burn the char. The combustor is sized assuming a superficial velocity of 2.5 ft/s and a transport disengagement height of 19 feet [23]. The reactor and combustor capital costs are scaled based on actual gas volumetric flow rate; consequently there is a significant capital cost reduction predicted for higher operating pressures. The capital cost for the fast pyrolysis reactor and condensation train is comparable to the 2013 PNNL-led report [21] if the reactor and combustor are scaled using a higher volumetric flow rate at a lower pressure of 20 psia. Note that higher operating pressures assumed in this report also result in higher combustion-air compression costs, which is factored in the process model. The residual ash and finer particles are entrained in the flue gas and separated by two cyclones in series. The fines are sent for disposal and the flue gases go through a heat recovery train. Sand is heated during the combustion process. The hot sand is partially cooled in a solids-cooler to produce high pressure steam; this allows the sand returning to the pyrolysis reactor to have the thermal capacity to maintain 500°C at the exit of the fast pyrolysis reactor because pyrolysis is an endothermic process. A 1% heat loss on a lower heating value (LHV) of biomass basis is assumed, each in the combustor and the pyrolysis reactor. The sand flow is calculated within the constraints of delivering the right amount of heat to the pyrolyzer, while at the same time maintaining the combustor at a specified temperature of 720°C (1,328°F). The solids cooler consists of a vessel containing a series of 2.5-inch diameter A335 P91 tubes, and is sized based on the required heat duty and an assumed overall heat transfer coefficient of 31.7 Btu/hr-ft<sup>2</sup>-°F [24]. The solids cooler price is scaled based on duty. All of the vessels and ducts are made of carbon steel with refractory lining, and were originally estimated based on a 150 psia design pressure [10]. Two parallel trains are proposed, each handling 1,000 dry metric tonnes per day of biomass, because of anticipated biomass feeding constraints into a single reactor.

### 3.2.1.2 In Situ Upgrading System

The *in situ* catalytic fast pyrolysis reactor has a similar design as the system described above. In this case, the circulating solid is a catalyst instead of sand. A significant change occurs in the thermal balance and heat removal requirements due to the formation of coke that needs to be burned along with the char in the combustor bed. Hydrogen partial pressure in the fluidizing gas was chosen to be slightly higher (still within the 72–95 psia range), with the consideration that some additional pressure will be necessary for hydrogen reactivity in a more challenging *in situ* catalytic environment (compared to the *ex situ* case). The assumption of pressure will be revised later (approximately within the 25 psia to 120 psia range) based on experimental results for both the *in situ* and *ex situ* systems. The *in situ* reactor design is otherwise similar to the non-catalytic system. Catalyst circulation is calculated within the thermal constraints described for the non-catalytic fast pyrolysis reactor. The combustor temperature was lower at 650°C (1,202°F), based on constraints for HZSM-5 [25]. Two percent of the catalyst inventory is replenished per day; typical FCC replenishment rates are between 1% and 3% per day [26]. An additional 1.6% of the inventory is assumed to be replaced to account for attrition. It is expected that an equilibrium catalyst (E-Cat) with activity commensurate to conversion requirements will be established as the system is operated. Catalyst costs and related assumptions are based on FCC catalysts, using the rare earth metals lanthanum and cerium for catalyst stability. The \$19,500/ton catalyst cost was in anticipation of the use of rare earth metals [27] and non-precious metals such as nickel for hydrogenation, in addition to a base catalyst cost [28]. As noted earlier, catalyst research will be key to the success of these conversion pathways, and these assumptions will be modified with advances in the research. Stripping steam is used in this reactor system and also in the *ex situ* upgrading reactor system to recover additional product from the catalyst surface. A design specification of 3 lbs of steam per 1,000 lbs of catalyst was used with a catalyst flux of 600 lb/min/ft<sup>2</sup> [14]. Cost of an additional vessel with structured 410SS packing internals was added for this purpose, and was sized assuming a height of 28 feet based on vendor estimates. The stripper is scaled based on catalyst flow rate, which is the primary variable affecting the vessel diameter.

### 3.2.1.3 Ex Situ Upgrading System

The *ex situ* system catalyst material assumptions are the same as for *in situ* systems. The catalyst replenishment rate was also assumed to be 2% of the inventory per day. In addition it is assumed that 1.6% of the inventory is added to the reactor system per day to account for attrition losses. The total replacement assumption of 3.6% of the inventory per day may be conservative; this leaves leeway for the future use of more expensive catalysts with lower replacement rates for the *in situ* and *ex situ* cases. The catalyst flow rate was fixed at 5 times the mass flow rate of dry biomass, which is lower than the corresponding value of 7.5 times for the *in situ* case, an assumption based on a more benign environment in the *ex situ* reactor. This is a parameter that can be adjusted in the simulation based on specific catalyst activity and performance. The heat balance in the *ex situ* reactor is significantly different because this system is expected to be exothermic (as also predicted by the Aspen Plus model) and an additional catalyst cooling step to 341°C (645°F) is necessary after the catalyst is regenerated at 650°C (1,202°F). While reactor design temperature in the base case is 500°C (932°F) at the outlet of the *ex situ* reactor, this temperature will likely be revised as experimental results become available. Also, there is no biomass feed into the *ex situ* vapor phase upgrading reactor because it follows a separate non-catalytic biomass fast pyrolysis reactor. Thus the *ex situ* reactor does not have the scale-up

constraints associated with biomass feed; in this report we limited each CFB system with biomass feed to 1,000 dry metric tonnes/day capacity based on publicly available industrial fast pyrolysis reactor sizing information. Therefore, a single large *ex situ* reactor can process the entire vapor stream from 2x1,000 dry metric tonnes/day fast pyrolysis reactors. Note that this scale-up is the primary reason for the lower cost of the *ex situ* reactor compared to the other CFB reactor systems (with biomass feed) shown in Table 5. The total heat loss in the *ex situ* reactor was assumed to be 1% of the LHV of biomass (0.5% each in the reactor and catalyst regenerator). The use of a hot gas filter is not considered in the base case, although some discussion is provided with the sensitivity analysis presented in Section 5. The use of precious metals in catalysts, which may be feasible in fixed bed reactor systems, is also left for future consideration and analysis.

### 3.2.1.4 Comparison of In Situ and Ex Situ Upgrading

A summary of some of the key differences between the *in situ* and *ex situ* upgrading approaches are summarized in Table 3.

**Table 3. Comparison of In Situ and Ex Situ Upgrading**

<i>In Situ</i>	<i>Ex Situ</i>
Fluidized bed systems only	Fluidized or fixed bed; fixed bed systems can use precious metal catalysts. Coke formation needs to be minimized for the feasibility of fixed bed systems.
Lower capital because of single reactor	Higher capital because of separate <i>ex situ</i> upgrading reactor.
Hot gas filter (HGF) not required	HGF necessary for fixed bed systems, and maybe desirable for fluidized systems; HGF can result in additional yield losses.
Catalyst mixes with biomass, char, mineral matter/ash	Biomass, char, mineral matter/ash reduced or removed upstream of reactor.
Higher catalyst replacement requirement because of higher irreversible catalyst deactivation from inorganic material (e.g., alkali)	Lower catalyst replacement requirement because of the removal of inorganic matter upstream of the reactor (using cyclones and optionally a hot gas filter).
Operating conditions closely tied to fast pyrolysis conditions	Flexibility to operate at different conditions (e.g., temperature, contact time) compared to upstream fast pyrolysis reactor; this will allow optimizations for higher carbon efficiency, product selectivity, deactivation rates, etc.

### 3.2.1.5 Pressure and Hydrogen Assumptions

The conceptual designs presented in this report assume higher than atmospheric pressures and hydrogen-enriched fluidizing gases as described above (Table 4). While the primary consideration for proposing an elevated pressure was the potential benefit to the chemistry including hydrodeoxygenation, hydrogenation, and yield improvements, there are also advantages from a process economics standpoint based on the following:

- Hydrogen partial pressure is below the embrittlement pressure for carbon steel as indicated by Nelson curves [29]. Based on this information it was not required to modify the proposed reactor materials of construction (refractory-lined carbon steel) for this conceptual process design.
- Capital costs are lower because of lower volumetric flow rates and smaller equipment.
- There is increased feasibility of using a hot gas filter in future variations of this design. Hot gas filter costs scale by the actual volumetric gas flow rate. The process can remain cost competitive even with the addition of a hot gas filter because of the lower volumetric flow rate at these slightly elevated pressures.

#### 3.2.1.6 Catalysts

Catalyst research and development will be key for achieving the functionality and product yields targeted in this report for 2022. Zeolite-based catalysts have been used extensively for fast pyrolysis vapor upgrading [30, 31]. Experimental results using ZSM-5 and its variations are the most widely reported in the literature [8, 32, 33, 34, 35, 36, 37]. In this report we assumed the use of similar catalysts, with metal additives for hydrogen activity, and rare earth metal additives for stability, deployed in a circulating fluidized bed system.

It is understood that performance outlined with respect to hydrodeoxygenation, hydrogenation, and molecular combination (coupling) will require significant advances in catalysts. In addition, with further maturity of the research and product characterization, ring-opening chemistry will likely become very desirable; the optimal location for utilizing such chemistry in the process configuration will need to be determined, with the downstream hydroprocessing step being an option to consider. The conceptual processes outlined in this report are expected to be modified (in the 2017 timeframe) based on experimental results for the catalysts being developed. The use of noble metals in fixed bed reactors (preceded by a hot gas filter) during *ex situ* upgrading is another promising configuration. The use of bifunctional catalysts has been suggested for this vapor upgrading step [9]. Information about the chemistry and candidate catalysts for enhancing coupling reactions such as ketonization, aldol condensation, and hydroalkylation are also available in literature [9, 38]. The biggest challenge for the *ex situ* pathway is to accomplish and optimize the chemistry to desired products within an economically feasible number of steps, while also minimizing yield losses in each step, including during any associated hot gas filtration.

It will be important to reduce rates of irreversible catalyst deactivation to improve longevity and reduce replacement rates. Critical catalyst deactivation mechanisms are poisoning by inorganic impurities, structural changes that result from elevated temperatures during regeneration, and the presence of water and acids leading to physical degradation. By analogy with FCC systems, all components of the catalyst (active site, matrix, binder) will need to exhibit stability under process conditions.

#### 3.2.2 Area 200 Design Basis

The design basis for the fast pyrolysis and catalytic vapor upgrading area is presented in Table 4. This basis reflects the overall plant capacity of 2,000 dry metric tonnes per day (2,205 dry tons per day). Product flow information is provided under Area 300. Detailed process flow diagrams



and stream summaries are presented in Appendix G (A-201 in Appendix G-1 for *in situ*, and A-201 to A-203 in Appendix G-2 for *ex situ*).

**Table 4. Design Basis for Fast Pyrolysis and Catalytic Vapor Upgrading**

Configuration	<i>In Situ</i>	<i>Ex Situ</i>	
	Reactor for Fast Pyrolysis with <i>In Situ</i> Vapor Upgrading	Reactor for Non-Catalytic Fast Pyrolysis	Reactor for <i>Ex Situ</i> Vapor Upgrading
<b>Reactor</b>			
Parallel trains for reactor and combustor	2	2	1
Total biomass feed rate per train, dry metric tonnes/day	1,000	1,000	N/A
Biomass moisture (wt %)	10	10	N/A
Exit temperature, °C (°F)	500 (932)	500 (932)	500 (932)
Pressure, psia (bar)	121 (8.3)	121 (8.3)	117 (8.1)
Bed solids material	Catalyst (ZSM-5)	Sand	Catalyst (ZSM-5)
Bed solids inventory (ton)	115	120	77
Catalyst replacement (% of reactor system inventory/day)	2	N/A	2
Additional catalyst attrition (% of reactor system inventory/day)	1.6	N/A	1.6
Ratio of bed solids to dry biomass (w/w)	7.5	7.8	5.0
Number of cyclones per reactor	2	2	2
Stripping steam (lb/1,000 lb catalyst)	3	-	3
Fluidizing gases to dry biomass (w/w)	0.86	0.76	-
H <sub>2</sub> partial pressure in fluidizing gas, psia (bar)	86 (6)	93 (6.4)	72 (5.0)
<b>Combustor/Regenerator</b>			
Temperature, °C (°F)	650 (1,202)	720 (1,328)	650 (1,202)
Pressure, psia (bar)	117 (8.1)	117 (8.1)	113 (7.8)
Excess air (%)	20	20	20
Solids temperature before transfer to reactor, °C (°F)	650 (1,202)	720 (1,328)	341 (645)
No. of cyclones per combustor	2	2	2

### 3.2.3 Area 200 Equipment Cost Estimations

Capital costs for the equipment in this area were estimated by Harris Group. A previously developed spreadsheet tool for gasifier costs was leveraged for this exercise. Cost estimates from this tool were compared with order of magnitude estimates from technology vendors and documented in Appendix I of Worley et al. [10]. Of particular interest for this report, because of significant parallels to the three reactors in our design (as discussed in Section 3.2.1), is the CFB

gasifier. The CFB gasifier estimation tool was used with the flow rates in the Aspen Plus model for developing cost estimates shown in Table 5. Another advantage of using the tool was its adaptability to add on estimates for additional vessels such as catalyst coolers and steam strippers, which were not originally built into the CFB gasifier configuration. The tool also provided estimates for the biomass feeder, which was not included into our economics because INL’s feedstock logistics already includes biomass feeding within the \$80/dry U.S. ton feedstock cost. Operating cost assumptions are shown in Section 4 and impacts on the overall economics are summarized in Appendix C.

**Table 5. Capital Cost Estimates for the Fast Pyrolysis and Catalytic Vapor Upgrading Area**

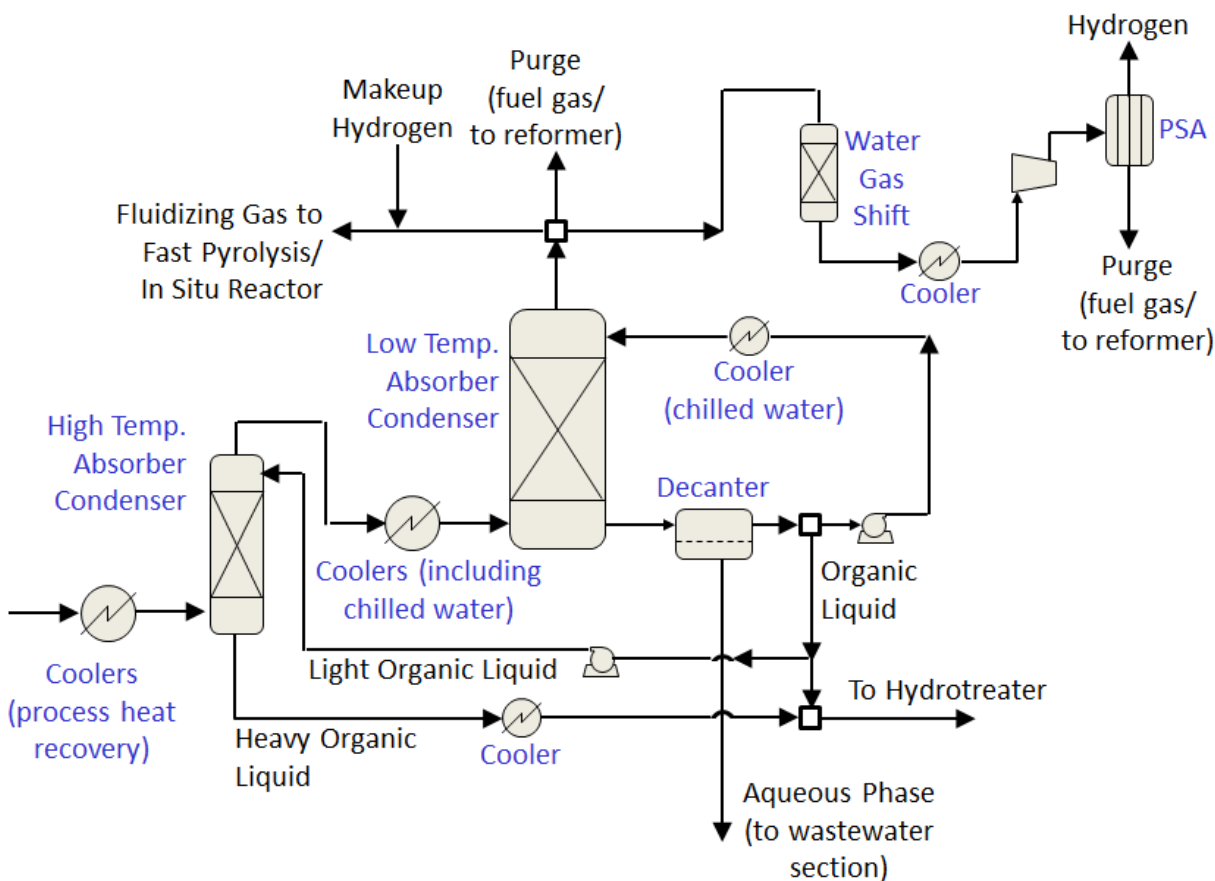
	<b>TPEC (2011\$k)</b>	<b>TIC (2011\$k)</b>
<b><i>In Situ Configuration</i></b>		
Catalytic fast pyrolysis CFB reactor/regenerator	\$28,558	\$85,829
Heat integration	\$2,524	\$6,651
<b>Area A200 subtotal</b>	<b>\$31,082</b>	<b>\$92,480</b>
<b><i>Ex Situ Configuration</i></b>		
Fast pyrolysis CFB reactor/combustor	\$23,163	\$71,847
<i>Ex situ</i> catalytic vapor upgrading reactor/regenerator	\$14,835	\$48,103
Heat integration	\$2,653	\$6,991
<b>Area A200 subtotal</b>	<b>\$40,651</b>	<b>\$126,941</b>

### 3.3 Area 300: Pyrolysis Vapor Quench and Product Recovery

The following section presents an overview, basis for design, and cost estimates for upgraded pyrolysis vapor quench, product recovery and fluidizing gas recycle.

#### 3.3.1 Area 300 Overview

Figure 6 is a simplified flow diagram showing the major equipment in this section.



**Figure 6. Simplified process flow diagram of pyrolysis vapor quench and product recovery**

Upgraded vapors from both *in situ* and *ex situ* configurations are quenched to condense and separate vapors from non-condensable gases. Note that there is a significant proportion of non-condensable gases beyond those produced from the pyrolysis reactions. In particular, the gases are rich in hydrogen because of a deliberate attempt to create a hydrogen-rich atmosphere to favorably impact the chemistry. In addition, water constitutes a large fraction of the condensable vapors. The base case assumes that there will remain concerns about fouling of indirect heat exchange equipment during the condensation of the heavy fraction of the organic vapors. Heat is recovered via indirect heat exchange up to the dew point of the vapors, predicted to be 241°C (466°F). A first absorber/condenser is then used to recover the heavy organic fraction using a quench stream of recycled liquid consisting of the light organic fraction. Nearly 40 wt % of the organic product is condensed out and recovered at the bottom of the absorber/condenser. The

overhead products exit at 176°C (348°F) and 181°C (358°F) for the *in situ* and *ex situ* cases, respectively, and enter an indirect heat exchanger train to cool down the remaining vapors. Process heat recovery, air cooling to 60°C (140°F), water cooling to 43.3°C (110°F) and chilled water cooling to 15.6°C (60°F) are used in sequence. This stream then enters a second absorber/condenser where a light organic phase and an aqueous phase are recovered as the bottoms product and separated by decantation. The recycled light organic product is chilled to 10°C (50°F) and used as the quench liquid. The light and heavy organic fractions are mixed and sent for hydroprocessing, while the aqueous fraction is sent to wastewater treatment. Filters are included for all three product streams (heavy organic, light organic, aqueous). Proper filtration to remove particulates from the organic phases is important for the maintenance of the downstream hydrotreating catalyst.

The non-condensable gases from the top of the absorber-condenser are split into (1) a purge stream (1%) to the reformer, (2) recycle to the fast pyrolysis reactor for fluidization (75% for *in situ* and 71% for *ex situ*), and (3) the balance sent to a sour water gas shift (WGS) reactor. The inlet temperature of the WGS reactor is 240°C (464°F) [39]. Steam for the WGS reactor is generated from the collected waste aqueous streams using a reboiler (discussed later under A800). The product from the WGS reactor is cooled and condensed water is sent to the wastewater section. The gases are then compressed to approximately 220 psia and cooled to 43.3°C (110°F) before being sent to a PSA unit with 84% hydrogen recovery at 99% purity. The PSA off-gases are sent to the reformer section for use either as fuel or reformer feed; this split is determined by the heat balance of the reformer system. The hydrogen is recycled back to the fast pyrolysis reactor (*ex situ* case) or the catalytic fast pyrolysis reactor (*in situ* case). In both the *in situ* and *ex situ* configurations, supplemental hydrogen is added to maintain the design H<sub>2</sub> partial pressure of approximately 72–95 psia in the fluidizing gas.

### 3.3.2 Area 300 Design Basis

Table 6 summarizes the design basis and other key information for this area. Detailed process flow diagrams and stream summaries are presented in Appendix G (A-301 to A-304 in Appendix G-1 for *in situ*, and A-301 to A-305 in Appendix G-2 for *ex situ*).

**Table 6. Design Basis for Pyrolysis Vapor Quench and Product Recovery**

<b>Configuration</b>	<b><i>In Situ</i></b>	<b><i>Ex Situ</i></b>
<b>Heavy fraction condenser-absorber</b>		
Overhead temperature, °F	348	358
Pressure, psia	114	110
Feed rate, lb/h	329,131	310,342
Recycle liquid flow, lb/h	86,730	81,043
Vapor product, lb/h	396,315	371,714
Bottoms liquid product, lb/h	19,547	19,671
<b>Light fraction condenser-absorber</b>		
Feed temperature, °F	60	60
Overhead pressure, psia	101	97
Recycle liquid flow, lb/h	964,869	901,600
Vapor product, lb/h	199,763	182,444
Bottoms liquid flow, lb/h	1,161,420	1,090,871
Mole % H <sub>2</sub> overhead in gas	62%	68%
<b>Aqueous phase</b>		
Flow rate, lb/h	77,273	77,811
Mass percent C	2.6%	1.6%
<b>Total organic phase (heavy + light)</b>		
Flow rate, lb/h	52,053	50,051
Mass percent C, H, O	80%, 10%, 10%	83%, 11%, 6%
<b>Water gas shift</b>		
Feed gas flow rate, lb/h	48,356	51,621
Inlet temperature, °F	464	464
Outlet temperature, °F	663	637
Pressure, psia	88	86
Steam flow rate, lb/h	29,556	30,755
Temperature approach to equilibrium, °F	35	35
Wastewater (condensate), lb/h	19,648	20,736
<b>Pressure swing adsorption (PSA)</b>		
Inlet flow rate, lb/h	58,265	61,652
Inlet hydrogen mole %	67%	71%
Hydrogen recovery %	84%	84%
Hydrogen purity %	99%	99%
Hydrogen product stream, lb/h	5,462	7,032

### 3.3.3 Area 300 Equipment Cost Estimations

Table 7 presents the capital cost summary for this area. Further capital cost details are available in Appendix B.

**Table 7. Cost Estimate for Pyrolysis Vapor Quench and Product Recovery**

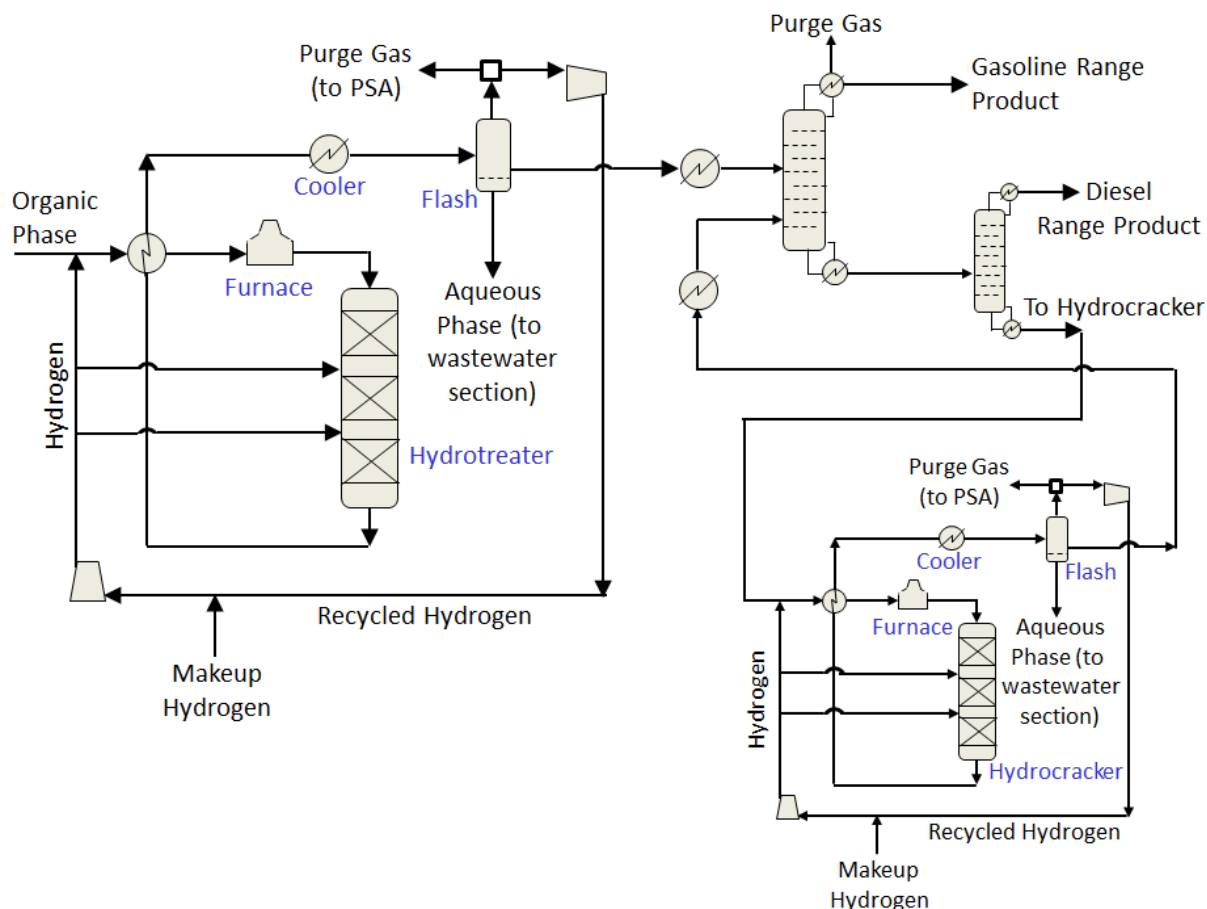
	<b>TPEC (2011\$k)</b>	<b>TIC (2011\$k)</b>
<b><i>In Situ Configuration</i></b>		
Product condensation and separation	\$4,977	\$8,542
Water gas shift and PSA	\$5,312	\$8,890
Heat integration	\$1,881	\$4,958
<b>Area A300 subtotal</b>	<b>\$12,170</b>	<b>\$22,390</b>
<b><i>Ex Situ Configuration</i></b>		
Product condensation and separation	\$5,071	\$8,652
Water gas shift and PSA	\$6,146	\$10,286
Heat integration	\$2,004	\$5,282
<b>Area A300 subtotal</b>	<b>\$13,221</b>	<b>\$24,220</b>

### 3.4 Area 400: Hydroprocessing and Product Separation

The following section presents an overview, basis for design, and cost estimates for the hydrotreating, hydrocracking, and product fractionation operations.

#### 3.4.1 Area 400 Overview

Figure 7 presents a simplified process flow diagram for this area. Some equipment, including many heat exchangers, is not shown for simplicity.



**Figure 7. Simplified process flow diagram of the hydroprocessing and product separation area**

The organic liquid fraction collected from the condensation of upgraded vapors in A300 is sent to a hydrotreater for further deoxygenation, as well as for saturating a portion of the products to reduce aromatic content. A sulfided CoMo catalyst is assumed for the hydrotreating reactor, although other catalysts may also be considered [40]. Note that the separation of the aqueous phase in A300 significantly reduces the liquid flow to the hydrotreater. The hydrotreater is modeled as a three-bed packed reactor with intermediate hydrogen quench to limit temperature rise in the reactor within 27.8°C (50°F). The organic liquid feed is mixed with 34% of the total hydrogen feed into the reactor. This feed is cross-exchanged with the hydrotreating reactor product for preheating the feed and cooling the reactor effluent. Following this a feed preheat furnace, designed for a 40°C (72°F) temperature rise, heats the feed to 375°C (707°F). The

remaining 66% of the hydrogen is introduced in equal amounts (33% each) between the reactor beds. The inlet temperature for these hydrogen streams is 43.3°C (110°F). The reactor outlet, after cross-exchange with the reactor feed, is further cooled via process, air, and water exchangers in series. The products are then sent to a flash drum where the gas (mostly hydrogen) and liquid streams are separated. The aqueous portion of the liquid stream is separated via decantation and sent to the wastewater handling section (A800). The organic portion is sent for fractionation (discussed below). The gases are then recycled to the hydrotreating reactor after recompression. A portion of the gases are purged (19% for the *in situ* case and 12% for the *ex situ* case) to maintain less than 10 mole % impurities in the feed hydrogen. Makeup hydrogen is added to account for purge losses and hydrogen consumption in the reactor. The purge stream is fed directly to the PSA in Area 500. The total hydrogen feed to the reactor based on these design assumptions was 14,174 scf/bbl (4,133 scf/bbl makeup) for the *in situ* case and 9,161 scf/bbl (2,306 scf/bbl makeup) for the *ex situ* case. While there is a significant amount of information in literature about petroleum refinery hydrotreating and rules of thumb for hydrogen use, there is very little information about hydrotreating highly oxygenated products at scale; hence, we decided to use the logical steps dictated by the process operations and temperature control considerations outlined above to determine hydrogen consumption and recycle. An acid gas removal system for controlling hydrogen sulfide (H<sub>2</sub>S) was not deemed necessary because of the low sulfur content in the biomass feedstock. PSA systems can be designed to handle low quantities of H<sub>2</sub>S produced or sulfur introduced for maintenance of sulfided hydrotreating catalysts [41]. H<sub>2</sub>S concentrations at the hydrotreater inlet in the model were ~100 ppm (*in situ* case) and ~170 ppm (*ex situ* case) on a mole basis, which should be capable of keeping the catalyst sulfided.

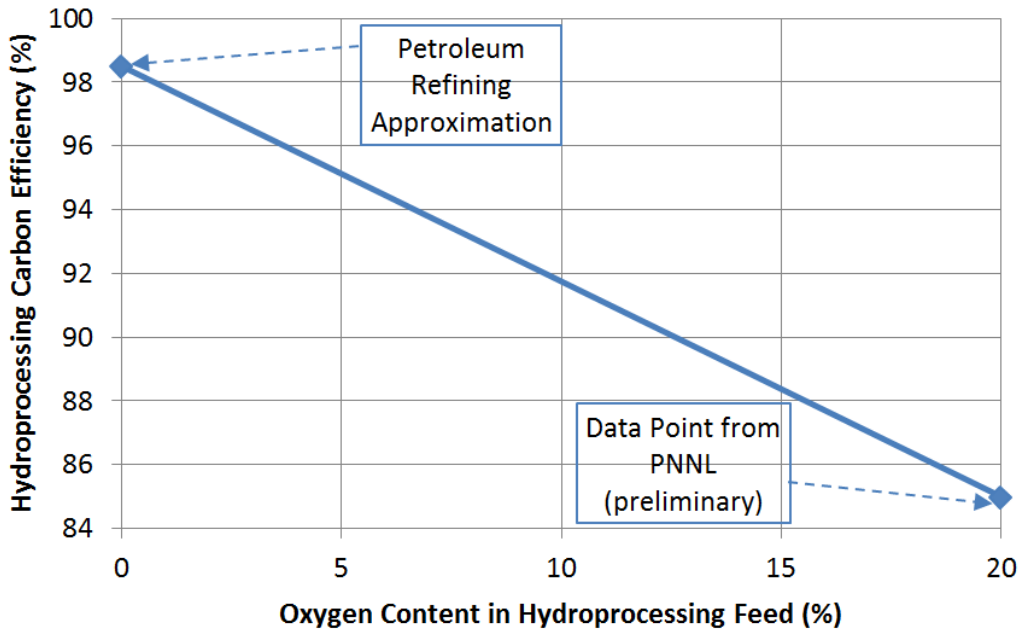
The hydrotreater inlet pressures for the *in situ* and *ex situ* cases were 1,845 psia and 1,545 psia, respectively. This decision was based on the premise that less severe hydrotreating will be necessary for the lower oxygen content product from the *ex situ* upgrading case. This assumption will require future experimental validation.

The product from the hydrotreater is sent for fractionation. The first column separates light gases and a gasoline boiling range fraction as its overhead product, with an off-gas stream purged and used as fuel. Note that products from hydrocracking are also fed to a lower section of this same column. The bottoms product from this column is sent to a second column where diesel boiling range product is recovered overhead. The heavier bottoms product is sent for hydrocracking; any products heavier than the distillate/diesel-range are recycled to extinction via hydrocracking.

The design of the hydrocracker follows the same logic outlined under the discussion for the hydrotreater. Note that the oxygen content of the organic liquid feed to the hydrocracker is assumed to be reduced to ~1% as a result of the previous hydrotreating operation. The catalyst is assumed to be crystalline silica-alumina based with rare earth metals and metals added for hydrogenation activity [42]. The hydrocracking inlet pressure was 1,945 psia, with a reactor inlet temperature of 392°C (738°F). The same limitations of a 27.8°C (50°F) temperature rise within the reactor and 10% impurity in the hydrogen feed were also assumed here. The hydrogen feed to the reactor was 16,347 scf/bbl (6,867 scf/bbl makeup) for the *in situ* case and 8,272 scf/bbl (3,091 scf/bbl makeup) for the *ex situ* case. Again, we relied on the simulated operational considerations mentioned above for a logical derivation of hydrogen consumption based on operational and temperature constraints.



Process model flow information for the hydrotreater, hydrocracker, and fractionation columns is summarized in Table 8. Detailed process flow diagrams and stream summaries are presented in Appendix G (A-401 to A-403 in Appendix G-1 for *in situ*, and A-401 to A-404 in Appendix G-2 for *ex situ*). Note that an additional design specification was added to scale the carbon efficiency based on oxygen content of the feed material entering the hydrotreater. A linear scale was assumed with 85% carbon efficiency for ~20% oxygen content [43] and 98.5% carbon efficiency for negligible oxygen content as is usually the case in petroleum refineries (based on approximations from case studies outlined by Gary and Handwerk for petroleum refineries [42]). This is shown in Figure 8.



**Figure 8. Assumed hydroprocessing carbon efficiency vs. oxygen content in organic liquid feed**

**Table 8. Process Model Flow Information for A400**

	<i>In Situ</i>	<i>Ex Situ</i>
<b>Hydrotreater</b>		
Liquid feed, lb/h	52,053	50,051
Liquid feed wt % C, H, O	80%, 10%, 10%	83%, 11%, 6%
Total hydrogen feed (pure H <sub>2</sub> ), lb/h	11,219	7,249
Hydrogen stream mole % purity	90%	90%
Makeup hydrogen (pure H <sub>2</sub> ), lb/h	3,274	1,824
Product gas (HP flash), lb/h	28,548	17,435
Product gas (HP flash) mole % hydrogen	87%	87%
Purge gas (HP flash), lb/h	5,327	2,061
Purge gas (LP flash), lb/h	870	787
Aqueous phase product, lb/h	4,696	2,912
Organic phase product, lb/h	45,023	46,446
Organic phase product wt % C,H,O	87%, 12%, 1%	86%, 13%, 1%
<b>Hydrocracker</b>		
Liquid feed, lb/h	8,833	16,654
Liquid feed wt % C, H, O	88%, 11%, 1%	88%, 11%, 1%
Total hydrogen feed (pure H <sub>2</sub> ), lb/h	2,154	2,109
Hydrogen stream mole % purity	90%	90%
Makeup hydrogen (pure H <sub>2</sub> ), lb/h	905	647
Product gas (HP flash), lb/h	5,487	4,353
Product gas (HP flash) mole % hydrogen	84%	87%
Purge gas (HP flash), lb/h	1,342	298
Purge gas (LP flash), lb/h	412	356
Aqueous phase product, lb/h	80	129
Organic phase product, lb/h	8,068	16,636
Organic phase product wt % C,H,O	85%, 15%, 0%	86%, 14%, 0%
<b>Gasoline boiling range column</b>		
Feed from hydrotreater, lb/h	45,023	46,446
Feed from hydrocracker, lb/h	8,068	16,636
Gasoline range product, lb/h	31,866	20,408
Light gases, lb/h	547	1,281
Bottoms flow to diesel column, lb/h	20,678	41,393
<b>Diesel boiling range column</b>		
Feed from gasoline-range column, lb/h	20,678	41,393
Diesel-range product, lb/h	11,845	24,739
Bottoms product to hydrocracker, lb/h	8,833	16,654
<b>Overall efficiency</b>		
Carbon efficiency %	91%	94%
Yield lb product/lb feed	0.84	0.90
Oxygen content in feed/product (wt %)	10.5%/0.5%	6.4%/0.4%

### 3.4.2 Area 400 Design Basis

For our equipment design, we assumed a relatively high severity would be required in hydrotreating. In addition to higher temperature and pressure, higher severity is characterized by lower weight hourly space velocity (WHSV):

$$\text{WHSV} = \frac{\text{mass flow of feed}}{\text{mass of catalyst}}$$

We chose WHSV to avoid using liquid density predictions, which can sometimes be highly dependent on the model compounds and physical property methods chosen. We assumed  $0.5 \text{ h}^{-1}$  for hydrotreating and hydrocracking in our design, which is considered severe for most petroleum refining hydroprocessing operations. A WHSV of  $0.5 \text{ h}^{-1}$  usually translates to a lower liquid hourly space velocity (LHSV) for most feedstock and catalyst combinations with an example of such conversion provided by Elliott et al. [44]. Hydrotreating of raw bio-oil without vapor phase deoxygenation is expected to be even more severe (lower space velocity) as indicated by LHSV values in literature [21, 40, 45]. For a given feed rate, the WHSV determines the total mass of catalyst required. Given a catalyst density, the total reactor volume is also determined by WHSV. However, because of the relatively high pressure requirements as noted above, these hydrotreating reactors have relatively thick walls of 2–4 inches and are thus quite heavy. When we estimated the price of the hydrotreating reactors, we therefore specified adders within the cost estimation software for field fabrication.

The design basis for the hydrotreating and hydrocracking reactor systems are presented in Table 9 and Table 10. Note that the vessel length of 48 feet is not entirely catalyst-full. Reactor internals were assumed to occupy 33% of the reactor volume, and additionally a 70% overdesign was applied to bed length to accommodate catalyst deactivation over time [46, 47]. Included among the reactor internals are inlet distributors, catalyst supports, redistribution trays, quench distributors, and outlet collection. The design catalyst bed length was therefore 19 feet.

The hydrotreating and hydrocracking reactor products are cooled and flashed at two different pressures to separate the hydrocarbons from reaction water and unreacted hydrogen. A recycle compressor serves the higher-pressure flash (approximately 20 psi below reactor outlet) gas stream. Both the hydrotreating and hydrocracking reactors also have hydrogen makeup compressors to bring hydrogen from Area 500 up to reactor pressure. The specifications for the compressors are summarized in Table 11.

**Table 9. Design Basis Parameters for Hydrotreating Reactor**

<b>Process Parameters</b>	<b><i>In Situ</i></b>	<b><i>Ex Situ</i></b>
Reactor inlet temperature, °C (°F)	375 (707)	375 (707)
Reactor outlet temperature, °C (°F)	403 (757)	403 (757)
Reactor pressure, psia	1,845	1,545
Reactor pressure drop, psi	30	30
Hydrogen inlet purity	90 mol%	90 mol%
Outlet hydrogen stream recycle/purge, %	81/19	88/12
Hydrogen feed (and makeup), scf/bbl HT feed	14,174 (4,133)	9,161 (2,306)
Chemical hydrogen consumption (lb/100 lb HT feed)	2.6	2.1
No. of internal beds per modeled reactor	3	3
<b>Reactor Design Parameters</b>		
Reactor length, ft	48	48
Reactor diameter, ft	10	10
Weight hourly space velocity, hour <sup>-1</sup>	0.5	0.5
Catalyst density, lb/ft <sup>3</sup>	78	78
Catalyst bed length overdesign	70%	70%
Reactor internals volume	33%	33%
Mass of catalyst (design), lb	122,520	112,000
Mass of catalyst (actual), lb	208,290	190,430
Material of construction	A204C with Inconel Cladding	

**Table 10. Design Basis Parameters for Hydrocracking Reactor**

<b>Process Parameters</b>	<b><i>In Situ</i></b>	<b><i>Ex Situ</i></b>
Reactor inlet temperature, °C (°F)	392 (738)	392 (738)
Reactor outlet temperature, °C (°F)	420 (788)	420 (788)
Reactor pressure, psia	1,945	1,945
Reactor pressure drop, psi	30	30
Hydrogen inlet purity	90 mol%	90 mol%
Outlet hydrogen stream recycle/purge, %	76/24	93/7
Hydrogen feed (and makeup), scf/bbl HC feed	16,347 (6,867)	8,272 (3,091)
Chemical hydrogen consumption (lb/100 lb HC feed)	5.4	3.1
No. of internal beds per modeled reactor	3	3
<b>Reactor Design Parameters</b>		
Reactor length, ft	48	48
Reactor diameter, ft	6.5	6.5
Weight hourly space velocity, hour <sup>-1</sup>	0.5	0.5
Catalyst density, lb/ft <sup>3</sup>	78	78
Catalyst bed length overdesign	70%	70%
Reactor internals volume	33%	33%
Mass of catalyst per reactor (design), lb	21,200	36,600
Mass of catalyst per reactor (actual), lb	36,060	62,200
Material of construction	A204C with Inconel Cladding	

**Table 11. Design Parameters for Hydrogen Compressors**

<b>Hydrotreating Recycle Compressor</b>	
Service	Recycled unreacted hydrogen
Inlet pressure	1,793 psia ( <i>in situ</i> )/1,493 psia ( <i>ex situ</i> )
Outlet pressure	1,900 psia ( <i>in situ</i> )/1,600 psia ( <i>ex situ</i> )
Inlet mass flow	27,085 lb/h ( <i>in situ</i> )/17,528 lb/h ( <i>ex situ</i> )
Inlet molecular weight	2
Drive power source	Electric motor
Inter-stage cooling	Process, air, cooling water
Number of stages	1
Electrical consumption	176 kW ( <i>in situ</i> )/134 kW ( <i>ex situ</i> )
<b>Hydrocracking Recycle Compressor</b>	
Service	Recycled unreacted hydrogen
Inlet pressure	1,893 psia
Outlet pressure	2,000 psia
Inlet mass flow	5,214 lb/h ( <i>in situ</i> )/4,819 lb/h ( <i>ex situ</i> )
Inlet molecular weight	2
Drive power source	Electric motor
Inter-stage cooling	Process, air, cooling water
Number of stages	1
Electrical consumption	32 kW ( <i>in situ</i> )/31 kW ( <i>ex situ</i> )
<b>Hydrotreating Makeup Compressor</b>	
Service	Pipeline hydrogen
Inlet pressure	245 psia
Outlet pressure	1,795 psia ( <i>in situ</i> )/1,495 psia ( <i>ex situ</i> )
Inlet mass flow	3,865 lb/h ( <i>in situ</i> )/2,154 lb/h ( <i>ex situ</i> )
Inlet molecular weight	2
Drive power source	Electric motor
Inter-stage cooling	Process, air, cooling water
Number of stages	4
Electrical consumption	1,765 kW ( <i>in situ</i> )/888 kW ( <i>ex situ</i> )
<b>Hydrocracking Makeup Compressor</b>	
Service	Pipeline hydrogen
Inlet pressure	245 psia
Outlet pressure	1,995 psia
Inlet mass flow	1,068 lb/h ( <i>in situ</i> )/764 lb/h ( <i>ex situ</i> )
Inlet molecular weight	2
Drive power source	Electric motor
Inter-stage cooling	Process, air, cooling water
Number of stages	4
Electrical consumption	516 kW ( <i>in situ</i> )/369 kW ( <i>ex situ</i> )

### 3.4.3 Area 400 Equipment Cost Estimations

The estimated purchased equipment costs and total installed costs for the hydroprocessing area were gathered from various sources, including technology licensors, industrial suppliers, published literature, and ACCE. The sources are listed in Appendix A.

Table 12 presents the equipment list and cost estimates for the hydroprocessing area of the plant.

**Table 12. Cost Estimate for the Hydroprocessing Area**

Equipment Description	<i>In Situ</i>		<i>Ex Situ</i>	
	TPEC (2011\$k)	TIC (2011\$k)	TPEC (2011\$k)	TIC (2011\$k)
Hydrotreating reactor	\$8,351	\$13,257	\$6,213	\$10,514
Hydrocracking reactor	\$1,548	\$3,274	\$2,472	\$5,116
Recycle and makeup compressors	\$7,013	\$11,221	\$5,159	\$8,254
Product separation columns	\$1,105	\$2,804	\$1,287	\$3,188
Heat integration	\$754	\$1,988	\$772	\$2,033
<b>Area A400 subtotal</b>	<b>\$18,771</b>	<b>\$32,544</b>	<b>\$15,902</b>	<b>\$29,106</b>

## 3.5 Area 500: Hydrogen Plant

The following section presents an overview, basis for design, and cost estimates for the steam reformer, water gas shift reactor, PSA, and associated equipment used for hydrogen production.

### 3.5.1 Area 500 Overview

A fixed-bed steam methane reformer package was used for hydrogen production. The small amount of natural gas feed (shown in Table 13) was used entirely for hydrogen production and fed to the reformer because there is sufficient fuel gas available in the process to provide all the heat duty necessary to run the reformer. The reformer was modeled as a Gibbs equilibrium reactor operating at 115 psia and 880°C (1,616°F) with a 30°C (54°F) approach to equilibrium. Steam is provided from a wastewater recycle boiler in Area 800. The product gases are quenched and sent to high temperature and low temperature shift reactors in series with intermediate heat exchange for temperature control. Following the reformer, the gases are cooled and condensate removed. The gases are then compressed to 278 psia for feeding to a PSA. The PSA design assumes 80% hydrogen recovery with 99% purity. Off-gases from the PSA are used as combustion fuel.

### 3.5.2 Area 500 Design Basis

Table 13 summarizes the design basis for the equipment in the hydrogen plant, including the steam methane reformer, WGS reactor, and PSA unit. Detailed process flow diagrams and stream summaries are presented in Appendix G (A-501 to A-504 in Appendix G-1 for *in situ*, and A-501 to A-505 in Appendix G-2 for *ex situ*).

**Table 13. Design Basis Parameters for Hydrogen Plant**

<b>Hydrogen Plant Design Parameters</b>	
Hydrogen production rate	30.0 MMscfd ( <i>in situ</i> )/27.4 MMscfd ( <i>ex situ</i> )
Supplemental natural gas*	54 lb/h ( <i>in situ</i> )/125 lb/h ( <i>ex situ</i> )
Hydrogen outlet purity	99 mol %
Hydrogen outlet pressure	266 psia

\*Negligible natural gas required because of the availability of fuel gas from the process.

### 3.5.3 Area 500 Equipment Cost Estimations

For consistency, the hydrogen plant cost was derived from the same sources and methodology cited in the 2013 design report led by PNNL [21]. The report documented equipment costs for a large hydrogen plant producing 44.5 million scf/day of hydrogen. The costs were reported as a package, including the sulfur guard bed, pre-reformer, SMR, WGS, PSA, compressors, and heat integration. The total cost was entered into our model and scaled to the required hydrogen production rates shown above using the same scaling law as in the 2013 report [21]. Table 14 shows the major costs in the hydrogen plant area.

**Table 14. Cost Estimate for Hydrogen Production Area**

<b>Equipment Description</b>	<b><i>In Situ</i></b>		<b><i>Ex Situ</i></b>	
	<b>TPEC</b>	<b>TIC</b>	<b>TPEC</b>	<b>TIC</b>
	<b>(2011\$k)</b>	<b>(2011\$k)</b>	<b>(2011\$k)</b>	<b>(2011\$k)</b>
SMR, WGS, PSA package	\$28,968	\$55,330	\$27,368	\$52,267
Pyrolysis off-gas compressor to SMR	\$4,447	\$7,159	\$4,219	\$6,799
Additional heat integration	\$3,093	\$8,152	\$2,920	\$7,696
<b>Area A500 subtotal</b>	<b>\$36,508</b>	<b>\$70,640</b>	<b>\$34,507</b>	<b>\$66,762</b>

## 3.6 Area 600: Steam System and Power Generation

The following section presents an overview, basis for design, and cost estimates for construction of the steam system and power generation facilities.

### 3.6.1 Area 600 Overview

A conventional steam cycle uses process heat to produce electricity. There is a significant amount of heat available in the process that needs to be managed efficiently to positively impact the economics. The big sources of heat are the char and coke combustors, upgraded pyrolysis vapors (including fluidization gases) cooling, steam reformer flue gas, and reformed gas quench. In both the *in situ* and *ex situ* designs there is excess electricity available after all consumption in the plant is met. This electricity is sold to the grid and reduces the MFSP by 4¢/GGE and

3¢/GGE for the *in situ* and *ex situ* cases, respectively. Excess heat available for power generation was determined by conducting an overall plant heat balance. The heat balance assumptions are checked for thermodynamic viability by drawing heating and cooling curves for pinch analysis and ensuring there is no crossover between the curves. Electricity is generated using two steam turbines, with intermediate reheat. Pre-heaters, steam generators, and super-heaters are integrated within the process design to generate the steam from boiler feed water (BFW). Process condensate is recycled to the steam cycle, de-gassed, treated, and combined with makeup water.

The steam turbine efficiencies are assumed to be 75% and the generator mechanical efficiencies are assumed to be 97%. The first stage turbine drops the steam pressure from 1,321 psia to 350 psia. The second stage turbine drops the pressure from 345 psia to 3.5 psia. The steam inlets to both turbine stages are preheated to 1,000°F.

Low pressure (3.5 psia) steam exhaust from the turbine is cooled by exchanging heat with other process streams and is condensed in an air-cooled condenser. While an air-cooled exchanger is considerably more expensive than a water cooler, it has the advantage of reducing water consumption through evaporation in the cooling towers and was preferred in this design for sustainability considerations. A condensate collection tank gathers the condensate returns from indirect heat exchange along with the steam turbine condensate. The condensate from the collection tank is treated in the hot condensate polishing unit, mixed with treated makeup water, and sent to the condensate surge tank. From the surge tank, the water is pumped, heated to the saturation temperature, and sent to the deaerator to remove any dissolved gases from the water. The water from the deaerator is pumped to a pressure of 1,351 psia and then pre-heated to its saturation (bubble point) temperature using a series of exchangers. Steam is generated by heat exchange with hot streams in the process. This saturated steam is collected in the steam drum. To prevent buildup of solids, water is periodically discharged from the steam drum (also known as blowdown). Saturated steam from the steam drum is superheated with another series of exchangers to 538°C (1,000°F) before it goes to the steam turbine. Detailed process flow diagrams and stream summaries are presented in Appendix G (A-601 to A-603 in Appendix G-1 for *in situ*, and A-601 to A-605 in Appendix G-2 for *ex situ*).

The Aspen Plus model increases or decreases the boiler feed water flow rate through the steam cycle in order to close the heat balance. The control system in the plant will function in a similar fashion by controlling the flow rate of boiler feed water makeup to the steam system in order to maintain levels in the deaerator and steam drum.

All compressors, pumps, fans, etc., utilize electric motor drives and are modeled and quoted accordingly. An allowance of ~4 MW of excess power is specified to account for miscellaneous usage which may not be accounted for in the simulation and general electric needs (such as lights and computers).



### 3.6.2 Area 600 Design Basis

Table 15 and Table 16 present summaries of the power requirements for each area for the *in situ* and *ex situ* cases, respectively. Excess electricity is sold to the grid.

**Table 15. Plant Power Requirements for *In Situ* Case**

<b>Plant Area</b>	<b>Generated (kW)</b>	<b>Consumed (kW)</b>
Feed handling and drying <sup>a</sup>		387
Pyrolysis		22,619
Condensation and product separation		3,500
Hydroprocessing		2,951
Hydrogen production and management		6,083
Steam system and power generation	48,291	1,588
Cooling water and other utilities		324
Wastewater management		1,798
Miscellaneous		3,925
Balance to grid		5,117
<b>Plant totals</b>	<b>48,291</b>	<b>48,291</b>

<sup>a</sup> Power costs for all feed handling, and for drying outside the plant, are included in the feedstock cost provided by INL. The small power consumption shown for this area reflects usage for a cross-flow dryer and flue gas blower.

**Table 16. Plant Power Requirements for *Ex Situ* Case**

<b>Plant Area</b>	<b>Generated (kW)</b>	<b>Consumed (kW)</b>
Feed handling and drying <sup>a</sup>		298
Pyrolysis		22,783
Condensation and product separation		3,914
Hydroprocessing		1,811
Hydrogen production and management		5,875
Steam system and power generation	44,247	1,461
Cooling water and other utilities		327
Wastewater management		846
Miscellaneous		3,731
Balance to grid		3,201
<b>Plant totals</b>	<b>44,247</b>	<b>44,247</b>

<sup>a</sup> Power costs for all feed handling, and for drying outside the plant, are included in the feedstock cost provided by INL. The small power consumption shown for this area reflects usage for a cross-flow dryer and flue gas blower.

### 3.6.3 Area 600 Equipment Cost Estimations

Table 17 presents the equipment list and cost estimates for the steam system and power generation area of the plant.

**Table 17. Cost Estimate for Steam System and Power Generation Area**

Equipment Description	<i>In Situ</i>		<i>Ex Situ</i>	
	TPEC	TIC	TPEC	TIC
	(2011\$k)	(2011\$k)	(2011\$k)	(2011\$k)
Power generation and associated equipment	\$26,183	\$44,237	\$23,875	\$40,579
Heat integration	\$3,116	\$8,212	\$2,776	\$7,316
<b>Area A600 subtotal</b>	<b>\$29,300</b>	<b>\$52,449</b>	<b>\$26,651</b>	<b>\$47,895</b>

## 3.7 Area 700: Cooling Water and Other Utilities

The following section presents an overview, basis for design, and cost estimates for construction of the cooling water facilities and other plant utility equipment.

### 3.7.1 Area 700 Overview

Equipment list for this area is included in Appendix B. Detailed process flow diagrams and stream summaries are presented in Appendix G (A-701 to A-703 in Appendix G-1 for *in situ*, and A-701 to A-703 in Appendix G-2 for *ex situ*). A mechanical draft cooling tower (M-701) provides cooling water to several heat exchangers in the plant. The tower utilizes fans to force air through circulated water.

An instrument air system is included to provide compressed air for both service and instruments. The system consists of an air compressor (K-701), dryer (S-701), and receiver (T-701). The instrument air is delivered at a pressure of 115 psia and a moisture dew point of -40°C (-40°F), and it is oil free.

Other miscellaneous items that are taken into account in the design include the following:

- Firewater storage tank (T-702) and firewater pump (P-702) for fire emergencies
- Diesel tank (T-703) and diesel pump (P-703) to fuel the front loaders
- Ammonia storage tank (T-704), ammonia pump (P-704), BFW chemical storage tank (T-708), and BFW chemical pump (P-707) for boiler feed water treatment
- Caustic (NaOH) storage tank (T-705) and pump (P-705)

### 3.7.2 Area 700 Design Basis

Table 18 summarizes the design basis parameters for the plant’s cooling water system.

**Table 18. Design Basis for Cooling Water System**

<b>Cooling Water System Design Parameters</b>	
Cooling water supply temperature ( $T_S$ )	90°F
Cooling water return temperature ( $T_R$ )	110°F
Losses from evaporation ( $F_{EVAP}$ )	$0.00085 * F_S * (T_R - T_S)$
Losses from drift	$0.002 * F_S$
Cycles of concentration (C)	5
Required blowdown	$F_{EVAP}/(C - 1)$
Cooling water makeup pressure	14.7 psia
Cooling water makeup temperature	60°F

Note:  $F_S$  = Cooling water supply rate in gallons per minute.

Water losses from the cooling water system include evaporation, drift (water entrained in the cooling tower exhaust air), and tower basin blowdown. Drift losses were estimated to be 0.2% of the cooling water supply rate. Evaporation losses and blowdown were calculated based on information and equations in Perry et al. [17] (as shown in Table 18).

### 3.7.3 Area 700 Cost Estimation

Table 19 presents the equipment list and cost estimates for the cooling water and other utilities area of the plant.

**Table 19. Cost Estimate for Cooling Water and Other Utilities Area**

<b>Equipment Description</b>	<i>In Situ</i>		<i>Ex Situ</i>	
	<b>TPEC</b>	<b>TIC</b>	<b>TPEC</b>	<b>TIC</b>
	<b>(2011\$k)</b>	<b>(2011\$k)</b>	<b>(2011\$k)</b>	<b>(2011\$k)</b>
Cooling water and other utilities	\$4,712	\$9,450	\$4,633	\$9,277
<b>Area A700 subtotal</b>	<b>\$4,712</b>	<b>\$9,450</b>	<b>\$4,633</b>	<b>\$9,277</b>

### 3.8 Area 800: Wastewater Management and Recycle

Area 800 has three process sub-areas for treating and recycling water discharges from the plant: a wastewater boiler, a regenerative thermal oxidizer, and a reverse osmosis unit for point treatment. The majority of the soluble carbon is found in the aqueous phase of the pyrolysis quench loop in Area 300. This stream, with a significantly smaller makeup of clean recycled water is sent to a waste heat boiler system to first generate steam for process use in the sour water gas shift reactor in Area 300. Any H<sub>2</sub>S present in the wastewater is expected to be stripped out of the water during this step. A following boiler generates steam for the reformer; small proportions of carbon species are also part of the steam and are expected to be utilized in the pre-reformer/reformer system for hydrogen production. Creating steam from the quench water serves to recycle some of the volatile carbon species back to the process, and also to concentrate the remaining soluble species like phenol. To avoid fouling in the boiler, not all the wastewater is evaporated.

The remaining wastewater, after the partial evaporation, has a chemical oxygen demand (COD) of 68 wt % for the *in situ* case and 71 wt % for the *ex situ* case. Most of this COD is from varied oxygenated organic species and are modeled using surrogate compounds such as phenol and benzenediol. These compounds are toxic to typical microbial consortia used in wastewater treatment. Therefore the concentrated wastewater cannot be treated by digestion without significant re-dilution, so it is sent to an aqueous regenerative thermal oxidizer to eliminate the remaining carbon species that may be present. A high-level schematic of such a system is shown on the website of Gulf Coast Environmental Systems [48]. The RTO essentially strips the wastewater into an excess of preheated air, and the resultant vapor is passed through hot ceramic blocks. The operation is cyclical with at least two sets of high heat capacity ceramic blocks. The ceramic blocks are heated by combustion products. Upon switching of the cycle these hot blocks preheat the inlet air, moisture, and carbonaceous matter; at this time the other set(s) of ceramic blocks are heated by combustion products. The preheated feed enters a combustion zone where supplemental fuel, such as natural gas, may be provided. Our Aspen Plus model of this sub-system predicts that the carbon content concentrated in the aqueous stream from the boiler has more than sufficient carbon and hydrogen to sustain the combustion and no supplemental fuel is necessary. The combustion zone is modeled as a reactor with complete oxidation of carbon (to CO<sub>2</sub>) and hydrogen at 820°C (1,508°F), in the presence of significant excess air (amount of air decided by the lower explosive limits of organic species). We acknowledge that an RTO has not specifically been applied for the type of process described here; however, we are aware that such equipment is currently in service at ethylene plants to treat cracking furnace quench water, a system with similarities to ours. Detailed process flow diagrams and stream summaries for our design are presented in Appendix G (A-801 to A-804 in Appendix G-1 for *in situ*, and A-801 to A-805 in Appendix G-2 for *ex situ*).

An on-site reverse osmosis (RO) unit is specified for point treatment and recycle of streams with low contamination. These include the cooling tower blowdown, water knockout from the PSA compressor in Area 300, and the flue gas scrubber effluent from Area 100. We assume that 75% of the water can be recovered and recycled to the flue gas scrubber, Area 600 boiler, and cooling tower to offset the total water demand for the process. The remaining 25% is collected for treatment, along with the hydroprocessing water knockout streams, which were considered unsuitable for the boiler and RTO due to nitrogen (ammonia) content. While we did not perform

a detailed design for an on-site wastewater treatment plant, it is expected that such treatment will entail demineralization of the RO retentate streams and probably activated sludge denitrification of the hydroprocessing water, followed by aerobic digestion and polishing. Anaerobic digestion is not likely to be economical due to the low remaining COD. We estimated an operating cost charge for wastewater using the aggregate CAPEX+OPEX cost contribution of the detailed wastewater facility designed for the 2011 biochemical ethanol design report [49]. At \$0.022/gal wastewater, this conservatively estimated cost of treating the relatively less contaminated streams from the pyrolysis plant is a factor of 10 higher than the value cited in Peters and Timmerhaus [16] for treatment of boiler blowdown streams.

Table 20 summarizes the water balance for the plant. The consumptive water demand for the process is 0.76 gal/GGE for the *in situ* process and 0.70 gal/GGE for the *ex situ* process. Along with uncertainties surrounding the choice of equipment in Area 800, we note that there could also be significant opportunities to recover valuable products from the wastewater using processes such as aqueous phase reforming or biological upgrading. These research areas are not considered in this design in order to focus on the core technology of *in situ* and *ex situ* vapor phase upgrading.

**Table 20. Pyrolysis Plant Water Balance**

<b>Area</b>	<b>Stream</b>	<b>Source/Destination</b>	<b>In Situ</b>	<b>Ex Situ</b>	
A100	Scrubber Water	Input	30,000	30,000	lb/h
	To Flue Gas	Loss	7,640	6,571	lb/h
	Scrubber Blowdown	To Point Treatment	22,360	23,429	lb/h
	<i>COD</i>		0	0	lb/h
A200	Catalyst Steam Stripper	From Boiler A800	4,151	2,756	lb/h
A300	Aqueous Phase	To Boiler A800	74,271	75,955	lb/h
	<i>COD</i>		5,490	3,457	lb/h
	WGS Steam Demand	From Boiler A800	29,430	30,663	lb/h
	PSA Water Knockout	To Point Treatment	19,552	20,658	lb/h
	<i>COD</i>		187	128	lb/h
A400	Hydrotreating HP Aq Phase	To Full Treatment	4,660	2,877	lb/h
	<i>COD</i>		1	0	lb/h
	Hydrocracking Aq Phase	To Full Treatment	80	129	lb/h
	<i>COD</i>		0	0	lb/h
A500	Reformer Steam Demand	From Boiler A800	40,842	45,491	lb/h
	PSA Water Knockout	To Boiler A800	13,979	15,786	lb/h
	<i>COD</i>		0	0	lb/h
A600	Makeup	Input	7,064	6,473	lb/h
	Makeup Chemicals (In Model)	Input	2	2	lb/h
	Steam Drum Knockout	To Cooling Tower Basin	7,067	6,475	lb/h
A700	Steam Drum Knockout	From A600	7,067	6,475	lb/h
	Makeup	Input	52,033	53,446	lb/h
	Blowdown	To Point Treatment	10,788	10,937	lb/h
	Drift	Loss	5,162	5,237	lb/h
	Evaporation	Loss	43,150	43,747	lb/h
A800	<i>Boiler</i>				
	BFW Makeup		0	1,926	lb/h
	Total Boiler Feed	To Boiler A800	74,271	77,881	lb/h
	<i>COD</i>		5,490	3,457	lb/h
	Process Steam Generated	To SMR+WGS	70,272	76,154	lb/h
	Remaining to RTO	Loss	3,999	1,727	lb/h
	<i>COD</i>		0	0	lb/h
	<i>Point Treatment</i>				
	Total Water for Treatment	75% Recovered	66,679	70,810	lb/h
	Water Recycled	Offsets Inputs	50,009	53,107	lb/h
	Remainder	To Full Treatment	16,670	17,702	lb/h
	<i>Full Treatment</i>				
	Total	Loss	21,410	20,708	lb/h
	<i>COD</i>		1	0	lb/h
	Total Water Makeup		93,251	94,603	lb/h
	Net Water Makeup		43,242	41,495	lb/h
	Net Water Makeup (Annual)		41.0	39.3	MMgal/y
	Water Usage		0.76	0.70	gal/GGE
	Liq Water Emission		21,410	20,708	lb/h
	Liq Water Emission (Annual)		20.3	19.6	MMgal/y

### 3.8.1 Area 800 Cost Estimation

Table 21 presents the equipment list and cost estimates for the wastewater treatment and recycle area. The RTO capital cost was based on estimates in a report from the U.S. Environmental Protection Agency (EPA) [50].

**Table 21. Cost Estimate for Wastewater Management Area**

Equipment Description	<i>In Situ</i>		<i>Ex Situ</i>	
	TPEC (2011\$k)	TIC (2011\$k)	TPEC (2011\$k)	TIC (2011\$k)
Wastewater boiler and ancillaries	\$139	\$631	\$162	\$661
Regenerative thermal oxidizer and ancillaries	\$4,938	\$11,295	\$3,112	\$7,118
Reverse osmosis and clarifier skid	\$1,022	\$2,248	\$1,032	\$2,264
Heat integration	\$1,132	\$2,982	\$1,090	\$2,871
<b>Area A800 subtotal</b>	<b>\$7,230</b>	<b>\$17,156</b>	<b>\$5,395</b>	<b>\$12,915</b>

### 3.9 Additional Process Design Information

Table 22 contains additional information used in the Aspen Plus model and design basis. For those interested, any deviations in the pressure drop assumptions can be found in the stream tables (Appendix G).

**Table 22. Utility and Miscellaneous Design Information**

Item	Design Information
Ambient air conditions <sup>a,b,c</sup>	Pressure: 14.7 psia T <sub>dry bulb</sub> : 90°F T <sub>wet bulb</sub> : 80°F Air composition (mol %): N <sub>2</sub> : 75.7% O <sub>2</sub> : 20.3% Ar: 0.9% CO <sub>2</sub> : 0.03% H <sub>2</sub> O: 3.1%
Pressure drop allowance	Air pre-heat exchangers = 1 psi Heat exchangers = 5 psi, 2 psi in vapor condensation train

<sup>a</sup> In the GPSA *Engineering Data Book* [51], see Table 11.4 for typical design values for dry bulb and wet bulb temperature by geography. Selected values would cover summertime conditions for most lower 48 states.

<sup>b</sup> In Weast [52], see F-172 for composition of dry air. Nitrogen value is adjusted slightly to force mole fraction closure using only nitrogen gas (N<sub>2</sub>), oxygen (O<sub>2</sub>), argon (Ar), and carbon dioxide (CO<sub>2</sub>) as air components.

<sup>c</sup> In Perry et al. [17], see psychrometric chart, Figure 12-2, for moisture content of air.

### 3.10 Pinch Analysis

While an energy balance was performed within the Aspen Plus process simulation, it was also necessary to ensure that there was no temperature crossover when the assumption was made that the cold process streams can be heated using the available heat in hot process streams. A pinch analysis was performed to show the temperatures at which hot and cold duties are available.

The concept of pinch technology offers a systematic approach for optimizing energy integration in process design. Temperature and heat flow (Q) data were gathered for the hot process streams (streams cooled in the process), cold process streams (streams heated in the process), and utility streams like steam, flue gas, and cooling water. A composite curve, a graphical presentation of stream temperature and heat flow (Q) data, was constructed for the hot and cold process streams. These two curves are shifted so that they touch at the pinch point. From this shifted graph, a grand composite curve is constructed that plots the difference in heat flow between the hot and cold composite curves as a function of temperature.

The total hot duty equals the total cold duty, as the Aspen Plus model is designed to adjust the water flow rate through the steam cycle until the heat balance in the system is closed. The minimum vertical distance between the curves is  $\Delta T_{\min}$ , which is theoretically the smallest approach temperature in the exchanger network. For the *in situ* case, the upper and lower pinch temperatures are 310.9°F and 288.3°F, respectively, resulting in  $\Delta T_{\min}$  of 22.6°F. For the *ex situ* case, the upper and lower pinch temperatures are 309.9°F and 285.0°F, respectively, resulting in  $\Delta T_{\min}$  of 24.9°F. Figure 9 and Figure 10 show those curves for the *in situ* and *ex situ* cases. The figures demonstrate the feasibility of developing a network based on the current process models (since there is no crossover). A complete heat exchange network is provided for the *ex situ* case in Appendix H. The total heat exchanger network costs for the *in situ* and sensitivity cases (Figure 15) were factored from the *ex situ* base case using total duties, and a scaling exponent of 0.65. Since heat exchangers span the various process areas, heat exchanger network costs were distributed among the various areas based on duties from respective areas. The process flow diagrams in Appendix G-2 for the *ex situ* case include information from the heat exchanger network design shown in Appendix H.



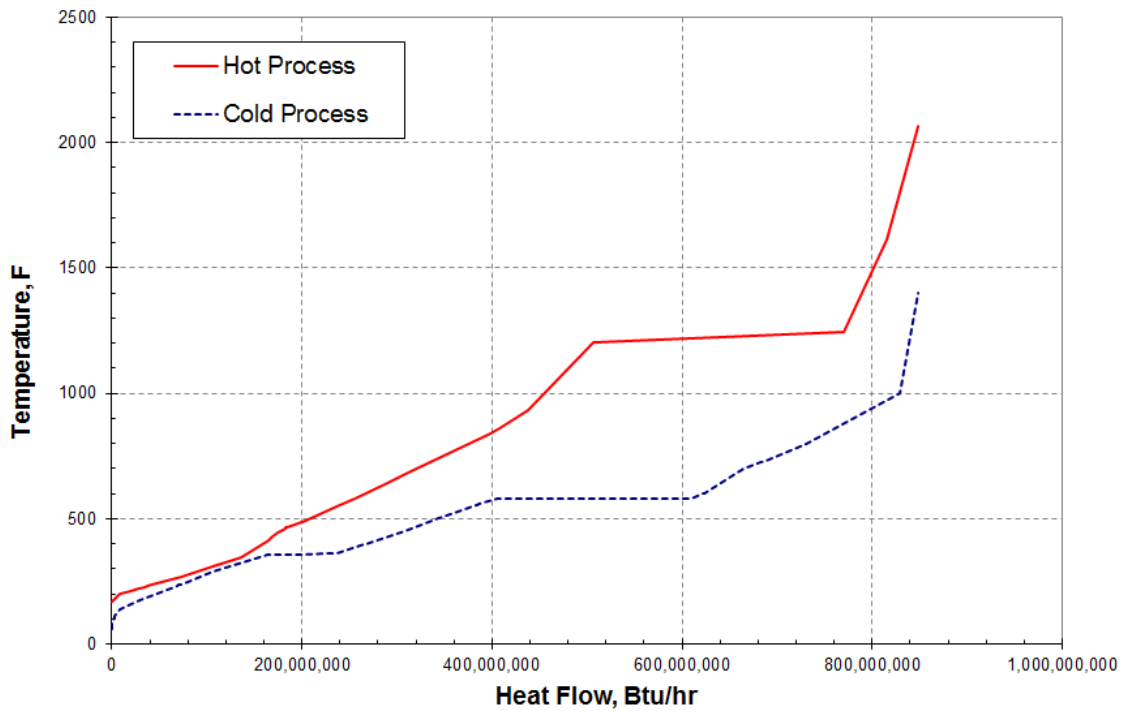


Figure 9. Pinch analysis composite curve for the *in situ* case

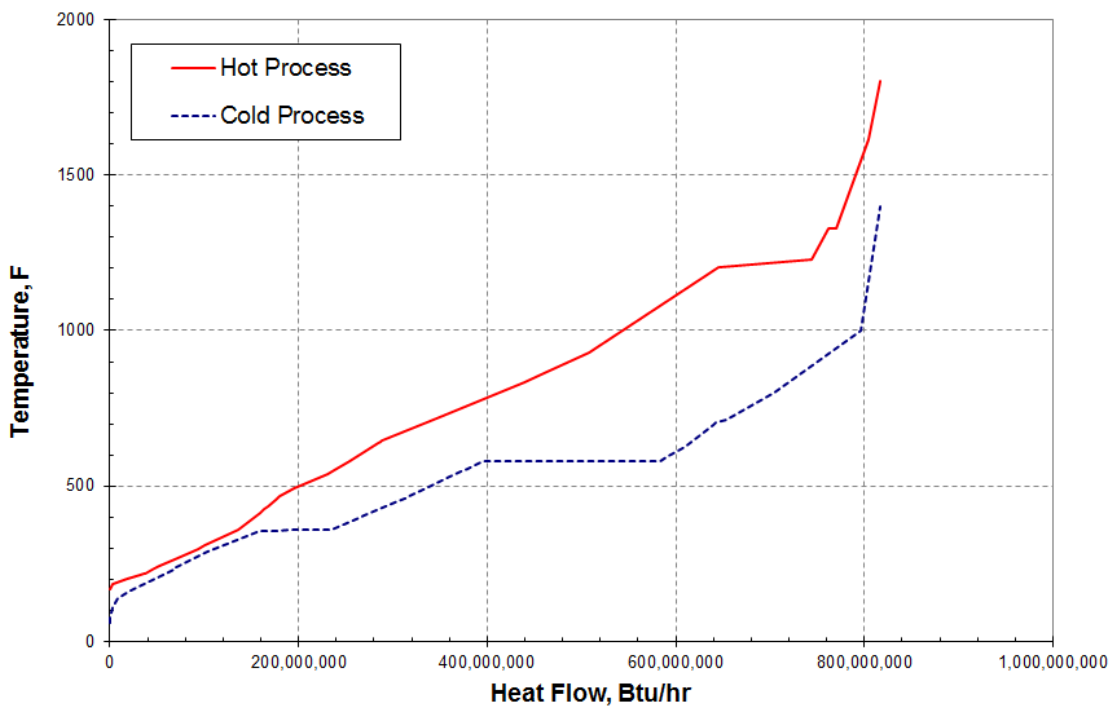


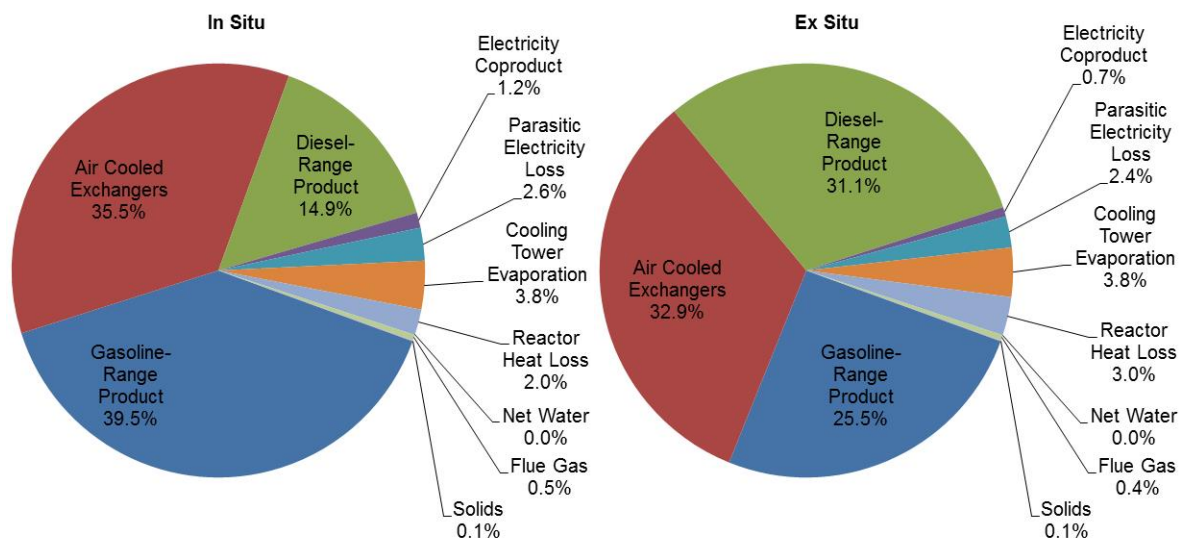
Figure 10. Pinch analysis composite curve for the *ex situ* case

### 3.11 Energy Balance

Energy integration is important to the overall economics and efficiency of the process. Therefore a detailed understanding of how and where the energy is utilized and recovered is required. Detailed energy balances around the major process areas were derived using data from the Aspen Plus simulation. Comparing the process energy inputs and outputs allows the energy efficiency of the process to be quantified. Tracing energy transfer between process areas also makes it possible to identify potential improvements to the energy efficiency.

This design for pyrolysis and upgrading of cellulosic biomass was constructed with the goal of utilization of heating values of solid (char and coke) and gaseous (off-gases) products within the process, with the export of excess electricity using any extra energy available. Relative to the energy in biomass, an insignificant amount of natural gas input is added to supplement process gases in the steam reformer for hydrogen production. The small amount of natural gas was introduced to maintain the process model in a state where natural gas could be introduced in the model to study sensitivity cases. Unreacted light-ends from pyrolysis are combusted to produce steam and electricity for the plant. On balance, the pyrolysis process requires no electricity from the grid and exports electricity instead.

The distribution of the total energy content in the feed is shown in Figure 11. The basis for these pie charts is the total energy in the dry portion of the feed (approximately 1,470 MMBtu/h) and the total energy in the small natural gas co-feed to the process (2 MMBtu/h for *in situ*, 3 MMBtu/h for *ex situ*). Figure 11 shows that >50% of the LHV is recovered as fuel-range hydrocarbon products in both cases. Another 1% is further exported as saleable surplus electricity. A significant amount (~35%) is lost through electricity-driven air-cooled exchangers, and the remainder of the energy is lost to the plant surroundings. Further optimization of the heat integration network can be evaluated if it is felt as necessary in the future.



**Figure 11. Overall energy balance (basis: LHV of wood + natural gas). Values rounded to nearest tenth.**

### 3.12 Sustainability Metrics

An important aspect of evaluating biofuel processes is the quantification of life-cycle resource consumption and environmental emissions. Life-cycle assessment (LCA) provides a framework from which the environmental sustainability of a given process may be quantified and assessed. This section presents the salient sustainability metrics of the current conceptual process at the conversion stage. Direct biorefinery emissions (i.e., CO<sub>2</sub>, NO<sub>2</sub>, and SO<sub>2</sub>), water consumption, and other process-related metrics were derived from the conversion process model described above.

SimaPro v. 8.02 software [53] was used to develop and link units quantifying life-cycle impacts. Greenhouse gas (GHG) basis values for natural gas (NG) and the U.S. average electricity mix from the grid were applied consistently with the basis from Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model software; this includes GHG emission factors of 3.25 kg CO<sub>2</sub>e/kg NG (LHV) and 0.65 kg CO<sub>2</sub>e/kWh grid electricity [54]. Likewise, the basis from GREET was also applied for non-renewable (fossil) energy consumption values of 52.1 MJ/kg (LHV) natural gas and 7.5 MJ/kWh grid electricity [54]. All other process input/output inventory estimates were derived from Ecoinvent v.2.0 [55] and the U.S. Life Cycle Inventory (LCI) [56] processes to fill the data gaps. The Ecoinvent processes were modified to reflect U.S. conditions and the U.S. LCI processes were adapted to account for embodied emissions and fossil energy usage. The material and energy flows of the conversion step capture the impacts of input raw materials, and outputs, such as emissions, wastes, and coproducts as predicted by the process model, as shown in Table 23 for the *in situ* case and Table 24 for the *ex situ* case.

**Table 23. Material and Energy Flows for the *In Situ* Case**

<b>Production Rate</b>			
<b>Products</b>	lb/hr	gal/hr	MMBtu/hr (LHV)
Gasoline fuel	31,866	4,978	579
Diesel fuel	11,845	1,885	219
<b>Byproducts</b>	kW		
Excess electricity	5,117		
<b>Resource Consumption</b>	<b>Flow Rate</b>	<b>Per Gal Gasoline</b>	<b>Per MMBtu</b>
	lb/hr	lb/gal	lb/MMBtu
Blended woody biomass (wet)	204,131	41.01	352.35
Blended woody biomass (dry)	183,718	36.91	317.12
Sand makeup	0	0.00	0.00
Natural gas	54	0.01	0.09
Zeolite catalyst	344	0.07	0.59
Hydrotreating catalyst	15	0.00	0.03
Hydrocracking catalyst	2	0.00	0.00
50 wt % caustic	291	0.06	0.50
Net water makeup	43,242	8.69	74.64
Boiler feed water chemicals	2	0.00	0.00
Cooling tower chemicals	1	2.01E-04	0.00
No. 2 diesel fuel	71	0.01	0.12
<b>Waste Streams</b>	lb/hr	lb/gal	lb/MMBtu
Solids purge from fluidized bed reactors	2,555	0.51	4.41
Wastewater	21,410	4.30	36.96
<b>Air Emissions</b>	lb/hr	lb/gal	lb/MMBtu
CO <sub>2</sub> (Fossil)	147	0.03	0.25
CO <sub>2</sub> (Biogenic)	204,428	41.07	352.86
CH <sub>4</sub>	0	0.00	0.00
CO	0	0.00	0.00
NO <sub>2</sub>	13	0.00	0.02
SO <sub>2</sub>	106	0.02	0.18
H <sub>2</sub> O	105,471	21.19	182.05
H <sub>2</sub> S	0	0.00	0.00

Note: Small quantities of HDS catalyst and ZnO used before steam reforming not shown.

**Table 24. Material and Energy Flows for the *Ex Situ* Case**

<b>Production Rate</b>			
<b>Products</b>	lb/hr	gal/hr	MMBtu/hr (LHV)
Gasoline fuel	20,408	3,236	375
Diesel fuel	24,739	3,930	456
<b>Byproducts</b>	kW		
Excess electricity	3,201		
<b>Resource Consumption</b>	<b>Flow Rate</b>	<b>Per Gal Gasoline</b>	<b>Per MMBtu</b>
	lb/hr	lb/gal	lb/MMBtu
Blended woody biomass (wet)	204,131	63.07	544.03
Blended woody biomass (dry)	183,718	56.77	489.63
Sand makeup	158	0.05	0.42
Natural gas	125	0.04	0.33
Zeolite catalyst	229	0.07	0.61
Hydrotreating catalyst	16	0.00	0.04
Hydrocracking catalyst	4	0.00	0.01
50 wt % caustic	294	0.09	0.78
Net water makeup	41,495	12.82	110.59
Boiler feed water chemicals	2	0.00	0.01
Cooling tower chemicals	1	3.09E-04	0.00
No. 2 diesel fuel	71	0.02	0.19
<b>Waste Streams</b>	lb/hr	lb/gal	lb/MMBtu
Solids purge from fluidized bed reactors	2,335	0.72	6.22
Wastewater	20,708	6.40	55.19
<b>Air Emissions</b>	lb/hr	lb/gal	lb/MMBtu
CO <sub>2</sub> (Fossil)	342	0.11	0.91
CO <sub>2</sub> (Biogenic)	200,605	61.98	534.64
CH <sub>4</sub>	0	0.00	0.00
CO	0	0.00	0.00
NO <sub>2</sub>	17	0.01	0.04
SO <sub>2</sub>	107	0.03	0.29
H <sub>2</sub> O	98,451	30.42	262.38
H <sub>2</sub> S	0	0.00	0.00

Note: Small quantities of HDS catalyst and ZnO before steam reforming not shown.

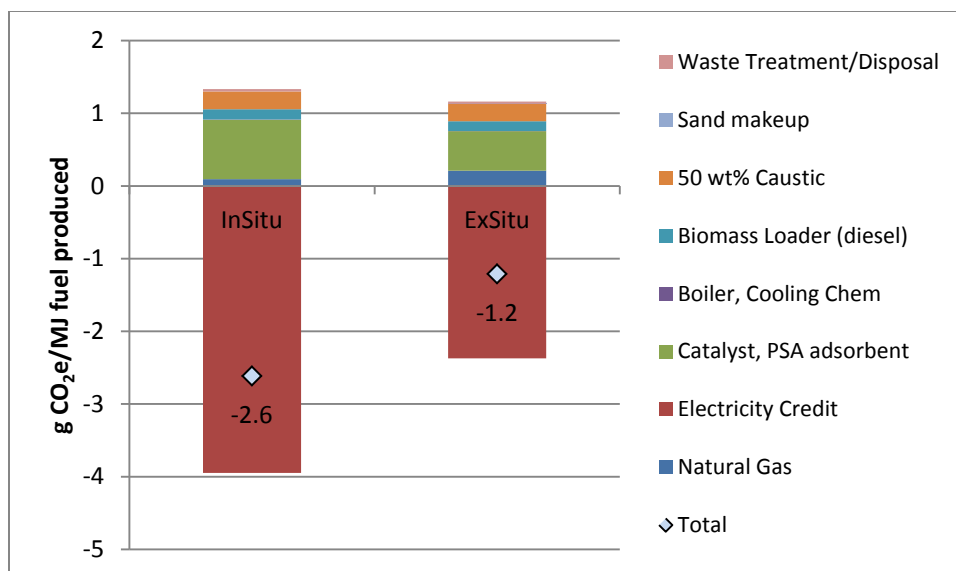
In addition to primary fuel production, the process also produces an excess amount of electricity as coproduct. It is assumed that the excess electricity would be sold to the grid translating to coproduct credits for avoided GHG emissions and fossil energy consumption. This exported electricity is treated as an avoided product using the product displacement method [57]. Coproduct displacement (also termed system boundary expansion) is based on the concept of displacing the existing product with the new product. The excess electricity coproduct displaces an equivalent amount of grid electricity, thus avoiding a significant amount of GHG emissions as

well as fossil energy consumption, assuming an average U.S. electricity grid mixture. The GHG and fossil energy consumption credits attributed to the displacement of an average U.S. electricity grid mixture is 0.65 kg CO<sub>2</sub>e/kWh and 7.5 MJ/kWh, respectively, as defined by GREET [54]. However, it is not clear whether power companies would be willing to buy the excess electricity generated from cellulosic biorefinery. Thus, a second scenario assumed that the excess electricity would not be sold to the grid and thus there were no coproduct credits for avoided GHG emissions and fossil energy consumption. Table 25 lists the SimaPro database processes used for the GHG calculations.

**Table 25. SimaPro Processes Used for Conversion Process Inputs**

<b>Key Inputs</b>	<b>SimaPro Processes</b>
Electricity	GREET
Natural gas	GREET
Sand makeup	Silica sand, at plant/DE WITH US ELECTRICITY U
Zeolite catalyst	Zeolite, powder, at plant/RER WITH US ELECTRICITY U
Hydrotreating catalyst	Zeolite, powder, at plant/RER WITH US ELECTRICITY U
Hydrocracking catalyst	Zeolite, powder, at plant/RER WITH US ELECTRICITY U
ZnO bed material	Zeolite, powder, at plant/RER WITH US ELECTRICITY U
HDS catalyst before reformer	Zeolite, powder, at plant/RER WITH US ELECTRICITY U
Steam reforming catalyst	Zeolite, powder, at plant/RER WITH US ELECTRICITY U
Shift catalyst	Zeolite, powder, at plant/RER WITH US ELECTRICITY U
PSA adsorbent	Zeolite, powder, at plant/RER WITH US ELECTRICITY U
50 wt % caustic	Sodium hydroxide, 50% in H <sub>2</sub> O, production mix, at plant/RER WITH US ELECTRICITY U
Net water makeup	Water, process, unspecified natural origin/kg
Boiler feed water chemicals	Sodium hydroxide, 50% in H <sub>2</sub> O, production mix, at plant/RER WITH US ELECTRICITY U; Sulphite, at plant/RER WITH US ELECTRICITY U, Hydrochloric acid, 30% in H <sub>2</sub> O, at plant/RER WITH US ELECTRICITY U
Cooling tower chemicals	Chemicals in organic, at plant/GLO WITH US ELECTRICITY U

On an energy basis and with electricity credits, the GHG emissions at the conversion stage for the *in situ* and *ex situ* cases are *negative* 2.6 g CO<sub>2</sub>e/MJ and *negative* 1.2 g CO<sub>2</sub>e/MJ, respectively. However, without electricity credits, the GHG emissions are higher, 1.3 and 1.2 g CO<sub>2</sub>e/MJ for the *in situ* and *ex situ* cases, respectively. Similarly, the fossil energy consumption for the case with electricity credits are *negative* 0.03 MJ/MJ and *negative* 0.01 MJ/MJ for the *in situ* and *ex situ* cases, respectively. Without electricity coproduct displacement credits, the fossil energy consumptions for both the *in situ* and *ex situ* cases are 0.02 MJ/MJ. The electricity coproduct displacement credits are only relevant to the GHG emissions and fossil energy consumption assessment and not to other metrics in Table 26. The contributions of individual inputs to the total conversion stage GHG are shown in Figure 12.



**Figure 12. Contributing processes to conversion GHGs for catalytic pyrolysis pathways**

In addition to GHG emissions and fossil energy consumption discussed above, water consumption (i.e., net water use during the biorefinery operation), total fuel efficiency (yield), and carbon-to-fuel efficiency are also reported in Table 26.

Biorefinery net water consumption includes, but is not limited to, water that is incorporated into the product and evaporation directly from process operations or indirectly from cooling and heating processes (e.g., cooling tower evaporative losses), but it does not include water that is directly returned to surface water or groundwater (such as blowdown). The net consumption for the *in situ* and *ex situ* cases are 468 and 449 m<sup>3</sup>/day, respectively. The total fuel yield is 74.9 GGE per dry ton for the *in situ* case and 78.0 GGE per dry ton for the *ex situ* case. The corresponding carbon-to-fuel efficiency for the *in situ* and *ex situ* cases are determined to be 40.4% and 41.5%, respectively, calculated strictly as a ratio of carbon in the liquid fuel products relative to carbon in the biomass feedstock.

**Table 26. Summary of Sustainability Metrics for the *In Situ* and *Ex Situ* Cases**

Design Cases:	<i>In Situ</i>		<i>Ex Situ</i>	
	Yes	No	Yes	No
Electricity credit	Yes	No	Yes	No
GHG emissions (g CO <sub>2</sub> e/MJ)	-2.6	1.3	-1.2	1.2
Net fossil energy consumption (MJ/MJ)	-0.03	0.02	-0.01	0.02
Water consumption (m <sup>3</sup> /day)	470		450	
Water consumption (gal/GGE fuel)	0.75		0.69	
Total fuel yield (GGE/dry ton)	74.9		78.0	
Carbon-to-fuel efficiency (C in fuel/C in biomass)	40.4%		41.5%	
Wastewater generation (m <sup>3</sup> /day)	233		225	
Wastewater generation (gal/GGE)	0.37		0.35	

The analysis was expanded to estimate the full life-cycle GHG emissions for fuels produced from the projected 2017 model feedstock, a blend of pulpwood (45%), wood residues (32%), switchgrass (3%), and construction and demolition waste (20%) [22]. Full life-cycle GHGs for gasoline fuel from the 2017 model feedstock are estimated at 9.2 g CO<sub>2</sub>e/MJ and 10.2 g CO<sub>2</sub>e/MJ for the *in situ* and *ex situ* cases, respectively. This corresponds to GHG reductions relative to the 2005 petroleum baseline GHGs (93.08 g CO<sub>2</sub>e/MJ) [58] of 90% and 89% for the *in situ* and *ex situ* cases, respectively. The underlying assumptions and detailed results for the full life-cycle GHG analysis are given in Appendix E. While this analysis provides a preliminary estimate of GHG reduction associated with this biofuel, it is important to note that the EPA conducts its own LCA to make final determination of fuel qualification under the Renewable Fuel Standard 2. In addition, Argonne National Laboratory will provide more detailed LCA for these pathways in the future.



## 4 Process Economics

The following section describes how the process model, detailed design, and cost estimation discussed so far is used to determine the economics of fuel production. The analysis is based entirely on estimated equipment costs and regular construction and project management costs associated with building a plant of this kind. The analysis does not take into account any policy factors such as carbon credits, subsidies, or mandates.

The TCI is first computed using a comprehensive list of mechanical equipment in the plant and its expected construction and project costs. Variable and fixed operating costs associated with plant operation and maintenance are determined next. With these estimated costs, a discounted cash flow analysis is used to determine an MFSP that resolves to a net present value of zero for the entire project at some assumed nonzero discount rate, also referred to in this report as the internal rate of return (IRR). In other words, given the production rates determined in the process model, fuel from the plant must be sold at its MFSP in order for the project to return the specified IRR and no more. This section describes the calculations and assumptions made in completing the discounted cash flow analysis.

### 4.1 Total Capital Investment

The following discussion summarizes the purchased and installed equipment costs presented in Section 3 and describes how the total installed costs for the plant serve as the basis for determining the total capital investment. As previously discussed, the equipment costs for each plant area were derived from various sources including equipment suppliers and licensors, cost estimates from Harris Group, published literature, and Aspen Capital Cost Estimator software. The sum of all items on a bare-equipment, freight on board (FOB) basis is the total purchased equipment cost. The installation cost for the bare equipment is estimated by applying installation factors to each piece of equipment. For those equipment costs estimated in ACCE, we used the installation factor implied by ACCE (total direct cost/equipment cost). For line items quoted as a package or drawn from other references (for example, the steam methane reformer), the installation factor implied in the source was used. Any remaining missing installation factors were determined as described in the 2011 NREL design report for biochemical ethanol [49], which used a table of installation factors by equipment type found in Walas [19], plus 0.3 to account for instrumentation, which NREL determined was deliberately excluded from these factors. See Appendix B for a complete listing of the equipment, along with its purchased and installed costs. Table 27 presents a summary of TPEC, aggregate installation factors ( $f_{\text{install}}$ ), and TIC for each area of the plant.

**Table 27. General Cost Factors in Determining Total Installed Equipment Costs**

Area	Process Description	<i>In Situ</i>			<i>Ex Situ</i>		
		TPEC (MM\$)	f <sub>install</sub>	TIC (MM\$)	TPEC (MM\$)	f <sub>install</sub>	TIC (MM\$)
100	Feed handling and drying <sup>a</sup>	0.3	1.96	0.5	0.2	1.97	0.4
200	Fast pyrolysis and vapor upgrading	31.1	2.98	92.5	40.7	3.12	126.9
300	Pyrolysis vapor quench and product recovery	12.2	1.84	22.4	13.2	1.83	24.2
400	Hydroprocessing and product separation	18.8	1.73	32.5	15.9	1.83	29.1
500	Hydrogen plant	36.5	1.93	70.6	34.5	1.93	66.8
600	Steam system and power generation	29.3	1.79	52.4	26.7	1.80	47.9
700	Cooling water and other utilities	4.7	2.01	9.4	4.6	2.00	9.3
800	Wastewater management and recycle	7.2	2.37	17.2	5.4	2.39	12.9
<b>ISBL (Areas 100–400)</b>		<b>62.3</b>	<b>2.38</b>	<b>147.9</b>	<b>70.0</b>	<b>2.58</b>	<b>180.7</b>
<b>OSBL (Areas 500–800)</b>		<b>77.7</b>	<b>1.93</b>	<b>149.7</b>	<b>71.2</b>	<b>1.92</b>	<b>136.8</b>
<b>Total</b>		<b>140.0</b>	<b>2.13</b>	<b>297.6</b>	<b>141.2</b>	<b>2.25</b>	<b>317.5</b>

<sup>a</sup> Most investment costs for feed handling and drying are included in the per-unit woody feedstock price. This cost is for a secondary biomass dryer that serves to recover heat.

The sum of equipment purchases and installation/construction costs is defined as the total direct cost (TDC). Indirect capital costs are non-construction costs typically associated with project management and engineering, procurement, and construction (EPC) services. Indirect costs are estimated with factors on the TDC as shown in Table 28. The sum of direct and indirect costs is defined as the fixed capital investment (FCI). Finally, working capital is determined to be 5% of the FCI. The sum of FCI and working capital is the TCI. Table 29 presents a summary of these capital quantities for the *in situ* and *ex situ* pyrolysis processes described in this report.

**Table 28. Cost Factors for Indirect Costs**

Indirect Costs	% of TDC*
Prorated expenses	10.0
Home office and construction fees	20.0
Field expenses	10.0
Project contingency	10.0
Other costs (start-up and permits)	10.0
<b>Total Indirect Costs</b>	<b>60.0</b>

\* Excluding land purchase cost.

**Table 29. Project Cost Worksheet**

		<i>In Situ</i>	<i>Ex Situ</i>
<b>Total purch. equipment cost (TPEC)</b>		<b>\$140,030,000</b>	<b>\$141,180,000</b>
Installation factor		2.125	2.249
<b>Total installed cost (TIC)</b>		<b>\$297,610,000</b>	<b>\$317,540,000</b>
<b>Other direct costs</b>			
Land (not depreciated)		\$1,610,000	\$1,610,000
Warehouse	4.0% of ISBL	\$5,920,000	\$7,230,000
Site development	10.0% of ISBL	\$14,790,000	\$18,070,000
Additional piping	4.5% of ISBL	\$6,660,000	\$8,130,000
<b>Total direct costs (TDC)</b>		<b>\$324,980,000</b>	<b>\$350,970,000</b>
<b>Indirect costs</b>	% of TDC (ex land)		
Prorated expenses	10.0%	\$32,500,000	\$35,100,000
Home office and construction fees	20.0%	\$65,000,000	\$70,190,000
Field expenses	10.0%	\$32,500,000	\$35,100,000
Project contingency	10.0%	\$32,500,000	\$35,100,000
Other costs (start-up and permits)	10.0%	\$32,500,000	\$35,100,000
<b>Total indirect costs</b>	<b>60.0%</b>	<b>\$194,990,000</b>	<b>\$210,580,000</b>
<b>Fixed capital investment (FCI)</b>		<b>\$519,960,000</b>	<b>\$561,550,000</b>
Working capital	5.0% of FCI (ex land)	\$26,000,000	\$28,080,000
<b>Total capital investment (TCI)</b>		<b>\$545,960,000</b>	<b>\$589,630,000</b>
TCI/TPEC		3.899	4.177
FCI Lang Factor = FCI/ISBL TPEC		8.349	8.023
TCI Lang Factor = TCI/ISBL TPEC		8.766	8.424

## 4.2 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 Plus material balance. Table 30 summarizes the basis for variable operating costs considered in this analysis. A detailed summary of variable plant operating costs is presented in Appendix C on a per-year and per-GGE basis.

**Table 30. Summary of Variable Operating Costs**

<b>Variable</b>	<b>Information and Operating Cost (cost year in parentheses)</b>
Fluidized bed media	For fast pyrolysis, the bed medium is sand. In catalytic fast pyrolysis ( <i>in situ</i> ) and vapor-phase upgrading ( <i>ex situ</i> ), the medium is assumed to be a zeolite catalyst. Initial fill then a total replacement rate of 3.6 wt % of circulation per day for both the <i>in situ</i> and <i>ex situ</i> cases.  Sand price: \$45.74/ton (2011) [59]; initial fill, then makeup for attrition.  Zeolite price: \$19,500/ton (2011); estimated cost based on modifications, such as to include rare earth [27] and non-precious metals like nickel (Ni) up to 5 wt %.
Hydrotreating and hydrocracking catalysts	To determine the amount of catalyst inventory, the hydroprocessors were sized for a WHSV of 0.5/h based on the expected hydroprocessing severity. Initial fill is then replaced every 2 years.  Price: \$20/lb (2011) based on NREL calculations using metals pricing and costs for manufacturing processes, and some buffer for modifications.
Steam methane reformer catalysts	Based on a literature value of price per unit hydrogen produced. Price: \$7.80/ton hydrogen (2011) [60].
Natural gas	Purchased from pipeline for feed to steam methane reformer for hydrogen production. Price: \$239/ton (\$5/MMBtu) (2011).
Solids disposal	Price: \$33/tonne (1998) [16].
Diesel fuel	Usage: 10 gal/h plant-wide use. 2012 price projection: \$21.29/MMBtu (2009) [61] = \$2.86/gal at 0.85 specific gravity.
Water makeup	Price: \$0.22/tonne (2001) [17] = \$0.20/ton.
Chemicals	Boiler feed water chemicals – Price: \$75/MM lb blowdown (2014 vendor estimate). Cooling tower chemicals – Price: \$33.84/yr per ton of cooling capacity (2014 vendor estimate). Caustic – Price: \$150/dry ton (2010) [49].
Wastewater	Most wastewater is cleaned using an RO system and recycled. Additional treatment is assumed for the balance. Price: \$0.022/gallon (2011). Based on Humbird et al. [49].

Note: Costs shown were updated to 2011 dollars using an inorganic cost index [62].

Values used: 1998 = 148.7; 2001 = 158.4; 2010 = 233.9; 2011 = 249.3, 2014 = 280.2 (extrapolated).

### 4.3 Fixed Operating Costs

Fixed operating costs, which include employee salaries and benefits, overhead, plant maintenance costs, insurance, and taxes (other than income taxes), are generally incurred in full whether or not the plant is producing at full capacity. Table 31 lists the expected number of employees for the plant and their associated salaries. The salaries listed do not include benefits, so a general overhead factor is applied, as shown in Table 32, along with fixed costs for insurance, taxes, and general plant maintenance, such as security, janitorial services, and communications. A detailed summary of fixed plant operating costs is presented in Appendix C.

**Table 31. Salary Costs for Plant Employees**

<b>Position Title</b>	<b>Salary (2007)</b>	<b>Number of Positions</b>	<b>Total Cost* (2011)</b>
Plant manager	\$147,000	1	\$161,362
Plant engineer	\$70,000	1	\$76,389
Maintenance supervisor	\$57,000	1	\$62,569
Laboratory manager	\$56,000	1	\$61,471
Shift supervisor	\$48,000	5	\$263,448
Lab technician	\$40,000	2	\$87,816
Maintenance technician	\$40,000	16	\$702,527
Shift operators	\$48,000	20	\$1,053,790
Yard employees	\$28,000	12	\$368,827
Clerks and secretaries	\$36,000	3	\$118,551
<b>Total salaries (2011\$/yr)</b>			<b>\$2,960,000</b>

\* Additional 10% escalation to costs indicated in this column, as shown in Table 32.

Note: Labor costs are indexed, if necessary, to values from the U.S. Bureau of Labor Statistics (<http://data.bls.gov/cgi-bin/srgate> CEU3232500008).

**Table 32. Fixed Operating Costs**

<b>Cost Item</b>	<b>Factor</b>	<b><i>In Situ</i></b>	<b><i>Ex Situ</i></b>
Salaries (plus 10% escalation)		\$3,250,000	\$3,250,000
Benefits and overhead	90.0% of total salaries (after adding 10%)	\$2,922,000	\$2,922,000
Maintenance	3.0% of fixed capital investment (FCI*)	\$15,599,000	\$16,847,000
Insurance and taxes	0.7% of fixed capital investment (FCI*)	\$3,640,000	\$3,931,000
<b>Total fixed operating costs (2011\$/yr)</b>		<b>\$25,410,000</b>	<b>\$26,950,000</b>

\* Percentages of FCI exclude land purchase cost.

## 4.4 Discounted Cash Flow Analysis and the Minimum Fuel Selling Price

Once the capital and operating costs are determined, an MFSP is determined using a discounted cash flow rate of return (DCFROR) analysis. The general methodology used is the same as that applied in previous NREL design reports [20, 49], with the small distinction that we normalize all fuel products from the plant (gasoline and diesel) by lower heating value to give a single gasoline-equivalent product. The discounted cash flow analysis determines the minimum selling price of a gallon of this gasoline-equivalent product, which yields a net present value of zero for the project. The financial parameters used to compute the net present value are as follows.

### *Discount Rate/IRR*

For this analysis, the cash flow discount rate was set to an internal rate of return of 10% on equity finance.

### *Equity Financing*

For this analysis, it was assumed that the plant would be 40% equity financed. The terms of the loan on the remaining 60% debt were taken to be 8% interest for 10 years. The principal is taken out in stages over the 3-year construction period. Interest on the loan is paid during this period, but principal is not paid back. (This implies that cash flow comes from a parent company until the plant starts up.)

### *Depreciation*

Capital depreciation is computed according to the IRS Modified Accelerated Cost Recovery System (MACRS). The bulk of the plant capital is depreciated over a 7-year recovery period. Because the plant described here is a net exporter of electricity, the steam plant and power generation equipment is depreciated over a 20-year recovery period, according to the IRS.

### *Taxes*

The federal corporate tax rate used in our analysis is 35%. Income tax is averaged over the plant life and that average is calculated on a per-GGE basis. The amount of income tax to be paid varies annually with changes in the volume of product produced and the allowable depreciation deduction. In fact, no income tax is paid in the first 8 years of operation because depreciation and loan interest deductions are greater than the net income. State taxes are not considered, primarily because the location of the plant has not been determined and tax rates vary from state to state (from 0% to 12%).

### *Construction Time*

The construction time was taken to be 24 months. Twelve months are added before construction for planning and engineering.

### *Start-Up Time*

Startup was taken to be 25% of the construction time, or 6 months in this case. It is assumed that the plant achieves 50% production during the start-up period while incurring 75% of variable expenses and 100% of fixed expenses.

### *Lifetime*

The plant and all equipment is assumed to have a 30-year life. No salvage value is assumed at the end of 30 years.

### *Working Capital*

Working capital was taken to be 5% of the fixed capital investment.

## 4.5 Value of Hydrocarbon Fuel Products From Biomass Pyrolysis

The results of the cash flow analyses for the base *in situ* and *ex situ* cases are summarized in Table 33. As noted above, gasoline and diesel are normalized by lower heating value to represent a single gasoline-equivalent product and MFSP. To re-obtain individual selling prices for gasoline and diesel, the MFSP per GGE is ratioed back to these products by lower heating value. The densities of the blendstocks were assumed to be those of U.S. conventional gasoline (2,819 grams/gallon or 6.215 lb/gallon) and diesel fuels (3,167 grams/gallon or 6.982 lb/gallon) [63].

**Table 33. Projected Selling Prices of Hydrocarbon Fuels From Biomass Pyrolysis**

	<i>In Situ</i>	<i>Ex Situ</i>
Lower heating value for gasoline-range products from pyrolysis (simulation result)	112,988 Btu/gal	114,267 Btu/gal
Lower heating value for diesel-range products from pyrolysis (simulation result)	129,006 Btu/gal	128,779 Btu/gal
Calculated gasoline-equivalent MFSP	<b>\$3.46/GGE</b>	<b>\$3.31/GGE</b>
Calculated actual MFSP for gasoline-range products	<b>\$3.37/gal</b>	<b>\$3.26/gal</b>
Calculated actual MFSP for diesel-range products	<b>\$3.85/gal</b>	<b>\$3.68/gal</b>
<i>Gasoline lower heating value for normalization</i>		<i>116,090 Btu/gal</i>

## 5 Process Economics Summary and Sensitivity Analysis

The contribution of individual areas toward the MFSP on a \$/GGE basis are shown in Figure 13 for the *in situ* case and Figure 14 for the *ex situ* case. Additional summary tables with a detailed breakdown of costs are shown in the Executive Summary and not repeated here.

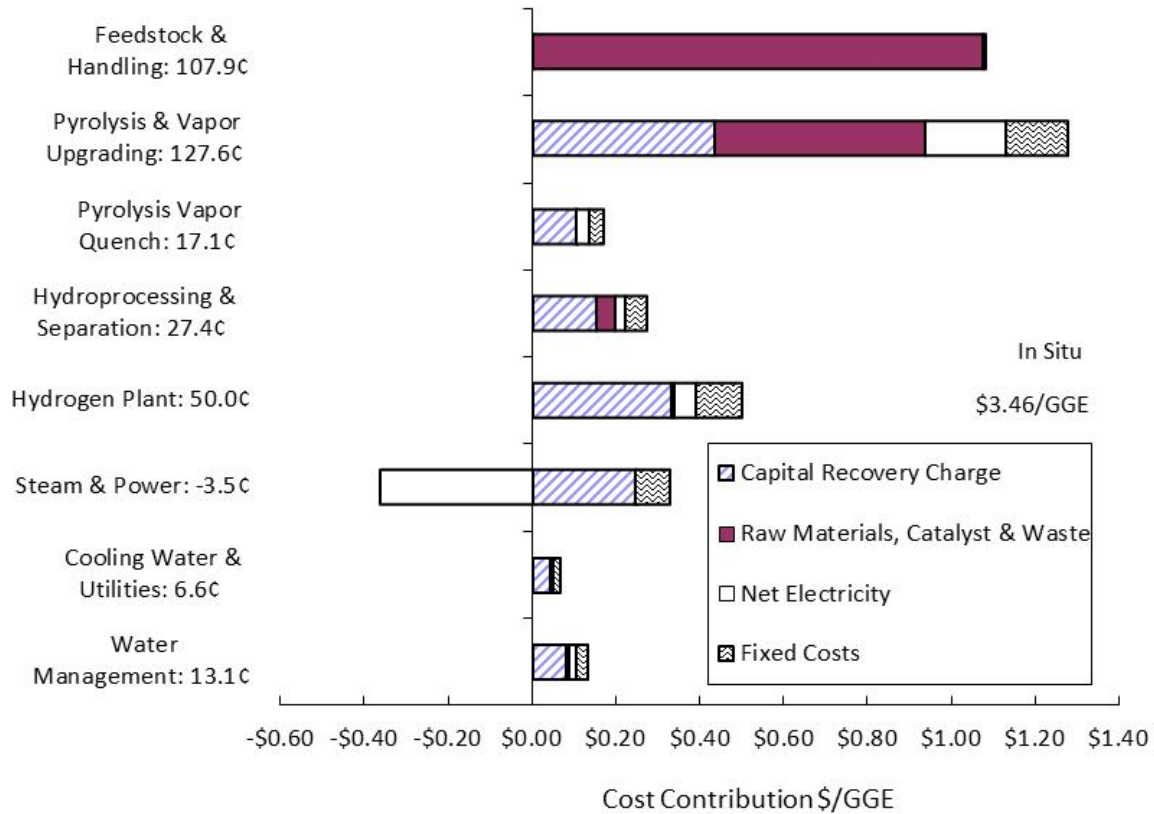
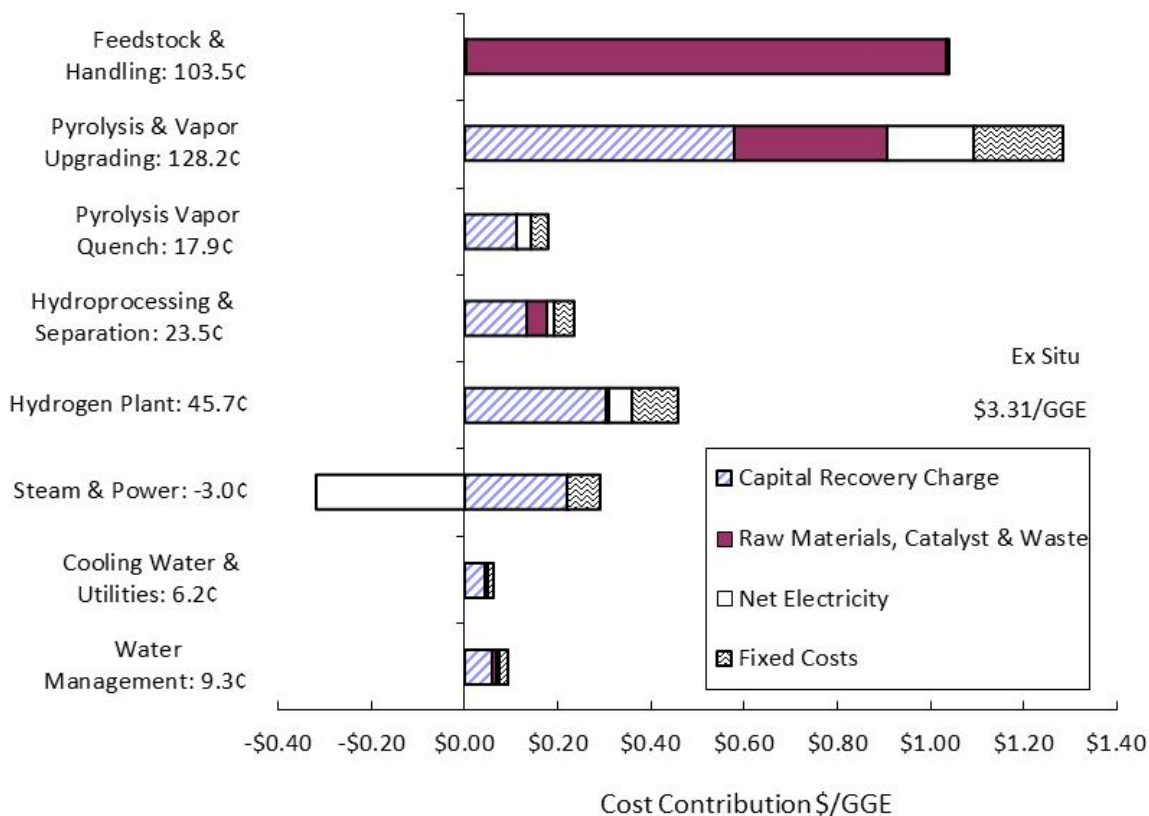


Figure 13. Cost contribution details from each process area for the *in situ* 2022 target case





**Figure 14. Cost contribution details from each process area for the *ex situ* 2022 target case**

Since the design basis for the *in situ* and *ex situ* cases were similar, except for the fast pyrolysis and vapor upgrading reactors, it is not surprising that they show similar cost distribution trends. The key points to be noted are:

1. The higher capital cost due to separate fast pyrolysis and vapor upgrading reactors in the *ex situ* case (versus a single combined reactor in the *in situ* case) is offset by the lower catalyst replacement rate in the *ex situ* case. The assumed rate is 2% of the inventory per day for both the *in situ* and *ex situ* cases, with an additional 1.6% added to account for attrition. The catalyst to biomass ratio is 7.5 for the *in situ* case compared to 5 for the *ex situ* case, which results in a higher *in situ* catalyst inventory, hence higher calculated losses.
2. The slightly higher hydroprocessing cost for the *in situ* case is primarily due to the higher oxygen content assumed in the organic liquid after vapor upgrading; hydrogen consumption and the hydrogen plant cost is also higher for the same reason.
3. Wastewater management costs are higher for the *in situ* case because of the assumption of higher carbon loss to the aqueous phase as a result of higher oxygen content in the organic liquid from *in situ* vapor upgrading.

While these are some of the key differences, there are other underlying differences within the process model and costs, as was noted in the tables comparing the two base cases throughout this report.

As previously pointed out, the *in situ* and *ex situ* base cases are two of many possible scenarios for cost competitiveness of these pathways through research focused primarily on catalyst development, and demonstration of credible process integration and scale-up. Significant uncertainties remain to be resolved through experimental corroboration. Thus, it is important to show the impacts of variations in some of the key underlying assumptions through sensitivity studies. Sensitivity scenarios for the *ex situ* case are summarized in Figure 15. Similar parameter variations for the *in situ* case are expected to follow the trends shown for the *ex situ* case.

Note that each sensitivity scenario in Figure 15 has an associated deviation value from the base case MFSP of \$3.31/GGE. The sensitivity scenarios are discussed in the following sections. The case numbers in the text refer to the numbers shown in the labels of Figure 15. This being a tornado chart, the results are sorted by the magnitudes of impacts on the MFSP.

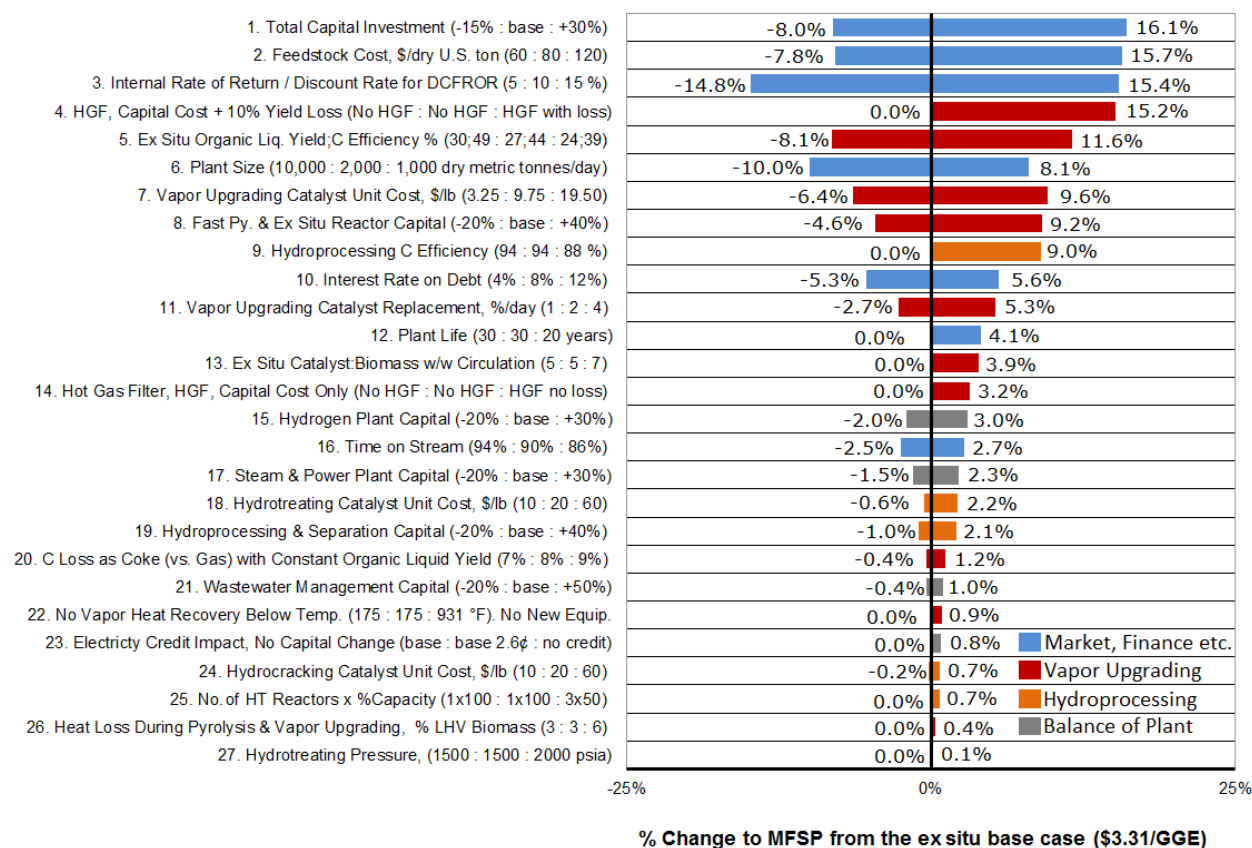


Figure 15. Results of sensitivity analyses for the *ex situ* case

## 5.1 Market, Financial, and Overall Assumptions

Variations in the TCI, shown in Case 1 of Figure 15, can have significant impacts on the MFSP. In this context it should be noted that some of the *major* equipment costs were derived from estimations based on similar equipment, or from costs derived from mechanical design tools. Variation in capital costs during an actual installation is potentially the biggest reason for changes in the TCI. A 30% increase in the TCI can increase the *ex situ* base case MFSP of \$3.31/GGE by 16.1%.

Case 3 shows that assuming a higher discount rate for DCFROR (also referred to here as the internal rate of return), of 15% instead of 10% can have a similar impact of 15.4% on the MFSP. Similarly, Case 10 shows the impact of assuming a higher interest rate.

Feedstock cost, which is shown as a significant contributor to the MFSP, can have a big impact as shown in Case 2. Increasing the feedstock cost from \$80/dry U.S. ton to \$120/dry U.S. ton increased the MFSP by 15.7%. There is ongoing work at INL and other institutions toward enabling the provision of feedstock at \$80/dry U.S. ton while meeting quality specifications. Some of their work is focused on improvements in feedstock logistics, and ways to soften market forces by expanding the feedstock pool to a wider range of blended material as mentioned earlier. The effects of blended material on product yields will be experimentally studied as part of ongoing research.

Case 6 shows the impact of a larger plant size, with feedstock available at the same price. This shows that the MFSP based on current assumptions can be significantly reduced to approximately \$3/GGE by scaling up. The impact can be significantly larger if the assumed 1,000 dry metric tonnes/day/reactor constraint imposed on the fast pyrolysis reactor is lifted and larger reactors can be designed. Additional references discuss economies of scale and refinery integration [64] and biorefinery sizing [65] as potential approaches toward cost reduction.

Assuming a plant life of 20 years instead of 30 years increases the MFSP by 4.1% as shown in Case 12. Case 16 shows that the assumption of 86% plant on-stream factor (versus 90% in the base case) results in an increase of 2.7% in the MFSP.

## 5.2 Fast Pyrolysis and Catalytic Vapor Upgrading

The estimated impacts on the MFSP from the inclusion of a hot gas filter in the process are shown in Cases 4 and 14. A hot gas filter may be necessary even in the *ex situ* system if cyclones are inadequate for sufficiently removing mineral matter/ash from the vapor stream to prevent detrimental impacts on the catalyst. The capital cost of the HGF was scaled using the actual vapor flow rate in the process model, starting from original equipment cost estimates obtained for a near atmospheric system. The 120 psia system pressure (versus near atmospheric pressure) in the fast pyrolysis and vapor upgrading sections helped reduce gas volumes and reduce the capital impact of the HGF; the MFSP increased by 3.2%, as shown in Case 14. However, yield losses have not been quantified in a process configuration similar to that assumed in this process design. Assuming an organic liquid product yield loss of 10% due to cracking and coking leads to a higher (15.2%) impact on the MFSP as shown in Case 4.

A 40% increase in the reactor capital in the *ex situ* case leads to an increase of 9.2% to the MFSP (Case 8). Organic liquid yield after vapor upgrading is key to the process economics as indicated by an 11.6% increase in the MFSP from a 10% drop in yield (Case 5).

The impacts of higher catalyst replacement rates, higher catalyst to biomass ratios, and higher catalyst costs on the MFSP are captured in Cases 11, 13, and 7, respectively.

Heat recovery from upgraded vapors can have impacts on process efficiencies and design. The impact of lower efficiency (without accounting for the likely inclusion of new equipment in addition to those in the base case) is shown in Case 22. It reflects the scenario when no heat can

be recovered from the hot upgraded vapors between 931°F and 466°F. The beginning temperature for vapor condensation using the model compounds in the simulation is 466°F; it is assumed in the base case that indirect exchange can be used to recover heat from 931°F to 466°F.

From an economic standpoint, Case 20 shows that losing carbon as gas is preferable over loss as coke. There are larger process operation and design implications of lower coke formation, especially if fixed bed vapor upgrading systems are used, and if regeneration protocols include reactor cycle times for offline regeneration.

Case 26 shows that there is a small impact of higher heat losses in the system. This is primarily due to a lower electricity credit.

### 5.3 Hydroprocessing

The catalytic vapor upgrading reduces the dependency on downstream hydroprocessing of condensed organic liquid. As a result the impacts on variations in this section are relatively smaller than those in the fast pyrolysis and catalytic vapor upgrading sections. As mentioned earlier (Figure 8), carbon efficiency of organic liquid feed to fractionated liquid products was assumed to scale linearly based on the oxygen content, assuming 85% efficiency for 20% oxygen content feed and 98.5% efficiency for feed with negligible oxygen content. Assumption of 88% carbon efficiency, versus 94% carbon efficiency in the *ex situ* case, results in a 9% increase in the MFSP, as shown in Case 9.

A 40% increase in hydroprocessing and separations area capital leads to a 2.1% increase in the MFSP (Case 19) using the underlying capital cost assumptions mentioned previously.

The impacts of hydrotreating and hydrocracking catalyst unit costs and hydrotreater operating pressure are shown in Cases 18, 24, and 27, respectively. Case 25 shows that using three hydrotreating reactors with 50% capacity each, to enable more frequent catalyst maintenance operations, adds 0.7% to the MFSP.

### 5.4 Other Operations and Overall Plant

Case 23 shows the impact of the electricity credit of 2.6¢ in the base case on the MFSP. It is to be noted that unlike in a syngas conversion process, non-condensable carbonaceous products are not recoverable as liquid products in this process. Unless there are other local consumers of the excess heat available in the process (due to the formation of char, coke, and non-condensable fuel gases), electricity production is the logical way to capture this thermal energy.

The impacts of hydrogen plant, steam plant, and wastewater treatment capital costs on the MFSP are shown in Cases 15, 17, and 21, respectively.

## 6 Conclusions

This analysis lays out conceptual process designs for *in situ* and *ex situ* upgrading of fast pyrolysis vapors for the production of significantly deoxygenated bio-oil intermediate, with further hydroprocessing of the bio-oil to produce hydrocarbon fuel blendstocks that can be cost-competitive with petroleum-derived sources; this is contingent on the research helping achieve the performance goals (for 2022) outlined in this report. Advances in catalysts will be necessary to improve the quality and yields of the bio-oil intermediate for the success of this conversion pathway. Targeted catalyst development should enable bio-oil yield improvements by reducing losses to coke and non-condensable gases, quality improvements via hydrodeoxygenation and hydrogenation, and increased diesel-range products via molecular combination (coupling) in the vapor phase. Higher diesel-range products are targeted for the *ex situ* process because more favorable reaction chemistry (coupling reactions) is possible in a separate reactor where, unlike in an *in situ* upgrading reactor, one does not have to deal with catalyst detriments such as biomass, char, and mineral matter/ash. The catalysts developed for both the *in situ* and *ex situ* cases need to be cost-justifiable with respect to maintenance, materials used, and reactor designs that are compatible with catalyst performance; the *ex situ* case can have added options such as the use of fixed bed reactors following a hot gas filter.

The improvements outlined are targeted for the 2022 timeframe; new understanding and learnings from research will require adjustments to the conceptual design in the coming years. While near-term developments (2017 timeframe) will likely enable yield improvements and deoxygenation, longer-term developments are expected to allow further hydrodeoxygenation and hydrogenation of the bio-oil intermediate, as well as coupling reactions for the production of a higher proportion of diesel-range molecules. In addition, further understanding of the bio-oil intermediate will lead to the optimization of downstream hydroprocessing. Valorization of carbon in the aqueous phase (separated from the bio-oil) can also be made feasible via research.

Techno-economic analysis in the near-term will identify and study process variations to encompass a wider range of research for these conversion pathways. Continued assessments of the state of technology based on research results, and re-evaluations of the feasibility of targets will be critical in the coming years. Characterization of products and intermediates and the understanding of their compatibility with the existing petroleum refining infrastructure will be important for optimal integration and deployment of products. Characterization will become more feasible and meaningful after some progress in the research, and the availability of larger volumes of products from experimental reactors.

While the target cases with underlying assumptions project MFSPs below \$3.5/GGE, further improvements and cost reductions to \$3/GGE are possible, as shown in the sensitivity analysis. Significant impacts identified in the sensitivity cases include economies of larger scales, lower catalyst costs through catalyst longevity and lower unit costs, and higher product yields.

## 7 Future TEA Work

This design reflects metrics for one possible base case each for the *in situ* and *ex situ* fast pyrolysis vapor upgrading pathways. This work will evolve with more understanding and experimental knowledge during the course of the research. Areas for further studies, among others, include the following:

- Research of other process configurations, including the use of a hot gas filter, fixed bed vapor upgrading reactors, and different catalysts.
- Inclusion of further understanding of compounds and their physical properties, including further speciation and phase equilibrium. This will lead to more predictive process models.
- Experimental development of reaction kinetics information. This can facilitate development of reactor models (with scale-up prediction capabilities) for use in TEA work.
- Impact of feedstock variability on yields.
- Refinement of equipment cost estimates through further understanding of the specifics of feasible conversion processes.
- Providing updated state of technology information based on experimental data and reassessment of technical targets for cost-competitiveness.
- Refinery integration and details of inclusion of products into the current infrastructure based on experimental information.

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## Appendix A. Equipment Description and Design Basis Summary

NREL's Process Engineering Team has compiled information on the equipment in the benchmark model. The compilation contains information about the cost, reference year, scaling factor, scaling characteristic, design information, and back-up cost referencing. The information is stored in the economic spreadsheet portion of the model.

The following table summarizes the important fields of information contained in the spreadsheet model. A partial listing of the information is attached for each piece of equipment. Additional information from the spreadsheet model is presented in Appendix B.

Equipment number: <sup>a,b</sup>	Unique identifier, the first letter indicates the equipment type and the first number represents the process area, e.g., P-601 is a pump in Area 600
Equipment name: <sup>a,b</sup>	Descriptive name of the piece of equipment
Equipment category: <sup>a</sup>	Code indicating the general type of equipment, e.g., PUMP
Equipment type: <sup>a</sup>	Code indicating the specific type of equipment, e.g., CENTRIFUGAL for a pump
Equipment description: <sup>a</sup>	Short description of the size or characteristics of the piece of equipment, e.g., 20 gpm, 82 ft head for a pump
Number required: <sup>b</sup>	Number of duplicate pieces of equipment needed
Number spares: <sup>b</sup>	Number of on-line spares
Original equip. cost: <sup>b</sup>	Equipment cost
Source/reference: <sup>a</sup>	Source of the equipment cost, e.g., Aspen Capital Cost Estimator or vendor quotation
Base year: <sup>b</sup>	Year in which the cost estimate is based
Design flow: <sup>b</sup>	Value of the scaling stream or variable used to obtain the base cost of the equipment
Actual flow: <sup>b</sup>	Value of the actual stream from model used to derive size ratio relative to design flow
Size ratio: <sup>b</sup>	Actual flow/Design flow
Units: <sup>b</sup>	Units of the scaling stream or variable, e.g., LB/HR, MMBtu/HR
Installation factor: <sup>b</sup>	Value of the installation factor. Installed Cost = Base Cost x Installation Factor
Scaling exponent: <sup>b</sup>	Value of the exponential scaling equation
MOC: <sup>a</sup>	Material of construction
Notes:	Any other important information about the design or cost

<sup>a</sup> These fields are listed for all pieces of equipment in Appendix A.

<sup>b</sup> These fields are part of the equipment cost listing in Appendix B.

Equip ID	Equipment Name	Equipment Category	Equipment Type	Design Pressure (psig)	Design Temp (F)	MOC	Sizing Information	Source/Reference
C-101	Hopper Feeder	CONVEYOR	VIBRATING-FEEDER			CS	Included in per unit cost of feedstock	Idaho National Lab
C-102	Screener Feeder Conveyor	CONVEYOR	BELT			CS	Included in per unit cost of feedstock	Idaho National Lab
C-103	Radial Stacker Conveyor	CONVEYOR	BELT			CS	Included in per unit cost of feedstock	Idaho National Lab
C-104	Dryer Feed Screw Conveyor	CONVEYOR	SCREW			CS	Included in per unit cost of feedstock	Idaho National Lab
C-105	Biomass Feed Screw Conveyor	CONVEYOR	SCREW			CS	Included in per unit cost of feedstock	Idaho National Lab
K-101	Flue Gas Blower	FAN	CENTRIFUGAL			CS	60,000 cfm 15" H2O 204 hp	ACCE V8.4
M-101	Hydraulic Truck Dump with Scale	SCALE	TRUCK-SCALE			CS	Included in per unit cost of feedstock	Idaho National Lab
M-102	Hammermill	MISC	SIZE REDUCER			CS	Included in per unit cost of feedstock	Idaho National Lab
M-103	Front End Loaders	VEHICLE	LOADER			CS	Included in per unit cost of feedstock	Idaho National Lab
M-104	Cross Flow Pellet Dryer	MISC	DRYER			CS	50 ton/h 5% moisture reduction	Idaho National Lab
S-101	Magnetic Head Pulley	SEPARATOR	MAGNET			CS	Included in per unit cost of feedstock	Idaho National Lab
S-102	Vibratory Conveyor	SEPARATOR	SCREEN			CS	Included in per unit cost of feedstock	Idaho National Lab
T-101	Dump Hopper	TANK	LIVE-BTM-BIN			CS	Included in per unit cost of feedstock	Idaho National Lab
T-102	Hammermill surge bin	TANK	LIVE-BTM-BIN			CS	Included in per unit cost of feedstock	Idaho National Lab
T-103	Dryer Feed Bin	TANK	LIVE-BTM-BIN			CS	Included in per unit cost of feedstock	Idaho National Lab
T-104	Dried Biomass Hopper	TANK	VERTICAL-VESSEL			CS	Included in per unit cost of feedstock	Idaho National Lab
T-105	Lock Hopper	TANK	VERTICAL-VESSEL			CS	Included in per unit cost of feedstock	Idaho National Lab
T-106	Feed Hopper	TANK	VERTICAL-VESSEL			CS	Included in per unit cost of feedstock	Idaho National Lab
A100	Pinch Exchanger CAPEX							
<b>Area A100: Feed Handling &amp; Drying ↑</b>								
C-212	Fines purge cooler	CONVEYOR	SCREW			CS		HGI FCC Costing Sheet
K-211	Fluidizing gas recycle compressor	COMPRESSOR	RECIPROCATING			SS	2-stage reciprocating 3648 hp	Vendor quote via HGI
K-212	Combustor air compressor	COMPRESSOR	CENTRIFUGAL			SS	Multi-stage oil-free 10,000 hp	Vendor quote via HGI
R-211	Fluidized Bed Reactor	REACTOR	FLUIDIZED BED	105	930	Refractory	1,000 tpd biomass 20,375 ACFM gas prod 7.8 lb media/lb	HGI FCC Costing Sheet
R-212	Char Combustor	REACTOR	FLUIDIZED BED	105	1200	Refractory	718,690 lb/h solids 12,000 ACFM gas prod	HGI FCC Costing Sheet
R-212C	Sand Cooler	HEAT EXCH	SOLIDS COOLER	105	1200	Refractory	3.7 MMBtu/h	HGI FCC Costing Sheet
S-211	Primary Cyclone	SEPARATOR	CYCLONE	105	930	CS	20,375 ACFM gas prod 718,690 lb/h solids 99.9% reject	HGI FCC Costing Sheet
S-212	Secondary Cyclone	SEPARATOR	CYCLONE	105	930	CS	20,375 ACFM gas prod 720 lb/h solids 99.9% reject	HGI FCC Costing Sheet
S-213	Char Combustor Primary Cyclone	SEPARATOR	CYCLONE	105	1200	CS	12,000 ACFM gas prod 718,690 lb/h solids 99.9% reject	HGI FCC Costing Sheet
S-214	Char Combustor Secondary Cyclone	SEPARATOR	CYCLONE	105	1200	CS	12,000 ACFM gas prod 720 lb/h solids 99.9% reject	HGI FCC Costing Sheet
T-211	Bed Media Bin	VESEL	PRESSURE STORAGE	105	650	CS		HGI FCC Costing Sheet
T-212	Depleted bed media and ash storage bin	MISC	ROLL-OFF DISPOSAL	0	300	CS		HGI FCC Costing Sheet
T-217	Char combustor bed media feed bin	VESEL	PRESSURE STORAGE	105	650	CS		HGI FCC Costing Sheet
A211	Pinch Exchanger CAPEX							ACCE V7.2
<b>Area A211: Ex Situ Fast Pyrolysis ↑</b>								
C-202	Fines purge cooler	CONVEYOR	SCREW			CS		HGI FCC Costing Sheet
K-201	Fluidizing gas recycle compressor	COMPRESSOR	RECIPROCATING			SS	2-stage reciprocating 3648 hp	Vendor quote via HGI
K-202	Combustor air compressor	COMPRESSOR	CENTRIFUGAL			SS	Multi-stage oil-free 10,000 hp	Vendor quote via HGI
R-201	Catalytic Fluidized Bed Reactor	REACTOR	FLUIDIZED BED	105	930	Refractory	1,000 tpd biomass 20,424 ACFM gas prod 7.8 lb media/lb	HGI FCC Costing Sheet
R-202	Char Combustor	REACTOR	FLUIDIZED BED	105	1200	Refractory	727,725 lb/h solids 20,000 ACFM gas prod	HGI FCC Costing Sheet
R-202C	Catalyst Cooler	HEAT EXCH	SOLIDS COOLER	105	1200	Refractory	128 MMBtu/h	HGI FCC Costing Sheet
S-201	Primary Cyclone	SEPARATOR	CYCLONE	105	930	CS	20,424 ACFM gas prod 712,880 lb/h solids 99.9% reject	HGI FCC Costing Sheet
S-202	Secondary Cyclone	SEPARATOR	CYCLONE	105	930	CS	21,341 ACFM gas prod 720 lb/h solids 99.9% reject	HGI FCC Costing Sheet
S-203	Char Combustor Primary Cyclone	SEPARATOR	CYCLONE	105	1200	CS	20,000 ACFM gas prod 713,000 lb/h solids 99.9% reject	HGI FCC Costing Sheet
S-204	Char Combustor Secondary Cyclone	SEPARATOR	CYCLONE	105	1200	CS	20,000 ACFM gas prod 720 lb/h solids 99.9% reject	HGI FCC Costing Sheet
T-201	Catalyst steam stripper	VESEL	PRESSURE STORAGE	105	650	CS	1 min cat res. time 3 lb steam/1000 lb catalyst	HGI FCC Costing Sheet
T-202	Depleted catalyst and ash storage bin	MISC	ROLL-OFF DISPOSAL	0	300	CS		HGI FCC Costing Sheet
T-207	Catalyst feed bin	VESEL	PRESSURE STORAGE	105	650	CS		HGI FCC Costing Sheet
A201	Pinch Exchanger CAPEX							ACCE V7.2
<b>Area A201: In Situ Catalytic Fast Pyrolysis ↑</b>								
M-251	Hot Gas Filter package	SEPARATOR	FILTER	20	950		94500 ACFM 7400 lb/h solids	Pall Corporation
<b>Area A251: Hot Gas Filter ↑</b>								
C-262	Fines purge cooler	CONVEYOR	SCREW			CS		HGI FCC Costing Sheet
K-262	Regenerator air compressor	COMPRESSOR	CENTRIFUGAL			SS	Multi-stage oil-free 10,000 hp	Vendor quote via HGI
R-261	Catalytic Fluidized Bed Reactor	REACTOR	FLUIDIZED BED	105	930	Refractory	2,000 tpd biomass equiv 42,200 ACFM gas prod 5.0 lb media/lb	HGI FCC Costing Sheet
R-262	Catalyst Regenerator	REACTOR	FLUIDIZED BED	105	1200	Refractory	918,760 lb/h solids 10,200 ACFM gas prod	HGI FCC Costing Sheet
R-262C	Catalyst Cooler	HEAT EXCH	SOLIDS COOLER	105	1200	Refractory	272 MMBtu/h total for R-262C and R-262C-1	HGI FCC Costing Sheet
R-262C1	Catalyst cooler (secondary, included)	HEAT EXCH	SOLIDS COOLER	105	1200	Refractory	Cost included with R-262C	HGI FCC Costing Sheet
S-261	Primary Cyclone	SEPARATOR	CYCLONE	105	930	CS	42,200 ACFM gas prod 918,760 lb/h solids 99.9% reject	HGI FCC Costing Sheet
S-262	Secondary Cyclone	SEPARATOR	CYCLONE	105	930	CS	42,200 ACFM gas prod 920 lb/h solids 99.9% reject	HGI FCC Costing Sheet
S-263	Char Combustor Primary Cyclone	SEPARATOR	CYCLONE	105	1200	CS	18,000 ACFM gas prod 918,760 lb/h solids 99.9% reject	HGI FCC Costing Sheet
S-264	Char Combustor Secondary Cyclone	SEPARATOR	CYCLONE	105	1200	CS	18,000 ACFM gas prod 920 lb/h solids 99.9% reject	HGI FCC Costing Sheet
T-261	Catalyst steam stripper	VESEL	PRESSURE STORAGE	105	650	CS	1 min cat res. time 3 lb steam/1000 lb catalyst	HGI FCC Costing Sheet
T-262	Depleted catalyst and ash storage bin	MISC	ROLL-OFF DISPOSAL	0	300	CS		HGI FCC Costing Sheet
T-267	Catalyst feed bin	VESEL	PRESSURE STORAGE	105	650	CS		HGI FCC Costing Sheet
A261	Pinch Exchanger CAPEX							ACCE V7.2
R-261	VPU Fixed Bed Reactor	VESEL	VERTICAL PRESSURE	130	1000	CS+Inconel	17" ø 48' T-T +20% internals	ACCE V8.4
A261	Pinch Exchanger CAPEX							ACCE V7.2
<b>Area A261: Ex Situ Vapor Phase Upgrading ↑</b>								

Equip ID	Equipment Name	Equipment Category	Equipment Type	Design Pressure (psig)	Design Temp (F)	MOC	Sizing Information			Source/Reference	
D-301	Heavy Fraction Condenser Absorber	VESSEL	TRAYED TOWER	120	500	316SS	12' Ø	70' T-T	14 trays	sieve	ACCE V8.4
D-302	Light Fraction Condenser Absorber	VESSEL	TRAYED TOWER	100	120	316SS	13' Ø	70' T-T	20 trays	sieve	ACCE V8.4
H-313	D-301 Vapor ACHE	HEAT EXCH	AIR COOLED	130		316SS	15,000 sq ft	45' tubes	3 bays x 15'	2 fan/bay	ACCE V8.4
H-314	D-302 Feed Cooler	HEAT EXCH	SHELL & TUBE	150	190	316SS	5,000 sq ft	Shell 43" Ø	20' L	955 X 1" tubes	ACCE V8.4
H-315	D-302 Feed/overhead exchanger	HEAT EXCH	SHELL & TUBE	110		316SS	18,500 sq ft	Shell 42" Ø	23' L	884 X 1" tubes 4 shells	ACCE V8.4
H-316	D-302 Liquid feed chiller	HEAT EXCH	SHELL & TUBE	150	190	316SS	3,650 sq ft	Shell 36" Ø	20' L	698 X 1" tubes	ACCE V8.4
H-320	Heavy fraction ACHE	HEAT EXCH	AIR COOLED	130		316SS	70 sq ft	5' tubes	1 bays x 2'	2 fan/bay	ACCE V8.4
H-320A	Heavy fraction cooler	HEAT EXCH	SHELL & TUBE	2085	190	SS Clad CS	343 sq ft	Shell 14" Ø	16' L	82 X 1" tubes	H-463C
H-326	D-302 Quench circulation chiller	HEAT EXCH	PLATE & FRAME	200	200	316SS	7,500 sq ft			486 plates	ACCE V8.4
P-318	D-301 Bottoms pump	PUMP	CENTRIFUGAL	125	250	316SS	56 gpm			75' head	ACCE V8.4
P-323	Circulation filter charge pump	PUMP	CENTRIFUGAL	135	250	316SS	2655 gpm			69' head	ACCE V8.4
P-329	Aqueous filter charge pump	PUMP	CENTRIFUGAL	125	250	316SS	182 gpm			30' head	ACCE V8.4
P-331	Organic product pump	PUMP	CENTRIFUGAL	125	250	316SS	124 gpm			30' head	ACCE V8.4
P-332	Quench recycle pump	PUMP	CENTRIFUGAL	125	250	316SS	215 gpm			9' head	ACCE V8.4
S-319	D-301 Bottoms filter	FILTER	CARTRIDGE			316SS	52 gpm				ACCE V8.4
S-322	D-302 Bottoms decanter	VESSEL	HORIZ LL SEP	110	150	316SS	11' Ø	35' T-T		+20% internals	ACCE V8.4
S-324	Quench circulation filter	FILTER	TUBULAR			316SS	2340 gpm			60 Mesh	ACCE V8.4
S-329	Aqueous phase filter	FILTER	TUBULAR			316SS	182 gpm			400 Mesh	ACCE V8.4
T-328	Organic product surge tank	VESSEL	VERTICAL PRESSURE	125	250	316SS	5' Ø	14' T-T			ACCE V8.4
T-332	D-301 Circulation surge tank	VESSEL	VERTICAL PRESSURE	125	250	316SS	5' Ø	14' T-T			T-328
A310	Pinch exchanger CAPEX										ACCE V7.2
<b>Area A310: Product Condensation and Separation ↑</b>											
H-373	Post-WGS ACHE	HEAT EXCH	AIR COOLED	150		316SS	1252 sq ft	24' tubes	1 bays x 8'	2 fan/bay	ACCE V8.4
H-374	Post-WGS cooler	HEAT EXCH	SHELL & TUBE	150	140	316SS	1188 sq ft	Shell 21" Ø	20' L	227 X 1" tubes	ACCE V8.4
K-390	PSA compressor: multistage	COMPRESSOR	RECIPROCATING			SS	2-stage reciprocating			3648 hp	Vendor quote via HGI
M-385	PSA	MISC									Vendor quote via HGI
P-377	Compressor condensate pump	PUMP	CENTRIFUGAL	125	250	316SS	56 gpm			30' head	P-318
R-365	High-temperature WGS	VESSEL	VERTICAL PRESSURE	450	1000	316SS	12' Ø	24' T-T		+20% internals	ACCE V8.4
S-385	PSA Compressor suction KO	VESSEL	VERTICAL PRESSURE	135	150	316SS	5' Ø	7.5' T-T			ACCE V8.4
S-386	PSA Compr disch KO	VESSEL	VERTICAL PRESSURE	280	160	316SS	4' Ø	7' T-T			ACCE V8.4
T-377	Compressor condensate tank	VESSEL	VERTICAL PRESSURE	125	250	316SS	5' Ø	14' T-T			T-328
A360	Pinch exchanger CAPEX										ACCE V7.2
<b>Area A360: Hydrogen Recycle and WGS ↑</b>											
H-410	Feed-effluent exchanger	HEAT EXCH	SHELL & TUBE	1910	650	316SS	2636 sq ft	Shell 32" Ø	23' L	504 X 1" tubes	ACCE V8.4
H-411	Feed furnace	HEAT EXCH	BOX FURNACE	1930	650	316SS	2.21 MMBtu/h			208 CFM gas	ACCE V8.4
H-413A	HT product ACHE	HEAT EXCH	AIR COOLED	150		316SS	432 sq ft	14' tubes	1 bays x 4'	2 fan/bay	ACCE V8.4
H-413C	HT product cooler	HEAT EXCH	SHELL & TUBE	2085	190	316SS	589 sq ft	Shell 18" Ø	16' L	141 X 1" tubes	ACCE V8.4
H-444	Quench hydrogen stage 2 cooler	HEAT EXCH	SHELL & TUBE	1650	650	316SS	57 sq ft	Shell 8" Ø	8' L	29 X 1" tubes	ACCE V8.4
H-445	Quench hydrogen stage 3 cooler	HEAT EXCH	SHELL & TUBE	1650	650	316SS	57 sq ft	Shell 8" Ø	8' L	29 X 1" tubes	H-444
K-412	Hydrogen makeup compressor	COMPRESSOR	RECIPROCATING				1,050 hp			4-stage recip	Vendor quote via HGI
K-442	Hydrogen recycle compressor	COMPRESSOR	RECIPROCATING				146 hp			single stage recip	Vendor quote via HGI
P-410	HT feed pump	PUMP	DIAPHRAGM		90	316SS	135 gpm			5275' head	ACCE V8.4
R-410	Hydrotreater, 1000 psi	VESSEL	VERTICAL PRESSURE	1130	850	CS+Inconel	10' Ø	48' T-T		+60% internals	ACCE V8.4
R-410	Hydrotreater, 1500 psi	VESSEL	VERTICAL PRESSURE	1640	850	CS+Inconel	10' Ø	48' T-T		+60% internals	ACCE V8.4
R-410	Hydrotreater, 2000 psi	VESSEL	VERTICAL PRESSURE	2070	850	CS+Inconel	10' Ø	48' T-T		+60% internals	ACCE V8.4
S-410	Vapor KO drum	VESSEL	VERTICAL PRESSURE	120	250	316SS	4.5' Ø	10' T-T			ACCE V8.4
S-411	HP HT effluent flash: 3 phase	VESSEL	HORIZ LL SEP	2025	160	316SS	3' Ø	10' T-T		+20% internals	ACCE V8.4
S-412	LP HT effluent flash: 3 phase	VESSEL	HORIZ LL SEP	70	170	316SS	4' Ø	13' T-T		+10% internals	ACCE V8.4
A410	Pinch exchanger CAPEX										ACCE V7.2
<b>Area A410: Whole Oil Hydroprocessing ↑</b>											
D-450	Gasoline column	VESSEL	TRAYED TOWER	35	650	316SS	7.5' Ø	64' T-T	26 trays	sieve	ACCE V8.4
D-451	Diesel column	VESSEL	TRAYED TOWER	35	800	316SS	3.5' Ø	64' T-T	26 trays	sieve	ACCE V8.4
H-450C	D-450 Condenser (startup)	HEAT EXCH	SHELL & TUBE	60	250	316SS	821 sq ft	Shell 18" Ø	20' L	157 X 1" tubes	ACCE V8.4
H-450R	D-450 Reboiler (startup)	HEAT EXCH	SHELL & TUBE	60	250	316SS	980 sq ft	Shell 30" Ø	25' L	94 X 1" tubes	ACCE V8.4
H-451C	D-451 Condenser (startup)	HEAT EXCH	SHELL & TUBE	150	190	316SS	72 sq ft	Shell 18" Ø	20' L	28 X 1" tubes	ACCE V8.4
H-451R	D-451 Reboiler (startup)	HEAT EXCH	SHELL & TUBE	60	250	316SS	980 sq ft	Shell 30" Ø	25' L	94 X 1" tubes	H-450R
H-454	Gasoline product cooler	HEAT EXCH	SHELL & TUBE	150	250	CS	589 sq ft	Shell 18" Ø	16' L	141 X 1" tubes	ACCE V8.4
H-457A	Diesel product ACHE	HEAT EXCH	AIR COOLED	150		CS	41 sq ft	10' tubes	1 bays x 1'	2 fan/bay	ACCE V8.4
H-457C	Diesel Product Cooler	HEAT EXCH	SHELL & TUBE	150	250	CS	58 sq ft	Shell 8" Ø	8' L	28 X 1" tubes	ACCE V8.4
H-459	D-450 Overhead vapor cooler	HEAT EXCH	SHELL & TUBE	150	250	CS	12 sq ft	Shell 4" Ø	8' L	6 X 1" tubes	ACCE V8.4
P-450	D-450 Reflux pump	PUMP	CENTRIFUGAL	35	250	316SS	253 gpm			225' head	ACCE V8.4
P-451	D-451 Reflux pump	PUMP	CENTRIFUGAL	35	250	316SS	108 gpm			225' head	ACCE V8.4
S-450	D-450 Overhead accumulator	VESSEL	HORIZ PRESSURE	35	250	316SS	4.5' Ø	13.5' T-T			ACCE V8.4
S-451	D-451 Overhead accumulator	VESSEL	HORIZ PRESSURE	35	400	316SS	3.5' Ø	10.5' T-T			ACCE V8.4
A450	Pinch exchanger CAPEX										ACCE V7.2
<b>Area A450: Oil Fractionation ↑</b>											

Equip ID	Equipment Name	Equipment Category	Equipment Type	Design Pressure (psig)	Design Temp (F)	MOC	Sizing Information				Source/Reference		
H-460	Feed-effluent exchanger	HEAT EXCH	SHELL & TUBE	2390	650	CS	276 sq ft	Shell 14"Ø	18' L	66 X 1" tubes	ACCE V8.4		
H-461	Feed furnace	HEAT EXCH	BOX FURNACE	2100	750	316SS	0.68 MMBtu/h			48 CFM gas	ACCE V8.4		
H-463A	HC product ACHE	HEAT EXCH	AIR COOLED	150		CS	243 sq ft	10' tubes	1 bays x 3'	2 fan/bay	ACCE V8.4		
H-463C	HC product Cooler	HEAT EXCH	SHELL & TUBE	2085	190	SS Clad CS	343 sq ft	Shell 14"Ø	16' L	82 X 1" tubes	ACCE V8.4		
H-494	Quench hydrogen stage 2 cooler	HEAT EXCH	SHELL & TUBE	1650	650	316SS	57 sq ft	Shell 8"Ø	8' L	29 X 1" tubes	H-444		
H-495	Quench hydrogen stage 3 cooler	HEAT EXCH	SHELL & TUBE	1650	650	316SS	57 sq ft	Shell 8"Ø	8' L	29 X 1" tubes	H-444		
K-462	Hydrogen makeup compressor	COMPRESSOR	RECIPROCATING				1,050 hp			4-stage recip	Vendor quote via HGI		
K-492	Hydrogen recycle compressor	COMPRESSOR	RECIPROCATING				146 hp			single stage recip	Vendor quote via HGI		
P-460	HC feed pump	PUMP	DIAPHRAGM		90	316SS	135 gpm			5275' head	P-410		
R-460	Hydrocracker	VESSEL	VERTICAL PRESSURE	2070	850	CS+Inconel	6.5" Ø	48' T-T		+60% internals	ACCE V8.4		
S-460	Vapor KO drum	VESSEL	VERTICAL PRESSURE	120	250	316SS	4.5' Ø	10' T-T			S-410		
S-461	HP effluent flash: 3 phase	VESSEL	HORIZ LL SEP	2025	160	316SS	3' Ø	10' T-T		+20% internals	ACCE V8.4		
S-462	LP effluent flash	VESSEL	HORIZ LL SEP	70	170	316SS	1' Ø	7' T-T			ACCE V8.4		
A460	Pinch exchanger CAPEX										ACCE V7.2		
<b>Area A460: Hydrocracking ↑</b>													
H-568A	WGS Effluent ACHE	HEAT EXCH	AIR COOLED	150		CS	1392 sq ft	24' tubes	1 bays x 8'	2 fan/bay	ACCE V8.4		
H-568C	WGS Effluent cooler	HEAT EXCH	SHELL & TUBE	60	250	CS	1281 sq ft	Shell 22"Ø	20' L	245 X 1" tubes	ACCE V8.4		
K-511	Pyrolysis offgas compressor to reformer	COMPRESSOR	RECIPROCATING			SS				2-stage reciprocating	3648 hp	K-211	
K-545	Reformer combustor air blower	INCLUDED											
K-580	PSA Compressor multistage	INCLUDED											
M-575	PSA	INCLUDED											
P-576	Compressor condensate pump	PUMP	CENTRIFUGAL	125	250	316SS	56 gpm			30' head		P-318	
R-530	Steam reformer package (PNNL)	MISC	PACKAGE UNIT									23053	
R-565	WGS reactor	INCLUDED											
R-566	LTS reactor	VESSEL	VERTICAL PRESSURE	450	1000	316SS	12' Ø	24' T-T		+20% internals		R-365	
S-575	Compressor suction KO drum	INCLUDED											
S-586	PSA Compressor discharge KO drum	INCLUDED											
T-576	Compressor condensate tank	VESSEL	VERTICAL PRESSURE	125	250	316SS	4.5' Ø	14' T-T				T-328	
A500	Pinch exchanger CAPEX											ACCE V7.2	
<b>Area A500: Hydrogen Plant ↑</b>													
H-601	Steam turbine condenser	HEAT EXCH	AIR COOLED				58.25 MMBtu/h per module					SPX Cooling	
H-603	Blowdown cooler	HEAT EXCH	Shell and tube	50		CS	0.4 MMBtu/Hr; LMTD = 15 F; U = 100 Btu/hr-ft <sup>2</sup> -F; Area = 265 Ft <sup>2</sup> ; U-Tube					51400 Icarus 2006.5	
M-601	BFW EDI+polishing	MISC	PACKAGE UNIT									Quote from 51400 (RO+EDI+polish) with RO removed	51400 Siemens
M-602A	Steam turbine generator Stage 1	GENERATOR	STEAM-TURBINE			CS						Vendor quotation for 30.14 MW system. Excludes steam turbine condenser.	Shin Nippon
M-602B	Steam turbine generator Stage 2	GENERATOR	STEAM-TURBINE			CS						Vendor quotation for 30.14 MW system. Excludes steam turbine condenser.	Shin Nippon
M-603	Startup boiler	MISC	PACKAGE UNIT			CS						40,000 lb/h (half of A800 steam at 2,000 TPD)	ACCE V8.4
P-601	Makeup pump	PUMP	CENTRIFUGAL			CS	160 gpm			35' head		51400 Icarus 2006.5	
P-602	Condensate pump	PUMP	CENTRIFUGAL			CS	500 gpm			60' head		51400 Icarus 2006.5	
P-603	EDI pump	PUMP	CENTRIFUGAL			CS	500 gpm			60' head		51400 Icarus 2006.5	
P-604	Boiler feed water pump	PUMP	POS-DISPLACEMENT			CS	1050 gpm			3340' head		51400 Icarus 2006.5	
P-605	Condensate collection pump	PUMP	CENTRIFUGAL			CS	500 gpm			60' head		P-603	
S-601	Blowdown flash drum	VESSEL	VERTICAL PRESSURE	1500		CS				Liquid 30 gpm; 10 Minute Residence Time; Vessel Volume = 900 gal		51400 Icarus 2006.5	
T-601	Condensate collection tank	VESSEL	VERTICAL PRESSURE			CS				Liquid 1,000 gpm; 5 minute Residence Time; Liquid Volume = 5,000 gal		51400 Icarus 2006.5	
T-602	Condensate surge tank	TANK	HORIZONTAL-VESSEL			CS				Liquid 1,000 gpm; 5 minute Residence Time; Liquid Volume = 5,000 gal		51400 Icarus 2006.5	
T-603	Deaerator	TANK	HORIZONTAL-VESSEL	50		CS				Liquid 1,050 gpm; 10 Minute Residence Time; Vessel Volume = 21,000 gal		51400 Icarus 2006.5	
T-603A	Deaerator packed column	COLUMN	PACKED COLUMN			CS				Inside Diameter = 2 ft; Height = 10 ft; Packing Height = 8 ft		51400 Icarus 2006.5	
T-605	Steam drum	TANK	HORIZONTAL-VESSEL			CS				Horizontal Drum; < 100% of Critical Velocity; Diameter = 5' T-T Length = 20'		51400 Icarus 2006.5	
T-606	Steam turbine condensate tank	VESSEL	VERTICAL PRESSURE			CS				Liquid 1,000 gpm; 5 minute Residence Time; Liquid Volume = 5,000 gal		T-601	
A600	Pinch exchanger CAPEX											ACCE V7.2	
<b>Area A600: Steam System &amp; Power Generation ↑</b>													



Equip ID	Equipment Name	Equipment Category	Equipment Type	Design Pressure (psig)	Design Temp (F)	MOC	Sizing Information	Source/Reference
K-701	Plant air compressor	COMPRESSOR	RECIPROCATING			CS	Flow Rate = 450 CFM; Outlet Pressure = 125 PSIG	51400 Icarus 2006.5
M-701	Cooling tower system	COOLNG TWR	INDUCED-DRAFT			FIBERGLASS	15,000 gpm, 110°F Cooling Tower Inlet Temperature	Cooling Tower Depot
M-702	Hydraulic truck dump with scale	SCALE	TRUCK-SCALE			CS	Hydraulic Truck Dumper with Scale	Vendor Quotation
M-703	Flue gas scrubber	MISC	VERTICAL-VESSEL			SS304	Scrubber costs from TurboSonic. Quotation basis = \$160,000/ACFM	TurboSonic
M-704	Flue gas stack	MISC	MISC			CS	Base Diameter = 72 inches; Stack Height = 200 ft	51400 Icarus 2006.5
M-708	Chilled water system	CHILLER	CENTRIFUGAL			CS	2,350 Ton	Trane
M-710	Product loading rack	MISC	MISC					Estimate
P-701	Cooling water pump	PUMP	CENTRIFUGAL			CS	18620 gpm 185' head	51400 Icarus 2006.5
P-702	Firewater pump	PUMP	CENTRIFUGAL			CS	2500 gpm 120' head	51400 Icarus 2006.5
P-703	Diesel pump	PUMP	CENTRIFUGAL			CS	5 gpm 150' head	51400 Icarus 2006.5
P-704	Ammonia pump	PUMP	CENTRIFUGAL			CS	1 gpm 150' head	51400 Icarus 2006.5
P-705	Caustic pump	PUMP	CENTRIFUGAL			CS	0.5 gpm 10' head	51400 Icarus 2006.5
P-707	BFW chemical pump	PUMP	CENTRIFUGAL			CS	1 gpm 150' head	51400 Icarus 2006.5
P-708	Flue gas scrubber circulation pump	PUMP	CENTRIFUGAL			CS	1010 gpm 60' head	51400 Icarus 2006.5
P-790	Gasoline product pump	PUMP	CENTRIFUGAL	35	250	316SS	108 gpm 225' head	P-450
P-792	Diesel product pump	PUMP	CENTRIFUGAL	35	250	316SS	108 gpm 225' head	P-450
S-701	Instrument air dryer	DRYER	PACKAGE UNIT			CS	400 SCFM Dewpt -40F	Richardson (51400)
T-701	Plant air receiver	TANK	VERTICAL-VESSEL	200		CS	1000 gal	51400 Icarus 2006.5
T-702	Firewater storage tank	TANK	FLAT-BTM-STORAGE	0.5		CS	600,000 gal flat roof	51400 Icarus 2006.5
T-703	Purchased diesel storage tank	TANK	FLAT-BTM-STORAGE	0.5		CS	12,000 gal floating roof	51400 Icarus 2006.5
T-704	Ammonia storage tank	TANK	HORIZ-STORAGE	350		CS	560 gal	51400 Icarus 2006.5
T-705	Caustic storage tank	TANK	FLAT-BTM-STORAGE	0.5		CS	5,400 gal flat roof	51400 Icarus 2006.5
T-708	BFW chemical storage tank	TANK	HORIZ-STORAGE	10		SS316	400 gal	51400 Icarus 2006.5
T-790	Gasoline product storage tanks	VESSEL	STORAGE	15	250	CS	47' Ø 40' H 500,000 gal	ACCE V8.4
T-792	Diesel product storage tank	VESSEL	STORAGE	15	250	CS	47' Ø 40' H 500,000 gal	T-790
<b>Area A700: Cooling Water &amp; Other Utilities ↑</b>								
H-840	RTO Feed/Effluent exchanger	MISC	MISC				Included with RTO	
K-831	RTO blower	FAN	CENTRIFUGAL					
M-805	Clarifier	SEPARATOR	CLARIFIER				1.4 Ft / Hr Rise Rate; 40' Diameter x 12' Height	51400 M-705
M-806	Belt press	MISC	MISC					51400 M-706
M-807	Sand filter	MISC	MISC					51400 M-707
M-833	Aqueous regenerative thermal oxidizer	MISC	MISC			Refractory	\$100/SCFM	EPA Guideline
M-861	Reverse osmosis unit	MISC	MISC				15 gal/ft2/day	HGI 9/21/14
P-801	Clarifier overflow pump	PUMP	CENTRIFUGAL	35	250	CS	50 gpm 40' head	ACCE V8.4
P-809	Slurry pump	PUMP	CENTRIFUGAL	45		CS	2 gpm 10' head	51400 Icarus 2006.5
P-810	Boiler charge pump	PUMP	CENTRIFUGAL	170	250	CS	200 gpm 160' head	ACCE V8.4
P-812	Condensate Pump	PUMP	CENTRIFUGAL	155	400	CS	140 gpm 20' head	ACCE V8.4
P-814	Boiler charge pump	PUMP	CENTRIFUGAL	160	400	CS	145 gpm 5' head	ACCE V8.4
P-815	Boiler makeup pump	PUMP	CENTRIFUGAL	170	70	CS	5 gpm 400' head	ACCE V8.4
P-822	Concentrated waste water pump	PUMP	CENTRIFUGAL	150	400	304SS	7 gpm 20' head	ACCE V8.4
P-860	RO Feed pump	PUMP	CENTRIFUGAL	85	250	CS	185 gpm 170' head	ACCE V8.4
P-866	Clean water pump	PUMP	CENTRIFUGAL	40	250	CS	140 gpm 50' head	ACCE V8.4
T-801	Clarifier overflow tank	VESSEL	STORAGE	15	250	CS	17' Ø 32' H 50,000 gal	ACCE V8.4
T-809	Slurry tank	VESSEL	STORAGE	15	250	CS	17' Ø 32' H 50,000 gal	T-801
T-810	Boiler Feed Tank	VESSEL	VERTICAL PRESSURE	110	250	CS	5' Ø 15' T-T	ACCE V8.4
T-812	Steam drum	VESSEL	VERTICAL PRESSURE	160	410	CS	4.5' Ø 14' T-T	ACCE V8.4
T-814	Boiler feed tank	VESSEL	VERTICAL PRESSURE	160	400	CS	4.5' Ø 14' T-T	ACCE V8.4
T-822	Steam drum	VESSEL	VERTICAL PRESSURE	160	410	CS	4' Ø 12' T-T	ACCE V8.4
T-860	RO Feed tank	VESSEL	STORAGE	15	250	CS	21.5' Ø 9.5' H	ACCE V8.4
T-866	Clean water tank	VESSEL	STORAGE	15	250	CS	42' Ø 19' H	ACCE V8.4
A800	Pinch exchanger CAPEX							ACCE V7.2
<b>Area A800: Water Management ↑</b>								

NOTES ACCE Aspen Capital Cost Estimator  
HGI Harris Group  
51400 2011 NREL mixed alcohols report  
23053 2013 PNNL Pyrolysis report

## **Appendix B-1. Individual Equipment Cost Summary (*In Situ* Case)**







Equip ID	Required Spares	Equipment Name	Design Flow (per unit)	Design Flow (total)	Actual Flow (total)	Units	Size Ratio	Original Equip Cost (per unit)	Base Year	Total Orig Equip Cost (Req+Spare) in Base Year	Scaling Exp.	Scaled Cost in Base Year	Install Factor	Installed Cost in Base Year	Installed Cost in 2011\$	Scaled Uninstalled Cost in 2011\$
H-840	1	RTO Feed/Effluent exchanger						INCLUDED								
K-831	1	RTO blower		900	2,222	hp	2.47	\$360,420	2009	\$360,420	0.60	\$619,845	1.60	\$991,752	\$1,112,989	\$695,618
M-805	1	Clarifier		220	220			\$96,221	2007	\$96,221	0.65	\$96,221	2.41	\$232,300	\$258,961	\$107,264
M-806	1	Belt press		1	1			\$135,000	2010	\$135,000	0.65	\$135,000	2.47	\$333,450	\$354,578	\$143,554
M-807	1	Sand filter		265	265			\$120,400	2010	\$120,400	0.65	\$120,400	2.47	\$297,388	\$316,231	\$128,029
M-833	1	Aqueous regenerative thermal oxidizer		18,500	38,359	SCFM	2.07	\$1,850,000	2002	\$1,850,000	0.60	\$2,865,414	2.40	\$6,876,994	\$10,181,637	\$4,242,349
M-861	1	Reverse osmosis unit		197,000	66,679	lb/h	0.34	\$350,000	2012	\$350,000	0.70	\$163,958	1.15	\$188,552	\$188,907	\$164,267
P-801	1	Clarifier overflow pump		50	53	gpm	1.06	\$4,500	2013	\$9,000	0.80	\$9,394	4.38	\$41,126	\$42,460	\$9,699
P-809	1	Slurry pump		1	1			\$3,242	2007	\$3,242	0.80	\$3,242	3.10	\$10,050	\$11,204	\$3,614
P-810	1	Boiler charge pump		200	179	gpm	0.90	\$6,500	2013	\$13,000	0.80	\$11,912	4.14	\$49,298	\$50,897	\$12,298
P-812	1	Condensate Pump		140	127	gpm	0.91	\$5,100	2013	\$10,200	0.80	\$9,422	4.59	\$43,229	\$44,631	\$9,727
P-814	1	Boiler charge pump		145	128	gpm	0.88	\$5,100	2013	\$10,200	0.80	\$9,204	4.59	\$42,231	\$43,600	\$9,503
P-815	1	Boiler makeup pump		5	0	gpm	0.00	\$14,700	2013	\$29,400	0.80	\$0	1.84	\$0	\$0	\$0
P-822	1	Concentrated waste water pump		7	14	gpm	2.05	\$4,900	2013	\$9,800	0.80	\$17,375	4.31	\$74,821	\$77,248	\$17,939
P-860	1	RO Feed pump		185	160	gpm	0.87	\$6,400	2013	\$12,800	0.80	\$11,402	3.84	\$43,828	\$45,250	\$11,772
P-866	1	Clean water pump		140	120	gpm	0.86	\$5,200	2013	\$5,200	0.80	\$4,596	4.35	\$19,977	\$20,624	\$4,745
T-801	1	Clarifier overflow tank		1	1		1.00	\$85,800	2013	\$85,800	0.65	\$85,800	2.27	\$195,000	\$201,325	\$88,583
T-809	1	Slurry tank		1	1		1.00	\$85,800	2013	\$85,800	0.65	\$85,800	2.27	\$195,000	\$201,325	\$88,583
T-810	1	Boiler Feed Tank		200	179	gpm	0.90	\$24,600	2013	\$24,600	0.70	\$22,789	4.49	\$102,365	\$105,685	\$23,528
T-812	1	Steam drum		100,800	96,797	ACFH	0.96	\$24,400	2013	\$24,400	0.70	\$23,718	4.46	\$105,854	\$109,288	\$24,487
T-814	1	Boiler feed tank		145	128	gpm	0.88	\$24,400	2013	\$24,400	0.70	\$22,302	4.46	\$99,538	\$102,766	\$23,026
T-822	1	Steam drum		156,000	140,136	ACFH	0.90	\$19,400	2013	\$19,400	0.70	\$17,997	5.23	\$94,066	\$97,117	\$18,581
T-860	1	RO Feed tank		185	160	gpm	0.87	\$76,000	2013	\$76,000	0.70	\$68,687	2.24	\$153,643	\$158,626	\$70,915
T-866	1	Clean water tank		140	120	gpm	0.86	\$194,200	2013	\$194,200	0.70	\$194,200	2.23	\$434,000	\$448,077	\$200,499
A800	1	Pinch exchanger CAPEX							2008	\$1,111,734		\$1,111,734	2.64	\$2,929,827	\$2,982,272	\$1,131,635
<b>Area AB00: Water Management ↑</b>										<b>\$4,661,217</b>		<b>\$5,710,414</b>	<b>2.37</b>	<b>\$13,554,287</b>	<b>\$17,155,696</b>	<b>\$7,230,214</b>
<b>Plant Total</b>										<b>\$144,452,905</b>		<b>\$132,445,567</b>	<b>2.13</b>	<b>\$282,758,716</b>	<b>\$297,613,083</b>	<b>\$140,029,476</b>

## **Appendix B-2. Individual Equipment Cost Summary (*Ex Situ* Case)**

Equip ID	Required Spares	Switch	Equipment Name	Design Flow (per unit)	Design Flow (total)	Actual Flow (total)	Units	Size Ratio	Original Equip Cost (per unit)	Base Year	Total Orig Equip Cost (Req+Spare) in Base Year	Scaling Exp.	Scaled Cost in Base Year	Install Factor	Installed Cost in Base Year	Installed Cost in 2011\$	Scaled Uninstalled Cost in 2011\$	
C-101			Hopper Feeder						INCLUDED									
C-102			Screening Feeder Conveyor						INCLUDED									
C-103			Radial Stacker Conveyor						INCLUDED									
C-104			Dryer Feed Screw Conveyor						INCLUDED									
C-105			Biomass Feed Screw Conveyor						INCLUDED									
K-101	2	on	Flue Gas Blower	204	408	383	hp	0.94	\$59,300	2013	\$118,600	0.78	\$112,835	1.94	\$218,439	\$225,524	\$116,495	
M-101			Hydraulic Truck Dump with Scale						INCLUDED									
M-102			Hammermill						INCLUDED									
M-103			Front End Loaders						INCLUDED									
M-104	2	ON	Cross Flow Pellet Dryer	102,066	204,131	204,131	lb/h	1.00	\$50,000	2011	\$100,000	0.80	\$100,000	2.00	\$200,000	\$200,000	\$100,000	
S-101			Magnetic Head Pulley						INCLUDED									
S-102			Vibratory Conveyor						INCLUDED									
T-101			Dump Hopper						INCLUDED									
T-102			Hammermill surge bin						INCLUDED									
T-103			Dryer Feed Bin						INCLUDED									
T-104			Dried Biomass Hopper						INCLUDED									
T-105			Lock Hopper						INCLUDED									
T-106			Feed Hopper						INCLUDED									
A100	1	on	Pinch Exchanger CAPEX							2008	\$0		\$0	2.64	\$0	\$0	\$0	
<b>Area A100: Feed Handling &amp; Drying ↑</b>																		
												<b>\$218,600</b>		<b>\$212,835</b>	<b>1.97</b>	<b>\$418,440</b>	<b>\$425,525</b>	<b>\$216,495</b>
C-212	2	FP	Fines purge cooler						INCLUDED									
K-211	2	FP	Fluidizing gas recycle compressor	3,648	7,296	2,887	hp	0.40	\$4,700,000	2014	\$9,400,000	0.90	\$4,081,188	1.60	\$6,529,901	\$6,664,163	\$4,165,102	
K-212	2	FP	Combustor air compressor	10,000	20,000	13,584	hp	0.68	\$2,600,000	2014	\$5,200,000	0.78	\$3,845,515	1.60	\$6,152,824	\$6,279,333	\$3,924,583	
R-211	2	FP	Fluidized Bed Reactor	1,222,474	2,444,948	2,433,724	ACFH	1.00	\$3,449,500	2011	\$6,899,000	0.50	\$6,883,146	4.01	\$27,601,417	\$27,601,417	\$6,883,146	
R-212	2	FP	Char Combustor	719,240	1,438,480	1,429,542	ACFH	0.99	\$3,483,784	2011	\$6,967,568	0.50	\$6,945,888	3.97	\$27,569,756	\$27,569,756	\$6,945,888	
R-212C	2	FP	Sand Cooler	3,671,901	7,343,802	7,323,460	Btu/h	1.00	\$623,441	2011	\$1,246,882	0.80	\$1,244,118	3.00	\$3,732,355	\$3,732,355	\$1,244,118	
S-211	2	FP	Primary Cyclone						INCLUDED									
S-212	2	FP	Secondary Cyclone						INCLUDED									
S-213	2	FP	Char Combustor Primary Cyclone						INCLUDED									
S-214	2	FP	Char Combustor Secondary Cyclone						INCLUDED									
T-211	2	FP	Bed Media Bin						INCLUDED									
T-212	2	FP	Depleted bed media and ash storage bin						INCLUDED									
T-217	2	FP	Char combustor bed media feed bin						INCLUDED									
A211	1	FP	Pinch Exchanger CAPEX							2008	\$1,841,846		\$1,841,846	2.64	\$4,853,940	\$4,940,828	\$1,874,816	
<b>Area A211: Ex Situ Fast Pyrolysis ↑</b>																		
												<b>\$31,555,296</b>		<b>\$24,841,702</b>	<b>3.08</b>	<b>\$76,440,192</b>	<b>\$76,787,851</b>	<b>\$25,037,654</b>
C-262	1	VPU	Fines purge cooler						INCLUDED									
K-262	1	VPU	Regenerator air compressor	10,000	10,000	11,036	hp	1.10	\$2,600,000	2014	\$2,600,000	0.78	\$2,807,856	1.60	\$4,492,569	\$4,584,941	\$2,865,588	
R-261	1	VPU	Catalytic Fluidized Bed Reactor	2,534,057	2,534,057	2,526,198	lb/h	1.00	\$3,818,400	2011	\$3,818,400	0.50	\$3,812,474	3.97	\$15,132,548	\$15,132,548	\$3,812,474	
R-262	1	VPU	Catalyst Regenerator	1,084,318	1,084,318	1,088,654	ACFH	1.00	\$4,207,313	2011	\$4,207,313	0.50	\$4,215,716	3.93	\$16,561,186	\$16,561,186	\$4,215,716	
R-262C	1	VPU	Catalyst Cooler	272,000,000	272,000,000	240,298,657	Btu/h	0.88	\$3,968,900	2011	\$3,968,900	0.80	\$3,594,315	3.00	\$10,782,944	\$10,782,944	\$3,594,315	
R-262C1	1	VPU	Catalyst cooler (secondary, included)			147,367,743	Btu/h											
S-261	1	VPU	Primary Cyclone						INCLUDED									
S-262	1	VPU	Secondary Cyclone						INCLUDED									
S-263	1	VPU	Char Combustor Primary Cyclone						INCLUDED									
S-264	1	VPU	Char Combustor Secondary Cyclone						INCLUDED									
T-261	1	VPU	Catalyst steam stripper	2,756	2,756	2,756	lb/h	1.00	\$347,005	2011	\$347,005	0.30	\$346,999	3.00	\$1,040,997	\$1,040,997	\$346,999	
T-262	1	VPU	Depleted catalyst and ash storage bin						INCLUDED									
T-267	1	VPU	Catalyst feed bin						INCLUDED									
A261	1	VPU	Pinch Exchanger CAPEX							2008	\$764,272		\$764,272	2.64	\$2,014,136	\$2,050,190	\$777,953	
R-261	2	1	FBVPU VPU Fixed Bed Reactor	161,200	322,400		0 lb/h	0.00	\$3,841,800	2013	\$0	0.70	\$0	1.21	\$0	\$0	\$0	
A261	1	FBVPU	Pinch Exchanger CAPEX							2008	\$0		\$0	2.64	\$0	\$0	\$0	
<b>Area A261: Ex Situ Vapor Phase Upgrading ↑</b>																		
												<b>\$15,705,890</b>		<b>\$15,541,632</b>	<b>3.22</b>	<b>\$50,024,382</b>	<b>\$50,152,808</b>	<b>\$15,613,046</b>









## **Appendix C-1. Discounted Cash Flow Rate of Return and Operating Cost Summary (*In Situ* Case)**

Year	-2	-1	0	1	2	3	4	5	6	7	8	9	10
Fixed Capital Investment	\$18,248,867	\$124,791,506	\$66,555,470										
Working Capital		\$25,998,230											
Loan Payment			\$46,494,036	\$46,494,036	\$46,494,036	\$46,494,036	\$46,494,036	\$46,494,036	\$46,494,036	\$46,494,036	\$46,494,036	\$46,494,036	\$46,494,036
Loan Interest Payment	\$1,996,664	\$16,971,445	\$24,958,301	\$23,235,442	\$23,374,755	\$21,374,755	\$19,365,212	\$17,194,907	\$16,850,976	\$12,319,632	\$9,585,571	\$6,632,894	\$3,444,003
Loan Principal	\$24,958,301	\$121,215,560	\$311,978,765	\$290,443,030	\$267,184,437	\$242,065,155	\$214,936,332	\$185,637,203	\$163,994,144	\$119,819,640	\$82,911,175	\$43,050,033	\$0
Fuel Product Sales			\$140,774,123	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830
Byproduct Credit			\$11,770,680	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907
Total Annual Sales			\$142,544,803	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737
Annual Manufacturing Cost			\$50,695,237	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413
Raw Materials			\$7,433,882	\$2,996,198	\$2,996,198	\$2,996,198	\$2,996,198	\$2,996,198	\$2,996,198	\$2,996,198	\$2,996,198	\$2,996,198	\$2,996,198
Catalyst Costs			\$24,612,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001
Other Variable Costs			\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303
Fixed Operating Costs			\$108,147,424	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916
Total Product Cost			\$108,147,424	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916
Annual Depreciation			14.3%	24.5%	17.5%	12.5%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%
General Plant % Depreciation			14.3%	24.5%	17.5%	12.5%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%
General Plant Depreciation			\$58,755,822	\$100,694,896	\$71,913,178	\$51,354,808	\$36,717,249	\$36,717,249	\$36,717,249	\$36,717,249	\$36,717,249	\$36,717,249	\$36,717,249
General Plant Remaining			\$32,411,579	\$251,716,683	\$179,803,504	\$128,448,696	\$91,731,447	\$55,053,315	\$18,338,066	\$0	\$0	\$0	\$0
Steam Plant % Depreciation			3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	5.29%	5.29%	5.29%	5.29%	5.29%
Steam Plant Depreciation			\$4,079,895	\$7,854,070	\$7,264,300	\$6,720,403	\$6,215,584	\$5,749,930	\$5,318,007	\$4,919,810	\$4,534,531	\$4,153,443	\$3,772,355
Steam Plant Remaining			\$104,717,312	\$96,863,241	\$89,598,852	\$82,878,448	\$76,662,864	\$70,912,932	\$65,594,924	\$60,675,114	\$55,820,583	\$50,967,140	\$46,113,785
Total Depreciation			\$62,835,717	\$108,548,967	\$79,177,568	\$58,075,212	\$42,932,833	\$32,426,065	\$21,012,780	\$19,048,059	\$18,000,059	\$16,992,375	\$15,966,640
Net Revenue			\$53,396,639	\$53,396,639	\$53,396,639	\$53,396,639	\$53,396,639	\$53,396,639	\$53,396,639	\$53,396,639	\$53,396,639	\$53,396,639	\$53,396,639
Losses Forward													
Taxable Income													
Income Tax													
Annual Cash Income													
Discount Factor													
Annual Present Value													
Total Capital Investment + Interest													
Net Present Worth													

Year	11	12	13	14	15	16	17	18	19	20
Fixed Capital Investment										
Working Capital										
Loan Payment										
Loan Interest Payment										
Loan Principal										
Fuel Product Sales	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830
Byproduct Credit	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907
Total Annual Sales	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737
Annual Manufacturing Cost										
Raw Materials										
Catalyst Costs										
Other Variable Costs										
Fixed Operating Costs										
Total Product Cost										
Annual Depreciation										
General Plant % Depreciation										
General Plant Depreciation										
General Plant Remaining										
Steam Plant % Depreciation										
Steam Plant Depreciation										
Steam Plant Remaining										
Total Depreciation										
Net Revenue										
Losses Forward										
Taxable Income										
Income Tax										
Annual Cash Income										
Discount Factor										
Annual Present Value										
Total Capital Investment + Interest										
Net Present Worth										

Year	21	22	23	24	25	26	27	28	29	30
DCFROR Worksheet										
Fixed Capital Investment										
Working Capital										
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
Loan Principal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Fuel Product Sales	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830	\$187,698,830
Byproduct Credit	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907	\$2,360,907
Total Annual Sales	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737	\$190,059,737
Annual Manufacturing Cost										
Raw Materials	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413
Catalyst Costs	\$5,185,172	\$298,198	\$5,185,172	\$298,198	\$5,185,172	\$298,198	\$5,185,172	\$298,198	\$5,185,172	\$298,198
Other Variable Costs	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001	\$28,128,001
Fixed Operating Costs	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303	\$25,406,303
Total Product Cost	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916	\$111,769,916
Annual Depreciation										
General Plant % Depreciation										
General Plant Remaining										
Steam Plant % Depreciation	2.23%									
Steam Plant Remaining	\$2,427,266									
Total Depreciation	\$2,427,266									
Net Present Value	\$70,975,582	\$78,289,821	\$73,402,847	\$78,289,821	\$73,402,847	\$78,289,821	\$73,402,847	\$78,289,821	\$73,402,847	\$78,289,821
Use Forward	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
taxable Income	\$70,975,582	\$78,289,821	\$73,402,847	\$78,289,821	\$73,402,847	\$78,289,821	\$73,402,847	\$78,289,821	\$73,402,847	\$78,289,821
Income Tax	\$24,841,454	\$27,401,437	\$25,690,997	\$27,401,437	\$25,690,997	\$27,401,437	\$25,690,997	\$27,401,437	\$25,690,997	\$27,401,437
Annual Cash Income	\$46,134,128	\$50,888,384	\$47,711,851	\$50,888,384	\$47,711,851	\$50,888,384	\$47,711,851	\$50,888,384	\$47,711,851	\$50,888,384
Discount Factor	0.155	0.123	0.112	0.102	0.092	0.084	0.076	0.069	0.065	0.057
Annual Present Value	\$6,562,129	\$8,251,453	\$5,328,372	\$5,166,474	\$4,403,613	\$4,269,813	\$3,639,349	\$3,528,771	\$3,007,727	\$2,916,340
Total Capital Investment + Interest										
Net Present Worth										

# Operating Cost Summary

In Situ

Raw Material	Scaling Flow		Quoted Price		Year of Price Quote	2011 Cost	2011 Cost (\$/h)	2011 Cost (MM\$/yr)	2011 Cost (¢/GGE)
<b>Variable Operating Costs</b>									
<b>Feedstock, Catalyst &amp; Chemicals</b>									
Feedstock - Wood Chips	102	US ton/h	\$ 72.00	/US ton	2011	\$ 72.00	7,348.73	57.937	106.88
Sand Makeup	-	lb/h	\$ 0.21	/lb	2011	\$ 0.21	-	-	-
VPU Zeolite Catalyst	-	lb/h	\$ 9.75	/lb	2011	\$ 9.75	-	-	-
CFP Zeolite Catalyst	344	lb/h	\$ 9.75	/lb	2011	\$ 9.75	3,358.11	26.475	48.84
Natural Gas to SMR	54	lb/h	\$ 0.12	/lb	2011	\$ 0.12	6.40	0.050	0.09
50 wt% Caustic	291	lb/h	\$ 0.08	/lb	2010	\$ 0.08	23.27	0.183	0.34
Boiler Chemicals	7,067	lb/h blowdn	\$ 75.00	/MM lb	2014	\$ 66.73	0.47	0.004	0.01
Cooling Tower Chemicals	4,627	ton cool	\$ 33.84	/ton cool/yr	2014	\$ 30.11	17.67	0.139	0.26
Regeneration Gas: FP	-	lb/h	\$ 0.12	/lb	2011	\$ 0.12	-	-	-
Regeneration Gas: CFP	0	lb/h	\$ 0.12	/lb	2011	\$ 0.12	0.00	0.000	0.00
Regeneration Gas: VPU	-	lb/h	\$ 0.12	/lb	2011	\$ 0.12	-	-	-
Net Water Makeup	43,242	lb/h	\$ 0.20	/ton	2001	\$ 0.31	6.79	0.054	0.10
Diesel Fuel	71	lb/h	\$ 0.40	/lb	2011	\$ 0.40	28.56	0.225	0.42
<b>Subtotal</b>							<b>10,790.01</b>	<b>85.068</b>	<b>156.93</b>
<b>Waste Streams</b>									
FP Purge	-	lb/h	\$ 0.016	/lb	1998	\$ 0.027	-	-	-
CFP Purge	2,512	lb/h	\$ 0.016	/lb	1998	\$ 0.027	68.77	0.542	1.00
VPU Purge	-	lb/h	\$ 0.016	/lb	1998	\$ 0.027	-	-	-
Quench Filter Solids	43	lb/h	\$ 0.016	/lb	1998	\$ 0.027	1.16	0.009	0.02
WWT Cost	21,410	lb/h	\$ 0.003	/lb	2011	\$ 0.003	56.52	0.446	0.82
<b>Subtotal</b>							<b>126.46</b>	<b>0.997</b>	<b>1.84</b>
<b>Coproduct Credits</b>									
Electricity	5,117	kW	\$ 0.0585	/kWh	2011	\$ 0.059	(299)	(2.36)	(4.36)
<b>Subtotal</b>							<b>(299.46)</b>	<b>(2.36)</b>	<b>(4.36)</b>
<b>Total Variable Operating Costs</b>							<b>10,617.01</b>	<b>83.705</b>	<b>154.41</b>
<b>Fixed Operating Costs</b>									
	<b>2007 Salary</b>	<b># Positions</b>	<b>2011 Cost</b>	<b>2011 Hourly Wage</b>					
Plant Manager	\$ 147,000	1	\$ 161,362	\$ 70.67					
Plant Engineer	\$ 70,000	1	\$ 76,839	\$ 33.65					
Maintenance Supr	\$ 57,000	1	\$ 62,569	\$ 27.40					
Lab Manager	\$ 56,000	1	\$ 61,471	\$ 26.92					
Shift Supervisor	\$ 48,000	5	\$ 263,448	\$ 23.08					
Lab Technician	\$ 40,000	2	\$ 87,816	\$ 19.23					
Maintenance Tech	\$ 40,000	16	\$ 702,527	\$ 19.23					
Shift Operators	\$ 48,000	20	\$ 1,053,790	\$ 23.08					
Yard Employees	\$ 28,000	12	\$ 368,827	\$ 13.46					
Clerks & Secretaries	\$ 36,000	3	\$ 118,551	\$ 17.31					
<b>Total Salaries</b>		<b>62</b>	<b>\$ 2,957,199</b>					<b>3.246</b>	<b>5.99</b>
				<b>Avg Salary (w/ Benefits)</b>					
Overhead and Benefits	Supervision = 90.0%		\$2,921,501	\$45.59 per Hour				2.922	5.39
Maintenance	% of FCI = 3.0%		\$15,598,938	\$94,818 per Year				15.599	28.78
Insurance & Taxes	% of FCI = 0.7%		\$3,639,752					3.640	6.71
<b>Total Fixed Operating Costs</b>							<b>25.406</b>	<b>46.87</b>	
<b>Total Operating Costs</b>								<b>109.111</b>	<b>201.28</b>
<b>Annual Capital Charge</b>								<b>91.514</b>	<b>168.82</b>

## **Appendix C-2. Discounted Cash Flow Rate of Return and Operating Cost Summary (*Ex Situ* Case)**





Year	21	22	23	24	25	26	27	28	29	30
Fixed Capital Investment										
Working Capital										
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
Loan Principal	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Fixed Product Sales	\$187,182,676	\$187,182,676	\$187,182,676	\$187,182,676	\$187,182,676	\$187,182,676	\$187,182,676	\$187,182,676	\$187,182,676	\$187,182,676
Byproduct Credit	\$1,476,631	\$1,476,631	\$1,476,631	\$1,476,631	\$1,476,631	\$1,476,631	\$1,476,631	\$1,476,631	\$1,476,631	\$1,476,631
Total Annual Sales	\$188,659,297	\$188,659,297	\$188,659,297	\$188,659,297	\$188,659,297	\$188,659,297	\$188,659,297	\$188,659,297	\$188,659,297	\$188,659,297
Annual Manufacturing Cost										
Raw Materials	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413	\$57,937,413
Catalyst Costs	\$5,325,566	\$72,994	\$5,325,566	\$72,994	\$5,325,566	\$72,994	\$5,325,566	\$72,994	\$5,325,566	\$72,994
Other Variable Costs	\$19,493,229	\$19,493,229	\$19,493,229	\$19,493,229	\$19,493,229	\$19,493,229	\$19,493,229	\$19,493,229	\$19,493,229	\$19,493,229
Fixed Operating Costs	\$26,945,046	\$26,945,046	\$26,945,046	\$26,945,046	\$26,945,046	\$26,945,046	\$26,945,046	\$26,945,046	\$26,945,046	\$26,945,046
Total Product Cost	\$109,701,254	\$104,648,642	\$109,701,254	\$104,648,642	\$109,701,254	\$104,648,642	\$109,701,254	\$104,648,642	\$109,701,254	\$104,648,642
Annual Depreciation										
General Plant % Depreciation										
General Plant Depreciation										
General Plant Remaining										
Steam Plant % Depreciation	2.23%									
Steam Plant Depreciation	\$2,365,083									
Steam Plant Remaining	\$0									
Total Depreciation	\$2,365,083									
Net Revenue	\$76,592,860	\$84,010,655	\$78,958,043	\$84,010,655	\$78,958,043	\$84,010,655	\$78,958,043	\$84,010,655	\$78,958,043	\$84,010,655
Losses Forward	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
Taxable Income	\$76,592,860	\$84,010,655	\$78,958,043	\$84,010,655	\$78,958,043	\$84,010,655	\$78,958,043	\$84,010,655	\$78,958,043	\$84,010,655
Income Tax	\$26,807,536	\$29,403,729	\$27,635,315	\$29,403,729	\$27,635,315	\$29,403,729	\$27,635,315	\$29,403,729	\$27,635,315	\$29,403,729
Annual Cash Income	\$52,150,507	\$54,606,926	\$51,322,728	\$54,606,926	\$51,322,728	\$54,606,926	\$51,322,728	\$54,606,926	\$51,322,728	\$54,606,926
Discount Factor	0.135	0.123	0.112	0.102	0.092	0.084	0.076	0.069	0.063	0.057
Annual Present Value	\$7,047,128	\$6,708,241	\$5,731,628	\$5,844,001	\$4,736,882	\$4,381,819	\$3,914,779	\$3,786,627	\$3,235,354	\$3,129,444
Total Capital Investment + Interest										
Net Present Worth										-\$1,701,354

**Operating Cost Summary**

**Ex Situ**

Raw Material	Scaling Flow		Quoted Price		Year of Price Quote	2011 Cost	2011 Cost (\$/h)	2011 Cost (MM\$/yr)	2011 Cost (¢/GGE)
<b>A200.A211.217P:MA</b>									
<b>Variable Operating Costs</b>									
<b>Feedstock, Catalyst &amp; Chemicals</b>									
Feedstock - Wood Chips	102	US ton/h	\$	72.00 /US ton	2011	\$ 72.00	7,348.73	57.937	102.60
Sand Makeup	158	lb/h	\$	0.21 /lb	2011	\$ 0.21	32.79	0.259	0.46
VPU Zeolite Catalyst	229	lb/h	\$	9.75 /lb	2011	\$ 9.75	2,229.26	17.576	31.12
CFP Zeolite Catalyst	-	lb/h	\$	9.75 /lb	2011	\$ 9.75	-	-	-
Natural Gas to SMR	125	lb/h	\$	0.12 /lb	2011	\$ 0.12	14.88	0.117	0.21
50 wt% Caustic	294	lb/h	\$	0.08 /lb	2010	\$ 0.08	23.54	0.186	0.33
Boiler Chemicals	6,475	lb/h blowdn	\$	75.00 /MM lb	2014	\$ 66.73	0.43	0.003	0.01
Cooling Tower Chemicals	4,694	ton cool	\$	33.84 /ton cool/yr	2014	\$ 30.11	17.93	0.141	0.25
Regeneration Gas: FP	0	lb/h	\$	0.12 /lb	2011	\$ 0.12	0.00	0.000	0.00
Regeneration Gas: CFP	-	lb/h	\$	0.12 /lb	2011	\$ 0.12	-	-	-
Regeneration Gas: VPU	0	lb/h	\$	0.12 /lb	2011	\$ 0.12	0.00	0.000	0.00
Net Water Makeup	41,495	lb/h	\$	0.20 /ton	2001	\$ 0.31	6.52	0.051	0.09
Diesel Fuel	71	lb/h	\$	0.40 /lb	2011	\$ 0.40	28.56	0.225	0.40
<b>Subtotal</b>							<b>9,702.64</b>	<b>76.496</b>	<b>135.46</b>
<b>Waste Streams</b>									
FP Purge	2,038	lb/h	\$	0.016 /lb	1998	\$ 0.027	55.78	0.440	0.78
CFP Purge	-	lb/h	\$	0.016 /lb	1998	\$ 0.027	-	-	-
VPU Purge	262	lb/h	\$	0.016 /lb	1998	\$ 0.027	7.17	0.056	0.10
Quench Filter Solids	36	lb/h	\$	0.016 /lb	1998	\$ 0.027	0.98	0.008	0.01
WWT Cost	20,708	lb/h	\$	0.003 /lb	2011	\$ 0.003	54.67	0.431	0.76
<b>Subtotal</b>							<b>118.59</b>	<b>0.935</b>	<b>1.66</b>
<b>Coproduct Credits</b>									
Electricity	3,201	kW	\$	0.0585 /kWh	2011	\$ 0.059	(187)	(1.48)	(2.61)
<b>Subtotal</b>							<b>(187.29)</b>	<b>(1.48)</b>	<b>(2.61)</b>
<b>Total Variable Operating Costs</b>							<b>9,633.94</b>	<b>75.954</b>	<b>134.50</b>
<b>Fixed Operating Costs</b>									
	<b>2007 Salary</b>	<b># Positions</b>		<b>2011 Cost</b>		<b>2011 Hourly Wage</b>			
Plant Manager	\$ 147,000	1	\$	161,362		\$ 70.67			
Plant Engineer	\$ 70,000	1	\$	76,839		\$ 33.65			
Maintenance Supr	\$ 57,000	1	\$	62,569		\$ 27.40			
Lab Manager	\$ 56,000	1	\$	61,471		\$ 26.92			
Shift Supervisor	\$ 48,000	5	\$	263,448		\$ 23.08			
Lab Technician	\$ 40,000	2	\$	87,816		\$ 19.23			
Maintenance Tech	\$ 40,000	16	\$	702,527		\$ 19.23			
Shift Operators	\$ 48,000	20	\$	1,053,790		\$ 23.08			
Yard Employees	\$ 28,000	12	\$	368,827		\$ 13.46			
Clerks & Secretaries	\$ 36,000	3	\$	118,551		\$ 17.31			
<b>Total Salaries</b>		<b>62</b>	<b>\$</b>	<b>2,957,199</b>				<b>3.246</b>	<b>5.75</b>
						<b>Avg Salary (w/ Benefits)</b>			
Overhead and Benefits	Labor & Supervision = 90.0%			\$2,921,501		\$45.59 per Hour		2.922	5.17
Maintenance	% of FCI = 3.0%			\$16,846,567		\$94,818 per Year		16.847	29.83
Insurance & Taxes	% of FCI = 0.7%			\$3,930,866				3.931	6.96
<b>Total Fixed Operating Costs</b>							<b>26.945</b>	<b>47.72</b>	
<b>Total Operating Costs</b>								<b>102.899</b>	<b>182.22</b>
<b>Annual Capital Charge</b>								<b>98.833</b>	<b>175.02</b>

# Appendix D-1. Process Parameter and Operating Summary (In Situ Case)

## Process Parameters and Operation Summary

## In Situ

FEEDSTOCK		VAPOR QUENCH		SEPARATION		FUEL PRODUCTION	
Biomass total	204,131 lb/h	<b>Heavy Fraction condenser-absorber</b>		<b>Gasoline column</b>		<b>Gasoline</b>	
Feed Moisture	10% wt	Temperature	348 °F	Feed from hydrotreater	45,023 lb/h	density	6.215 lb/gal (1)
Moisture flow	20,413 lb/h	Pressure	114 psia	Feed from hydrocracker	8,068 lb/h	Oxygen content	0.69% wt%
Dry feed rate	183,718 lb/h	Feed rate	329,131 lb/h	Gasoline range product	31,866 lb/h	production	31,866 lb/h
Feedstock %C	50.9% dry wt	Recycle liquid flow	86,730 lb/h	Light gases	547 lb/h	Gasoline range product	251.2 MMlb/yr
Feedstock %H	6.0% dry wt	Vapor product	396,315 lb/h	Bottoms to diesel column	20,678 lb/h	actual volume	123,060 gal/day
Feedstock %O	41.9% dry wt	Bottoms liquid flow	19,547 lb/h	<b>Diesel column</b>		40.4 MMgal/yr	
Feedstock %S	0.0% dry wt	<b>Light fraction condenser-absorber</b>		Feed from gasoline column	20,678 lb/h	55.8 gal/dry ton	
Feedstock %N	0.2% dry wt	Temperature	60 °F	Diesel-range product	11,845 lb/h	HHV (Aspen)	19,422 Btu/lb
Feedstock %Ash	0.9% dry wt	Pressure	101 psia	Bottoms to hydrocracker	8,833 lb/h	120,705 Btu/gal	
Specific LHV	7,989 Btu/lb	Recycle liquid flow	964,869 lb/h	<b>Overall hydroprocess efficiency</b>		HHV equiv volume	39.2 MMGGE/yr
Specific HHV	8,578 Btu/lb	Vapor product	199,763 lb/h	Carbon efficiency %	91%	54.2 GGE/dry ton	
<b>PYROLYSIS MAIN CFB</b>		Bottoms liquid flow	1,161,420 lb/h	Yield lb product/lb feed	84%	LHV (Aspen)	18,180 Btu/lb
<b>Reactor</b>		Mole % H <sub>2</sub> overhead	62%	Oxygen content in feed/product	10.5%, 0.5% wt%	112,988 Btu/gal	
Parallel trains (reactor+combustor)		<b>Total aqueous phase</b>		<b>HYDROTREATING RECYCLE COMPRESSOR</b>		LHV Vol Equip	39.3 MMGGE/yr
Biomass feed per train	1000 dry MT/day	Flow	77,273 lb/h	Inlet pressure	1793 psia	54.3 GGE/dry ton	
Biomass moisture	10% wt%	wt% carbon	2.6%	Outlet pressure	1900 psia	<b>Diesel</b>	
Temperature	500°C 932°F	% carbon loss to aq phase	2.1%	Inlet mass flow	27085 lb/h	density	6.982 lb/gal (1)
Pressure	121 psia 8.3 bar	<b>Total organic phase</b>		Inlet molecular weight	2	Oxygen content	0.00% wt%
Bed solids material	Catalyst (ZSM-5)	Flow	52,053 lb/h	Electrical consumption	176 kW	production	11,845 lb/h
Bed solids inventory	115 ton	wt% C	80%	<b>HYDROCRACKING RECYCLE COMPRESSOR</b>		93.4 MMlb/yr	
Catalyst makeup (% rxr inventory)	2.00%	wt% H	10%	Inlet pressure	1893 psia	actual volume	40,716 gal/day
Ratio of bed solids to dry biomass	6.8 w/w	wt% O	10%	Outlet pressure	2000 psia	13.4 MMgal/yr	
Number of cyclones per reactor	2	organic H/C	1.47	Inlet mass flow	5214 lb/h	18.5 gal/dry ton	
Stripping steam	3.0 lb/1000 lb cat	carbon eff to organic phs	44%	Inlet molecular weight	2	HHV (Aspen)	19,792 Btu/lb
Fluidizing gases to dry biomass	0.77 w/w	<b>HYDROGEN RECYCLE</b>		Inlet mass flow	5214 lb/h	138,185 Btu/gal	
H <sub>2</sub> partial pressure in fluidizing gas	86 psia 5.9 bar	Water gas shift		Inlet molecular weight	2	HHV equiv volume	14.86 MMGGE/yr
<b>Combustor/Regenerator</b>		Gas flow rate	48,356 lb/h	Electrical consumption	32 kW	20.5 GGE/dry ton	
Temperature	650°C 1202°F	Inlet temperature	464 °F	<b>HYDROTREATING MAKEUP COMPRESSOR</b>		LHV (Aspen)	18,477 Btu/lb
Pressure	117 psia 8.1 bar	Outlet temperature	663 °F	Inlet pressure	245 psia	129,006 Btu/gal	
Excess air (%)	20%	Pressure	88 psia	Outlet pressure	1795 psia	LHV Vol Equip	14.86 MMGGE/yr
Upstream solids temperature	650°C 1202°F	Steam flow rate	29,556 lb/h	Inlet mass flow	3865 lb/h	20.5 GGE/dry ton	
No. of cyclones per combustor	2	Temperature approach	35 °F	Inlet molecular weight	2	<b>Total</b>	
<b>VAPOR PHASE UPGRADING CFB</b>		Wastewater (condensate)	19,648 lb/h	Electrical consumption	1765 kW	production	43,711 lb/h
<b>Reactor</b>		<b>Pressure swing adsorption (PSA)</b>		<b>HYDROCRACKING MAKEUP COMPRESSOR</b>		actual volume	53.8 MMgal/yr
Parallel trains (reactor+combustor)	N/A	Inlet flow rate	58,265 lb/h	Inlet pressure	245 psia	163,776 gal/day	
Biomass feed per train	N/A dry MT/day	Inlet hydrogen mole %	67%	Outlet pressure	1995 psia	74.3 gal/dry ton	
Biomass moisture	10% wt%	Hydrogen recovery %	84%	Inlet mass flow	1068 lb/h	HHV equiv volume	54.1 MMGGE/yr
Temperature	N/A	Hydrogen purity %	99%	Inlet molecular weight	2	LHV equiv volume	54.2 MMGGE/yr
Pressure	N/A	Hydrogen product stream	5,462 lb/h	Electrical consumption	516 kW	% Gasoline	73%
Bed solids material	N/A	<b>HYDROPROCESSING</b>		<b>HYDROGEN PLANT</b>		% Diesel	27%
Bed solids inventory	N/A ton	<b>Hydrotreater</b>		Hydrogen production rate	29956483.7 MMscfd	<b>THEORETICAL PRODUCTION</b>	
Catalyst makeup (% rxr inventory)	N/A	Pressure	1,815 psia	Supplemental natural gas	54 lb/h	total HHV	1577 MMbtu/h
Ratio of bed solids to dry biomass	N/A w/w	Liquid feed	52,053 lb/h	Hydrogen outlet purity	99 mol%	HHV Theo. Volume	13,066 gge/h
Number of cyclones per reactor	2	Liquid feed C, H, O	80%, 10%, 10% wt%	Hydrogen outlet pressure	266 psia	HHV Theo. Yield	142 gal/ton
Stripping steam	N/A lb/1000 lb cat	Total H <sub>2</sub> feed (pure)	11,229 lb/h	<b>Hydrogen Balance</b>		<b>ENERGY EFFICIENCY</b>	
Fluidizing gases to dry biomass	N/A	H <sub>2</sub> purity	90% mol%	Pyrolysis Reactor Makeup	8,288 lb/h	LHV	HHV
H <sub>2</sub> partial pressure in fluidizing gas	N/A	Makeup H <sub>2</sub> (pure)	3,274 lb/h	Hydrotreating Makeup	3,865 lb/h	Inputs (MMBtu/h)	
<b>Combustor/Regenerator</b>		Product gas (HP flash)	28,548 lb/h	Hydrocracking Makeup	1,068 lb/h	Feedstock	1,468
Temperature	N/A	Product gas (HP flash) H <sub>2</sub>	87% mol%	Total consumed	13,221 lb/h	Natural Gas	1
Pressure	N/A	Purge gas (HP flash)	5,327 lb/h	Produced from recycle PSA	5,462 lb/h	Outputs (MMBtu/h)	
Excess air (%)	20%	Purge gas (LP flash)	870 lb/h	Produced from reformer	7,759 lb/h	Gasoline product	579
Upstream solids temperature	N/A	Aqueous phase product	4,696 lb/h	Total produced	13,221 lb/h	Diesel product	219
No. of cyclones per combustor	2	Organic phase product	45,023 lb/h	<b>STEAM SYSTEM</b>		Electricity product	17
<b>UPGRADED PRODUCT COMPOSITION</b>		Organic phase C,H,O	87%, 12%, 1% wt%	HP Turbine Brake Power	-17228 hp	Fuel/Biomass Effc.	54.4%
Hydrogen incorporated	1.3% wt% dry BM	<b>Hydrocracker</b>		IP Turbine Brake Power	-21952 hp	Fuel/(Biomass+NG)	54.3%
Gas	22.9% wt% dry BM	Liquid feed	8,833 lb/h	LP Turbine Brake Power	-25578 hp	(Fuel+Elec)/(Biomass+NG)	55.5%
Aqueous	28.7% wt% dry BM	Liquid feed C, H, O	88%, 11%, 1% wt%	<b>POWER SUMMARY (kW)</b>		<b>CARBON EFFICIENCY</b>	
Organic	28.3% wt% dry BM	Total H <sub>2</sub> feed (pure)	2,154 lb/h	Feed handling and drying	387	Fuel yield, mass basis	23.8% wt% dry BM
Coke	8.1% wt% dry BM	H <sub>2</sub> purity	90% mol%	Pyrolysis	22,619	Fuel/Biomass Effc.	40.4%
Char	12.0% wt% dry BM	Makeup H <sub>2</sub> (pure)	905 lb/h	Condensation & separation	3,500	Fuel/(Biomass+NG) Effc.	40.4%
Net Water	27.3% wt% dry BM	Product gas (HP flash)	5,487 lb/h	Hydroprocessing	2,951		
		Product gas (HP flash) H <sub>2</sub>	84% mol%	Hydrogen production	6,083		
		Purge gas (HP flash)	1,342 lb/h	Steam & power	48,291		
		Purge gas (LP flash)	412 lb/h	Cooling water & utilities	1,588		
		Aqueous phase product	80 lb/h	Wastewater management	1,798		
		Organic phase product	8,068 lb/h	Miscellaneous	3,925		
		Organic phase C,H,O	85%, 15%, 0% wt%	Balance to grid	5,117		
				Plant totals	48,291		
				Total Pinch Duty	848 MMBtu/h		

(1) From: [http://cta.ornl.gov/bedb/appendix\\_a/Lower\\_and\\_Higher\\_Heating\\_Values\\_of\\_Gas\\_Liquid\\_and\\_Solid\\_Fuels.pdf](http://cta.ornl.gov/bedb/appendix_a/Lower_and_Higher_Heating_Values_of_Gas_Liquid_and_Solid_Fuels.pdf)  
 Conventional gasoline 2,819 grams/gallon = 6.214831 lb/gal  
 US conventional diesel 3,167 grams/gallon = 6.98204 lb/gal

# Appendix D-2. Process Parameter and Operating Summary (Ex Situ Case)

Process Parameters and Operation Summary				Ex Situ			
<b>FEEDSTOCK</b>		<b>VAPOR QUENCH</b>		<b>SEPARATION</b>		<b>FUEL PRODUCTION</b>	
Biomass total	204,131 lb/h	<b>Heavy Fraction condenser-absorber</b>		<b>Gasoline column</b>		<b>Gasoline</b>	density 6.215 lb/gal (1)
Feed Moisture	10% wt	Temperature	358 °F	Feed from hydrotreater	46,446 lb/h	Oxygen content	0.78% wt%
Moisture flow	20,413 lb/h	Pressure	110 psia	Feed from hydrocracker	16,636 lb/h	production	20,408 lb/h
Dry feed rate	183,718 lb/h	Feed rate	310,342 lb/h	Gasoline range product	20,408 lb/h		160.9 MMB/yr
Feedstock %C	50.9% dry wt	Recycle liquid flow	81,043 lb/h	Light gases	1,281 lb/h	actual volume	78,809 gal/day
Feedstock %H	6.0% dry wt	Vapor product	371,714 lb/h	<b>Bottoms to diesel column</b>	41,393 lb/h		25.9 MMgal/yr
Feedstock %O	41.9% dry wt	<b>Bottoms liquid flow</b>	19,671 lb/h	<b>Diesel column</b>			35.7 gal/dry ton
Feedstock %S	0.0% dry wt	<b>Light fraction condenser-absorber</b>		Feed from gasoline column	41,393 lb/h	HHV (Aspen)	19,719 Btu/lb
Feedstock %N	0.2% dry wt	Temperature	60 °F	Diesel-range product	24,739 lb/h	HHV equiv volume	122,549 Btu/gal
Feedstock %Ash	0.9% dry wt	Pressure	97 psia	<b>Bottoms to hydrocracker</b>	16,654 lb/h		25.5 MMGGE/yr
Specific LHV	7,989 Btu/lb	Recycle liquid flow	901,601 lb/h	<b>Overall hydroprocess efficiency</b>			35.2 GGE/dry ton
Specific HHV	8,578 Btu/lb	Vapor product	182,444 lb/h	Carbon efficiency %	94%	LHV (Aspen)	18,386 Btu/lb
		Bottoms liquid flow	1,090,871 lb/h	Yield lb product/lb feed	90%		114,267 Btu/gal
<b>PYROLYSIS MAIN CFB</b>		Mole % H <sub>2</sub> overhead	68%	Oxygen content in feed/product	6.4%, 0.4% wt%	LHV Vol Equiv	25.5 MMGGE/yr
<b>Reactor</b>		<b>Total aqueous phase</b>		<b>HYDROTREATING RECYCLE COMPRESSOR</b>			35.2 GGE/dry ton
Parallel trains (reactor+combustor)	2	Flow	77,811 lb/h	Inlet pressure	1493 psia	<b>Diesel</b>	density 6.982 lb/gal (1)
Biomass feed per train	1000 dry MT/day	wt% carbon	1.6%	Outlet pressure	1600 psia	Oxygen content	0.00% wt%
Biomass moisture	10%	% carbon loss to aq phase	1.3%	Inlet mass flow	17528 lb/h	production	24,739 lb/h
Temperature	500°C 932°F	<b>Total organic phase</b>		Inlet molecular weight	2		195.0 MMB/yr
Pressure	121 psia 8.3 bar	Flow	50,051 lb/h	Electrical consumption	134 kW	actual volume	85,037 gal/day
Bed solids material	Sand	wt% C	83%	<b>HYDROCRACKING RECYCLE COMPRESSOR</b>			27.9 MMgal/yr
Bed solids inventory	120 ton	wt% H	11%	Inlet pressure	1893 psia		38.6 gal/dry ton
Catalyst makeup (% rxr inventory)	N/A	wt% O	6%	Outlet pressure	2000 psia	HHV (Aspen)	19,752 Btu/lb
Ratio of bed solids to dry biomass	7.0 w/w	organic H/C	1.57	Inlet mass flow	4819 lb/h	HHV equiv volume	137,910 Btu/gal
Number of cyclones per reactor	2	carbon eff to organic phs	44%	Inlet molecular weight	2		30.98 MMGGE/yr
Stripping steam	N/A lb/1000 lb cat	<b>HYDROGEN RECYCLE</b>		Electrical consumption	31 kW	HHV equiv volume	42.8 GGE/dry ton
Fluidizing gases to dry biomass	0.69 w/w	<b>Water gas shift</b>		<b>HYDROTREATING MAKEUP COMPRESSOR</b>		LHV (Aspen)	18,444 Btu/lb
H <sub>2</sub> partial pressure in fluidizing gas	93 psia 6.4 bar	Gas flow rate	51,621 lb/h	Inlet pressure	245 psia		53.8 MMgal/yr
<b>Combustor/Regenerator</b>		Inlet temperature	464 °F	Outlet pressure	1495 psia	LHV Vol Equiv	30.99 MMGGE/yr
Temperature	720°C 1328°F	Outlet temperature	637 °F	Inlet mass flow	2154 lb/h		42.8 GGE/dry ton
Pressure	117 psia 8.1 bar	Pressure	84 psia	Inlet molecular weight	2	<b>Total</b>	production 45,146 lb/h
Excess air (%)	20%	Steam flow rate	30,755 lb/h	Electrical consumption	888 kW		355.9 MMB/yr
Upstream solids temperature	720°C 1328°F	Temperature approach	35 °F	<b>HYDROCRACKING MAKEUP COMPRESSOR</b>		actual volume	53.8 MMgal/yr
No. of cyclones per combustor	2	Wastewater (condensate)	20,723 lb/h	Inlet pressure	245 psia		163,846 gal/day
<b>VAPOR PHASE UPGRADING CFB</b>		<b>Pressure swing adsorption (PSA)</b>		Outlet pressure	1995 psia		74.3 gal/dry ton
<b>Reactor</b>		Inlet flow rate	61,652 lb/h	Inlet mass flow	764 lb/h	HHV equiv volume	56.5 MMGGE/yr
Parallel trains (reactor+combustor)	1	Inlet hydrogen mole %	71%	Inlet molecular weight	2	LHV equiv volume	56.5 MMGGE/yr
Biomass feed per train	2000 dry MT/day	Hydrogen recovery %	84%	Electrical consumption	369 kW	% Gasoline	45%
Biomass moisture	10%	Hydrogen purity %	99%	<b>HYDROGEN PLANT</b>		% Diesel	55%
Temperature	500°C 932°F	Hydrogen product stream	7,032 lb/h	Hydrogen production rate	27420512.8 MMscfd	<b>THEORETICAL PRODUCTION</b>	
Pressure	119 psia 8.2 bar	<b>HYDROPROCESSING</b>		Supplemental natural gas	125 lb/h	total HHV	1579 MMBtu/h
Bed solids material	st (ZSM-5)	<b>Hydrotreater</b>		Hydrogen outlet purity	99 mol%	HHV Theo. Volume	12,882 gge/h
Bed solids inventory	77 ton	Pressure	1,515 psia	Hydrogen outlet pressure	266 psia	HHV Theo. Yield	140 gpl/ton
Catalyst makeup (% rxr inventory)	2.00%	Liquid feed	50,051 lb/h	<b>Hydrogen Balance</b>		<b>ENERGY EFFICIENCY</b>	
Ratio of bed solids to dry biomass	4.5 w/w	Total H <sub>2</sub> feed (pure)	7,249 lb/h	Pyrolysis Reactor Makeup	11,217 lb/h	LHV	HHV
Number of cyclones per reactor	2	H <sub>2</sub> purity	90% mol%	Hydrotreating Makeup	2,154 lb/h	Inputs (MMBtu/h)	
Stripping steam	3.0 lb/1000 lb cat	Makeup H <sub>2</sub> (pure)	1,825 lb/h	Hydrocracking Makeup	764 lb/h	Feedstock	1,468
Fluidizing gases to dry biomass	N/A	Product gas (HP flash)	17,435 lb/h	Total consumed	14,134 lb/h	Natural Gas	2
H <sub>2</sub> partial pressure in fluidizing gas	73 psia 5.1 bar	Product gas (HP flash) H <sub>2</sub>	87% mol%	Produced from recycle PSA	7,032 lb/h	Outputs (MMBtu/h)	
<b>Combustor/Regenerator</b>		Purge gas (HP flash)	2,061 lb/h	Produced from reformer	7,102 lb/h	Gasoline product	375
Temperature	650°C 1202°F	Purge gas (LP flash)	787 lb/h	Total produced	14,134 lb/h	Diesel product	456
Pressure	113 psia 7.8 bar	Aqueous phase product	2,912 lb/h	<b>STEAM SYSTEM</b>		Electricity product	11
Excess air (%)	20%	Organic phase product	46,446 lb/h	HP Turbine Brake Power	-15786 hp	Fuel/Biomass Eff. c.	56.7%
Upstream solids temperature	341°C 645°F	Organic phase C,H,O	87%, 13%, 1% wt%	IP Turbine Brake Power	-20114 hp	Fuel/(Biomass+NG)	56.4%
No. of cyclones per combustor	2	<b>HYDROCRACKER</b>		LP Turbine Brake Power	-23436 hp	(Fuel+Elec)/(Biomass+NG)	57.3%
<b>UPGRADED PRODUCT COMPOSITION</b>		Liquid feed	16,654 lb/h	<b>POWER SUMMARY (kW)</b>		<b>CARBON EFFICIENCY</b>	
Hydrogen incorporated	1.8% wt% dry BM	Total H <sub>2</sub> feed (pure)	2,109 lb/h	Feed handling and drying	298	Fuel yield, mass basis	24.6% wt% dry BM
Gas	23.0% wt% dry BM	H <sub>2</sub> purity	90% mol%	Pyrolysis	22,783	Fuel/Biomass Eff. c.	41.5%
Aqueous	29.7% wt% dry BM	Makeup H <sub>2</sub> (pure)	647 lb/h	Condensation & separation	3,914	Fuel/(Biomass+NG) Eff. c.	41.5%
Organic	27.2% wt% dry BM	Product gas (HP flash)	4,353 lb/h	Hydroprocessing	1,811		
Coke	8.0% wt% dry BM	Product gas (HP flash) H <sub>2</sub>	87% mol%	Hydrogen production	5,875		
Char	12.0% wt% dry BM	Purge gas (HP flash)	298 lb/h	Steam & power	44,247		
Net Water	28.9% wt% dry BM	Purge gas (LP flash)	356 lb/h	Cooling water & utilities	327		
		Aqueous phase product	129 lb/h	Wastewater management	846		
		Organic phase product	16,636 lb/h	Miscellaneous	3,731		
		Organic phase C,H,O	86%, 14%, 0% wt%	Balance to grid	3,201		
				Plant totals	44,247		
				HEAT INTEGRATION			
				Total Pinch Duty	816 MMBtu/h		

(1) From: [http://cta.ornl.gov/bedb/appendix\\_a/Lower\\_and\\_Higher\\_Heating\\_Values\\_of\\_Gas\\_Liquid\\_and\\_Solid\\_Fuels.pdf](http://cta.ornl.gov/bedb/appendix_a/Lower_and_Higher_Heating_Values_of_Gas_Liquid_and_Solid_Fuels.pdf)  
Conventional gasoline 2,819 grams/gallon = 6.214831 lb/gal  
US conventional diesel 3,167 grams/gallon = 6.98204 lb/gal

## Appendix E. Assumptions and Analysis for Full Life-Cycle GHG Emissions

To provide an initial estimate of life-cycle fuel GHGs associated with this conversion pathway, a preliminary life-cycle GHG analysis was performed for fuel produced via the *in situ* and *ex situ* catalytic pyrolysis pathways using the model 2017 blended feedstock (45% pulpwood, 32% wood residues, 3% switchgrass, and 20% construction and demolition waste). The data and sources used for each of the life-cycle stages are described in the following paragraphs, along with the results of the analysis.

### Feedstock Crop Establishment and Growing

For the production of the purpose-grown bioenergy crops, pulpwood and switchgrass, emissions calculations from the GREET 2014 model (GREET 2014) were aggregated and used in the SimaPro fuel life-cycle model. Poplar was used to represent pulpwood in the feedstock blend. Switchgrass and poplar farming emissions were taken from the “EtOH” worksheet in the GREET model. Information on the development of GREET crop production parameters from Wang et al. (2013) was used to subtract the harvesting energy (which is accounted for in the next stage) from the GREET model total farming energy values in order to calculate emissions for only the establishment and growing phase of farming operations. Table E-1 shows the total farming energy assumed in GREET (including harvesting) and the estimated energy value for establishment and growing operations (“Farming Energy Excluding Harvesting” in Table E-1) used in this analysis.

**Table E-1. Farming Energy Values from GREET and Modified for this Analysis**

	GREET Farming Energy (including harvesting), Btu/dry ton	Farming Energy Excluding Harvesting (estimated from GREET), Btu/dry ton
Switchgrass*	201,995 (92.8% diesel; 7.2% electricity)	56,870 (100% diesel)
Poplar	219,200 (100% diesel)	20,496 (100% diesel)

\*Values include 14% dry matter loss.

The overall emissions from crop establishment and growing operations including fertilizer and herbicide application for switchgrass and poplar estimated from the GREET model data are 107,434 g CO<sub>2</sub>-e/dry ton and 40,056 g CO<sub>2</sub>-e/dry ton, respectively. For the production of the remaining feedstocks, wood residues, and construction/demolition waste, it is assumed that these are strictly waste products. As such, their life cycle begins at the waste pile and they do not receive any energy or GHG burdens from the upstream processes from which they are generated.

### Feedstock Harvesting, Preprocessing, and Transportation

Jacobson et al. (2014) has estimated the GHG emissions associated with the logistics required for production of a conversion reactor-ready 2017 design case feedstock blend at 75.91 kg CO<sub>2</sub>-e/dry ton. This value includes energy and emissions associated with harvesting of purpose-grown crops (pulpwood, switchgrass), collection of waste (wood residues, construction and demolition waste), preprocessing and handling required at the landing, centralized feedstock processing

facility (depot) and the biorefinery, and transportation of biomass from the landing to the depot and from the depot to the biorefinery. About 70% of the feedstock logistics GHGs stems from preprocessing of the feedstock materials. The 2017 feedstock supply chain design incorporates several research advances that will significantly reduce energy use and cost compared to the current state of technology. More detail on the individual process steps and associated energy requirements for the feedstock supply system can be found in the recent design report published by INL (Jacobson et al. 2014). The aggregated value of 75.91 kg CO<sub>2</sub>-e/dry ton of conversion plant feedstock was used in the SimaPro model for calculation of the full fuel lifecycle emissions.

## Conversion

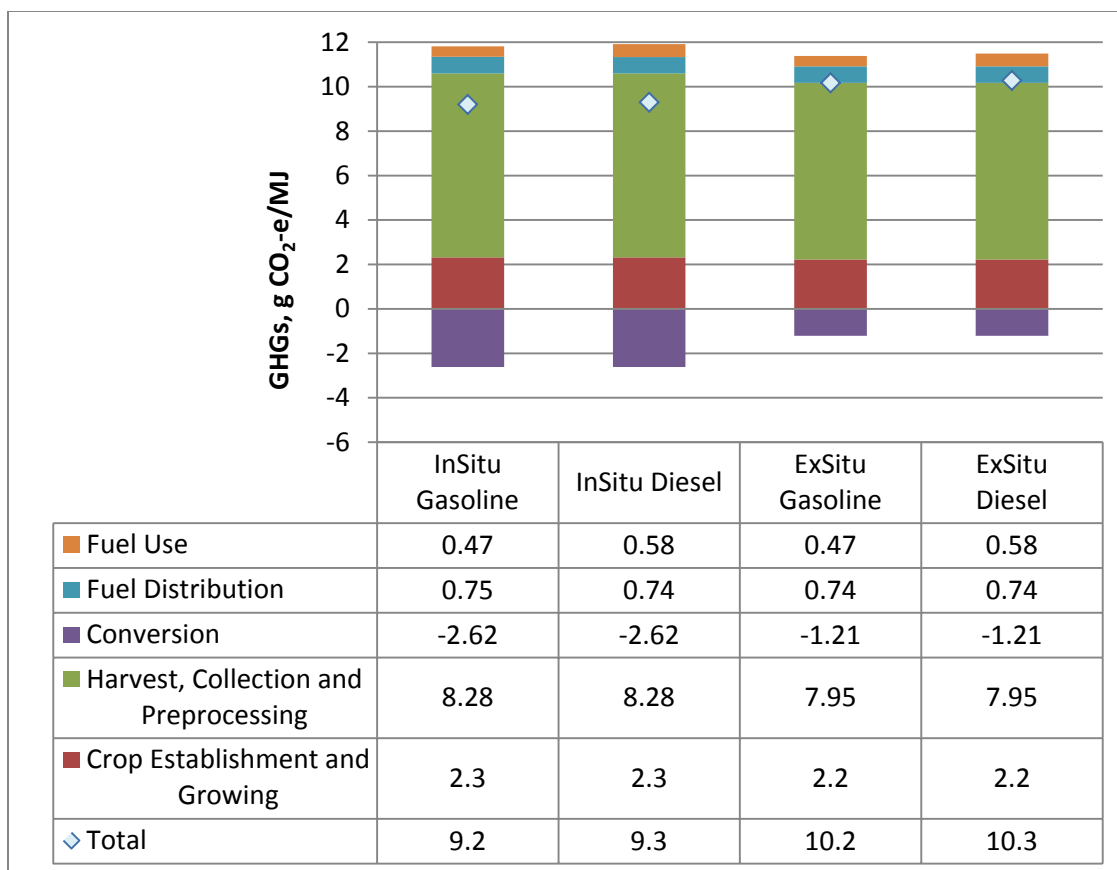
The inventory for the conversion stages of the life cycle are listed in Table 23 and Table 24. Assumptions for the conversion stage processes are given in Section 3.12.

## Fuel Distribution and Consumption

Emissions associated with fuel distribution to the end user (fuel transportation and operation of storage tanks and fueling stations) are modeled using an EcoInvent database (2010) process (“petrol, unleaded, at refinery/kg/RER/U”). Emissions of biogenic methane and N<sub>2</sub>O from combustion of gasoline and diesel fuel in a vehicle are adapted from GREET (2014).

## Life Cycle GHG Results

Figure E-1 shows the full life-cycle GHGs for gasoline and diesel fuel via the catalytic pyrolysis and upgrading pathways (including electricity credits). For the *in situ* case, emissions are estimated at 9.2 g CO<sub>2</sub>e/MJ for gasoline and 9.3 g CO<sub>2</sub>e/MJ for diesel. Relative to the 2005 petroleum baseline GHGs (93.08 g CO<sub>2</sub>e/MJ for gasoline and 91.94 g CO<sub>2</sub>e/MJ for diesel) (EPA 2010), this is a GHG reduction of 90% and 89% for gasoline and diesel, respectively. For the *ex situ* case, emissions are estimated at 10.2 g CO<sub>2</sub>e/MJ for gasoline and 10.3 g CO<sub>2</sub>e/MJ for diesel, corresponding to a GHG reduction of 89% for both fuels. This preliminary analysis suggests that these fuels would meet the Energy Independence and Security Act Renewable Fuel Standard cellulosic biofuel definition (60% GHG reduction); however, final qualification is made by the EPA based on their own analysis and determination. In addition, through collaboration with Argonne National Laboratory, conversion energy and materials inventory from this work will be integrated into the GREET model for more detailed analyses.



**Figure E-1. Life-cycle GHG emissions for fuels from catalytic pyrolysis using the INL 2017 blended feedstock (45% pulpwood, 32% wood residues, 3% switchgrass, and 20% construction and demolition waste) (Jacobson 2014)**

## Appendix E References

Ecoinvent, v.2.2. (2010). Duebendorf, Switzerland: Swiss Center for Life Cycle Inventories.

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U.S. EPA. (2010). “Fuel-Specific Lifecycle Greenhouse Gas Emissions Results.” Docket # EPA-HQ-OAR-2005-0161-3173. Washington, DC: U.S. Environmental Protection Agency. Accessed from: <http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2005-0161-3173>.

Wang, Z.; Dunn, J.; Han, J.; Wang, M. (2013). *Material and Energy Flows in the Production of Cellulosic Feedstocks for Biofuels for the GREET Model*. ANL/ESD-13/9. Chicago, IL: Argonne National Laboratory.



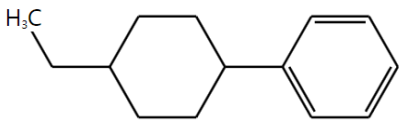
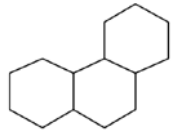
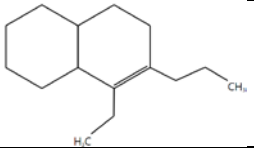
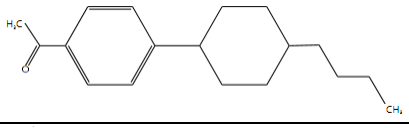
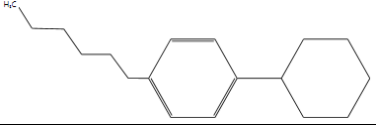
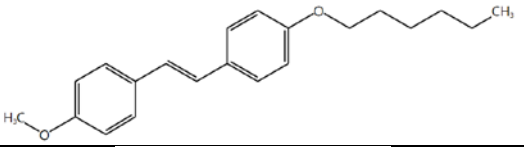
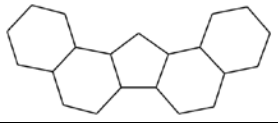
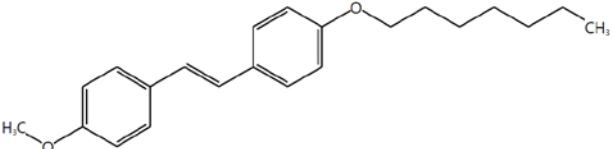
## Appendix F. Compounds in Aspen Plus Simulation

This appendix provides information about compounds selected to represent the process in Aspen Plus. Note that these are model compounds used to represent a much more numerous and varied set that actually occurs in systems such as these.

**Table F-1. Compounds in Aspen Plus Simulation**

Argon	1,2-Benzenediol	1-Naphthalenol
Nitrogen	Hydroxymethylfurfural	Coniferyl Aldehyde
Oxygen	2,5-dimethylfuran	Tetralin
SO <sub>2</sub>	Methyl Cyclopentenone	Isoeugenol
NO <sub>2</sub>	Hydroxymethylcyclopentenone	Decalin
Hydrogen	Cyclohexanone	2,5-Dimethyloctane
Ammonia	Levoglucosan	1-Methyl naphthalene
H <sub>2</sub> S	1-Hexanal	1-methyl decahydronaphthene
Water	Dimethoxytetrahydrofuran	Dibenzothiophene
Carbon Monoxide	Cyclohexane	Biphenyl
Carbon Dioxide	N-Hexane	5-hexyl-O-cresol
Methane	Hexanol	n-Heptylcyclohexane
Methanol	Toluene	C <sub>14</sub> H <sub>20</sub> -N <sub>35</sub>
Formic Acid	2-Methylphenol	C <sub>14</sub> H <sub>24</sub> -N <sub>5</sub>
Glyoxal	3-Methyl-phenol	3,5-Dimethyldodecane
Ethylene	Guaiacol	C <sub>15</sub> H <sub>26</sub> -N <sub>4</sub>
Acetaldehyde	Methyl-Cyclohexane	6,8-Dimethyltridecane
Hydroxyacetaldehyde	2-Methylhexane	1,4-Dimethyl-Phenanthrene
Acetic Acid	VinylPhenol	N-Cetane
Ethane	O-Xylene	C <sub>18</sub> H <sub>26</sub> O
Propylene	Ethylbenzene	C <sub>18</sub> H <sub>28</sub>
1-Hydroxy-2-propanone	2,3-Dimethyl-phenol	C <sub>21</sub> H <sub>26</sub> O <sub>2</sub>
Propionic Acid	2,6-dimethoxyphenol	C <sub>21</sub> H <sub>34</sub>
Propane	Vanillyl alcohol	C <sub>22</sub> H <sub>28</sub> O <sub>2</sub>
Furan	2,4,6-Trimethylpyridine	Carbon
1-Butene	Cis-1,2-dimethyl cyclohexane	Sulfur
Tetrahydrofuran	Trans-1,2-dimethylcyclohexane	Sand/Catalyst Solids
N-Butane	Ethylcyclohexane	Ash
Furfural	4-Methylheptane	Wood
2-methylfuran	2-Methyl-Benzofuran	Char
Furfuryl Alcohol	Indane	Coke
n-Pentane	2-methoxy-4-vinylphenol	
Pentenone	Syringaldehyde	
Benzene	n-Propylbenzene	
Phenol	Naphthalene	

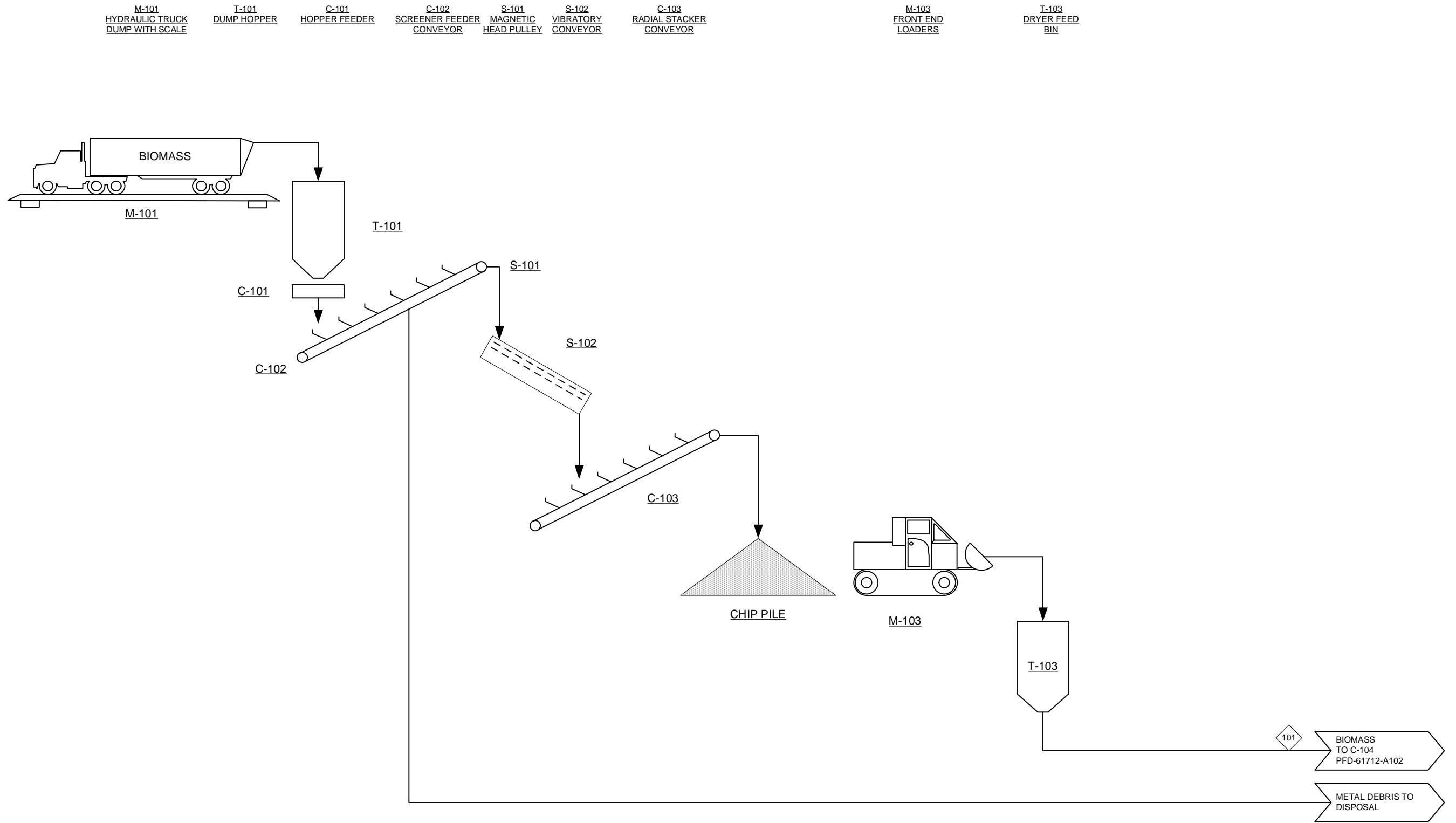
**Table F-2. Structures of Compounds Identified by Formula**

C14H20-N35	
C14H24-N5	
C15H26-N4	
C18H26O	
C18H28	
C21H26O2	
C21H34	
C22H28O2	

**Table F-3. Ultimate Analysis of Non-Conventional Components**

	Char	Coke
Ash	7.67	0
Carbon	69.07	96.06
Hydrogen	4.66	0
Nitrogen	1.24	0
Chlorine	0	0
Sulfur	0.19	0
Oxygen	17.16	3.94

## Appendix G-1. Process Flow Diagrams and Stream Summary for the *In Situ* Case



M-101 HYDRAULIC TRUCK DUMP WITH SCALE  
 T-101 DUMP HOPPER  
 C-101 HOPPER FEEDER  
 C-102 SCREENER FEEDER CONVEYOR  
 S-101 MAGNETIC HEAD PULLEY  
 S-102 VIBRATORY CONVEYOR  
 C-103 RADIAL STACKER CONVEYOR  
 M-103 FRONT END LOADERS  
 T-103 DRYER FEED BIN

BIOMASS  
 M-101

T-101

C-101

S-101

S-102

C-102

C-103

CHIP PILE

M-103

T-103

101

BIOMASS TO C-104 PFD-61712-A102

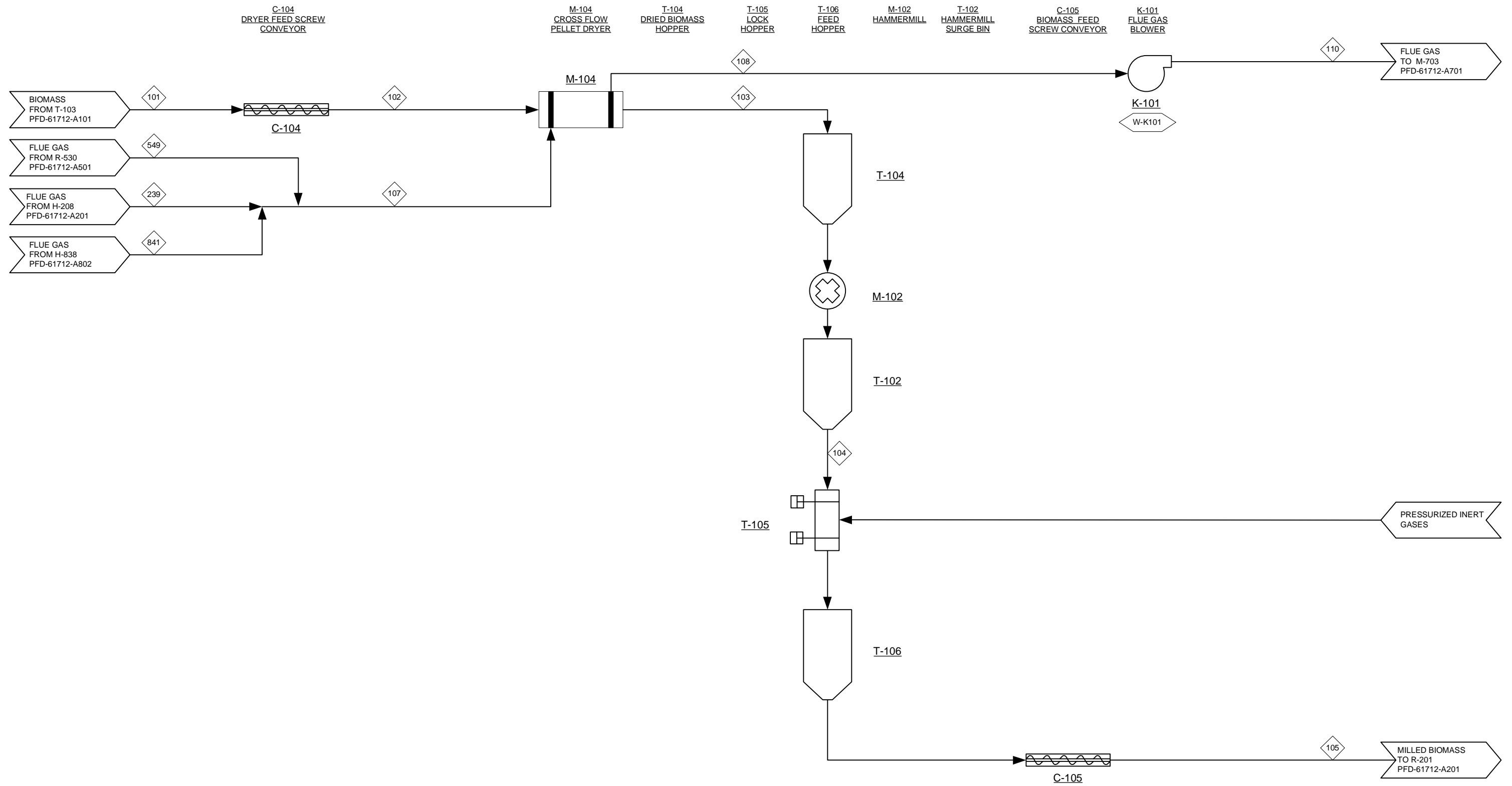
METAL DEBRIS TO DISPOSAL

NOTE: FEEDSTOCK HANDLING COSTS ARE INCLUDED IN THE TARGET FEEDSTOCK COST PROVIDED BY THE IDAHO NATIONAL LABORATORY. ONLY A CROSS FLOW DRYER USING PROCESS FLUE GASES FOR FEED PREHEAT IS INCLUDED IN THE CONVERSION COST.

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	PROCESS FLOW DIAGRAM AREA 100: FEED HANDLING														
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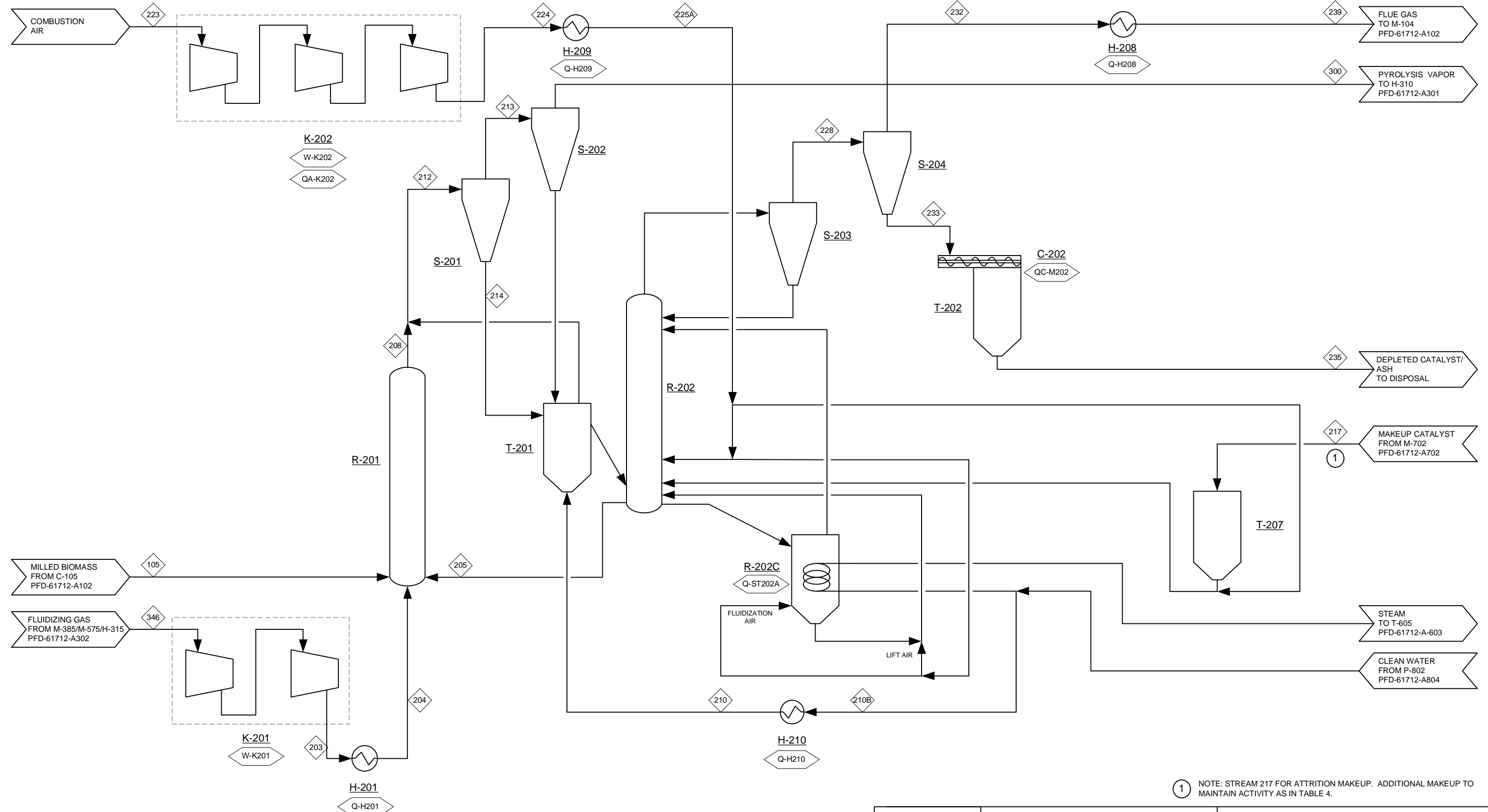


NOTE: FEEDSTOCK HANDLING COSTS ARE INCLUDED IN THE TARGET FEEDSTOCK COST PROVIDED BY THE IDAHO NATIONAL LABORATORY. ONLY A CROSS FLOW DRYER USING PROCESS FLUE GASES FOR FEED PREHEAT IS INCLUDED IN THE CONVERSION COST.

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	PROCESS FLOW DIAGRAM AREA 100: FEED HANDLING AND DRYING																					
	Project No: 30482.00	Drawing: PFD-61712-A102	Rev: 2																			
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1	12/12/14	DMS	UPDATED EQ NUMBERS																			
0	9/29/14	JAR	ISSUED FOR DESIGN REPORT																			



K-202 COMBUSTOR AIR COMPRESSOR    H-209 AIR PREHEATER    K-201 FLUIDIZING GAS RECYCLE COMPRESSOR    H-201 FLUIDIZING GAS HEATER    R-201 CATALYTIC FLUIDIZED BED REACTOR    S-201 PRIMARY CYCLONE    S-202 SECONDARY CYCLONE    T-201 CATALYST STEAM STRIPPER    R-202C CATALYST COOLER    R-202 CHAR COMBUSTOR    S-203 CHAR COMBUSTOR PRIMARY CYCLONE    S-204 CHAR COMBUSTOR SECONDARY CYCLONE    C-202 FINES PURGE COOLER    H-210C STEAM STRIPPER SUPERHEATER    H-210B STEAM STRIPPER BOILER    T-202 DEPLETED CATALYST AND ASH STORAGE BIN    T-207 CATALYST FEED BIN    H-208 FLUE GAS HEAT RECOVERY



① NOTE: STREAM 217 FOR ATTRITION MAKEUP. ADDITIONAL MAKEUP TO MAINTAIN ACTIVITY AS IN TABLE 4.

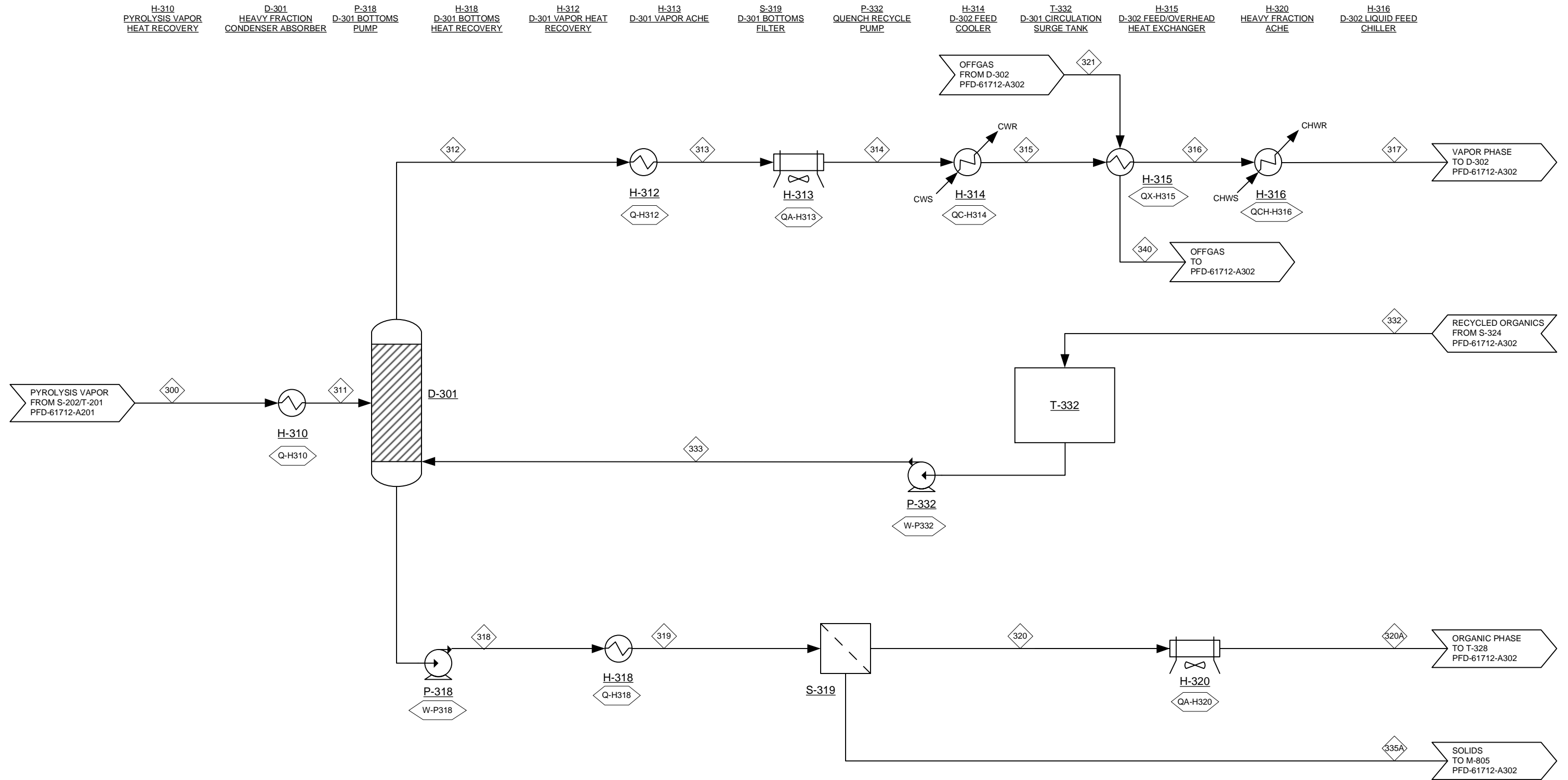
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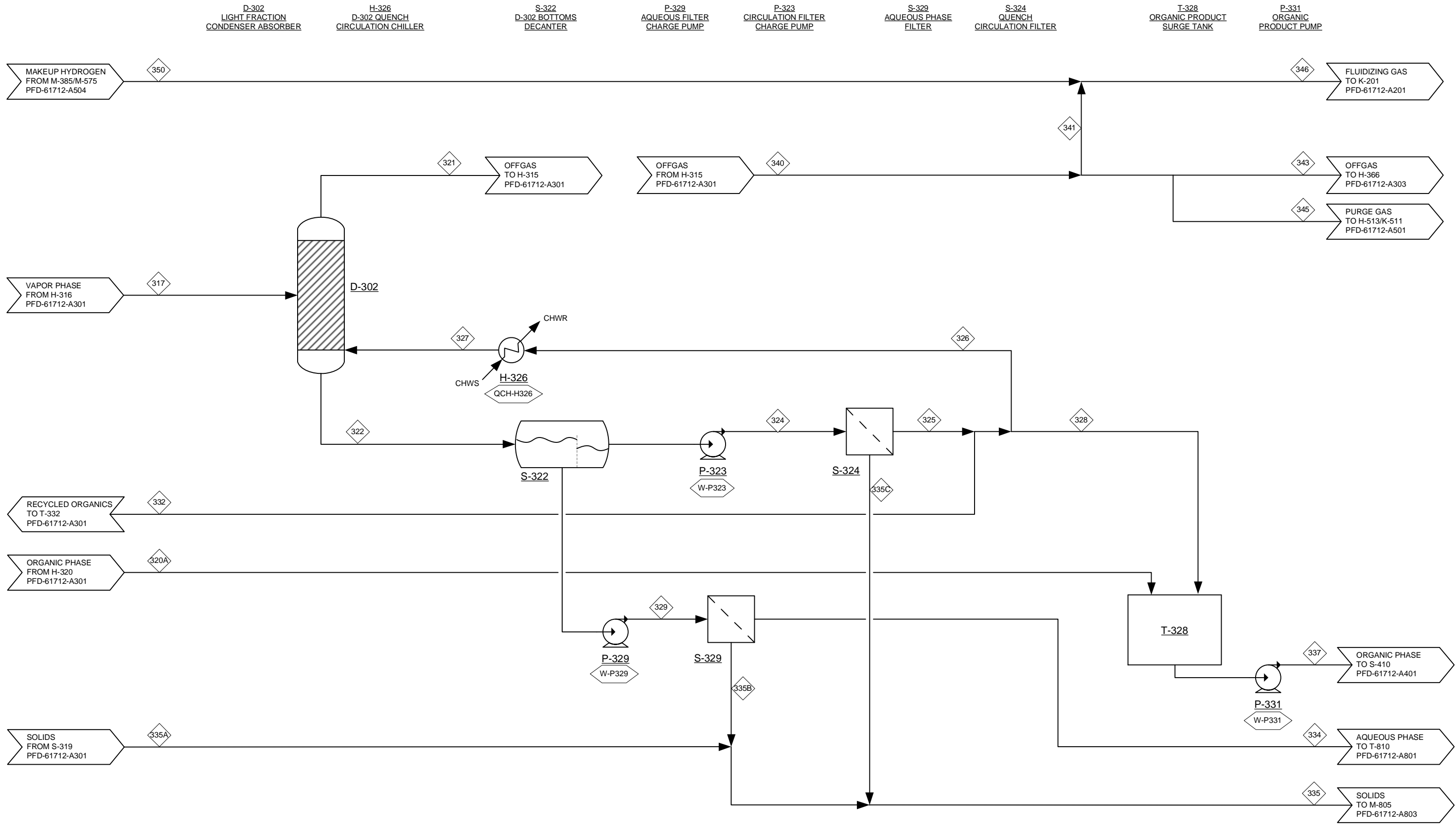
Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\_30482 Pyrolysis In-Situ PFDs 61712 150128.vsd





			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS	
	PROCESS FLOW DIAGRAM AREA 300: CONDENSATION STAGE 1		Project No: 30482.00	Drawing: PFD-61712-A301
1 0 Rev.	12/12/14 9/29/14 Date	DMS JAR By	UPDATED EQ NUMBERS ISSUED FOR DESIGN REPORT Description	1



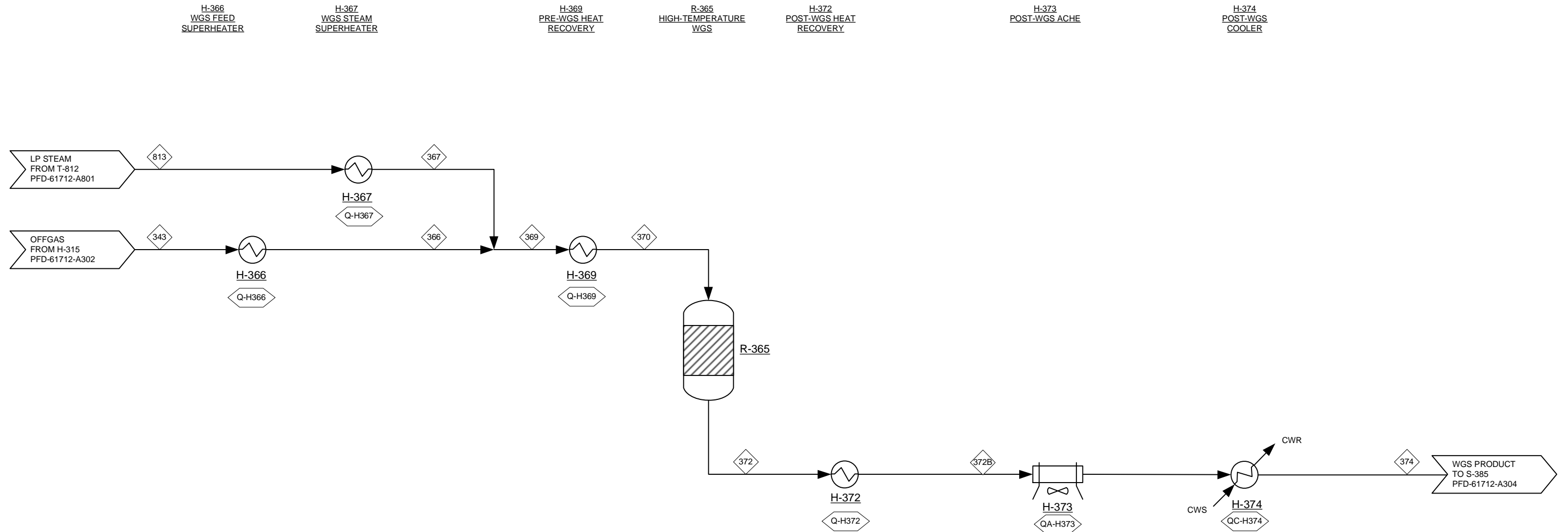
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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS																
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Rev.	Date	By	Description																	
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1	12/12/14	DMS	UPDATED EQ NUMBERS																	
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Project No: 30482.00		Drawing: PFD-61712-A302		Rev: 2																



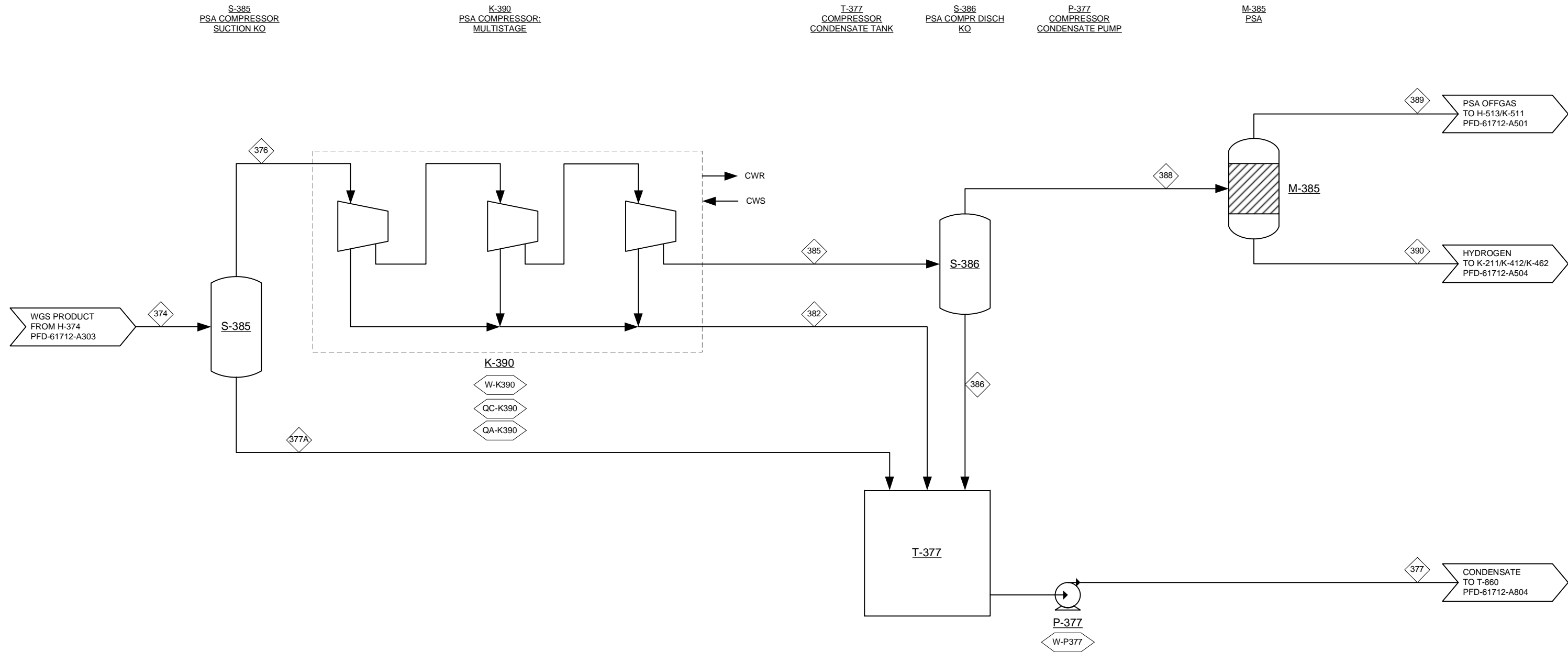
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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS		
	PROCESS FLOW DIAGRAM AREA 300: WATER GAS SHIFT					
1	12/12/14	DMS	UPDATED EQ NUMBERS	Project No:	30482.00	Rev:
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Rev.	Date	By	Description			



Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis In-Situ PFDs 61712 150128.vsd

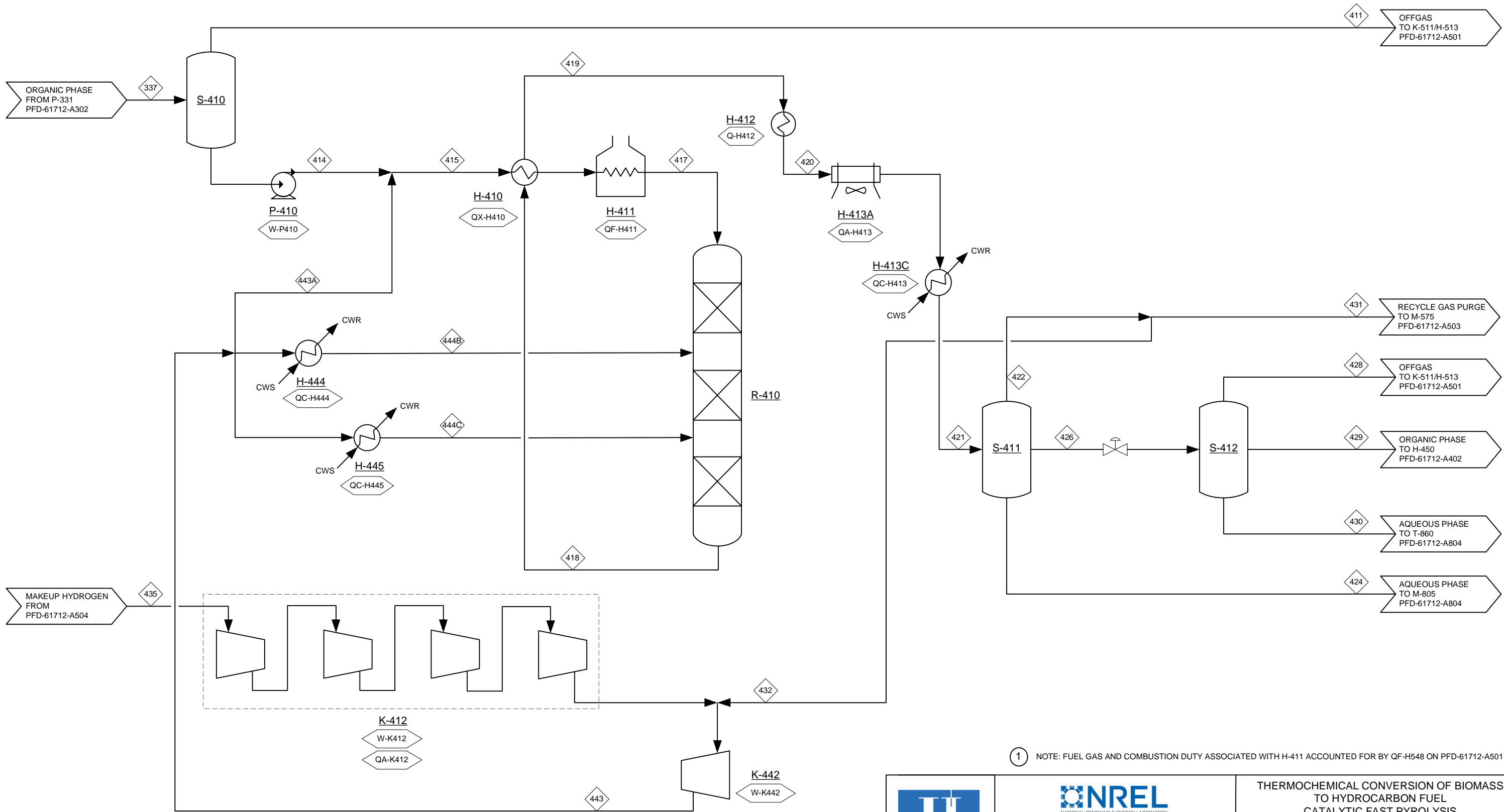


	 NATIONAL RENEWABLE ENERGY LABORATORY			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS															
	PROCESS FLOW DIAGRAM AREA 300: PSA																		
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1	12/12/14	DMS	UPDATED EQ NUMBERS																
0	9/29/14	JAR	ISSUED FOR DESIGN REPORT																





S-410 VAPOR KO DRUM    P-410 HT FEED PUMP    H-444 QUENCH HYDROGEN STAGE 2 COOLER    H-445 QUENCH HYDROGEN STAGE 3 COOLER    K-412 HYDROGEN MAKEUP COMPRESSOR    H-410 FEED-EFFLUENT EXCH    H-411 FEED FURNACE    R-410 HYDROTREATER    K-442 HYDROGEN RECYCLE COMPRESSOR    H-412 HT PRODUCT HEAT RECOVERY    H-413A HT PRODUCT ACHE    H-413C HT PRODUCT COOLER    S-411 HP HT EFFLUENT FLASH: 3 PHASE    S-412 LP HT EFFLUENT FLASH: 3 PHASE



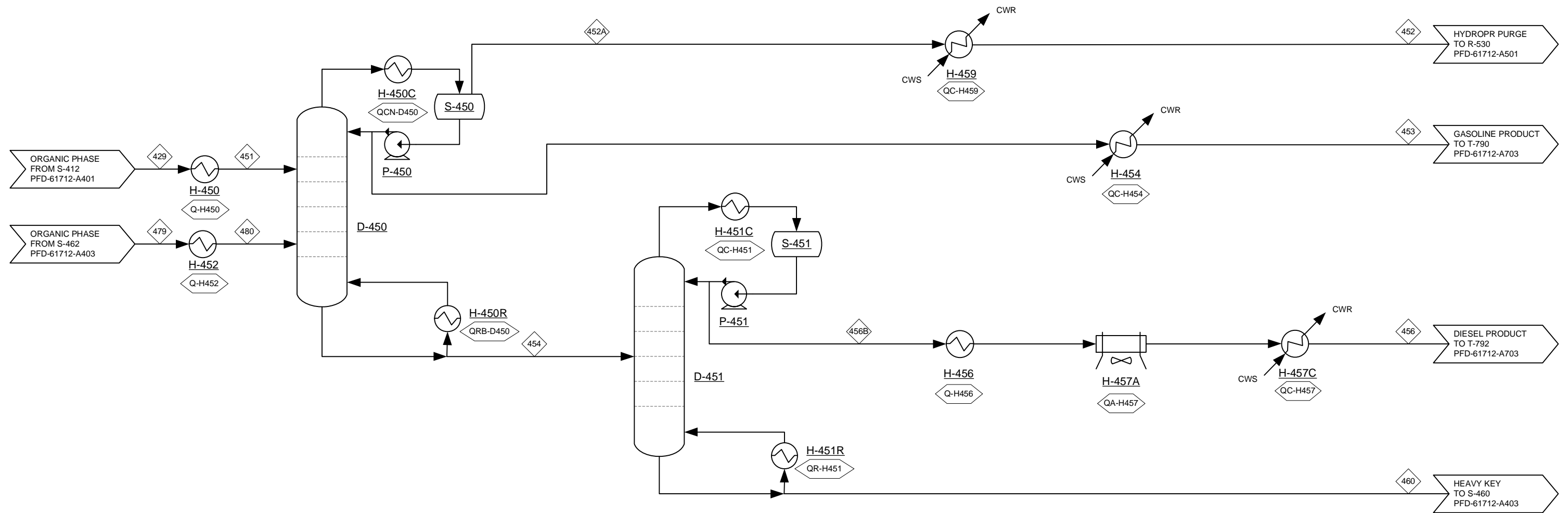
① NOTE: FUEL GAS AND COMBUSTION DUTY ASSOCIATED WITH H-411 ACCOUNTED FOR BY QF-H548 ON PFD-61712-A501

Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis In-Situ PFDs 61712-150128.vsd

			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS	
	PROCESS FLOW DIAGRAM AREA 400: HYDROTREATING		Project No: 30482.00	Drawing: PFD-61712-A401
1    12/12/14    DMS    UPDATED EQ NUMBERS	0    9/29/14    JAR    ISSUED FOR DESIGN REPORT	Rev.	Date	By
Description	Description	Description	Description	Description



H-450 GASOLINE COLUMN HEAT RECOVERY    H-452 GASOLINE COLUMN HEAT RECOVERY    D-450 GASOLINE COLUMN    H-450C D-450 CONDENSER    P-450 D-450 REFLUX PUMP    H-450R D-450 REBOILER    S-450 D-450 OVERHEAD ACCUMULATOR    D-451 DIESEL COLUMN    H-451C D-451 CONDENSER    P-451 D-451 REFLUX PUMP    H-451R D-451 REBOILER    S-451 D-451 OVERHEAD ACCUMULATOR    H-459 D-450 OVERHEAD VAPOR COOLER    H-456 DIESEL PRODUCT HEAT RECOVERY    H-454 GASOLINE PRODUCT COOLER    H-457A DIESEL PRODUCT ACHE    H-457C DIESEL PRODUCT COOLER

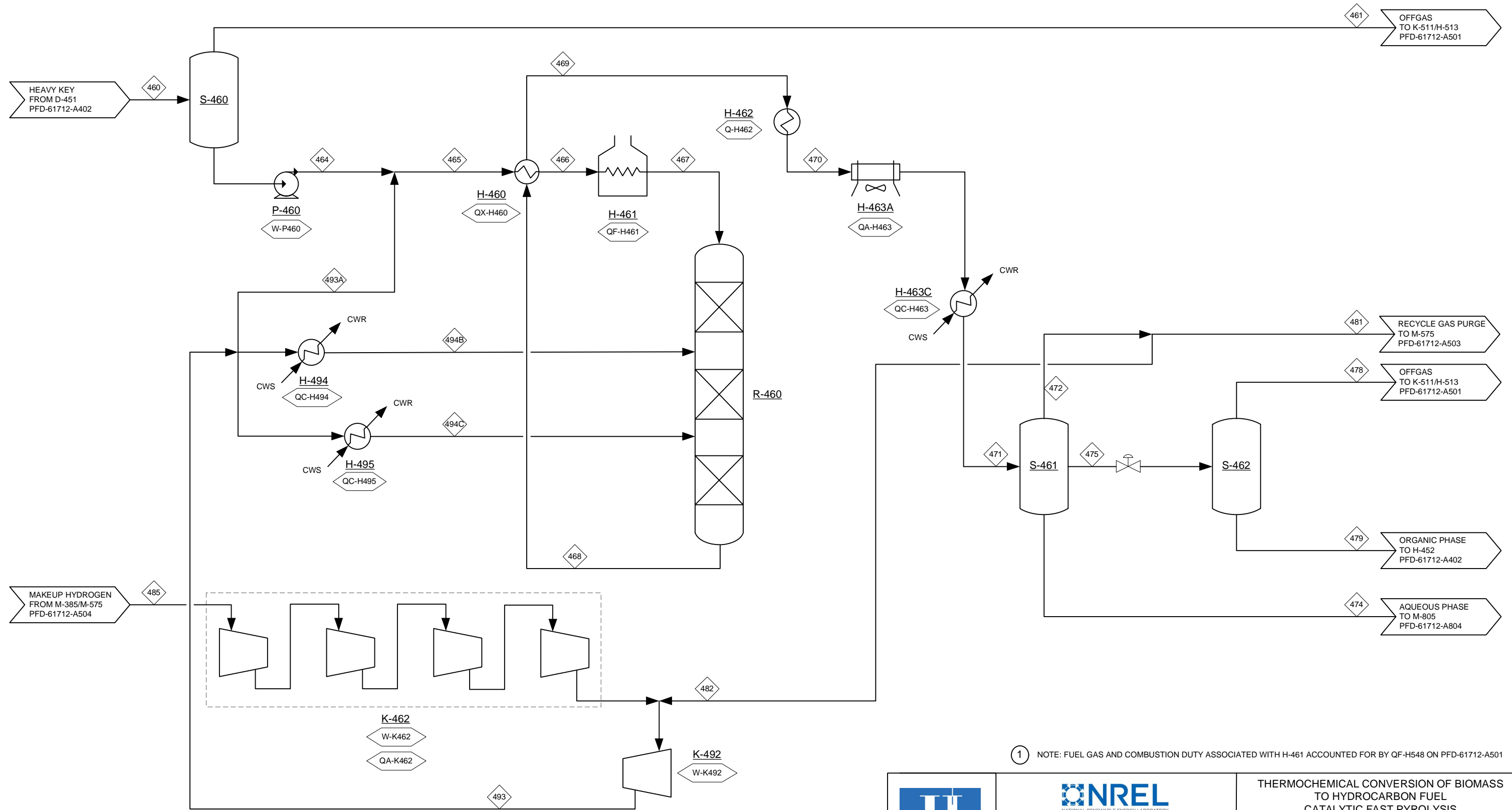


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	PROCESS FLOW DIAGRAM AREA 400: PRODUCT SEPARATION			Project No: 30482.00	Drawing: PFD-61712-A402	Rev: 1											
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Rev.	Date	By	Description														
1	12/12/14	DMS	UPDATED EQ NUMBERS														
0	9/29/14	JAR	ISSUED FOR DESIGN REPORT														



S-460 VAPOR KO DRUM    P-460 HC FEED PUMP    H-494 QUENCH HYDROGEN STAGE 2 COOLER    H-495 QUENCH HYDROGEN STAGE 3 COOLER    K-462 HYDROGEN MAKEUP COMPRESSOR    H-460 FEED-EFFLUENT EXCH    H-461 FEED FURNACE    R-460 HYDROCRACKER    K-492 HYDROGEN RECYCLE COMPRESSOR    H-462 HC PRODUCT HEAT RECOVERY    H-463A HC PRODUCT ACHE    H-463C HC PRODUCT COOLER    S-461 HP EFFLUENT FLASH: 3 PHASE    S-462 LP EFFLUENT FLASH



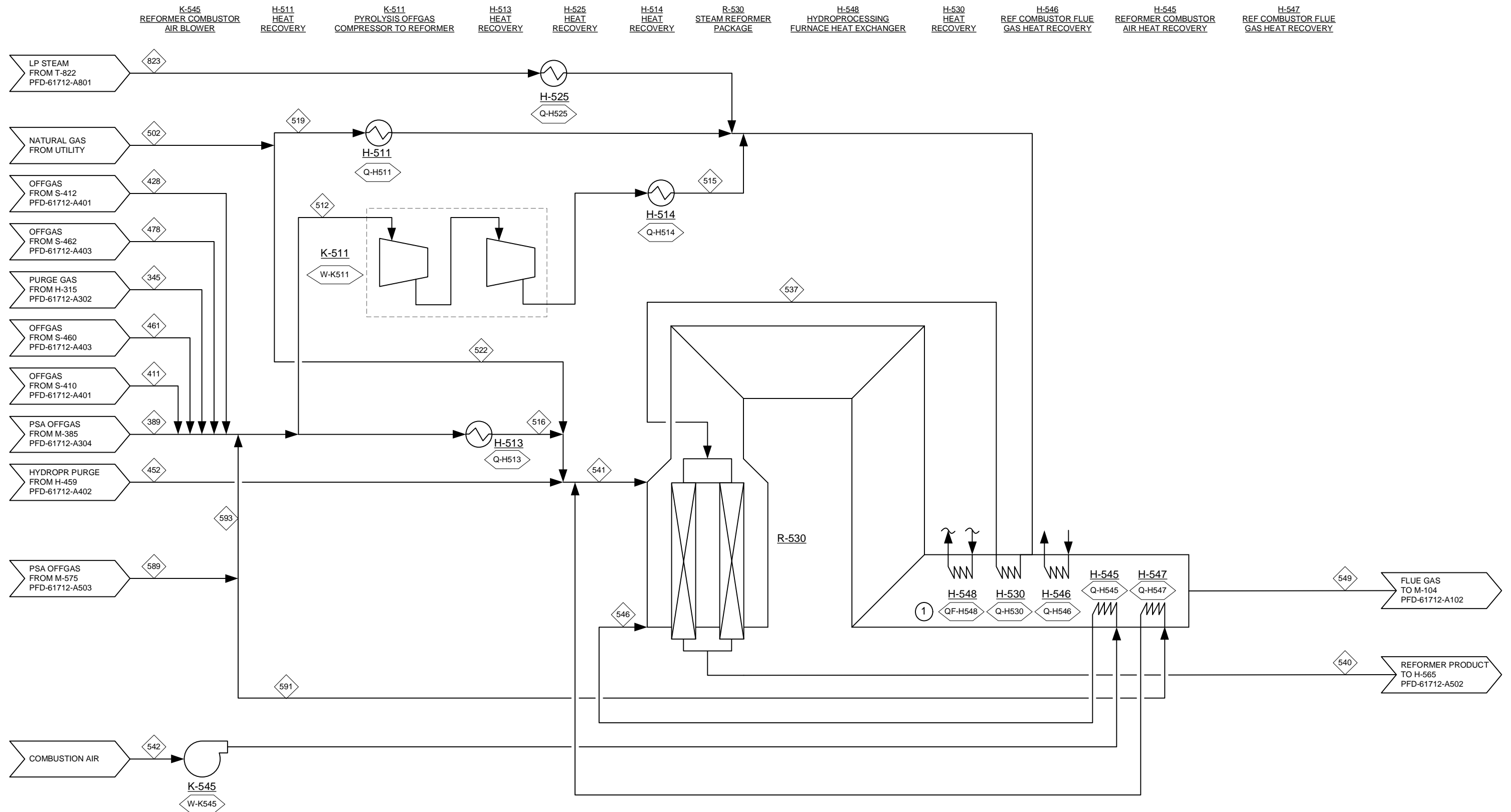
① NOTE: FUEL GAS AND COMBUSTION DUTY ASSOCIATED WITH H-461 ACCOUNTED FOR BY QF-H548 ON PFD-61712-A501

Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis In-Situ PFDs 61712 150128.vsd

	 NATIONAL RENEWABLE ENERGY LABORATORY			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS	
	2 12/29/14 JAR	1 12/12/14 DMS	0 9/29/14 JAR	MINOR UPDATES UPDATED EQ NUMBERS ISSUED FOR DESIGN REPORT	Project No: 30482.00
Rev.	Date	By	Description	30482.00	PFD-61712-A403



Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis In-Situ PFDs 61712 150128.vsd



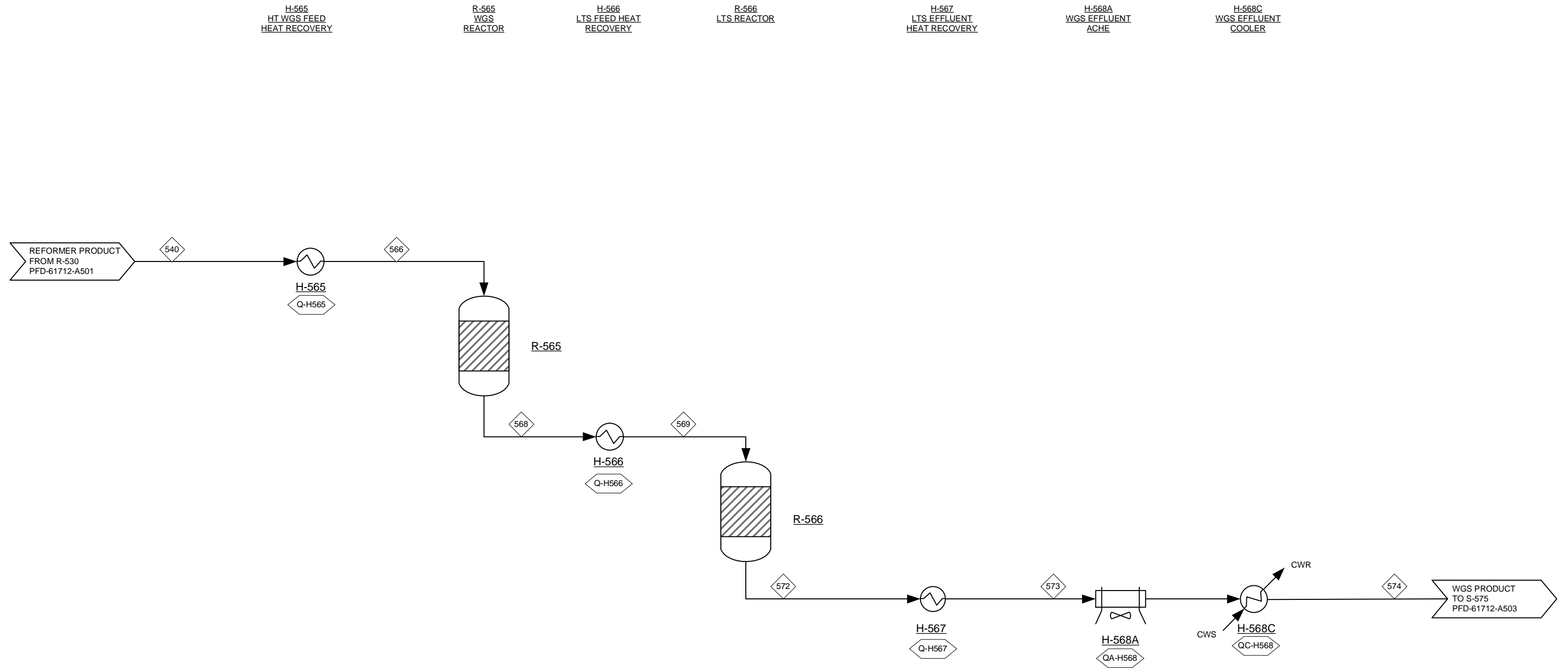
① NOTE: H-548 NOT PHYSICALLY PRESENT IN R-530 FLUE, BUT IS SHOWN TO ACCOUNT FOR FLUE GASES AND COMBUSTION DUTIES OF H-411 AND H-461



	 <small>NATIONAL RENEWABLE ENERGY LABORATORY</small>			<b>THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS</b>				
	<b>PROCESS FLOW DIAGRAM AREA 500: REFORMER</b>			Project No:	30482.00	Drawing:	PFD-61712-A501	Rev:
	Rev.	Date	By	Description				
	1	12/12/14	DMS	UPDATED EQ NUMBERS				
	0	9/29/14	JAR	ISSUED FOR DESIGN REPORT				





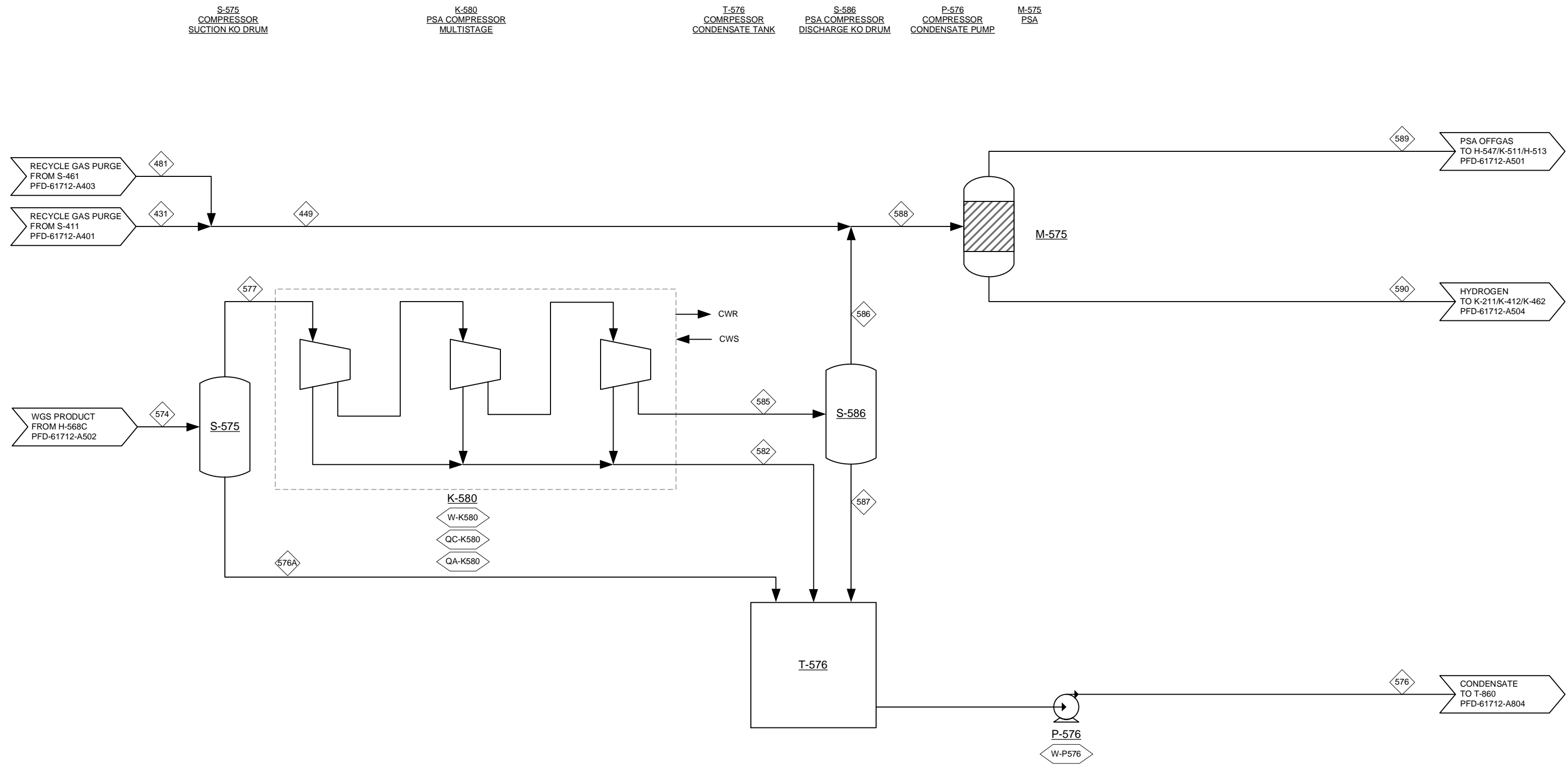
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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS		
				PROCESS FLOW DIAGRAM AREA 500: WATER GAS SHIFT		
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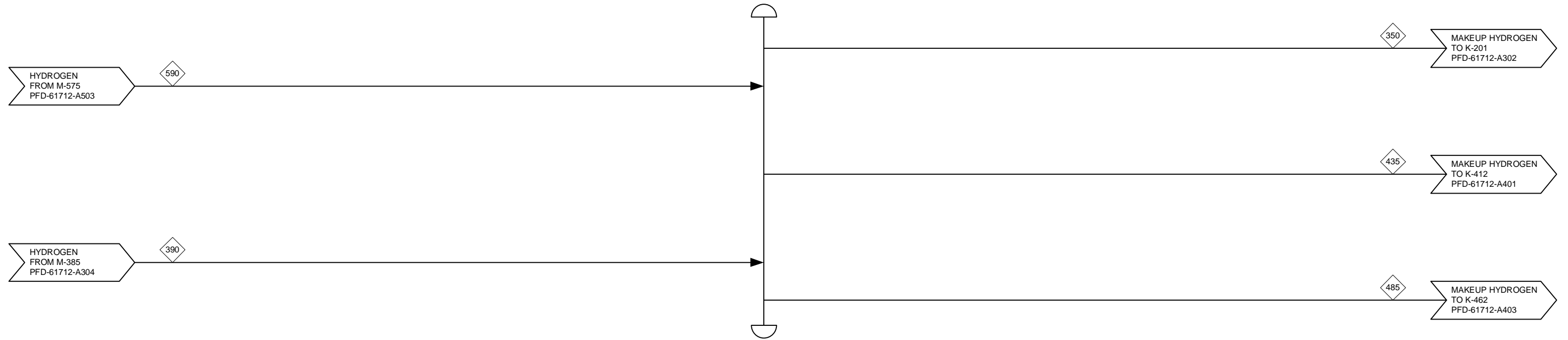




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	 <small>NATIONAL RENEWABLE ENERGY LABORATORY</small>			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS		
	PROCESS FLOW DIAGRAM AREA 500: PSA					
	2 1 0 Rev.	12/29/14 12/12/14 9/29/14 Date	JAR DMS JAR By	MINOR UPDATES UPDATED EQ NUMBERS ISSUED FOR DESIGN REPORT Description	Project No: 30482.00	Drawing: PFD-61712-A503

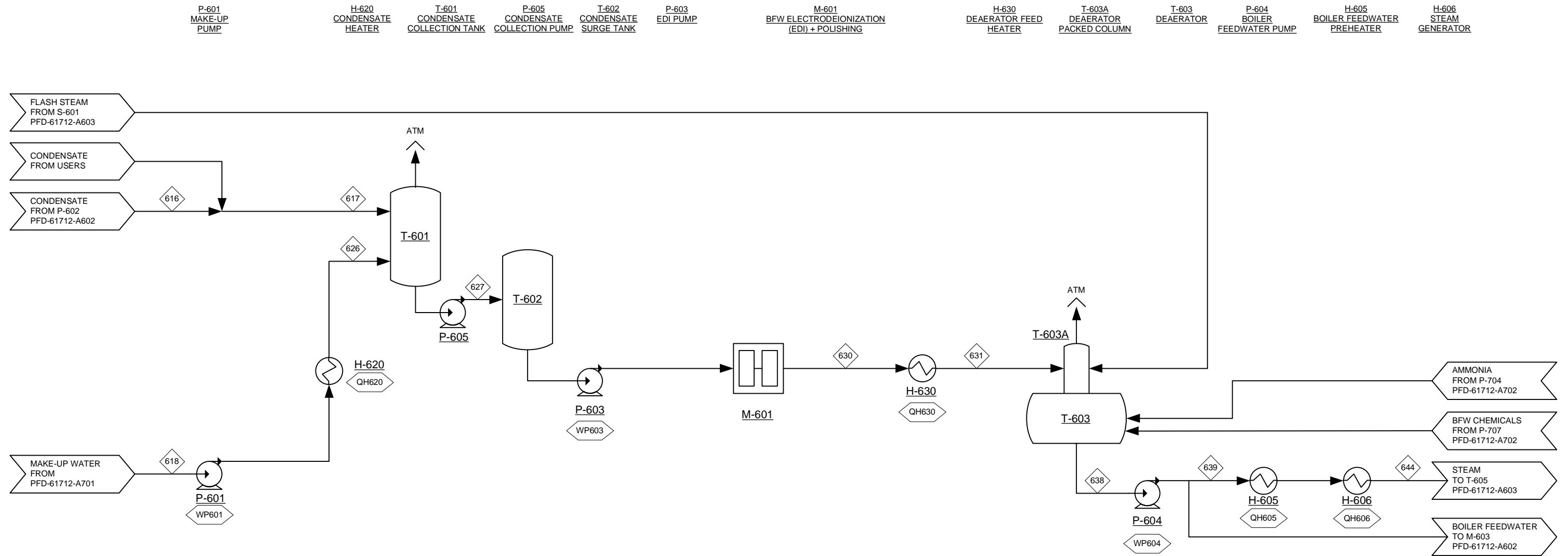






				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS					
	PROCESS FLOW DIAGRAM AREA 500: HYDROGEN DISTRIBUTION								
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0	9/29/14	JAR	ISSUED FOR DESIGN REPORT						
Rev.	Date	By	Description						



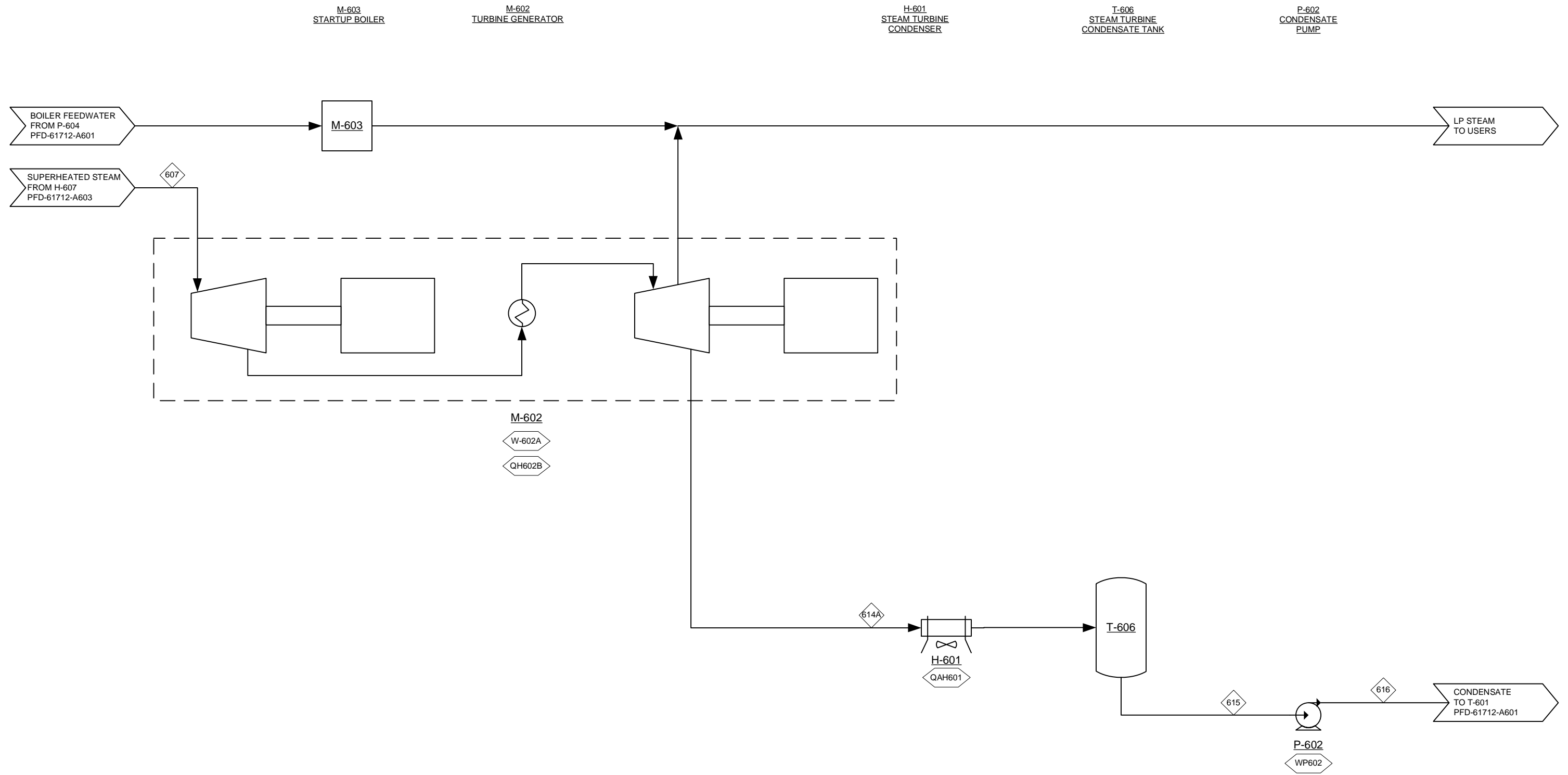
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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS											
				PROCESS FLOW DIAGRAM AREA 600: STEAM SYSTEM & POWER GENERATION											
<table border="1"> <thead> <tr> <th>Rev.</th> <th>Date</th> <th>By</th> <th>Description</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>12/12/14</td> <td>DMS</td> <td>UPDATED EQ NUMBERS</td> </tr> <tr> <td>0</td> <td>9/29/14</td> <td>JAR</td> <td>ISSUED FOR DESIGN REPORT</td> </tr> </tbody> </table>	Rev.	Date	By	Description	1	12/12/14	DMS	UPDATED EQ NUMBERS	0	9/29/14	JAR	ISSUED FOR DESIGN REPORT	Project No: 30482.00	Drawing: PFD-61712-A601	Rev: 1
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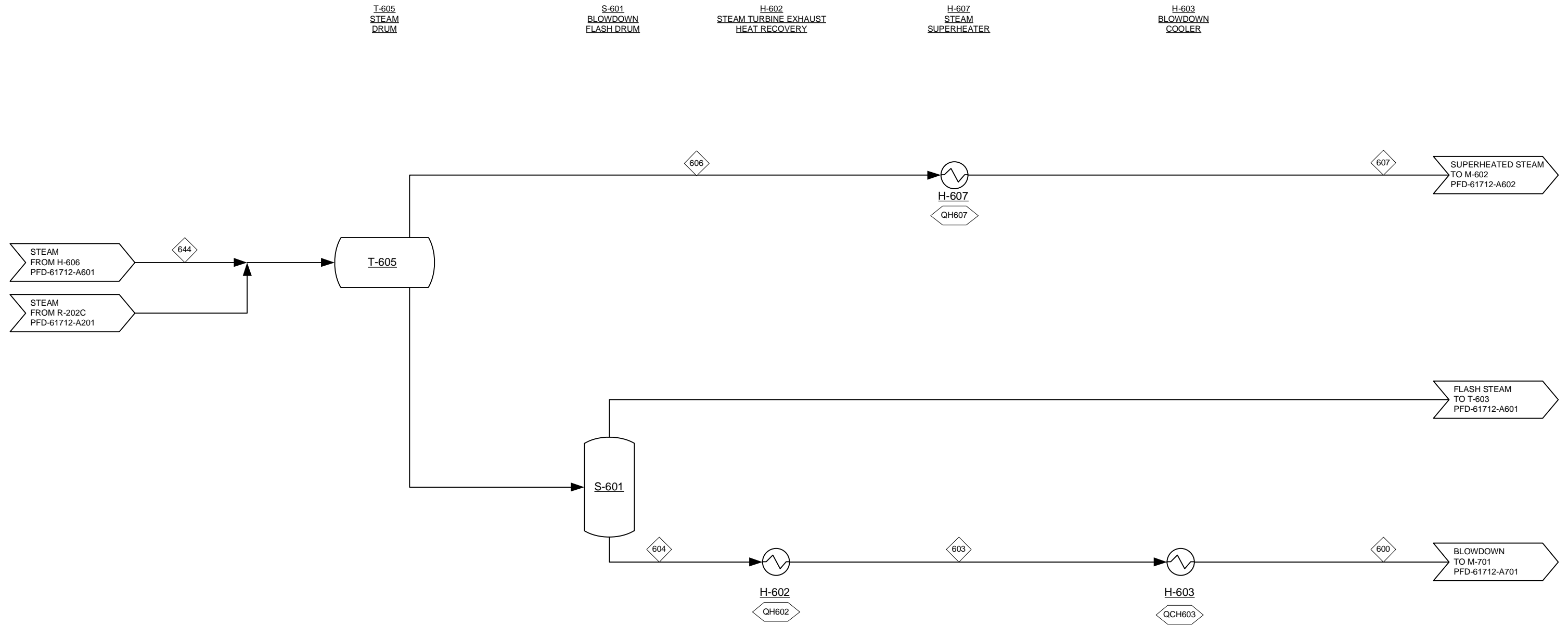








				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS		
	PROCESS FLOW DIAGRAM AREA 600: STEAM SYSTEM & POWER GENERATION					
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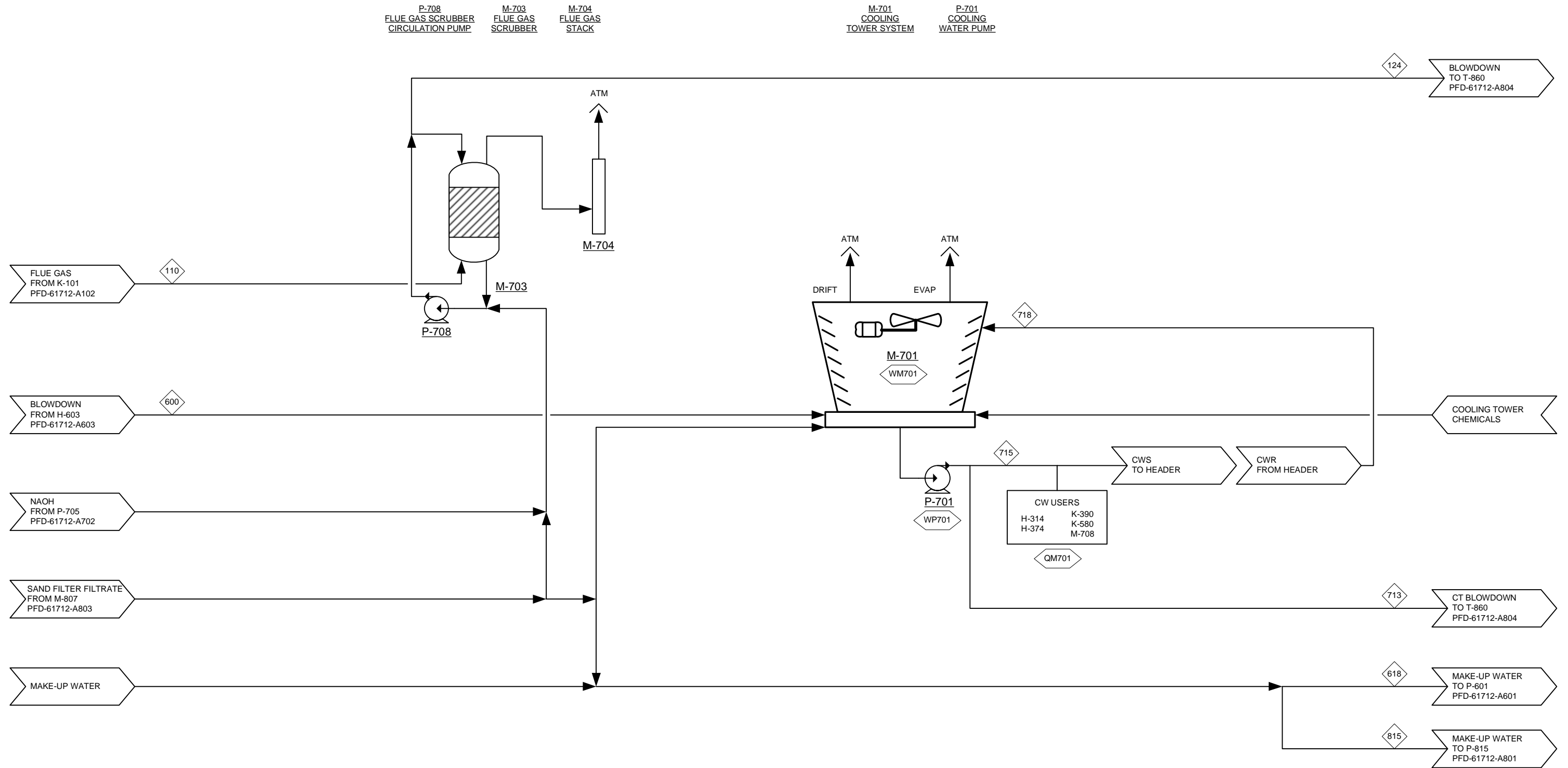






				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS		
	PROCESS FLOW DIAGRAM AREA 600: STEAM SYSTEM & POWER GENERATION					
	1	12/12/14	DMS	UPDATED EQ NUMBERS		
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					Rev:	1



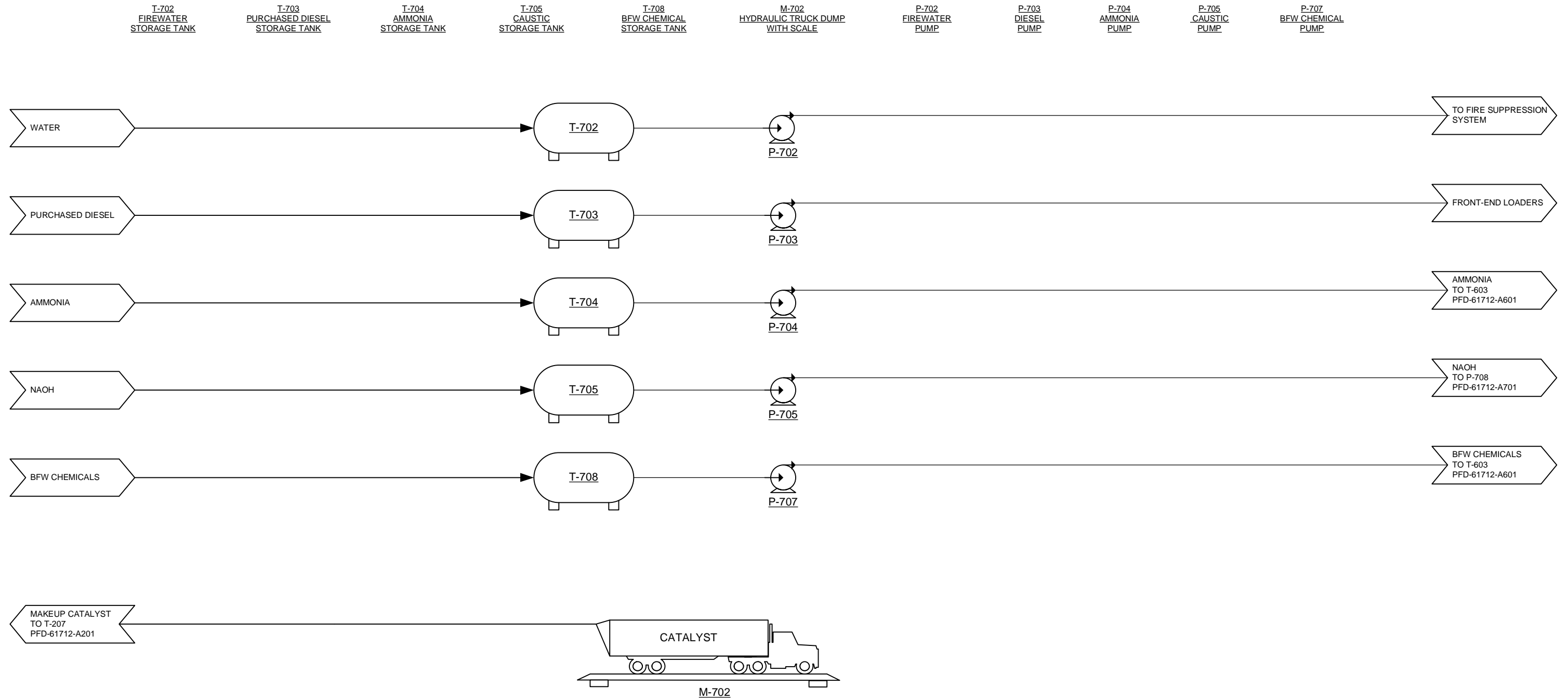
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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS																
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Rev.	Date	By	Description																	
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1	12/12/14	DMS	UPDATED EQ NUMBERS																	
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Project No: 30482.00		Drawing: PFD-61712-A701		Rev: 2																



Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis In-Situ PFDs 61712 150 28.vsd



				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS		
	PROCESS FLOW DIAGRAM AREA 700: MATERIALS STORAGE					
	1 0 Rev.	12/12/14 9/29/14 Date	DMS JAR By	UPDATED EQ NUMBERS ISSUED FOR DESIGN REPORT Description	Project No: 30482.00	Drawing: PFD-61712-A702





K-701  
PLANT AIR  
COMPRESSOR

S-701  
INSTRUMENT  
AIR DRYER

T-701  
PLANT AIR  
RECEIVER

T-792  
DIESEL PRODUCT  
STORAGE TANK

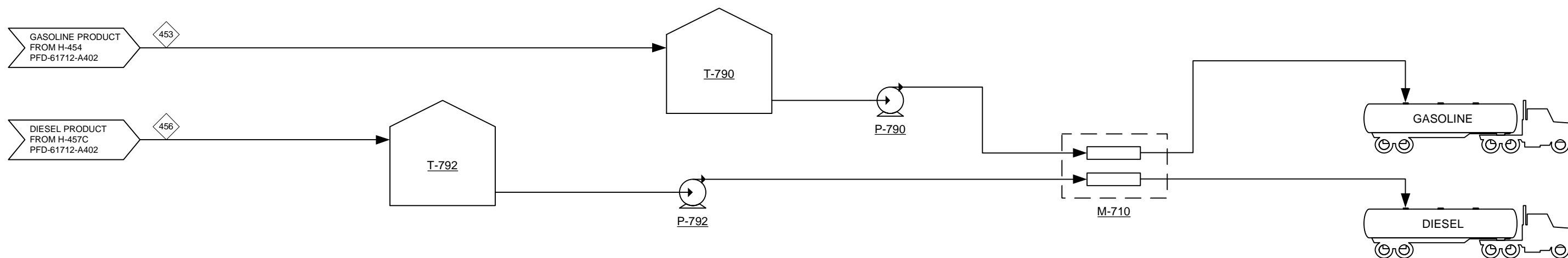
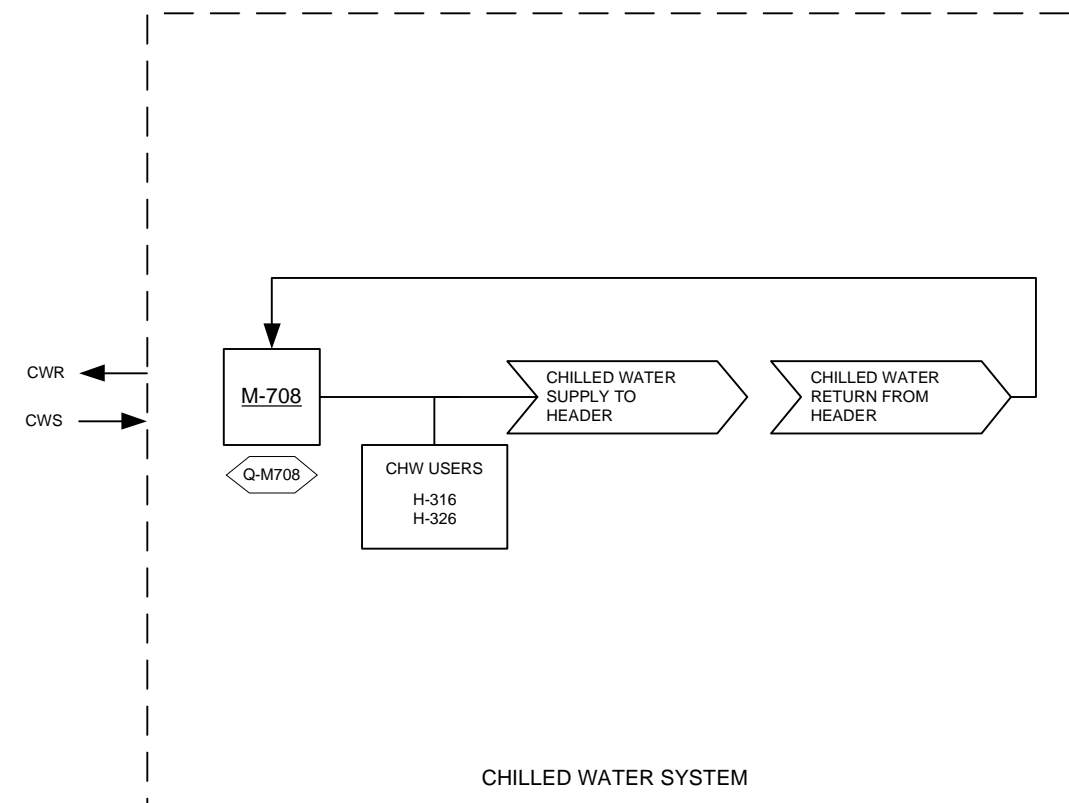
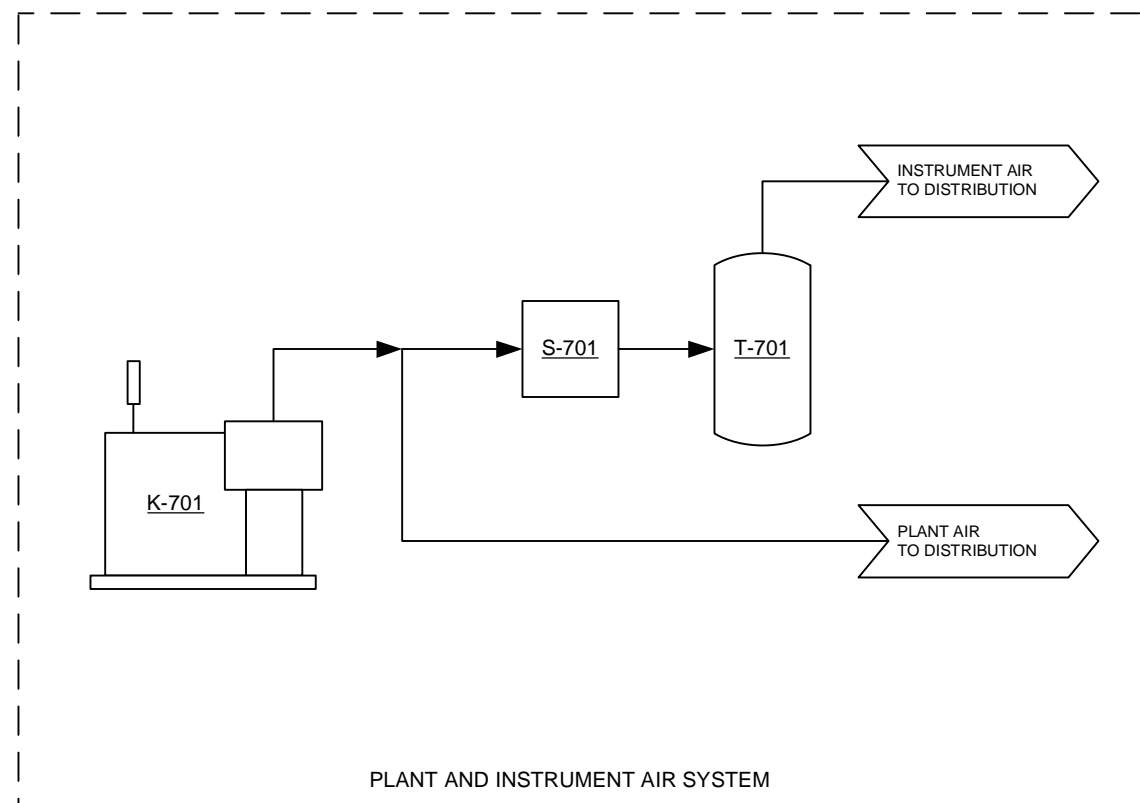
P-792  
DIESEL PRODUCT  
PUMP

T-790  
GASOLINE PRODUCT  
STORAGE TANK

P-790  
GASOLINE PRODUCT  
PUMP

M-710  
PRODUCT  
LOADING RACK

M-708  
CHILLED WATER  
SYSTEM

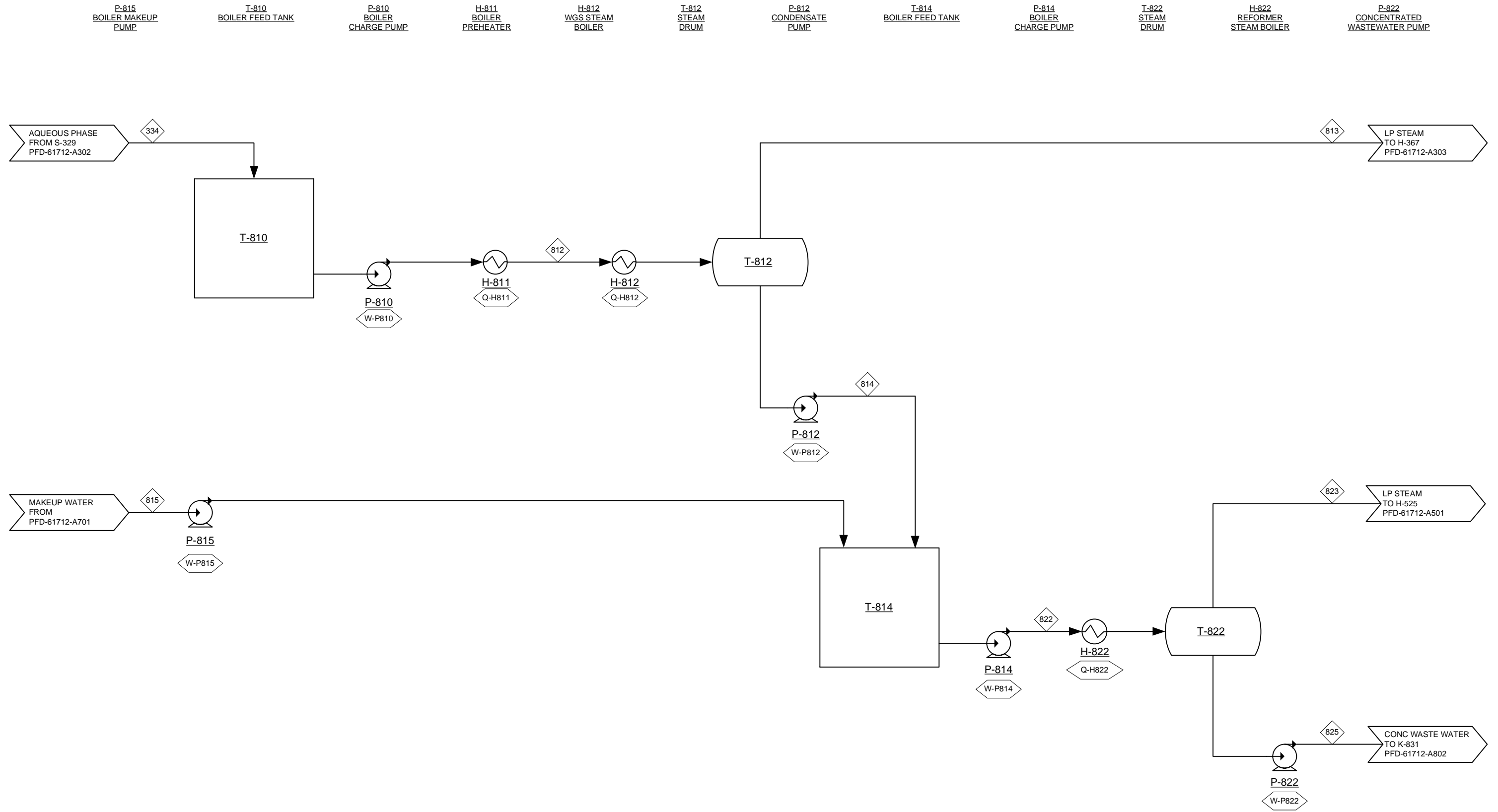




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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS	
				PROCESS FLOW DIAGRAM AREA 700: UTILITIES AND PRODUCT LOADOUT	
	2 12/29/14 JAR MINOR UPDATES	1 12/12/14 DMS UPDATED EQ NUMBERS	0 9/29/14 JAR ISSUED FOR DESIGN REPORT	Project No: 30482.00	Drawing: PFD-61712-A703
Rev.	Date	By	Description		



Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis In-Situ PFDs 61712-150128.vsd



				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS											
				PROCESS FLOW DIAGRAM AREA 800: WASTEWATER MANAGEMENT											
<table border="1"> <thead> <tr> <th>Rev.</th> <th>Date</th> <th>By</th> <th>Description</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>12/12/14</td> <td>DMS</td> <td>UPDATED EQ NUMBERS</td> </tr> <tr> <td>0</td> <td>9/29/14</td> <td>JAR</td> <td>ISSUED FOR DESIGN REPORT</td> </tr> </tbody> </table>	Rev.	Date	By	Description	1	12/12/14	DMS	UPDATED EQ NUMBERS	0	9/29/14	JAR	ISSUED FOR DESIGN REPORT	Project No: 30482.00	Drawing: PFD-61712-A801	Rev: 1
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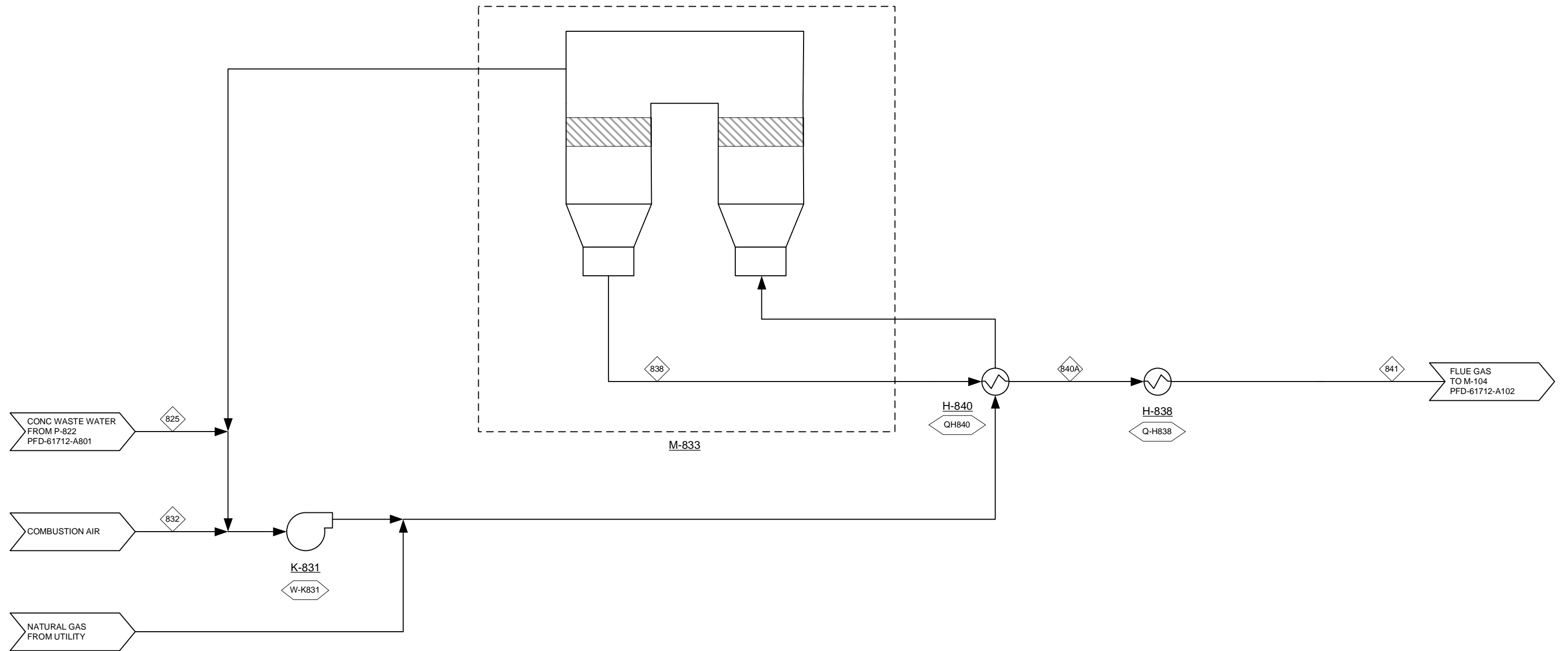


K-831  
RTO  
BLOWER

M-833  
AQUEOUS REGENERATIVE  
THERMAL OXIDIZER

H-840  
RTO FEED/EFFLUENT  
EXCHANGER

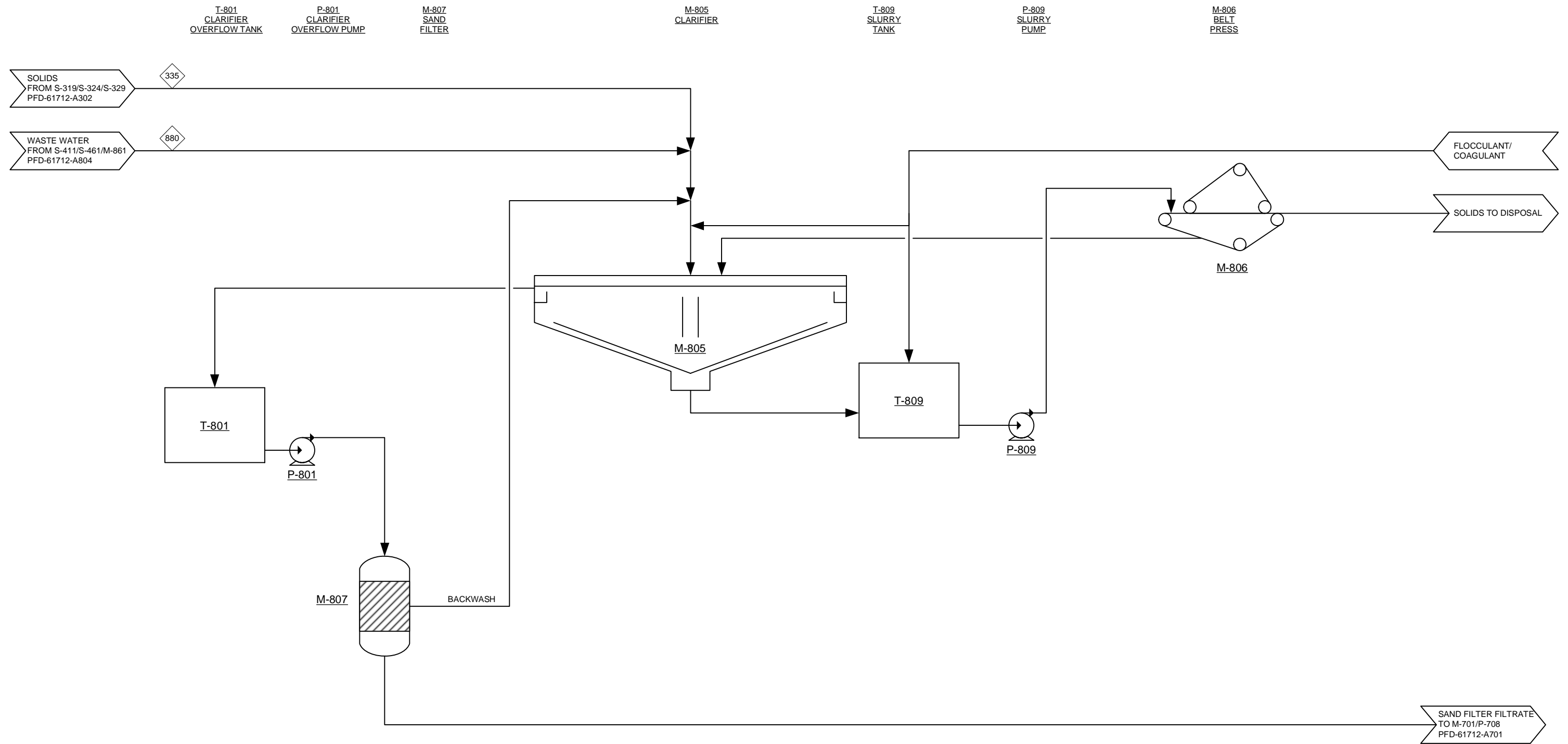
H-838  
HEAT  
RECOVERY



Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis In-Situ PFDs 61712 150128.vsd

	 NATIONAL RENEWABLE ENERGY LABORATORY			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS											
	PROCESS FLOW DIAGRAM AREA 800: AQUEOUS RTO														
	<table border="1"> <thead> <tr> <th>Rev.</th> <th>Date</th> <th>By</th> <th>Description</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>12/12/14</td> <td>DMS</td> <td>UPDATED EQ NUMBERS</td> </tr> <tr> <td>0</td> <td>9/29/14</td> <td>JAR</td> <td>ISSUED FOR DESIGN REPORT</td> </tr> </tbody> </table>	Rev.	Date	By	Description	1	12/12/14	DMS	UPDATED EQ NUMBERS	0	9/29/14	JAR	ISSUED FOR DESIGN REPORT	Project No: 30482.00	Drawing: PFD-61712-A802
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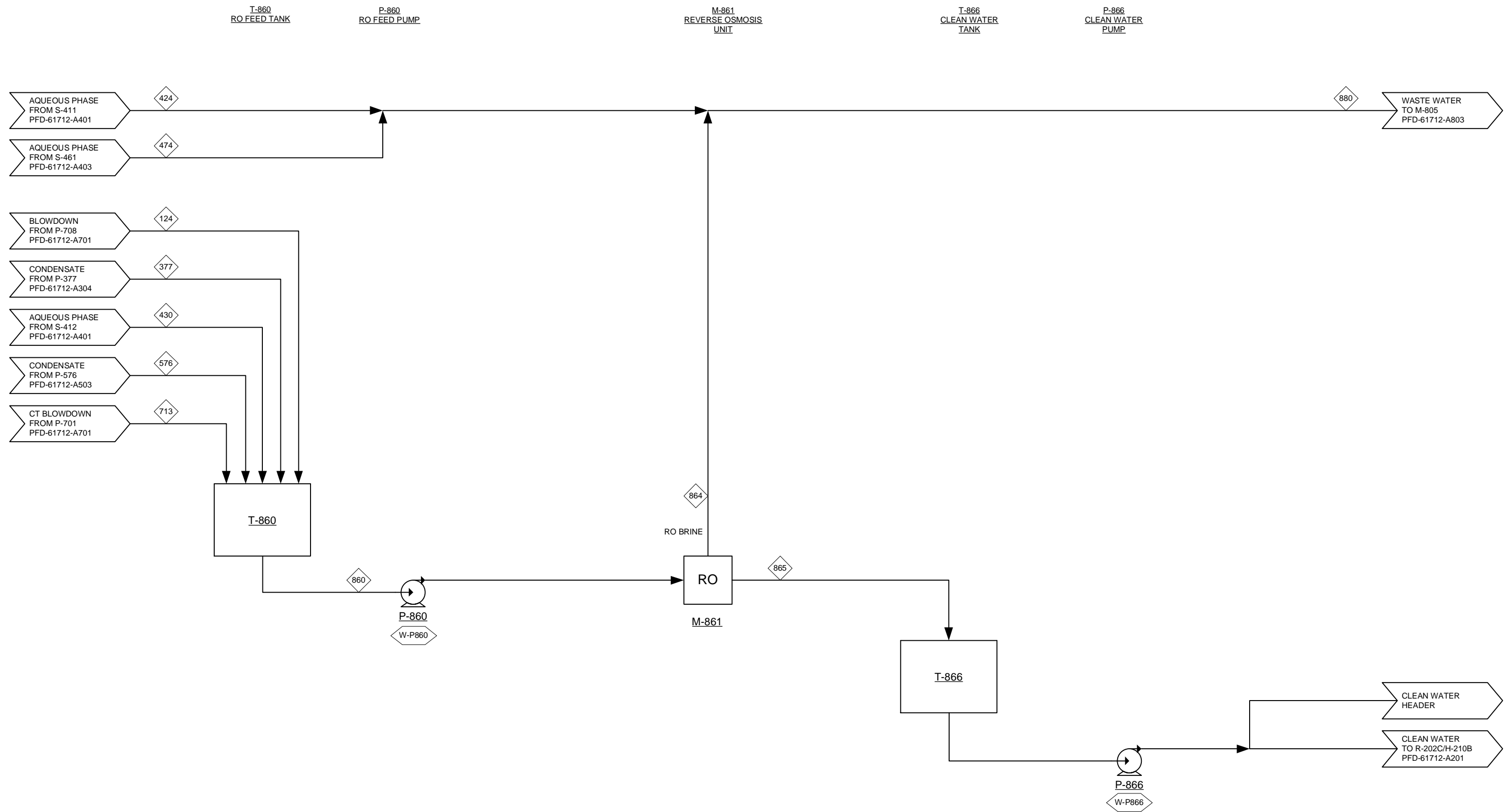




	 <small>NATIONAL RENEWABLE ENERGY LABORATORY</small>			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS				
	PROCESS FLOW DIAGRAM AREA 800: CLARIFIER AND SAND FILTER							
	2	12/29/14	JAR	MINOR UPDATES				
	1	12/12/14	DMS	UPDATED EQ NUMBERS				
0	9/29/14	JAR	ISSUED FOR DESIGN REPORT					
Rev.	Date	By	Description					
			Project No:	30482.00	Drawing:	PFD-61712-A803	Rev:	2



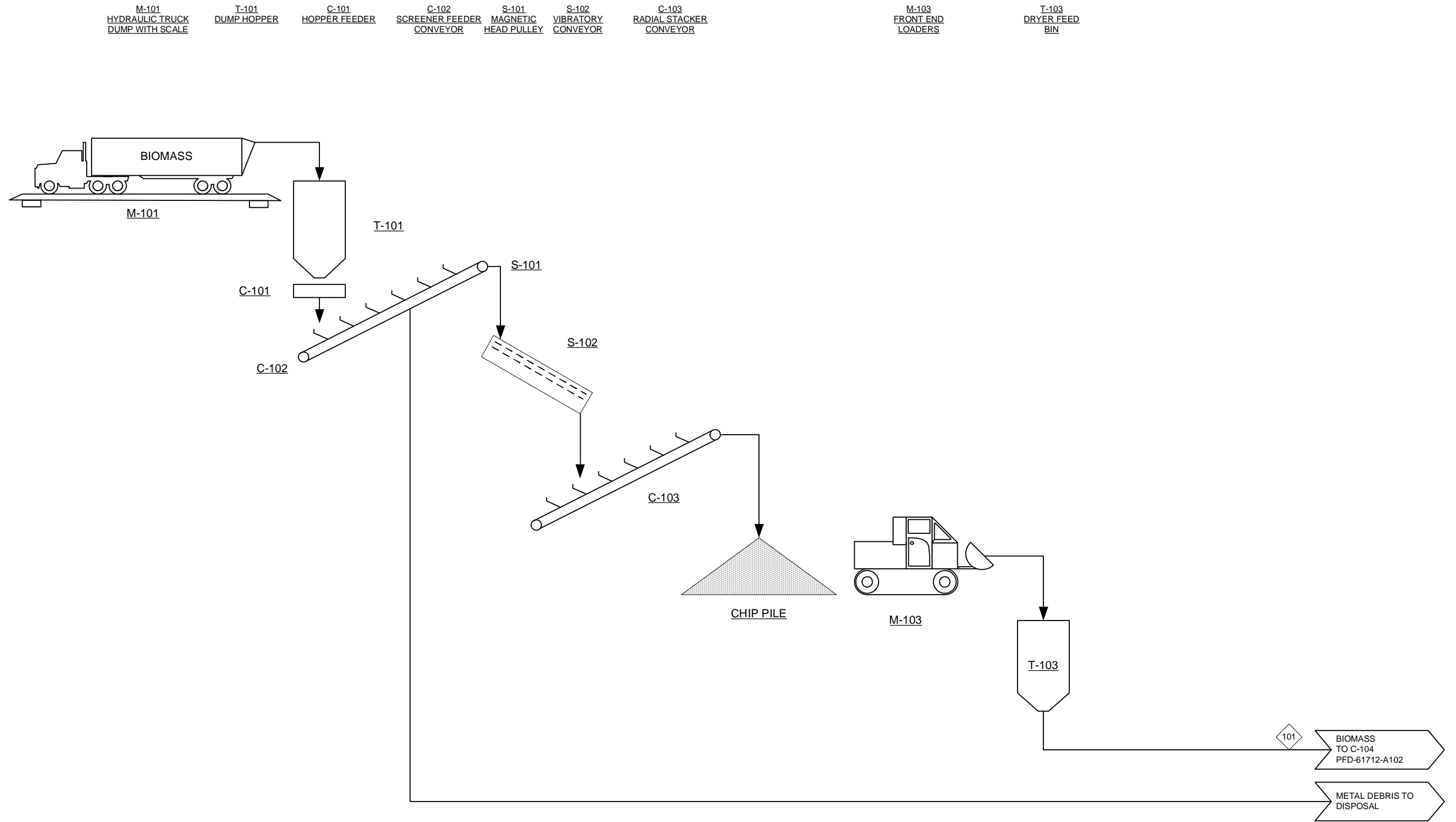




				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL CATALYTIC FAST PYROLYSIS		
	PROCESS FLOW DIAGRAM AREA 800: WASTEWATER REVERSE OSMOSIS			Project No: 30482.00	Drawing: PFD-61712-A804	Rev: 1
1 0	12/12/14 9/29/14	DMS JAR	UPDATED EQ NUMBERS ISSUED FOR DESIGN REPORT	Description		



## **Appendix G-2. Process Flow Diagrams and Stream Summary for the *Ex Situ* Case, Including Detailed Heat Exchange Network**



M-101 HYDRAULIC TRUCK DUMP WITH SCALE  
 T-101 DUMP HOPPER  
 C-101 HOPPER FEEDER  
 C-102 SCREENER FEEDER CONVEYOR  
 S-101 MAGNETIC HEAD PULLEY  
 S-102 VIBRATORY CONVEYOR  
 C-103 RADIAL STACKER CONVEYOR  
 M-103 FRONT END LOADERS  
 T-103 DRYER FEED BIN

BIOMASS  
 M-101

T-101

C-101

S-101

S-102

C-102

C-103

CHIP PILE

M-103

T-103

101

BIOMASS TO C-104  
 PFD-61712-A102

METAL DEBRIS TO DISPOSAL

NOTE: FEEDSTOCK HANDLING COSTS ARE INCLUDED IN THE TARGET FEEDSTOCK COST PROVIDED BY THE IDAHO NATIONAL LABORATORY. ONLY A CROSS FLOW DRYER USING PROCESS FLUE GASES FOR FEED PREHEAT IS INCLUDED IN THE CONVERSION COST.

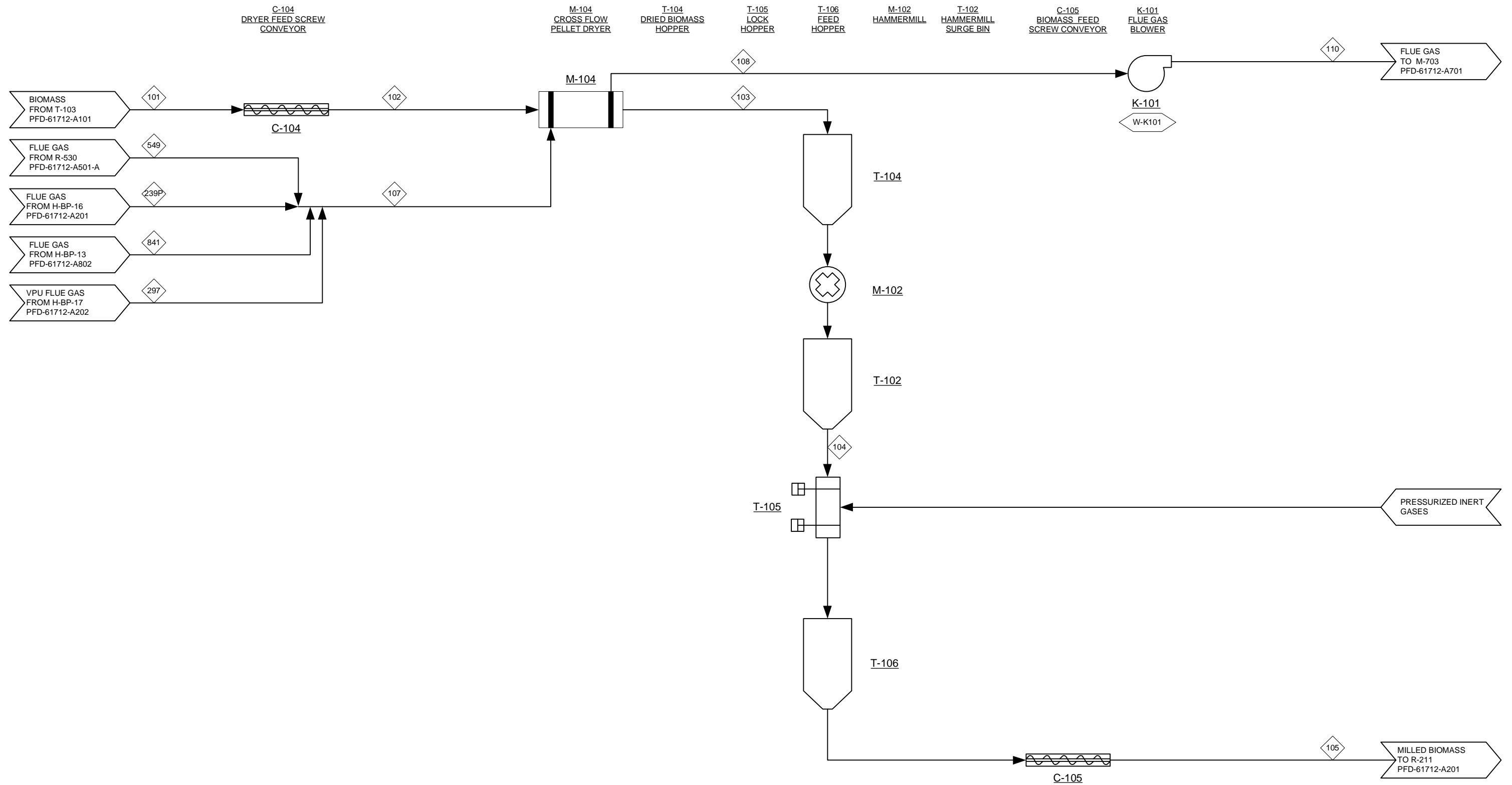
Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712 150128.vsd

				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING			
	PROCESS FLOW DIAGRAM AREA 100: FEED HANDLING				Project No: 30482.00	Drawing: PFD-61712-A101	Rev: 1
	1 Rev.	12/12/14 Date	DMS By	ADDED HX NETWORK Description			
0 Rev.	9/29/14 Date	JAR By	ISSUED FOR DESIGN REPORT Description				

<b>PFD-61712-A101</b>		101																		
Total Flow	lb/h	204,131																		
Temperature	F	60																		
Pressure	Psia	15																		
Vapor Fraction																				
Enthalpy Flow	MMBtu/h	-569																		
Argon	lb/h																			
Nitrogen	lb/h																			
Oxygen	lb/h																			
SO2	lb/h																			
NO2	lb/h																			
Hydrogen	lb/h																			
Ammonia	lb/h																			
H2S	lb/h																			
Water	lb/h	20,413																		
Carbon Monoxide	lb/h																			
Carbon Dioxide	lb/h																			
Methane	lb/h																			
Methanol	lb/h																			
Formic Acid	lb/h																			
Glyoxal	lb/h																			
Ethylene	lb/h																			
Acetaldehyde	lb/h																			
Hydroxyacetaldehyde	lb/h																			
Acetic Acid	lb/h																			
Ethane	lb/h																			
Propylene	lb/h																			
1-Hydroxy-2-propanone	lb/h																			
Propionic Acid	lb/h																			
Propane	lb/h																			
Furan	lb/h																			
1-Butene	lb/h																			
Tetrahydrofuran	lb/h																			
N-Butane	lb/h																			
Furfural	lb/h																			
2-methylfuran	lb/h																			
Furfuryl Alcohol	lb/h																			
n-Pentane	lb/h																			
Pentenone	lb/h																			
Benzene	lb/h																			
Phenol	lb/h																			
1,2-Benzenediol	lb/h																			
Hydroxymethylfurfural	lb/h																			
2,5-dimethylfuran	lb/h																			
Methyl Cyclopentenone	lb/h																			
Hydroxymethylcyclopentenone	lb/h																			
Cyclohexanone	lb/h																			
Levoglucosan	lb/h																			
1-Hexanal	lb/h																			
Dimethoxytetrahydrofuran	lb/h																			
Cyclohexane	lb/h																			
N-Hexane	lb/h																			
Hexanol	lb/h																			
Toluene	lb/h																			
2-Methylphenol	lb/h																			
3-Methyl-phenol	lb/h																			
Guaiacol	lb/h																			
Methyl-Cyclohexane	lb/h																			
2-Methylhexane	lb/h																			
Vinylphenol	lb/h																			
O-Xylene	lb/h																			
Ethylbenzene	lb/h																			
2,3-Dimethyl-phenol	lb/h																			
2,6-dimethoxyphenol	lb/h																			
Vanillyl alcohol	lb/h																			
2,4,6-Trimethylpyridine	lb/h																			
Cis-1,2-dimethyl cyclohexane	lb/h																			
Trans-1,2-dimethylcyclohexane	lb/h																			
Ethylcyclohexane	lb/h																			
4-Methylheptane	lb/h																			
2-Methyl-Benzofuran	lb/h																			
Indane	lb/h																			
2-methoxy-4-vinylphenol	lb/h																			
Syringaldehyde	lb/h																			
n-Propylbenzene	lb/h																			
Naphthalene	lb/h																			
1-Naphthalenol	lb/h																			
Coniferyl Aldehyde	lb/h																			
Tetralin	lb/h																			
Isoeugenol	lb/h																			
Decalin	lb/h																			
2,5-Dimethyloctane	lb/h																			
1-Methyl naphthalene	lb/h																			
1-methyl decahydronaphthene	lb/h																			
Dibenzothiophene	lb/h																			
Biphenyl	lb/h																			
5-hexyl-O-cresol	lb/h																			
n-Heptylcyclohexane	lb/h																			
C14H20-N35	lb/h																			
C14H24-N5	lb/h																			
3,5-Dimethyldodecane	lb/h																			
C15H26-N4	lb/h																			
6,8-Dimethyltridecane	lb/h																			
1,4-Dimethyl-Phenanthrene	lb/h																			
N-Cetane	lb/h																			
C18H26O	lb/h																			
C18H28	lb/h																			
C21H26O2	lb/h																			
C21H34	lb/h																			
C22H28O2	lb/h																			
Carbon	lb/h																			
Sulfur	lb/h																			
Sand/Catalyst Solids	lb/h																			
Ash	lb/h	0																		
Wood	lb/h	183,718																		
Char	lb/h	0																		
Coke	lb/h	0																		

Heat	MMBtu/h

Work	hp	MMBtu/h



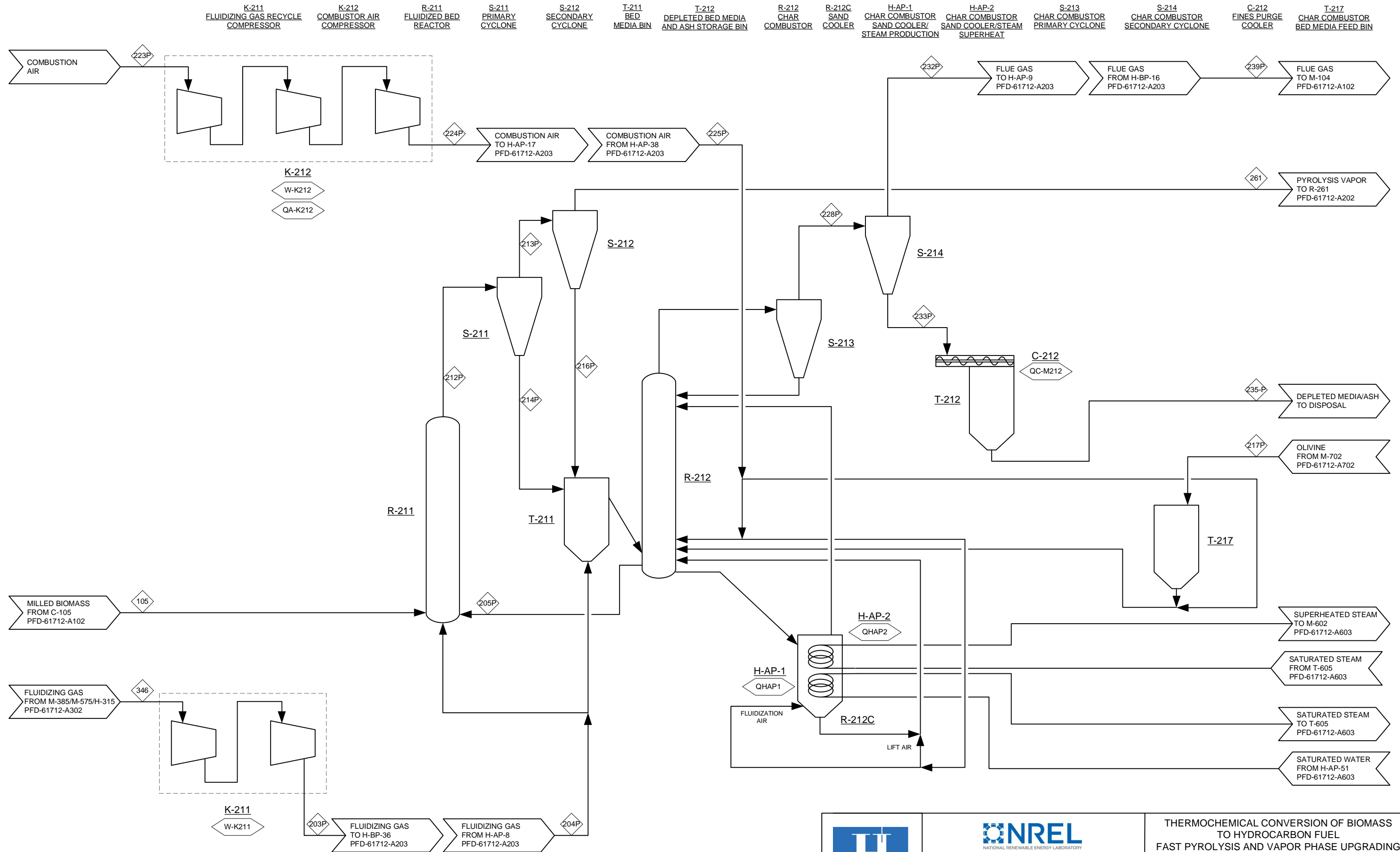
NOTE: FEEDSTOCK HANDLING COSTS ARE INCLUDED IN THE TARGET FEEDSTOCK COST PROVIDED BY THE IDAHO NATIONAL LABORATORY. ONLY A CROSS FLOW DRYER USING PROCESS FLUE GASES FOR FEED PREHEAT IS INCLUDED IN THE CONVERSION COST.

				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING			
	PROCESS FLOW DIAGRAM AREA 100: FEED HANDLING AND DRYING				Project No: 30482.00	Drawing: PFD-61712-A102	Rev: 2
	2 12/29/14 JAR	MINOR UPDATES					
1 12/12/14 DMS	ADDED HX NETWORK						
0 9/29/14 JAR	ISSUED FOR DESIGN REPORT						
Rev.	Date	By	Description				





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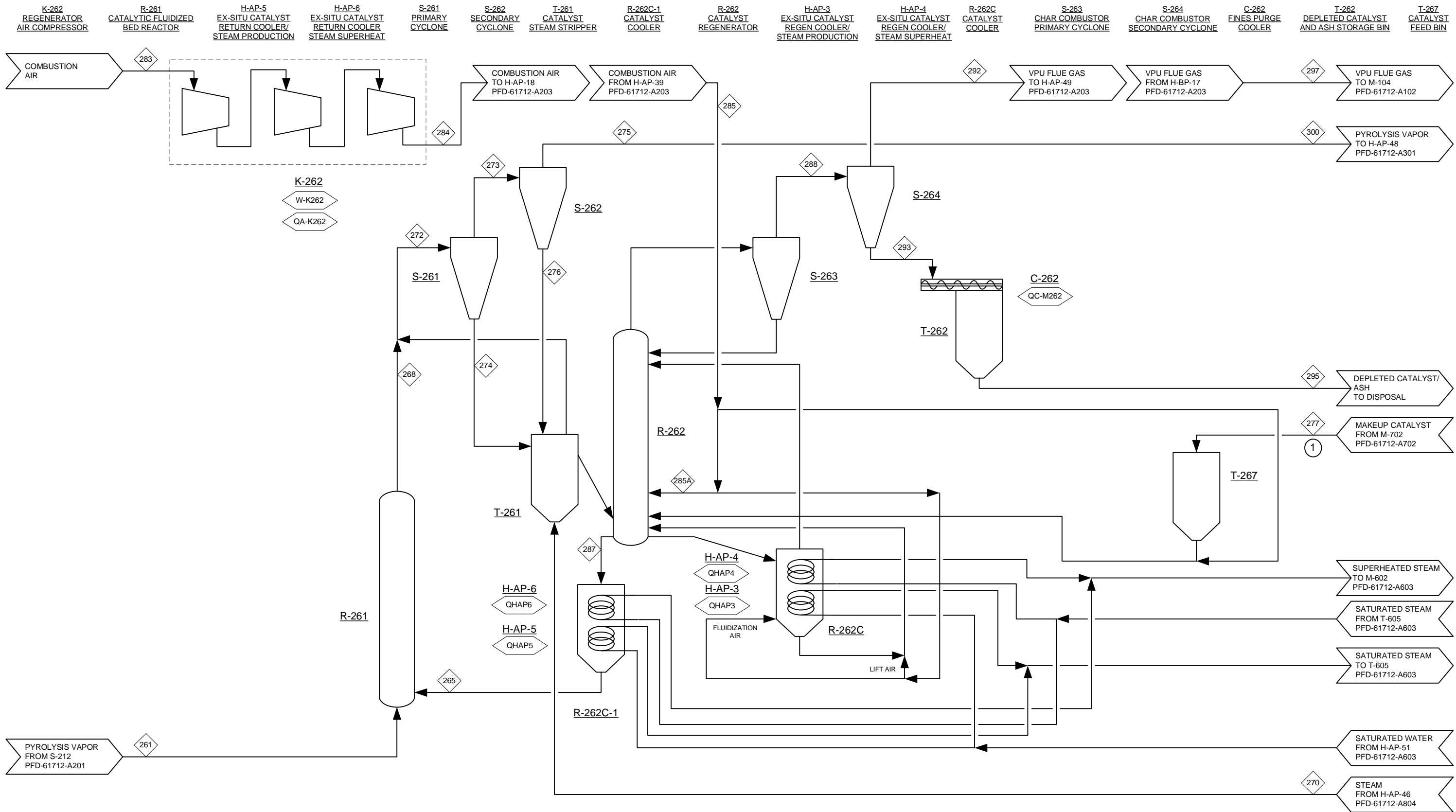


				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING	
	PROCESS FLOW DIAGRAM AREA 200: FAST PYROLYSIS				
Rev. 2 Date 12/29/14 By JAR Description MINOR UPDATES	Rev. 1 Date 12/12/14 By DMS Description ADDED HX NETWORK	Rev. 0 Date 9/29/14 By JAR Description ISSUED FOR DESIGN REPORT	Project No: 30482.00	Drawing: PFD-61712-A201	Rev: 2

Table with columns for PFD-61712-A201 and flow components (Total Flow, Temperature, Pressure, Vapor Fraction, Enthalpy Flow, and various chemical species like Argon, Nitrogen, Oxygen, SO2, NO2, Hydrogen, Ammonia, H2S, Water, Carbon Monoxide, Carbon Dioxide, Methane, Methanol, Formic Acid, Glyoxal, Ethylene, Acetaldehyde, Hydroxyacetaldehyde, Acetic Acid, Ethane, Propylene, 1-Hydroxy-2-propanone, Propionic Acid, Propane, Furan, 1-Butene, Tetrahydrofuran, N-Butane, Furfural, 2-methylfuran, Furfuryl Alcohol, n-Pentane, Pentenone, Benzene, Phenol, 1,2-Benzenediol, Hydroxymethylfurfural, 2,5-dimethylfuran, Methyl Cyclopentenone, Hydroxymethylcyclopentenone, Cyclohexanone, Levoglucosan, 1-Hexanal, Dimethoxytetrahydrofuran, Cyclohexane, N-Hexane, Hexanol, Toluene, 2-Methylphenol, 3-Methylphenol, Guaiacol, Methyl-Cyclohexane, 2-Methylhexane, Vinylphenol, O-Xylene, Ethylbenzene, 2,3-Dimethyl-phenol, 2,6-dimethoxyphenol, Vanillyl alcohol, 2,4,6-Trimethylpyridine, Cis-1,2-dimethyl cyclohexane, Trans-1,2-dimethylcyclohexane, Ethylcyclohexane, 4-Methylheptane, 2-Methyl-Benzofuran, Indane, 2-methoxy-4-vinylphenol, Syringaldehyde, n-Propylbenzene, Naphthalene, 1-Naphthalenol, Coniferyl Alddehyde, Tetralin, Isoeugenol, Decalin, 2,5-Dimethyloctane, 1-Methyl naphthalene, 1-methyl decahydronaphthene, Dibenzothiophene, Biphenyl, 5-hexyl-O-cresol, n-Heptylcyclohexane, C14H20-N35, C14H24-N5, 3,5-Dimethyldodecane, C15H26-N4, 6,8-Dimethyltridecane, 1,4-Dimethyl-Phenanthrene, N-Cetane, C18H26O, C18H28, C21H26O2, C21H34, C22H28O2, Carbon, Sulfur, Sand/Catalyst Solids, Ash, Wood, Char, Coke.

Table with columns: Heat, MMBtu/h. Rows: QA-K212 (23), QC-M212 (0), QHAP1 (5), QHAP2 (3), Q-ST212A (-7).

Table with columns: Work, hp, MMBtu/h. Rows: W-K211 (2,887 hp, 7 MMBtu/h), W-K212 (13,584 hp, 35 MMBtu/h).



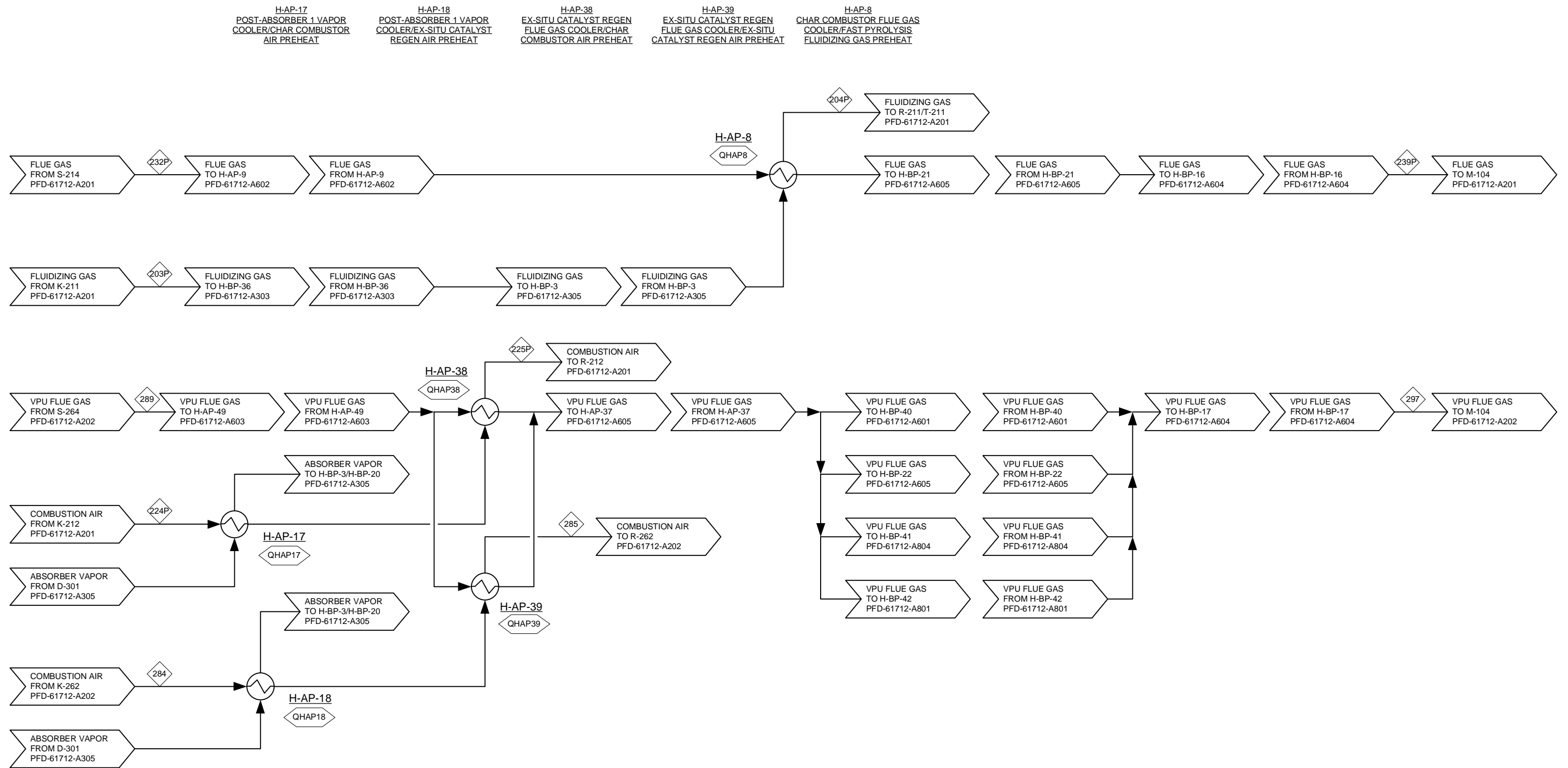
① NOTE: STREAM 277 FOR ATTRITION MAKEUP. ADDITIONAL MAKEUP TO MAINTAIN ACTIVITY AS IN TABLE 4.



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			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING	
	PROCESS FLOW DIAGRAM AREA 200: VAPOR PHASE UPGRADING			
1 0 Rev.	12/12/14 9/29/14 Date	DMS JAR By	ADDED HX NETWORK ISSUED FOR DESIGN REPORT Description	Project No: 30482.00
				Drawing: PFD-61712-A202
				Rev: 1

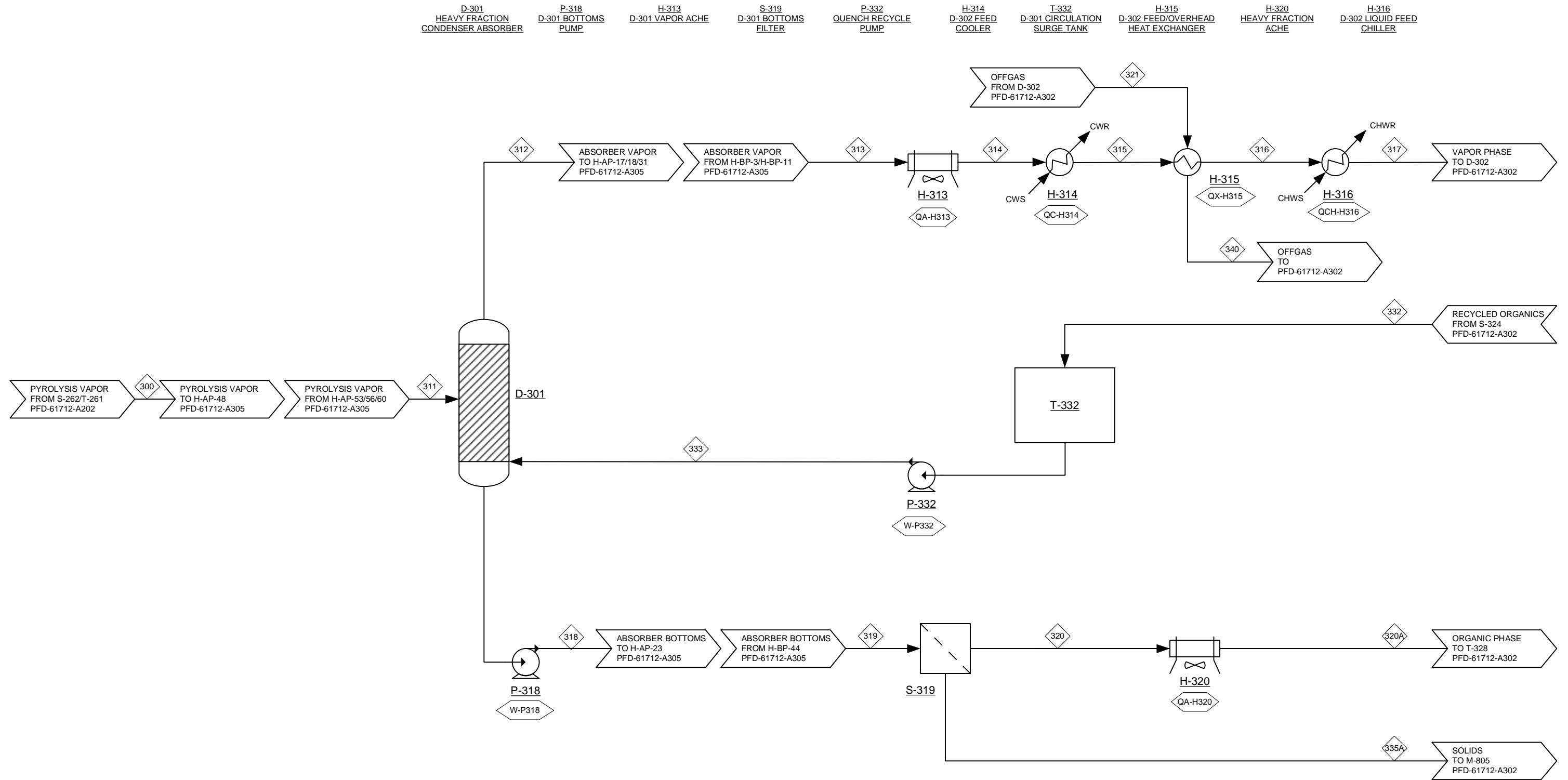




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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING		
	PROCESS FLOW DIAGRAM AREA 200: A200 HEAT RECOVERY					
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Rev.	Date	By	Description	Drawing:	PFD-61712-A203	



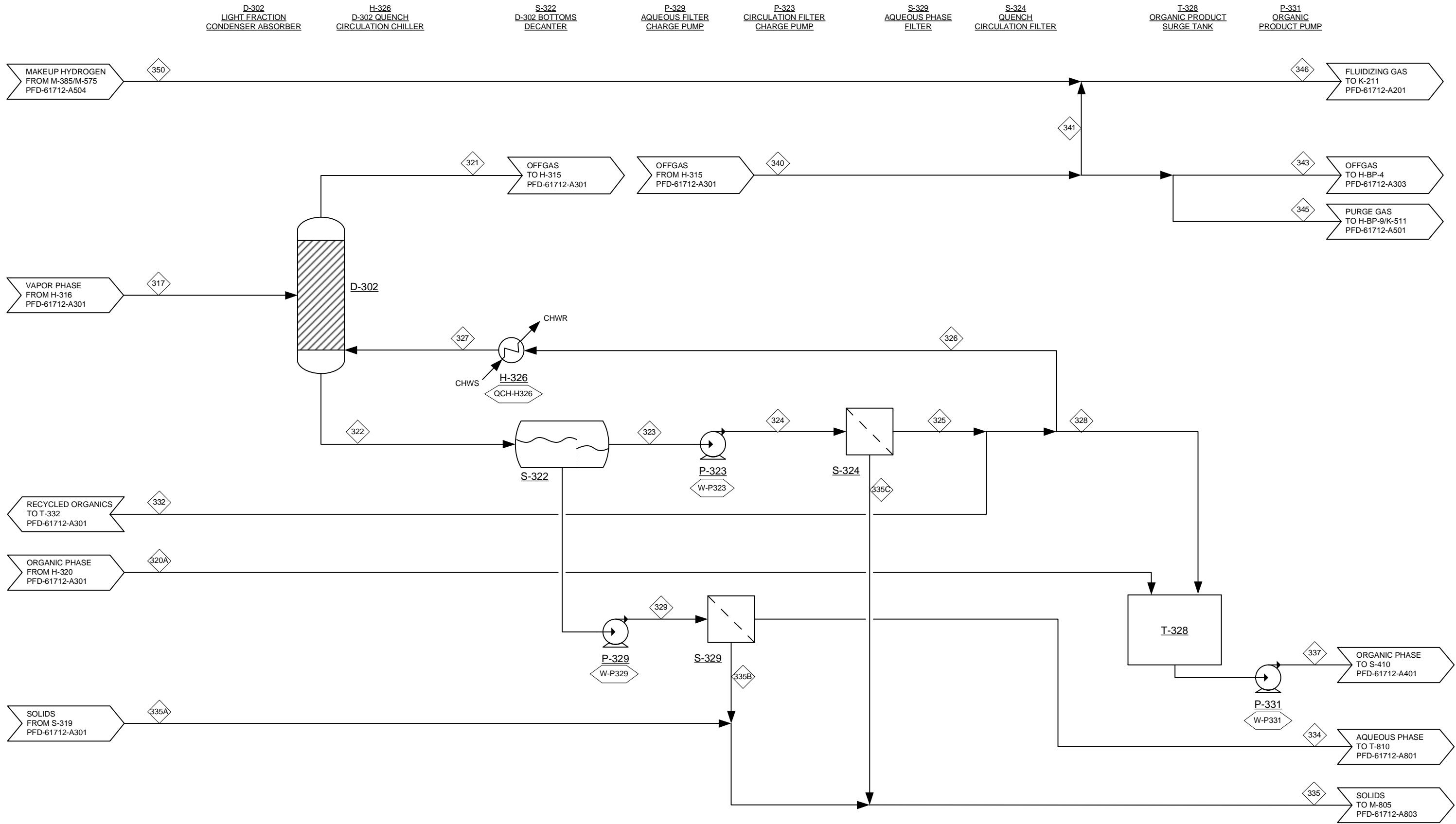




			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING												
	PROCESS FLOW DIAGRAM AREA 300: CONDENSATION STAGE 1														
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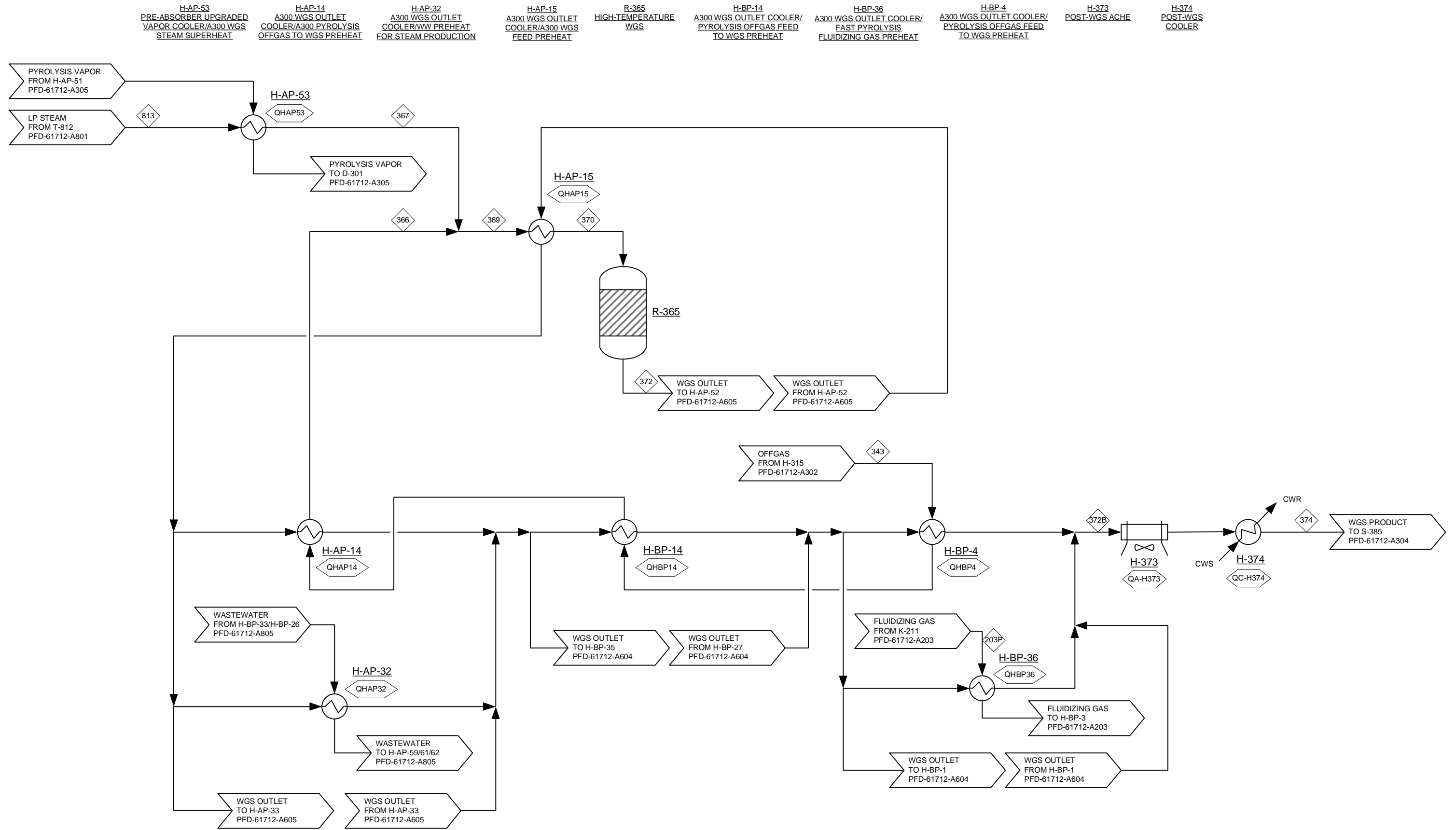




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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING																	
	PROCESS FLOW DIAGRAM AREA 300: CONDENSATION STAGE 2		Project No: 30482.00	Drawing: PFD-61712-A302	Rev: 2																
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Rev.	Date	By	Description																		
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0	9/29/14	JAR	ISSUED FOR DESIGN REPORT																		

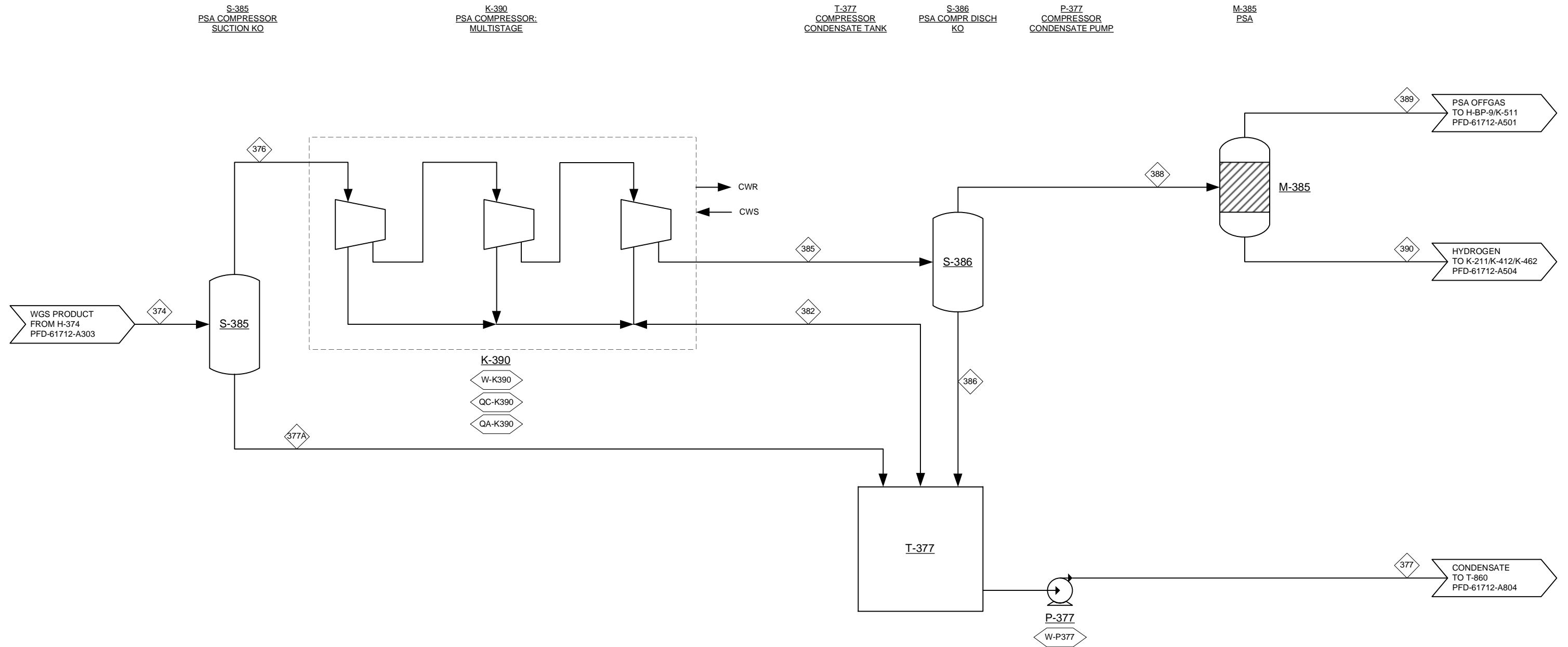






				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADE			
	PROCESS FLOW DIAGRAM AREA 300: WATER GAS SHIFT				Project No: 30482.00	Drawing: PFD-61712-A303	Rev: 1
1 0	12/12/14 9/29/14	DMS JAR	ADDED HX NETWORK ISSUED FOR DESIGN REPORT	Rev.	Date	By	Description

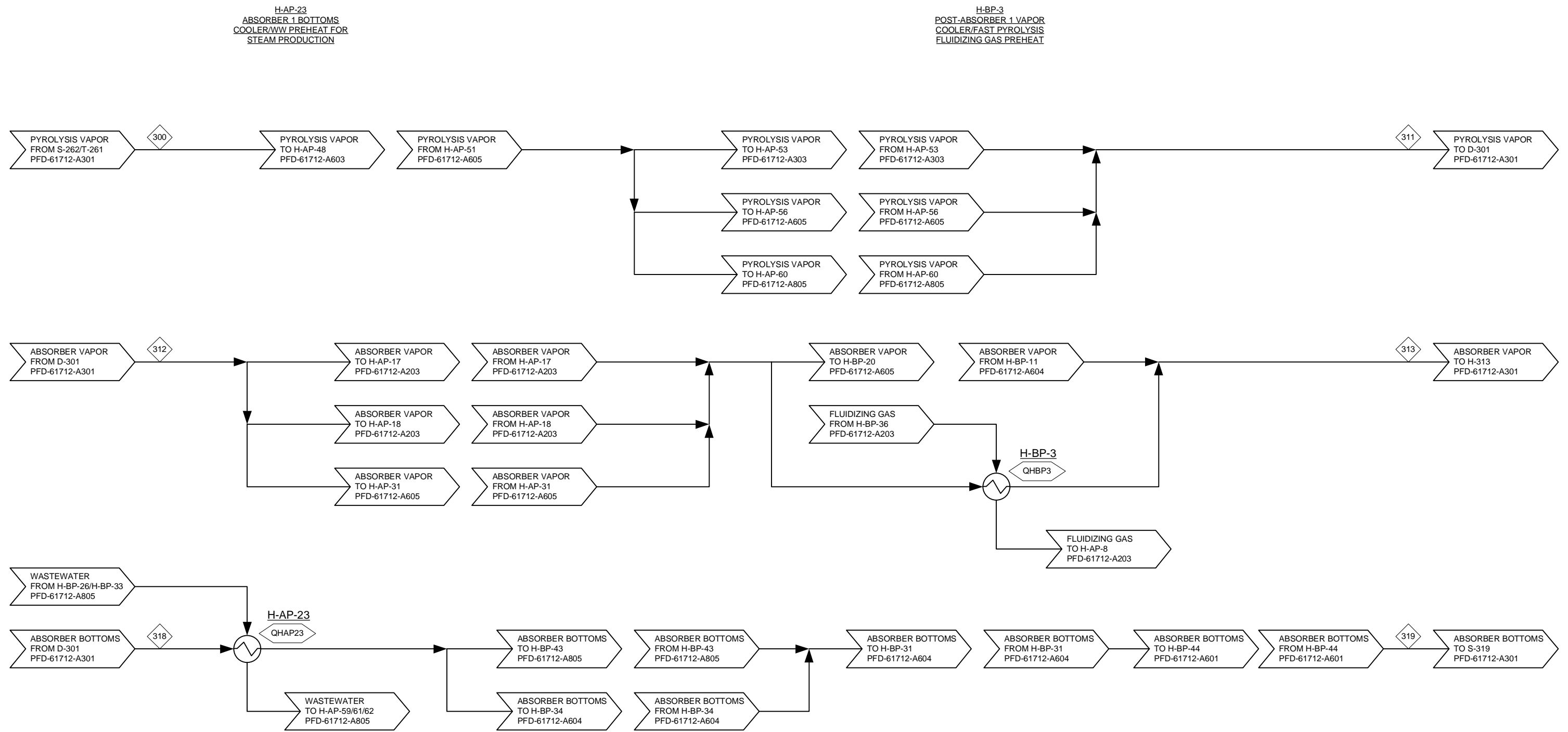


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	 NATIONAL RENEWABLE ENERGY LABORATORY				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING														
	PROCESS FLOW DIAGRAM AREA 300: PSA																		
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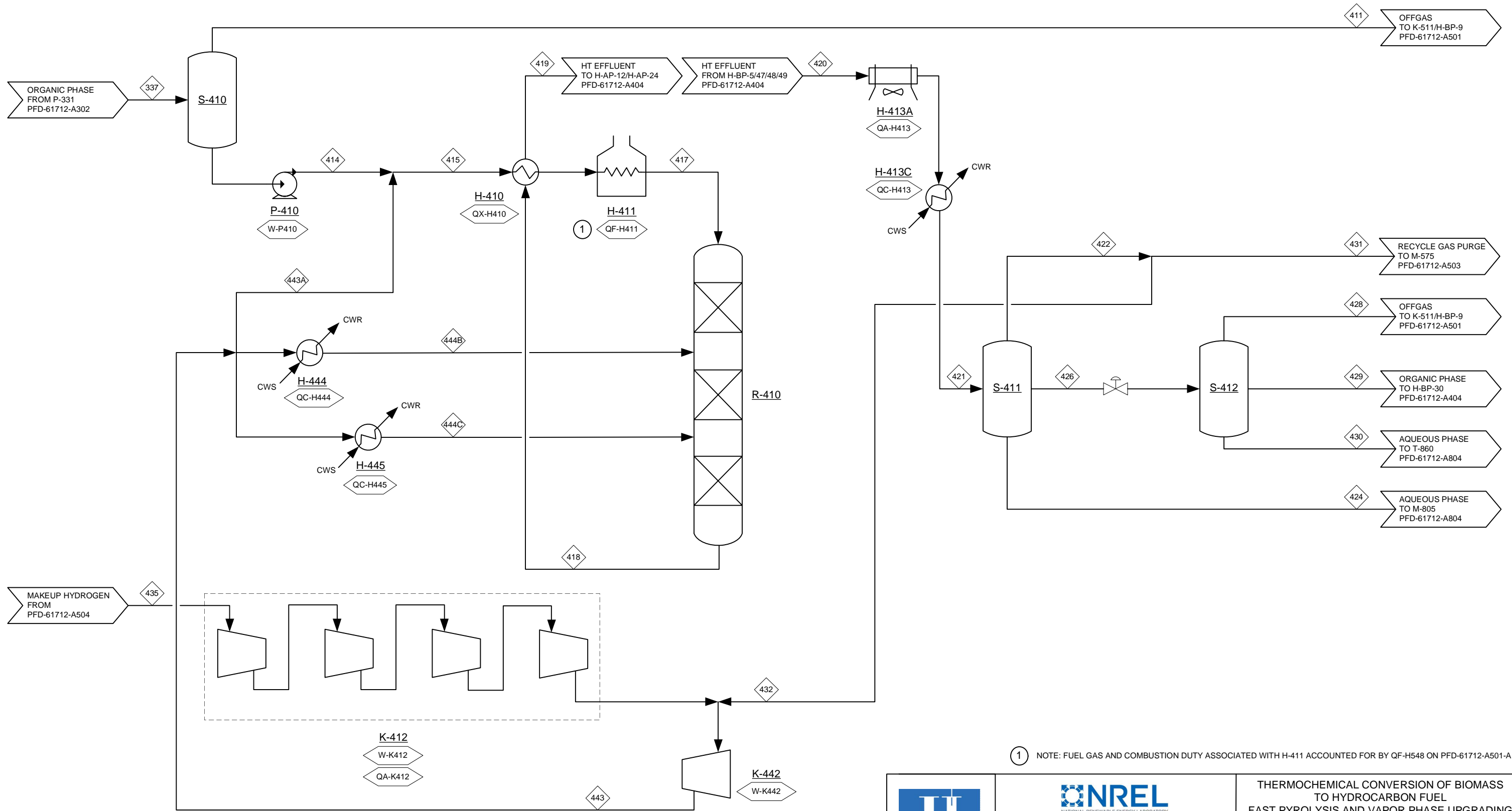


	 NATIONAL RENEWABLE ENERGY LABORATORY			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING		
	PROCESS FLOW DIAGRAM AREA 300: A300 HEAT RECOVERY					
0	12/12/14	DMS	ADDED HX NETWORK	Project No:	30482.00	Rev: 0
Rev.	Date	By	Description	Drawing:	PFD-61712-A305	





S-410 VAPOR KO DRUM    P-410 HT FEED PUMP    H-444 QUENCH HYDROGEN STAGE 2 COOLER    H-445 QUENCH HYDROGEN STAGE 3 COOLER    K-412 HYDROGEN MAKEUP COMPRESSOR    H-410 FEED-EFFLUENT EXCH    H-411 FEED FURNACE    R-410 HYDROTREATER    K-442 HYDROGEN RECYCLE COMPRESSOR    H-413A HT PRODUCT ACHE    H-413C HT PRODUCT COOLER    S-411 HP HT EFFLUENT FLASH: 3 PHASE    S-412 LP HT EFFLUENT FLASH: 3 PHASE

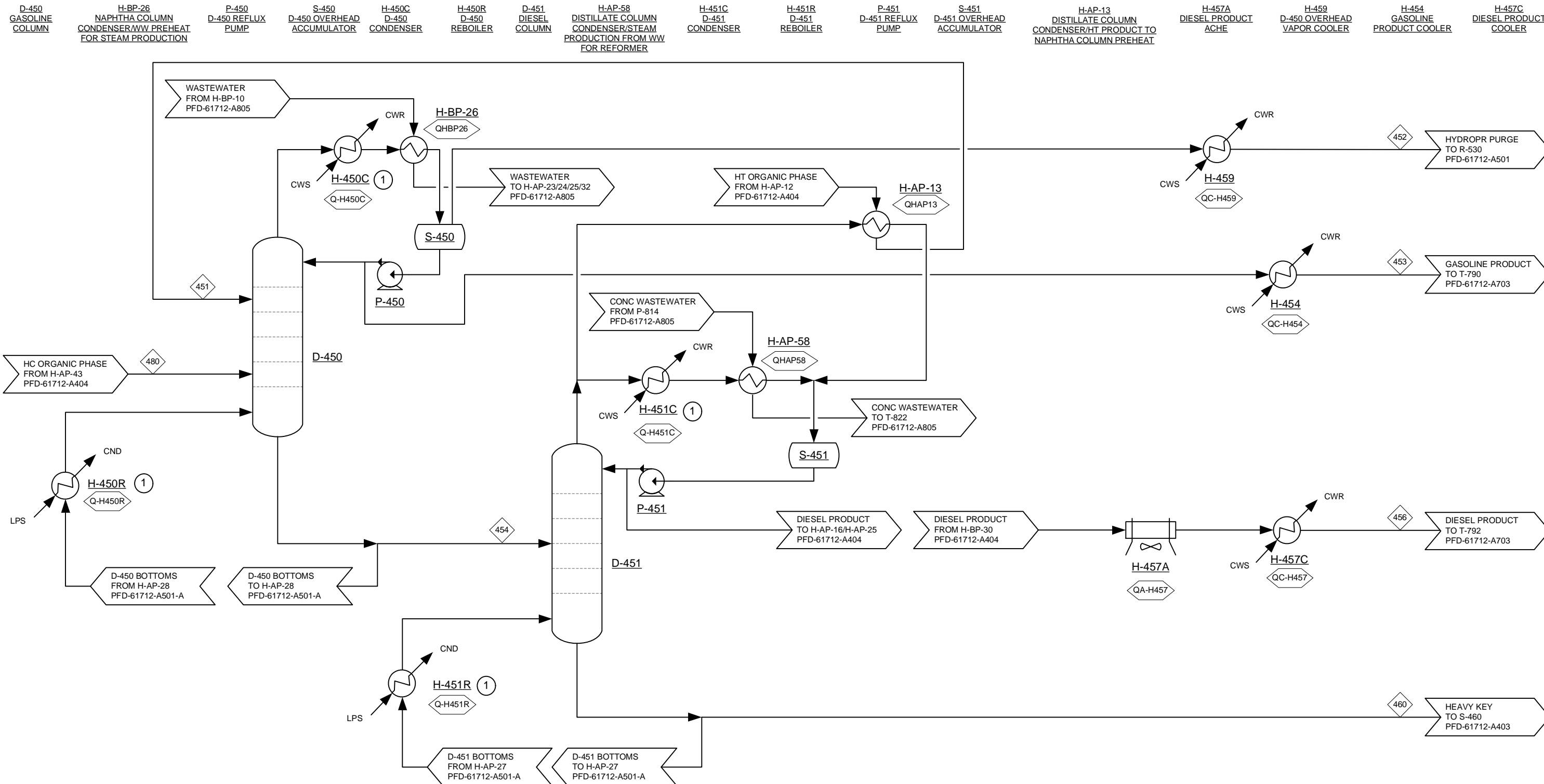


① NOTE: FUEL GAS AND COMBUSTION DUTY ASSOCIATED WITH H-411 ACCOUNTED FOR BY QF-H548 ON PFD-61712-A501-A

Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs 61712 150128.vsd

			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING	
	PROCESS FLOW DIAGRAM AREA 400: HYDROTREATING		Project No: 30482.00	Drawing: PFD-61712-A401
1    12/12/14    DMS    ADDED HX NETWORK	0    9/29/14    JAR    ISSUED FOR DESIGN REPORT	Rev.    Date    By    Description	30482.00	PFD-61712-A401





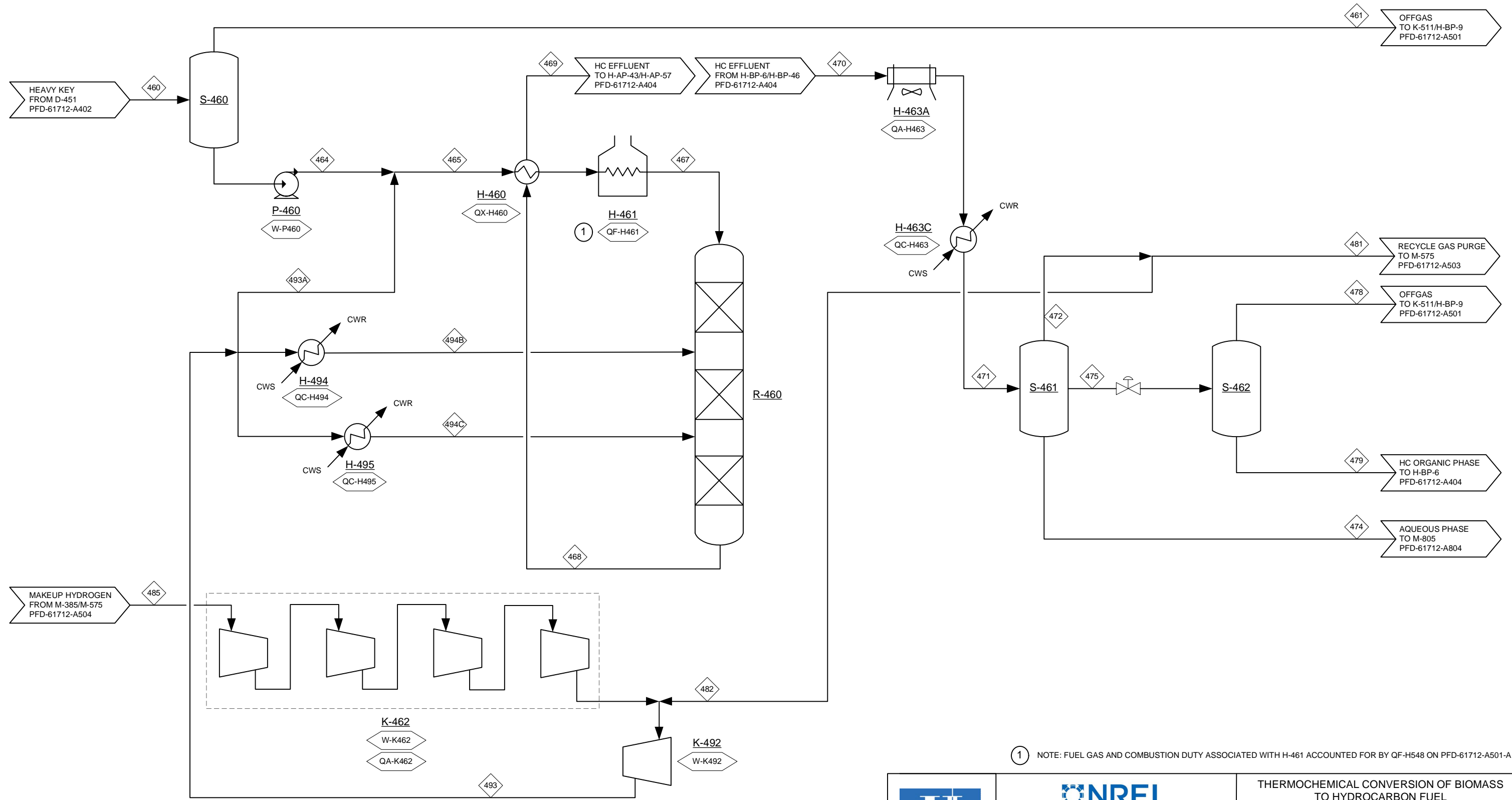
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Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochem\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712\_150128.vsd

	 <small>NATIONAL RENEWABLE ENERGY LABORATORY</small>		<b>THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING</b>						
	<b>PROCESS FLOW DIAGRAM AREA 400: PRODUCT SEPARATION</b>		Project No:	30482.00					
		Rev.	Date	By	Description	Drawn:	PFD-61712-A402	Rev:	0
		1	12/12/14	DMS	ADDED HX NETWORK				
		0	9/29/14	JAR	ISSUED FOR DESIGN REPORT				



S-460 VAPOR KO DRUM    P-460 HC FEED PUMP    H-494 QUENCH HYDROGEN STAGE 2 COOLER    H-495 QUENCH HYDROGEN STAGE 3 COOLER    K-462 HYDROGEN MAKEUP COMPRESSOR    H-460 FEED-EFFLUENT EXCH    H-461 FEED FURNACE    R-460 HYDROCRACKER    K-492 HYDROGEN RECYCLE COMPRESSOR    H-463A HC PRODUCT ACHE    H-463C HC PRODUCT COOLER    S-461 HP EFFLUENT FLASH: 3 PHASE    S-462 LP EFFLUENT FLASH



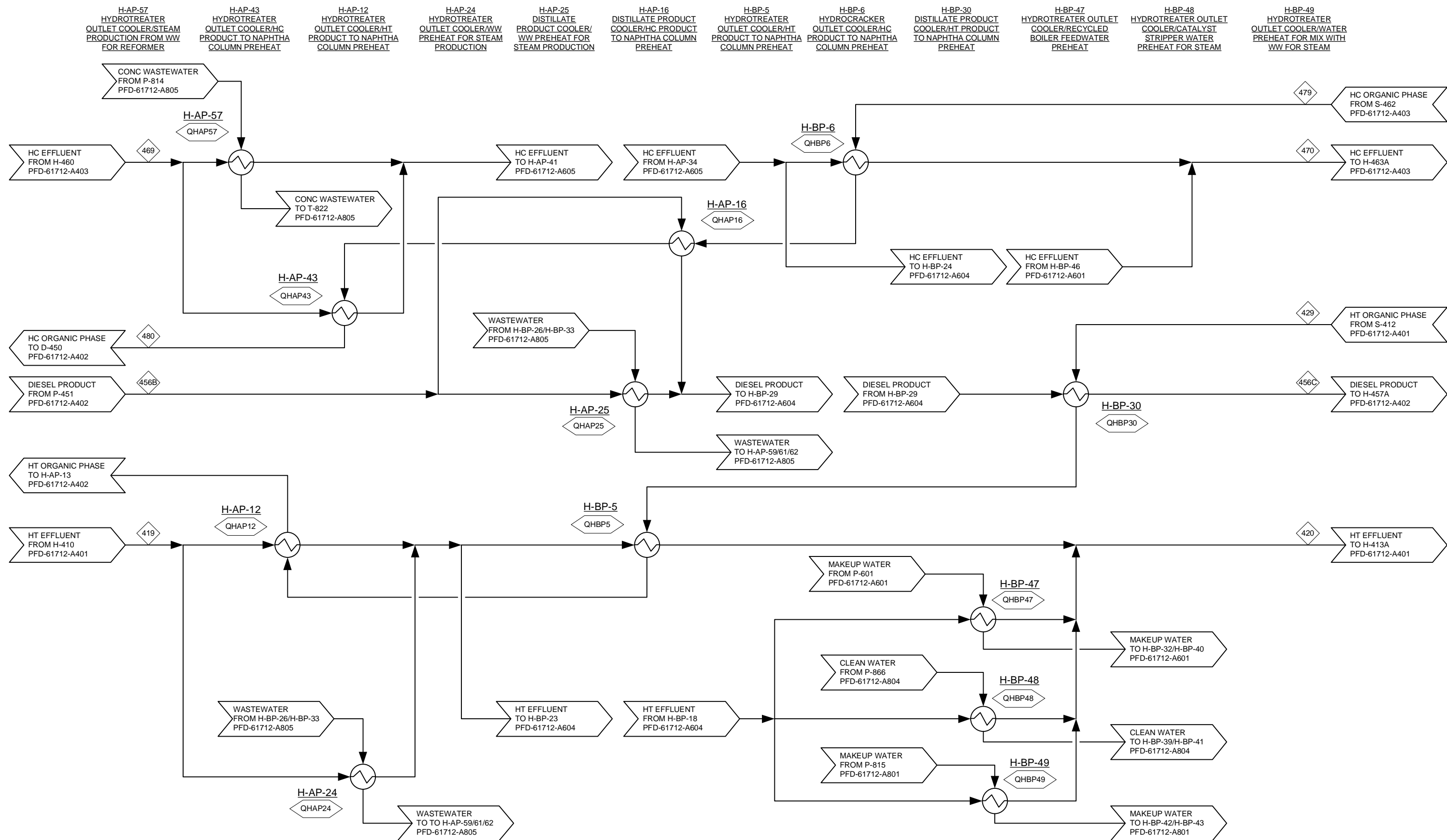
① NOTE: FUEL GAS AND COMBUSTION DUTY ASSOCIATED WITH H-461 ACCOUNTED FOR BY QF-H548 ON PFD-61712-A501-A

Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs 61712 150128.vsd

				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING	
	PROCESS FLOW DIAGRAM AREA 400: HYDROCRACKING				
2 1 0 Rev.	12/29/14 12/12/14 9/29/14 Date	JAR DMS JAR By	MINOR UPDATES ADDED HX NETWORK ISSUED FOR DESIGN REPORT Description	Project No: 30482.00	Drawing: PFD-61712-A403
				Rev:	2



Plot date: 1/29/2015 J:\11A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712 150128.vsd



	 <small>NATIONAL RENEWABLE ENERGY LABORATORY</small>	<b>THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL</b> <b>FAST PYROLYSIS AND VAPOR PHASE UPGRADING</b>									
		<b>PROCESS FLOW DIAGRAM</b> <b>AREA 400: A400 HEAT RECOVERY</b>									
<table border="1"> <thead> <tr> <th>Rev.</th> <th>Date</th> <th>By</th> <th>Description</th> </tr> </thead> <tbody> <tr> <td>0</td> <td>12/12/14</td> <td>DMS</td> <td>ADDED HX NETWORK</td> </tr> </tbody> </table>	Rev.	Date	By	Description	0	12/12/14	DMS	ADDED HX NETWORK	Project No: 30482.00	Drawing: PFD-61712-A404	Rev: 0
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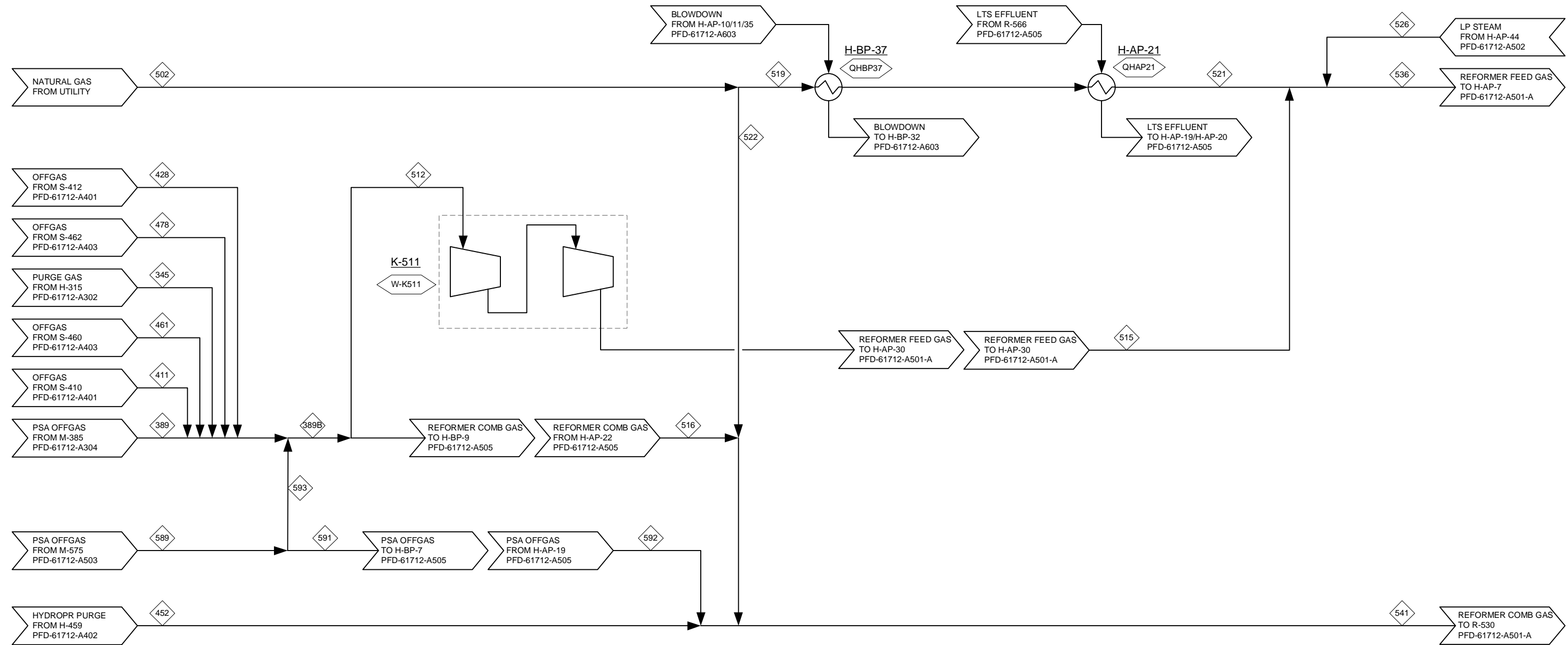


Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712\_150128.vsd

K-511  
PYROLYSIS OFFGAS  
COMPRESSOR TO REFORMER

H-BP-37  
BOILER FEEDWATER  
BLOWDOWN COOLER/NATURAL  
GAS TO REFORMER PREHEAT

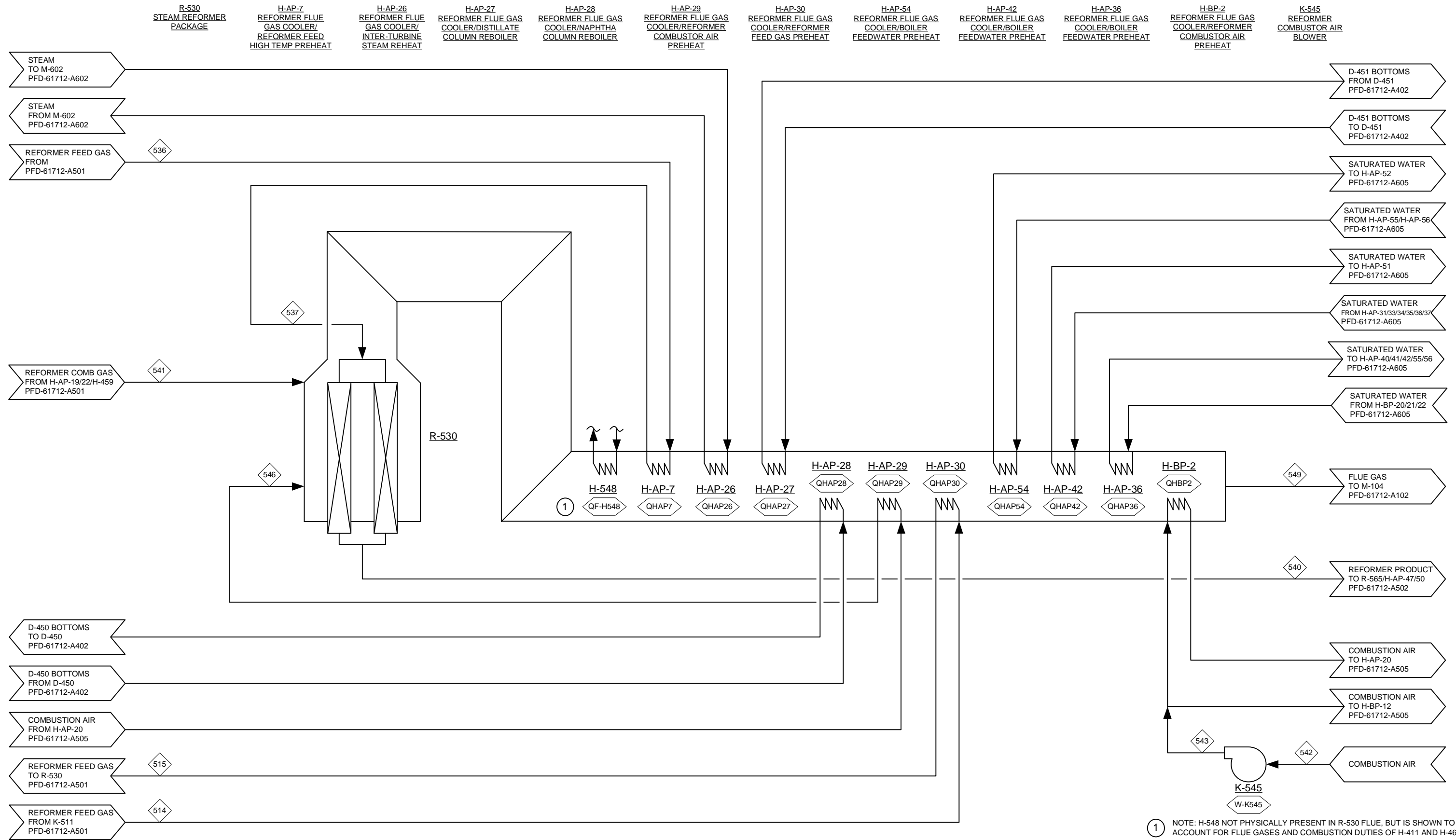
H-AP-21  
A500 LOW TEMP WGS  
COOLER/NATURAL GAS  
TO REFORMER PREHEAT



			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING	
	PROCESS FLOW DIAGRAM AREA 500: REFORMER		Project No: 30482.00	Drawing: PFD-61712-A501
1 0 Rev.	12/12/14 9/29/14 Date	DMS JAR By	ADDED HX NETWORK ISSUED FOR DESIGN REPORT Description	1

PFD-61712-A501		345	389	3898	411	428	452	461	478	502	512	515	516	519	526	536	541	589	591	592	593																		
Total Flow	lb/h	1,824	54,620	57,669	0	787	1,281	0	356	125	56,467	56,467	1,203	125	46,210	102,802	84,672	82,271	82,189	82,189	82																		
Temperature	F	95	110	109	0	110	110	0	110	60	109	500	500	60	556	526	438	109	109	109	450	109																	
Pressure	Psia	95	22	22	113	53	33	20	53	200	22	118	20	200	130	118	20	22	22	20	22																		
Vapor Fraction		1	1	1	0	1	1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1																	
Enthalpy Flow	MMBtu/h	-3	-158	-163	0	-1	-1	0	-1	0	-160	-152	-3	0	-254	-405	-294	-298	-298	-290	0																		
Argon	lb/h																																						
Nitrogen	lb/h									2	0	0	0	2		2	5	5	5	5	0																		
Oxygen	lb/h																																						
SO2	lb/h			0							0	0	0			0	0	0	0	0	0																		
NO2	lb/h																																						
Hydrogen	lb/h	213	1,135	1,432	0	56	2		27		1,402	1,402	30		0	1,402	1,534	1,504	1,503	1,503	2																		
Ammonia	lb/h			4		4	3				4	4	0			4	6	3	3	3	0																		
H2S	lb/h			5		5	3				5	5	0			5	12	9	9	9	0																		
Water	lb/h	5	514	546		18	55		9		535	535	11		45,491	46,027	508	442	441	441	0																		
Carbon Monoxide	lb/h	662	3,348	4,078		51	2		13		3,993	3,993	85		0	3,993	4,539	4,457	4,452	4,452	4																		
Carbon Dioxide	lb/h	553	38,522	39,331		139	53		42	1	38,511	38,511	820	1	0	38,512	75,367	74,569	74,494	74,494	75																		
Methane	lb/h	83	2,354	2,624		115	15		70	109	2,569	2,569	55	109	0	2,679	966	897	896	896	1																		
Methanol	lb/h			0							0	0	0			0	0	0	0	0	0																		
Formic Acid	lb/h			0							0	0	0			0	0	0	0	0	0																		
Glyoxal	lb/h			0							0	0	0			0	0	0	0	0	0																		
Ethylene	lb/h	167	4,714	4,899		11	5		7		4,797	4,797	102		0	4,797	125	18	18	18	0																		
Acetaldehyde	lb/h			0							0	0	0			0	0	0	0	0	0																		
Hydroxyacetaldehyde	lb/h			0							0	0	0			0	0	0	0	0	0																		
Acetic Acid	lb/h			0							0	0	0			0	0	0	0	0	0																		
Ethane	lb/h			265		147	94		118	7	260	260	6	7	0	267	299	199	199	199	0																		
Propylene	lb/h	56	1,594	1,650		1	1				1,616	1,616	34		0	1,616	35	0	0	0	0																		
1-Hydroxy-2-propanone	lb/h			0							0	0	0			0	0	0	0	0	0																		
Propionic Acid	lb/h			0							0	0	0			0	0	0	0	0	0																		
Propane	lb/h			14		14	15			3	14	14	0	3		17	25	10	10	10	0																		
Furan	lb/h	7	200	207							203	203	4		0	203	4																						
1-Butene	lb/h	28	790	819		1	2				802	802	17		0	802	20	1	1	1	0																		
Tetrahydrofuran	lb/h	6	169	175							171	171	4		0	171	4																						
N-Butane	lb/h			80		80	158			2	79	79	2	2		80	213	53	53	53	0																		
Furfural	lb/h			0							0	0	0			0	0	0	0	0	0																		
2-methylfuran	lb/h	7	187	193							189	189	4		0	189	4																						
Furfuryl Alcohol	lb/h			0							0	0	0			0	0	0	0	0	0																		
n-Pentane	lb/h			22		22	70				22	22	0			22	83	13	13	13	0																		
Pentone	lb/h			0							0	0	0			0	0	0	0	0	0																		
Benzene	lb/h			22		22	96				22	22	0			22	110	13	13	13	0																		
Phenol	lb/h	0	31	31		0	0				30	30	1			31	61	1	0	0	0																		
1,2-Benzenediol	lb/h	0	0	0							0	0	0			686	686	0																					
Hydroxymethylfurfural	lb/h			0							0	0	0			0	0	0	0	0	0																		
2,5-dimethylfuran	lb/h	0	1	1		0	0				1	1	0			1	0	0	0	0	0																		
Methyl Cyclopentenone	lb/h			0							0	0	0			0	0	0	0	0	0																		
Hydroxymethylcyclopentenone	lb/h			0							0	0	0			0	0	0	0	0	0																		
Cyclohexanone	lb/h			0							0	0	0			0	0	0	0	0	0																		
Levoglucosan	lb/h			0							0	0	0			0	0	0	0	0	0																		
1-Hexanal	lb/h			0							0	0	0			0	0	0	0	0	0																		
Dimethoxytetrahydrofuran	lb/h	0	0	0							0	0	0			0	0	0	0	0	0																		
Cyclohexane	lb/h	24	670	745		51	230		1		729	729	16		0	729	276	31	31	31	0																		
N-Hexane	lb/h			59		12	180		46		58	58	1			58	198	17	17	17	0																		
Hexanol	lb/h			0							0	0	0			0	0	0	0	0	0																		
Toluene	lb/h			2		2	13				2	2	0			2	15	2	2	2	0																		
2-Methylphenol	lb/h	0	0	0							0	0	0			0	0	0	0	0	0																		
3-Methyl-phenol	lb/h			0							0	0	0			0	0	0	0	0	0																		
Guaiacol	lb/h	0	0	0							0	0	0			0	0	0	0	0	0																		
Methyl-Cyclohexane	lb/h	3	76	85		6	31				83	83	2		0	83	36	4	4	4	0																		
2-Methylhexane	lb/h			24		4	88		21		24	24	1			24	95	7	7	7	0																		
VinylPhenol	lb/h	0	0	0							0	0	0			0	0	0	0	0	0																		
O-Xylene	lb/h			2		2	16				2	2	0			2	18	2	2	2	0																		

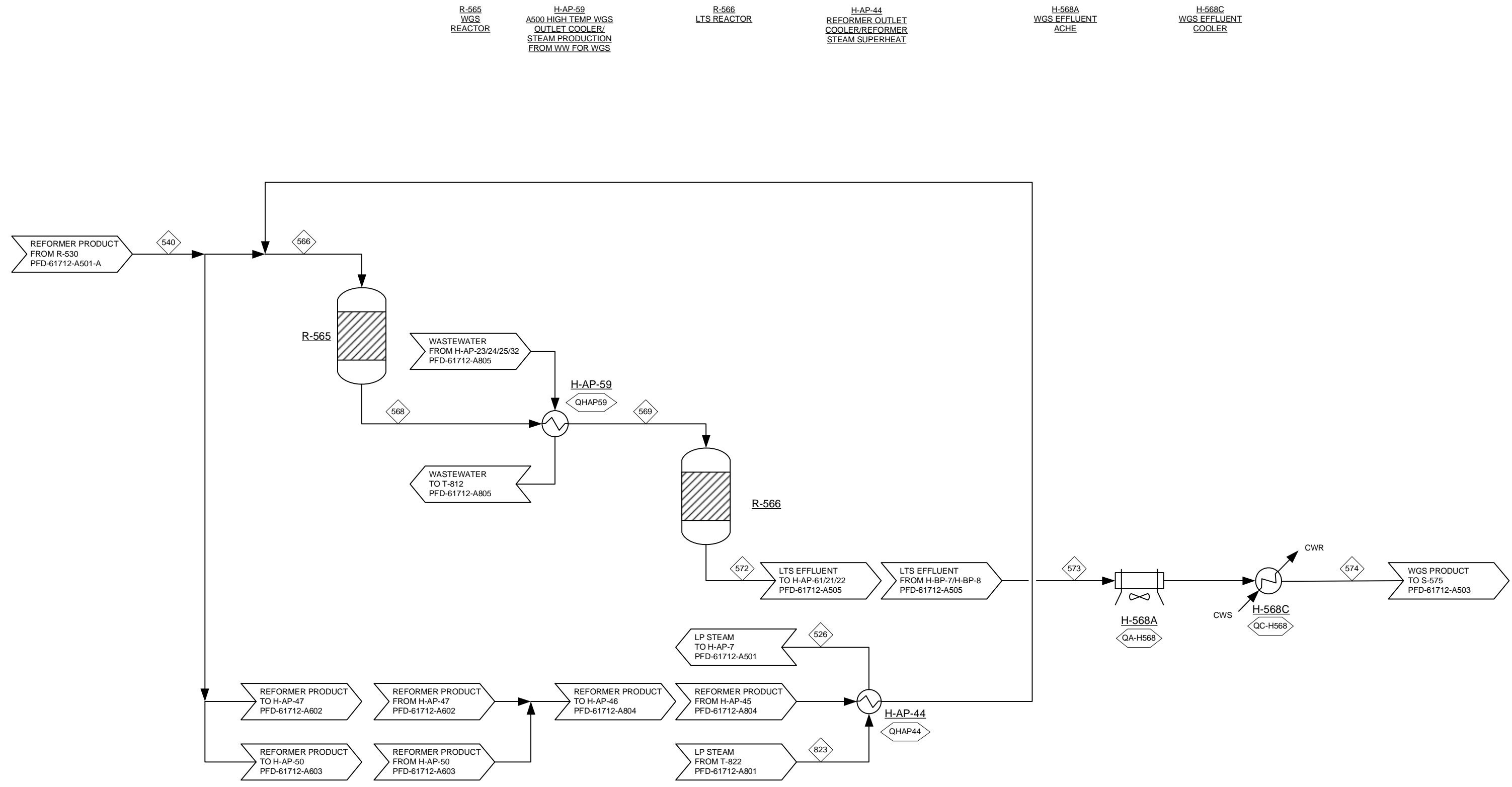
Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712\_150128.vsd





		THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING	
		PROCESS FLOW DIAGRAM AREA 500: REFORMER	
1 12/29/14 JAR MINOR UPDATES	0 12/12/14 DMS ADDED HX NETWORK	Project No: 30482.00	Drawing: PFD-61712-A501-A
Rev. Date By Description	30482.00	PFD-61712-A501-A	Rev. 1



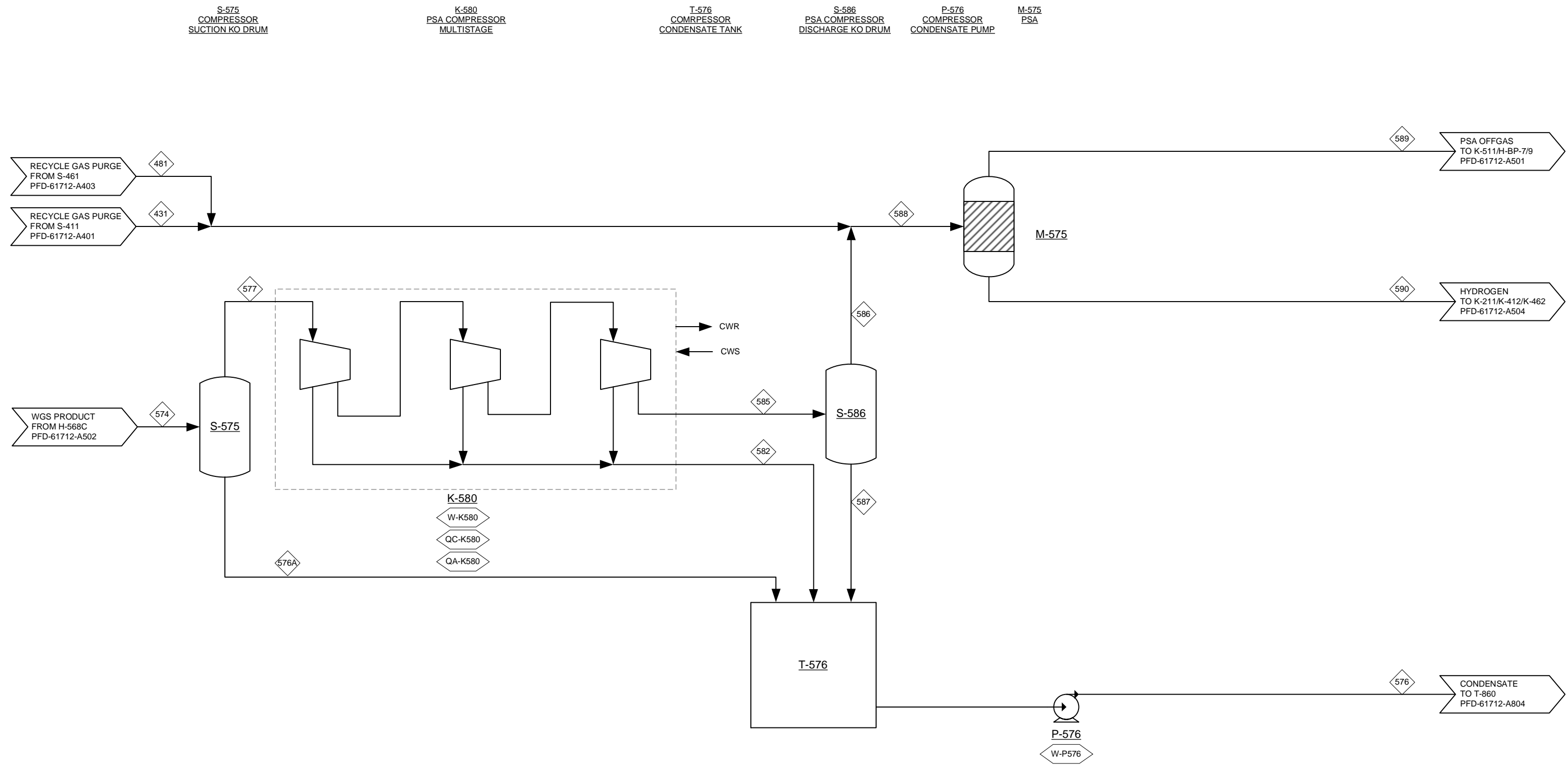
Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs 61712 150128.vsd



			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING	
	PROCESS FLOW DIAGRAM AREA 500: WATER GAS SHIFT		Project No: 30482.00	Drawing: PFD-61712-A502
1 0	12/12/14 9/29/14	DMS JAR	ADDED HX NETWORK ISSUED FOR DESIGN REPORT	Rev: 1



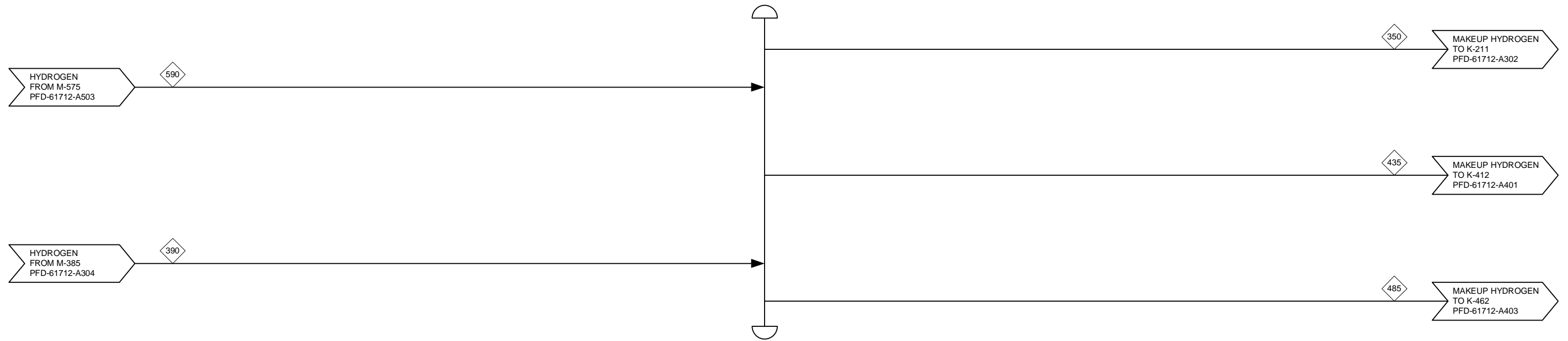
Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712\_150128.vsd





				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING		
	PROCESS FLOW DIAGRAM AREA 500: PSA					
	2 12/29/14 JAR MINOR UPDATES	1 12/12/14 DMS ADDED HX NETWORK	0 9/29/14 JAR ISSUED FOR DESIGN REPORT	Project No: 30482.00	Drawing: PFD-61712-A503	Rev: 2
Rev.	Date	By	Description			

PFD-61712-A503		431	481	574	576	576A	577	582	585	586	587	588	589	590							
Total Flow	lb/h	2,061	298	102,802	15,788	15,077	87,725	550	87,176	87,014	162	89,373	82,271	7,102							
Temperature	F	110	110	110	110	110	110	110	110	110	110	109	109	109							
Pressure	Psia	1493	1893	97	102	97	97	97	278	276	276	276	22	266							
Vapor Fraction		1	1	1	1	1	1	1	1	1	1	1	1	1							
Enthalpy Flow	MMBtu/h	-2	0	-405	-108	-103	-302	-4	-299	-298	-1	-301	-298	-3							
Argon	lb/h																				
Nitrogen	lb/h			5	0	0	5	0	5	5	0	5	5								
Oxygen	lb/h																				
SO2	lb/h			0	0	0	0	0	0	0	0	0	0								
NO2	lb/h																				
Hydrogen	lb/h	727	107	6,686	0	0	6,686	0	6,686	6,686	0	7,520	1,504	6,016							
Ammonia	lb/h	3		0	0	0	0	0	0	0	0	3	3								
H2S	lb/h	4		5	0	0	5	0	5	5	0	9	9								
Water	lb/h	9	1	16,218	15,786	15,075	1,143	550	593	432	162	442	442								
Carbon Monoxide	lb/h	414	32	4,433	0	0	4,433	0	4,433	4,433	0	4,879	4,457	422							
Carbon Dioxide	lb/h	180	19	75,035	1	1	75,033	0	75,033	75,033	0	75,232	74,569	663							
Methane	lb/h	397	80	420	0	0	420	0	420	420	0	897	897								
Methanol	lb/h			0	0	0	0	0	0	0	0	0	0								
Formic Acid	lb/h			0	0	0	0	0	0	0	0	0	0								
Glyoxal	lb/h			0	0	0	0	0	0	0	0	0	0								
Ethylene	lb/h	14	3	0	0	0	0	0	0	0	0	18	18								
Acetaldehyde	lb/h			0	0	0	0	0	0	0	0	0	0								
Hydroxyacetaldehyde	lb/h																				
Acetic Acid	lb/h			0	0	0	0	0	0	0	0	0	0								
Ethane	lb/h	157	42	0	0	0	0	0	0	0	0	199	199								
Propylene	lb/h	0	0	0	0	0	0	0	0	0	0	0	0								
1-Hydroxy-2-propanone	lb/h																				
Propionic Acid	lb/h			0	0	0	0	0	0	0	0	0	0								
Propane	lb/h	10	0	0	0	0	0	0	0	0	0	10	10								
Furan	lb/h																				
1-Butene	lb/h	1										1	1								
Tetrahydrofuran	lb/h																				
N-Butane	lb/h	53										53	53								
Furfural	lb/h																				
2-methylfuran	lb/h																				
Furfuryl Alcohol	lb/h																				
n-Pentane	lb/h	13										13	13								
Pentenone	lb/h																				
Benzene	lb/h	13										13	13								
Phenol	lb/h	0										0	0								
1,2-Benzenediol	lb/h																				
Hydroxymethylfurfural	lb/h																				
2,5-dimethylfuran	lb/h	0										0	0								
Methyl Cyclopentenone	lb/h																				
Hydroxymethylcyclopentenone	lb/h																				
Cyclohexanone	lb/h																				
Levoglucosan	lb/h																				
1-Hexanal	lb/h																				
Dimethoxytetrahydrofuran	lb/h																				
Cyclohexane	lb/h	31	0									31	31								
N-Hexane	lb/h	8	9									17	17								
Hexanol	lb/h																				
Toluene	lb/h	2										2	2								
2-Methylphenol	lb/h																				
3-Methyl-phenol	lb/h																				
Guaiacol	lb/h																				
Methyl-Cyclohexane	lb/h	4										4	4								
2-Methylhexane	lb/h	2	4									7	7								
VinylPhenol	lb/h																				
O-Xylene	lb/h	2										2	2								
Ethylbenzene	lb/h	0										0	0								
2,3-Dimethyl-phenol	lb/h																				
2,6-dimethoxyphenol	lb/h																				
Vanillyl alcohol	lb/h																				
2,4,5-Trimethylpyridine	lb/h																				
Cis-1,2-dimethyl cyclohexane	lb/h	5										5	5								
Trans-1,2-dimethylcyclohexane	lb/h	10										10	10								
Ethylcyclohexane	lb/h	1										1	1								
4-Methylheptane	lb/h	1										1	1								
2-Methyl-Benzofuran	lb/h																				
Indane	lb/h																				
2-methoxy-4-vinylphenol	lb/h																				
Syringaldehyde	lb/h																				
n-Propylbenzene	lb/h	0										0	0								
Naphthalene	lb/h	0	0									0	0								
1-Naphthalenol	lb/h																				
Coniferyl Aldehyde	lb/h																				
Tetraol	lb/h	0	0									0	0								
Isoeugenol	lb/h																				
Decalin	lb/h	0	0									0	0								
2,5-Dimethyloctane	lb/h											0	0								
1-Methyl naphthalene	lb/h	0	0									0	0								
1-methyl decahydronaphthene	lb/h	0	0									0	0								
Dibenzothiophene	lb/h																				
Biphenyl	lb/h	0	0									0	0								
5-hexyl-O-cresol	lb/h																				
n-Heptylcyclohexane	lb/h	0	0									0	0								
C14H20-N35	lb/h	0	0									0	0								
C14H24-N5	lb/h	0	0									0	0								

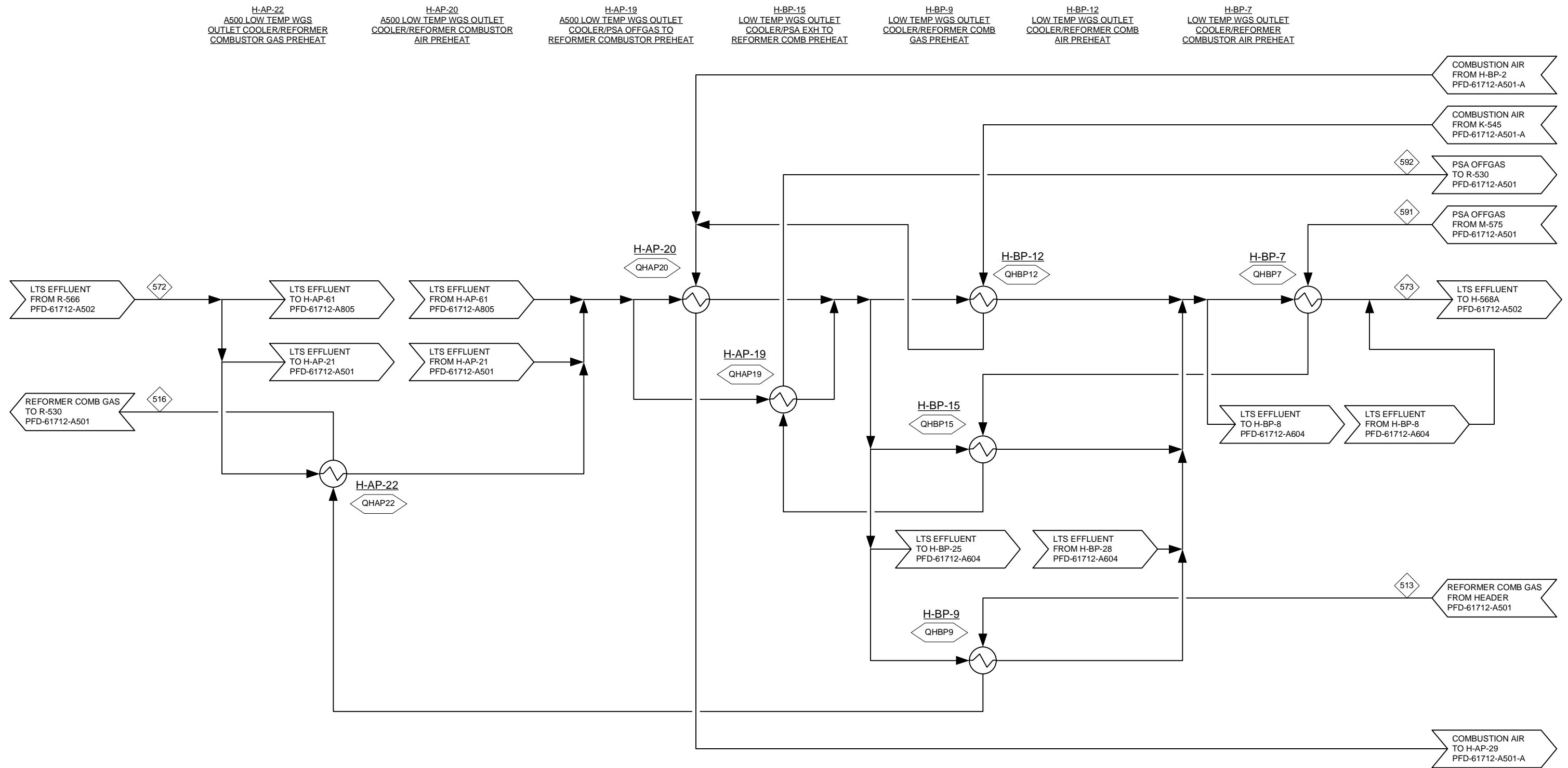






				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING					
	PROCESS FLOW DIAGRAM AREA 500: HYDROGEN DISTRIBUTION								
	1	12/12/14	DMS	ADDED HX NETWORK	Project No:	30482.00	Drawing:	PFD-61712-A504	Rev:
0	9/29/14	JAR	ISSUED FOR DESIGN REPORT						
Rev.	Date	By	Description						



Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712 150128.vsd

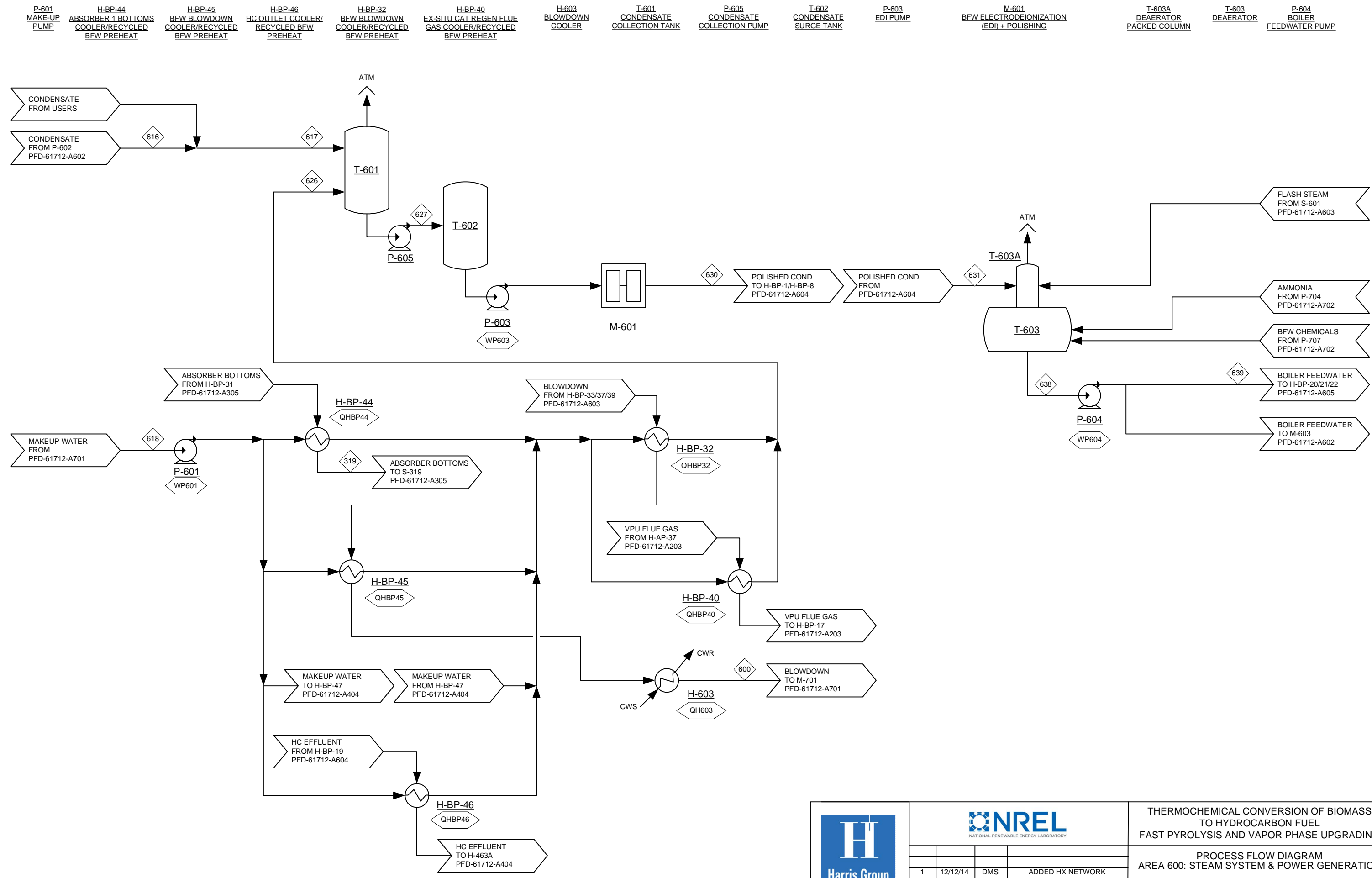




				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING		
	PROCESS FLOW DIAGRAM AREA 500: A500 HEAT RECOVERY					
0	12/12/14	DMS	ADDED HX NETWORK	Project No:	30482.00	Rev: 0
Rev.	Date	By	Description	Drawing:	PFD-61712-A505	

PFD-61712-A505		513	516	572	573	591	592															
Total Flow	lb/h	1,203	1,203	102,802	102,802	82,189	82,189															
Temperature	F	109	500	540	185	109	450															
Pressure	Psia	22	20	101	99	22	20															
Vapor Fraction		1	1	1	1	1	1															
Enthalpy Flow	MMBtu/h	-3	-3	-368	-393	-298	-290															
Argon	lb/h																					
Nitrogen	lb/h	0	0	5	5	5	5															
Oxygen	lb/h																					
SO2	lb/h	0	0	0	0	0	0															
NO2	lb/h																					
Hydrogen	lb/h	30	30	6,686	6,686	1,503	1,503															
Ammonia	lb/h	0	0	0	0	3	3															
H2S	lb/h	0	0	5	5	9	9															
Water	lb/h	11	11	16,218	16,218	441	441															
Carbon Monoxide	lb/h	85	85	4,433	4,433	4,452	4,452															
Carbon Dioxide	lb/h	820	820	75,035	75,035	74,494	74,494															
Methane	lb/h	55	55	420	420	896	896															
Methanol	lb/h	0	0	0	0	0	0															
Formic Acid	lb/h	0	0	0	0	0	0															
Glyoxal	lb/h	0	0	0	0	0	0															
Ethylene	lb/h	102	102	0	0	18	18															
Acetaldehyde	lb/h	0	0	0	0	0	0															
Hydroxyacetaldehyde	lb/h																					
Acetic Acid	lb/h	0	0	0	0	0	0															
Ethane	lb/h	6	6	0	0	199	199															
Propylene	lb/h	34	34	0	0	0	0															
1-Hydroxy-2-propanone	lb/h																					
Propionic Acid	lb/h	0	0	0	0	0	0															
Propane	lb/h	0	0	0	0	10	10															
Furan	lb/h	4	4																			
1-Butene	lb/h	17	17			1	1															
Tetrahydrofuran	lb/h	4	4																			
N-Butane	lb/h	2	2			53	53															
Furfural	lb/h																					
2-methylfuran	lb/h	4	4																			
Furfuryl Alcohol	lb/h																					
n-Pentane	lb/h	0	0			13	13															
Pentenone	lb/h																					
Benzene	lb/h	0	0			13	13															
Phenol	lb/h	1	1			0	0															
1,2-Benzenediol	lb/h	0	0																			
Hydroxymethylfurfural	lb/h																					
2,5-dimethylfuran	lb/h	0	0			0	0															
Methyl Cyclopentenone	lb/h																					
Hydroxymethylcyclopentenone	lb/h																					
Cyclohexanone	lb/h																					
Levoglucosan	lb/h																					
1-Hexanal	lb/h																					
Dimethoxytetrahydrofuran	lb/h	0	0																			
Cyclohexane	lb/h	16	16			31	31															
N-Hexane	lb/h	1	1			17	17															
Hexanol	lb/h																					
Toluene	lb/h	0	0			2	2															
2-Methylphenol	lb/h	0	0																			
3-Methyl-phenol	lb/h																					
Guaiacol	lb/h	0	0																			
Methyl-Cyclohexane	lb/h	2	2			4	4															
2-Methylhexane	lb/h	1	1			7	7															
Vinylphenol	lb/h	0	0																			
O-Xylene	lb/h	0	0			2	2															
Ethylbenzene	lb/h	0	0			0	0															
2,3-Dimethyl-phenol	lb/h	0	0																			
2,6-dimethoxyphenol	lb/h	0	0																			
Vanillyl alcohol	lb/h	0	0																			
2,4,5-Trimethylpyridine	lb/h	0	0																			
Cis-1,2-dimethyl cyclohexane	lb/h	3	3			5	5															
Trans-1,2-dimethylcyclohexane	lb/h	4	4			10	10															
Ethylcyclohexane	lb/h	0	0			1	1															
4-Methylheptane	lb/h	0	0			1	1															
2-Methyl-Benzofuran	lb/h	0	0																			
Indane	lb/h																					
2-methoxy-4-vinylphenol	lb/h	0	0																			
Syringaldehyde	lb/h																					
n-Propylbenzene	lb/h	0	0			0	0															
Naphthalene	lb/h	0	0			0	0															
1-Naphthalenol	lb/h	0	0																			
Coniferyl Aldehyde	lb/h	0	0																			
Tetralin	lb/h	0	0			0	0															
Isoeugenol	lb/h	0	0																			
Decalin	lb/h	0	0			0	0															
2,5-Dimethyloctane	lb/h	0	0			0	0															
1-Methyl naphthalene	lb/h	0	0			0	0															
1-methyl decahydronaphthene	lb/h	0	0			0	0															
Dibenzothiophene	lb/h	0	0																			
Biphenyl	lb/h	0	0			0	0															
5-hexyl-O-cresol	lb/h	0	0																			
n-Heptylcyclohexane	lb/h	0	0			0	0															
C14H20-N35	lb/h	0	0			0	0															
C14H24-N5	lb/h	0	0			0	0															
3,5-Dimethyldodecane	lb/h	0	0			0	0															
C15H26-N4	lb/h	0	0			0	0															
6,8-Dimethyltridecane	lb/h	0	0			0	0															
1,4-Dimethyl-Phenanthrene	lb/h	0	0			0	0															
N-Cetane	lb/h	0	0			0	0															
C18H26O	lb/h	0	0																			
C18H28	lb/h	0	0			0	0															
C21H26O2	lb/h	0	0			0	0															
C21H34	lb/h	0	0			0	0															
C22H28O2	lb/h	0	0			0	0															
Carbon	lb/h																					
Sulfur	lb/h																					
Sand/Catalyst Solids	lb/h																					
Ash	lb/h																					
Wood	lb/h																					
Char	lb/h																					
Coke	lb/h																					

Heat	MMBtu/h
QHAP19	4
QHAP20	6
QHAP22	0
QHBP12	0

Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Design-Model\Drawings\_30482 Pyrolysis Ex-Situ PFDs 61712150128.vsd



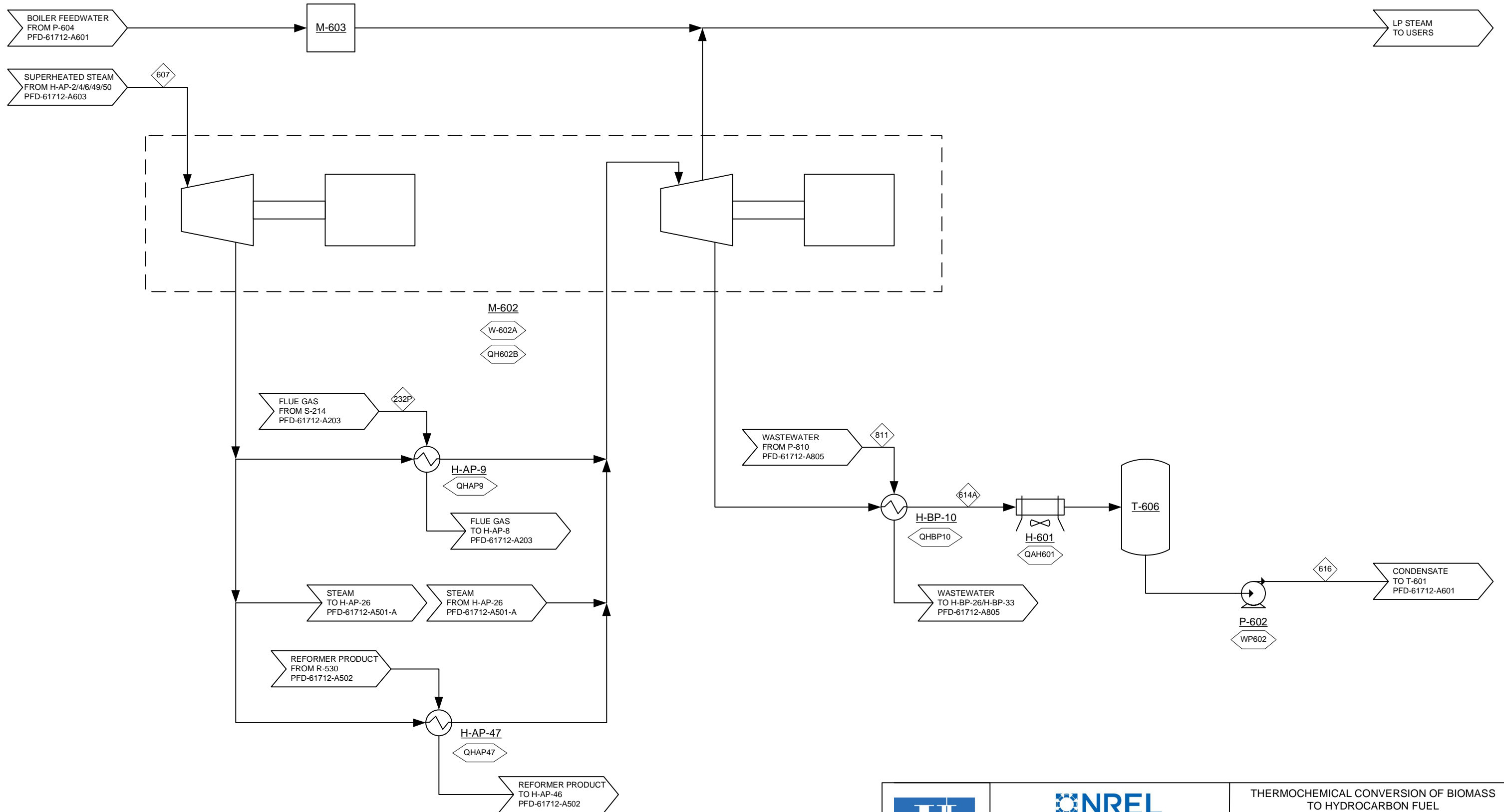
	 <small>NATIONAL RENEWABLE ENERGY LABORATORY</small>		THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING						
	PROCESS FLOW DIAGRAM AREA 600: STEAM SYSTEM & POWER GENERATION		Project No:	30482.00					
		Rev.	Date	By	Description	Drawing:	PFD-61712-A601	Rev:	1
		1	12/12/14	DMS	ADDED HX NETWORK				
		0	9/29/14	JAR	ISSUED FOR DESIGN REPORT				

PFD-61712-A601		319	600	616	617	618	626	627	630	631	638	639										
Total Flow	lb/h	19,671	6,475	317,274	317,274	6,473	6,473	323,747	323,747	323,747	323,749	323,749										
Temperature	F	175	113	136	136	60	212	138	138	232	232	235										
Pressure	Psia	123	15	25	15	15	15	15	25	22	22	1401										
Vapor Fraction							0															
Enthalpy Flow	MMBtu/h	-10	-44	-2145	-2145	-44	-43	-2189	-2189	-2158	-2158	-2156										
Argon	lb/h																					
Nitrogen	lb/h																					
Oxygen	lb/h																					
SO2	lb/h																					
NO2	lb/h																					
Hydrogen	lb/h	1																				
Ammonia	lb/h																					
H2S	lb/h																					
Water	lb/h	43	6,475	317,274	317,274	6,473	6,473	323,747	323,747	323,747	323,749	323,749										
Carbon Monoxide	lb/h	3																				
Carbon Dioxide	lb/h	7																				
Methane	lb/h	1																				
Methanol	lb/h																					
Formic Acid	lb/h																					
Glyoxal	lb/h																					
Ethylene	lb/h	2																				
Acetaldehyde	lb/h																					
Hydroxyacetaldehyde	lb/h																					
Acetic Acid	lb/h																					
Ethane	lb/h																					
Propylene	lb/h	1																				
1-Hydroxy-2-propanone	lb/h																					
Propionic Acid	lb/h																					
Propane	lb/h																					
Furan	lb/h	1																				
1-Butene	lb/h	1																				
Tetrahydrofuran	lb/h	1																				
N-Butane	lb/h																					
Furfural	lb/h																					
2-methylfuran	lb/h	1																				
Furfuryl Alcohol	lb/h																					
n-Pentane	lb/h																					
Pentenone	lb/h																					
Benzene	lb/h																					
Phenol	lb/h	11																				
1,2-Benzenediol	lb/h	20																				
Hydroxymethylfurfural	lb/h																					
2,5-dimethylfuran	lb/h	0																				
Methyl Cyclopentenone	lb/h																					
Hydroxymethylcyclopentenone	lb/h																					
Cyclohexanone	lb/h																					
Levoglucosan	lb/h																					
1-Hexanal	lb/h																					
Dimethoxytetrahydrofuran	lb/h	0																				
Cyclohexane	lb/h	9																				
N-Hexane	lb/h																					
Hexanol	lb/h																					
Toluene	lb/h																					
2-Methylphenol	lb/h	0																				
3-Methyl-phenol	lb/h																					
Guaiacol	lb/h	0																				
Methyl-Cyclohexane	lb/h	2																				
2-Methylhexane	lb/h																					
VinylPhenol	lb/h	0																				
O-Xylene	lb/h																					
Ethylbenzene	lb/h																					
2,3-Dimethyl-phenol	lb/h	30																				
2,6-dimethoxyphenol	lb/h	29																				
Vanillyl alcohol	lb/h	32																				
2,4,6-Trimethylpyridine	lb/h	2																				
Cis-1,2-dimethyl cyclohexane	lb/h	12																				
Trans-1,2-dimethylcyclohexane	lb/h	14																				
Ethylcyclohexane	lb/h																					
4-Methylheptane	lb/h																					
2-Methyl-Benzofuran	lb/h	5																				
Indane	lb/h																					
2-methoxy-4-vinylphenol	lb/h	0																				
Syringaldehyde	lb/h																					
n-Propylbenzene	lb/h																					
Naphthalene	lb/h																					
1-Naphthalenol	lb/h	16																				
Coniferyl Aldehyde	lb/h	373																				
Tetralin	lb/h																					
Isoeugenol	lb/h	0																				
Decalin	lb/h	0																				
2,5-Dimethylcyclohexane	lb/h																					
1-Methyl naphthalene	lb/h	11																				
1-methyl decahydronaphthene	lb/h	1																				
Dibenzothiophene	lb/h	41																				
Biphenyl	lb/h																					
5-hexyl-O-cresol	lb/h	333																				
n-Heptylcyclohexane	lb/h																					
C14H20-N35	lb/h																					
C14H24-N5	lb/h	185																				
3,5-Dimethyldodecane	lb/h																					
C15H26-N4	lb/h	163																				
6,8-Dimethyltridecane	lb/h																					
1,4-Dimethyl-Phenanthrene	lb/h	427																				
N-Cetane	lb/h																					
C18H26O	lb/h	4,923																				
C18H28	lb/h																					
C21H26O2	lb/h	3,421																				
C21H34	lb/h	7,751																				
C22H28O2	lb/h	1,788																				
Carbon	lb/h																					
Sulfur	lb/h																					
Sand/Catalyst Solids	lb/h	9																				
Ash	lb/h	0																				
Wood	lb/h	0																				
Char	lb/h	0																				
Coke	lb/h	1																				



Heat	MMBtu/h
QH603	0
QHBP32	0
QHBP40	0
QHBP44	0
QHBP45	0
QHBP46	0

Work	hp	MMBtu/h
WP601	0	0
WP603	13	0
WP604	740	2

M-603 STARTUP BOILER    H-AP-9 CHAR COMBUSTOR FLUE GAS COOLER/INTER-TURBINE STEAM REHEAT    H-AP-47 REFORMER OUTLET COOLER/INTER-TURBINE STEAM REHEAT    M-602 TURBINE GENERATOR    H-BP-10 STEAM TURBINE EXHAUST COOLER/WW PREHEAT FOR STEAM PRODUCTION    H-601 STEAM TURBINE CONDENSER    T-606 STEAM TURBINE CONDENSATE TANK    P-602 CONDENSATE PUMP



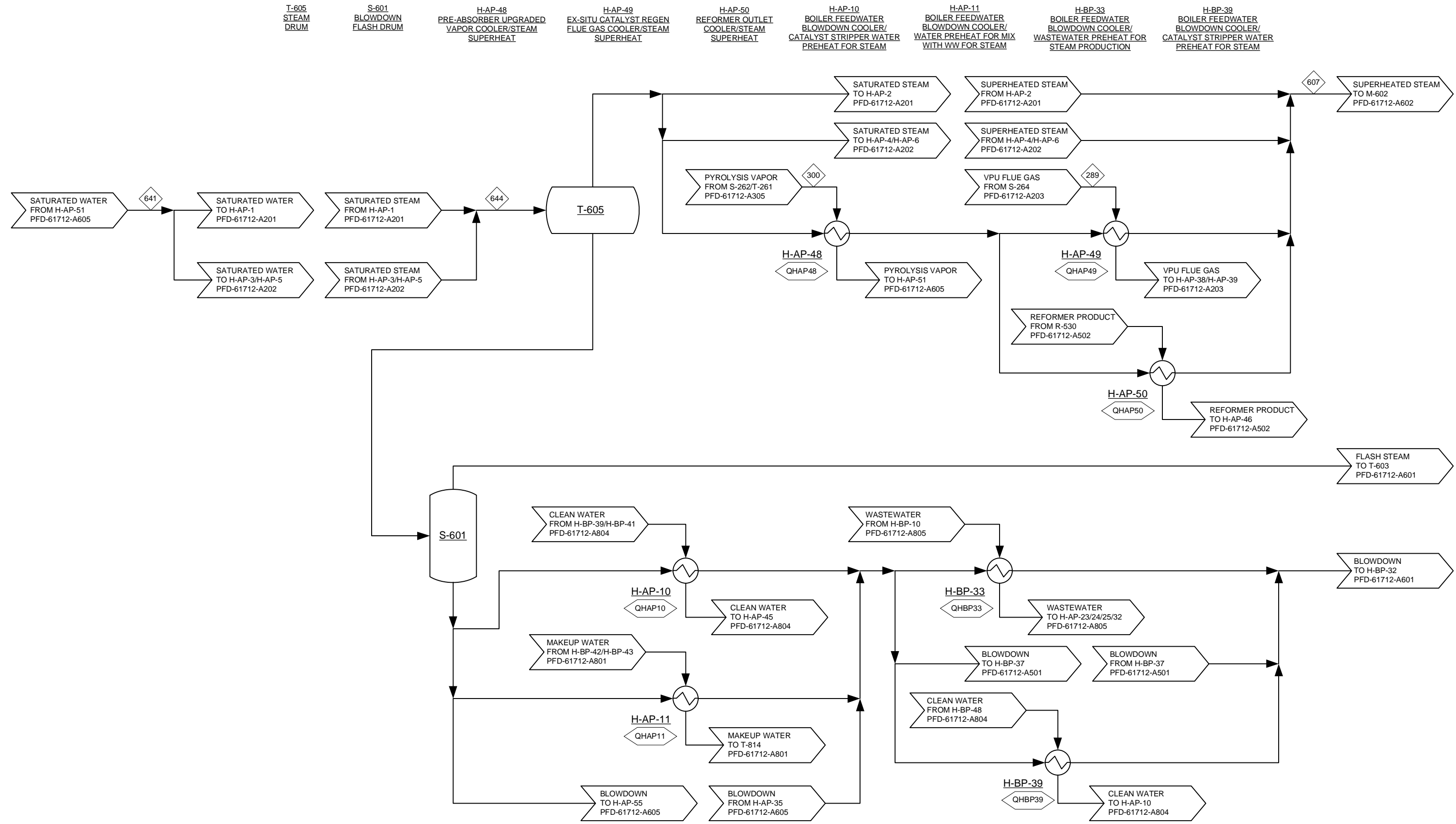
Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712\_150128.vsd

				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING		
	PROCESS FLOW DIAGRAM AREA 600: STEAM SYSTEM & POWER GENERATION				Project No: 30482.00	Drawing: PFD-61712-A602
	1    12/12/14    DMS    ADDED HX NETWORK					
	0    9/29/14    JAR    ISSUED FOR DESIGN REPORT					
	Rev.    Date    By    Description					





Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712\_150128.vsd





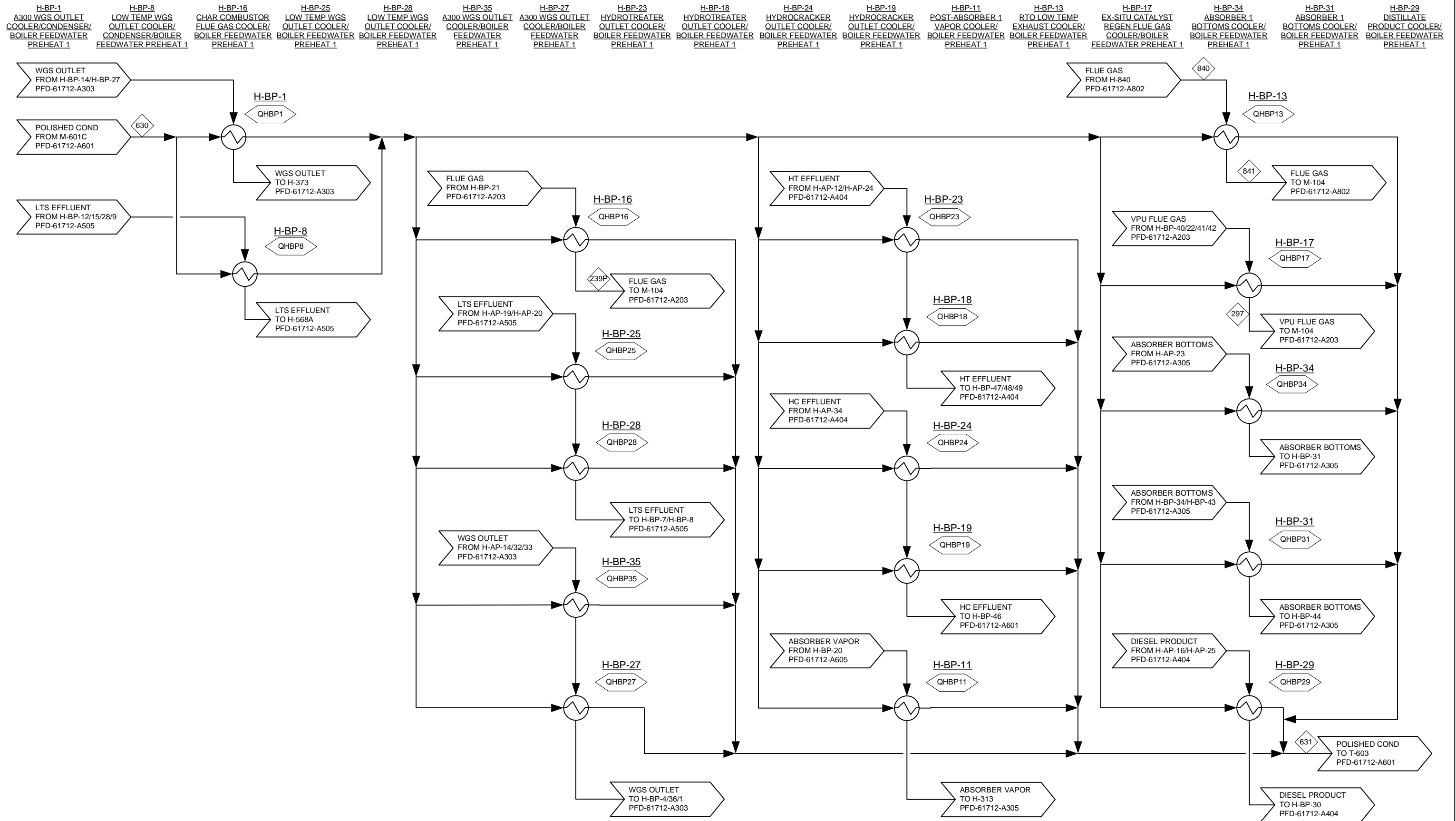


				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING		
	PROCESS FLOW DIAGRAM AREA 600: STEAM SYSTEM & POWER GENERATION					
1	12/12/14	DMS	ADDED HX NETWORK			Project No: 30482.00
0	9/29/14	JAR	ISSUED FOR DESIGN REPORT			
Rev.	Date	By	Description			Drawing: PFD-61712-A603
						Rev: 1

Table with 24 columns and 225 rows. Columns include labels like PFD-61712-A603, Total Flow, Temperature, Pressure, Vapor Fraction, and various chemical species names. Rows provide data for these species in different units (lb/h, MMbtu/h).

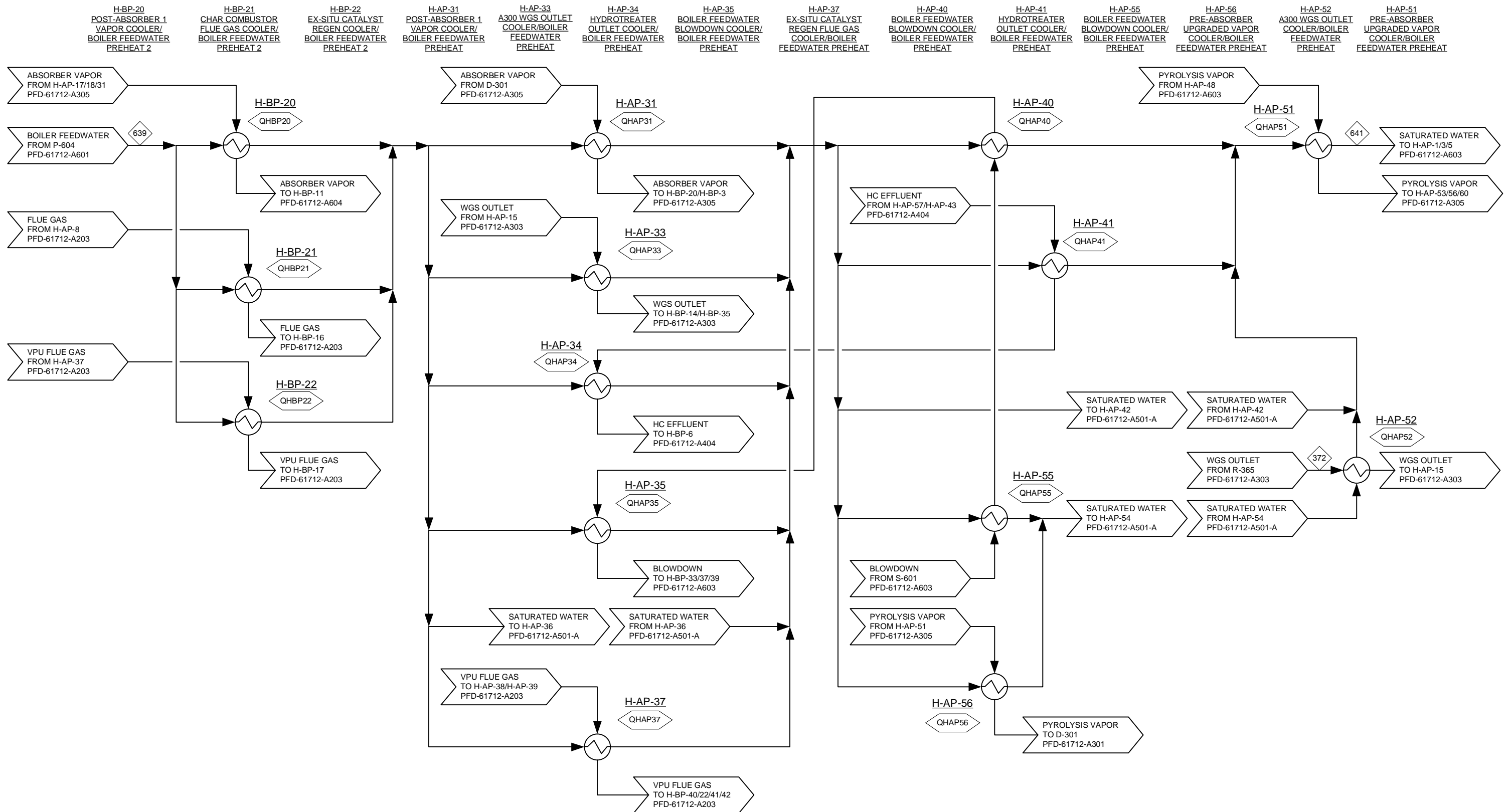
Table with 2 columns: Heat, MMbtu/h. Rows include QHAP10 through QHBP39 with values 0, 0, 6, 17, 16, 0, 0.



Table with 3 columns: Work, hp, MMbtu/h. Contains mostly zero values across multiple rows.



				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING											
	PROCESS FLOW DIAGRAM AREA 600: BOILER FEEDWATER PREHEAT 1														
<table border="1"> <thead> <tr> <th>Rev.</th> <th>Date</th> <th>By</th> <th>Description</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>12/29/14</td> <td>JAR</td> <td>MINOR UPDATES</td> </tr> <tr> <td>0</td> <td>12/12/14</td> <td>DMS</td> <td>ADDED HX NETWORK</td> </tr> </tbody> </table>	Rev.	Date	By	Description	1	12/29/14	JAR	MINOR UPDATES	0	12/12/14	DMS	ADDED HX NETWORK	Project No: 30482.00	Drawing: PFD-61712-A604	Rev: 1
Rev.	Date	By	Description												
1	12/29/14	JAR	MINOR UPDATES												
0	12/12/14	DMS	ADDED HX NETWORK												

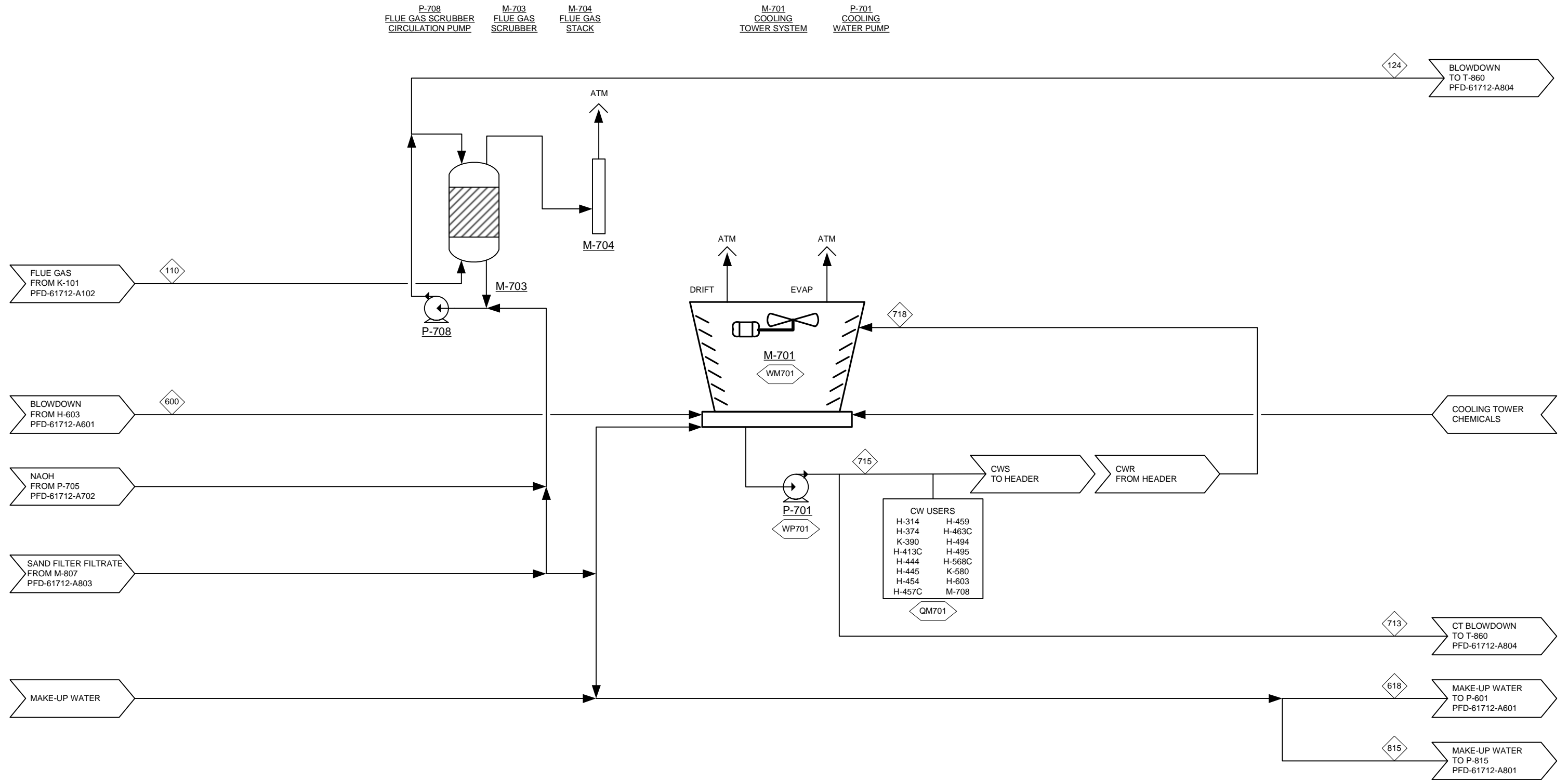




				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING			
	PROCESS FLOW DIAGRAM AREA 600: BOILER FEEDWATER PREHEAT 2				Project No: 30482.00	Drawing: PFD-61712-A605	Rev: 1
	1 0 Rev.	12/29/14 12/12/14 Date	JAR DMS By	MINOR UPDATES ADDED HX NETWORK Description			



Plot date: 1/29/2015 J:\1A - Process Solutions\30482 MREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs 61712 150128.vsd



	 <small>NATIONAL RENEWABLE ENERGY LABORATORY</small>	<b>THERMOCHEMICAL CONVERSION OF BIOMASS          TO HYDROCARBON FUEL          FAST PYROLYSIS AND VAPOR PHASE UPGRADING</b>																				
	<b>PROCESS FLOW DIAGRAM          AREA 700: COOLING WATER &amp; FLUE GAS SCRUBBER</b>																					
	<table border="1" style="width: 100%; border-collapse: collapse;"> <thead> <tr> <th>Rev.</th> <th>Date</th> <th>By</th> <th>Description</th> </tr> </thead> <tbody> <tr> <td>2</td> <td>12/29/14</td> <td>JAR</td> <td>MINOR UPDATES</td> </tr> <tr> <td>1</td> <td>12/12/14</td> <td>DMS</td> <td>ADDED HX NETWORK</td> </tr> <tr> <td>0</td> <td>9/29/14</td> <td>JAR</td> <td>ISSUED FOR DESIGN REPORT</td> </tr> </tbody> </table>	Rev.	Date	By	Description	2	12/29/14	JAR	MINOR UPDATES	1	12/12/14	DMS	ADDED HX NETWORK	0	9/29/14	JAR	ISSUED FOR DESIGN REPORT	<table border="1" style="width: 100%; border-collapse: collapse;"> <tr> <td style="width: 50%;">Project No: 30482.00</td> <td style="width: 50%;">Drawing: PFD-61712-A701</td> </tr> <tr> <td style="width: 50%;"></td> <td style="width: 50%; text-align: right;">Rev: 2</td> </tr> </table>	Project No: 30482.00	Drawing: PFD-61712-A701		Rev: 2
Rev.	Date	By	Description																			
2	12/29/14	JAR	MINOR UPDATES																			
1	12/12/14	DMS	ADDED HX NETWORK																			
0	9/29/14	JAR	ISSUED FOR DESIGN REPORT																			
Project No: 30482.00	Drawing: PFD-61712-A701																					
	Rev: 2																					

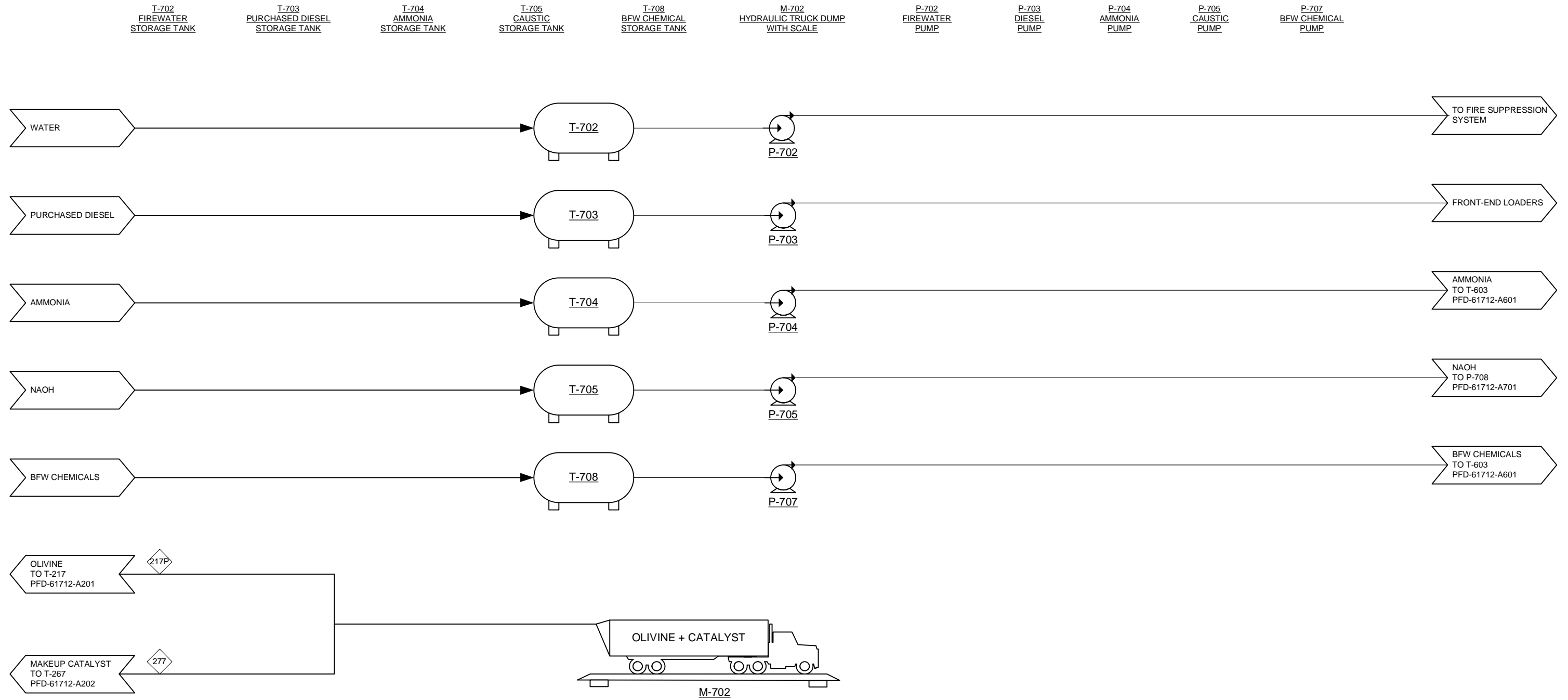
PFD-61712-A701		110	124	600	618	713	715	718	815										
Total Flow	lb/h	770,436	23,429	6,475	6,473	10,937	2,618,485	2,618,485	1,926										
Temperature	F	160	123	113	60	90	90	110	60										
Pressure	Psia	16	15	15	15	15	75	60	15										
Vapor Fraction		1																	
Enthalpy Flow	MMBtu/h	-1005	-160	-44	-44	-75	-17932	-17876	-13										
Argon	lb/h	8,183	0																
Nitrogen	lb/h	480,047	0																
Oxygen	lb/h	38,240	0																
SO2	lb/h	107	0																
NO2	lb/h	17	0																
Hydrogen	lb/h																		
Ammonia	lb/h																		
H2S	lb/h																		
Water	lb/h	42,895	23,429	6,475	6,473	10,937	2,618,485	2,618,485	1,926										
Carbon Monoxide	lb/h																		
Carbon Dioxide	lb/h	200,947	0																
Methane	lb/h																		
Methanol	lb/h																		
Formic Acid	lb/h																		
Glyoxal	lb/h																		
Ethylene	lb/h																		
Acetaldehyde	lb/h																		
Hydroxyacetaldehyde	lb/h																		
Acetic Acid	lb/h																		
Ethane	lb/h																		
Propylene	lb/h																		
1-Hydroxy-2-propanone	lb/h																		
Propionic Acid	lb/h																		
Propane	lb/h																		
Furan	lb/h																		
1-Butene	lb/h																		
Tetrahydrofuran	lb/h																		
N-Butane	lb/h																		
Furfural	lb/h																		
2-methylfuran	lb/h																		
Furfuryl Alcohol	lb/h																		
n-Pentane	lb/h																		
Pentenone	lb/h																		
Benzene	lb/h																		
Phenol	lb/h																		
1,2-Benzenediol	lb/h																		
Hydroxymethylfurfural	lb/h																		
2,5-dimethylfuran	lb/h																		
Methyl Cyclopentenone	lb/h																		
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N-Hexane	lb/h																		
Hexanol	lb/h																		
Toluene	lb/h																		
2-Methylphenol	lb/h																		
3-Methyl-phenol	lb/h																		
Guaiacol	lb/h																		
Methyl-Cyclohexane	lb/h																		
2-Methylhexane	lb/h																		
VinylPhenol	lb/h																		
O-Xylene	lb/h																		
Ethylbenzene	lb/h																		
2,3-Dimethyl-phenol	lb/h																		
2,6-dimethoxyphenol	lb/h																		
Vanillyl alcohol	lb/h																		
2,4,5-Trimethylpyridine	lb/h																		
Cis-1,2-dimethyl cyclohexane	lb/h																		
Trans-1,2-dimethylcyclohexane	lb/h																		
Ethylcyclohexane	lb/h																		
4-Methylheptane	lb/h																		
2-Methyl-Benzofuran	lb/h																		
Indane	lb/h																		
2-methoxy-4-vinylphenol	lb/h																		
Syringaldehyde	lb/h																		
n-Propylbenzene	lb/h																		
Naphthalene	lb/h																		
1-Naphthalenol	lb/h																		
Coniferyl Aldehyde	lb/h																		
Tetraol	lb/h																		
Isoeugenol	lb/h																		
Decalin	lb/h																		
2,5-Dimethyloctane	lb/h																		
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C14H20-N35	lb/h																		
C14H24-N5	lb/h																		
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C15H26-N4	lb/h																		
6,8-Dimethyltridecane	lb/h																		
1,4-Dimethyl-Phenanthrene	lb/h																		
N-Cetane	lb/h																		
C18H26O	lb/h																		
C18H28	lb/h																		
C21H26O2	lb/h																		
C21H34	lb/h																		
C22H28O2	lb/h																		
Carbon	lb/h																		
Sulfur	lb/h																		
Sand/Catalyst Solids	lb/h																		
Ash	lb/h																		
Wood	lb/h																		
Char	lb/h																		
Coke	lb/h																		



Heat	MMBtu/h
QM701	56

Work	hp	MMBtu/h
WM701	147	0
WP701	252	1



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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING		
	PROCESS FLOW DIAGRAM AREA 700: MATERIALS STORAGE					
	1 0 Rev.	12/12/14 9/29/14 Date	DMS JAR By	ADDED HX NETWORK ISSUED FOR DESIGN REPORT Description	Project No: 30482.00	Drawing: PFD-61712-A702



K-701  
PLANT AIR  
COMPRESSOR

S-701  
INSTRUMENT  
AIR DRYER

T-701  
PLANT AIR  
RECEIVER

T-792  
DIESEL PRODUCT  
STORAGE TANK

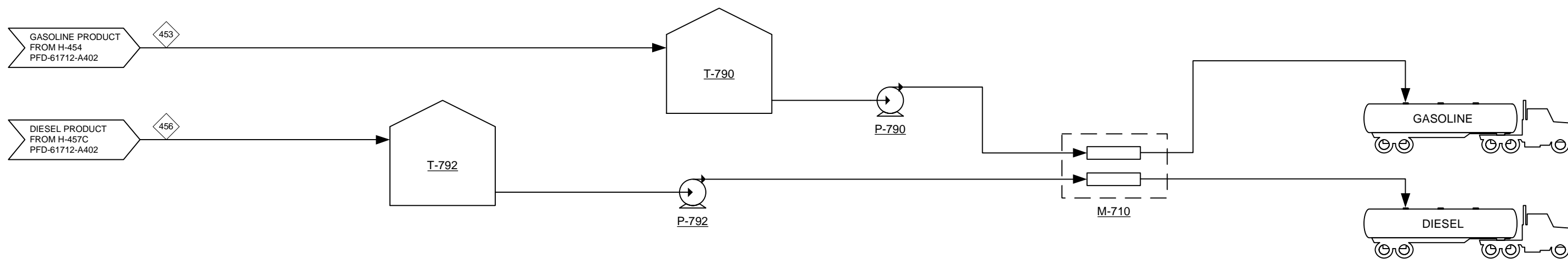
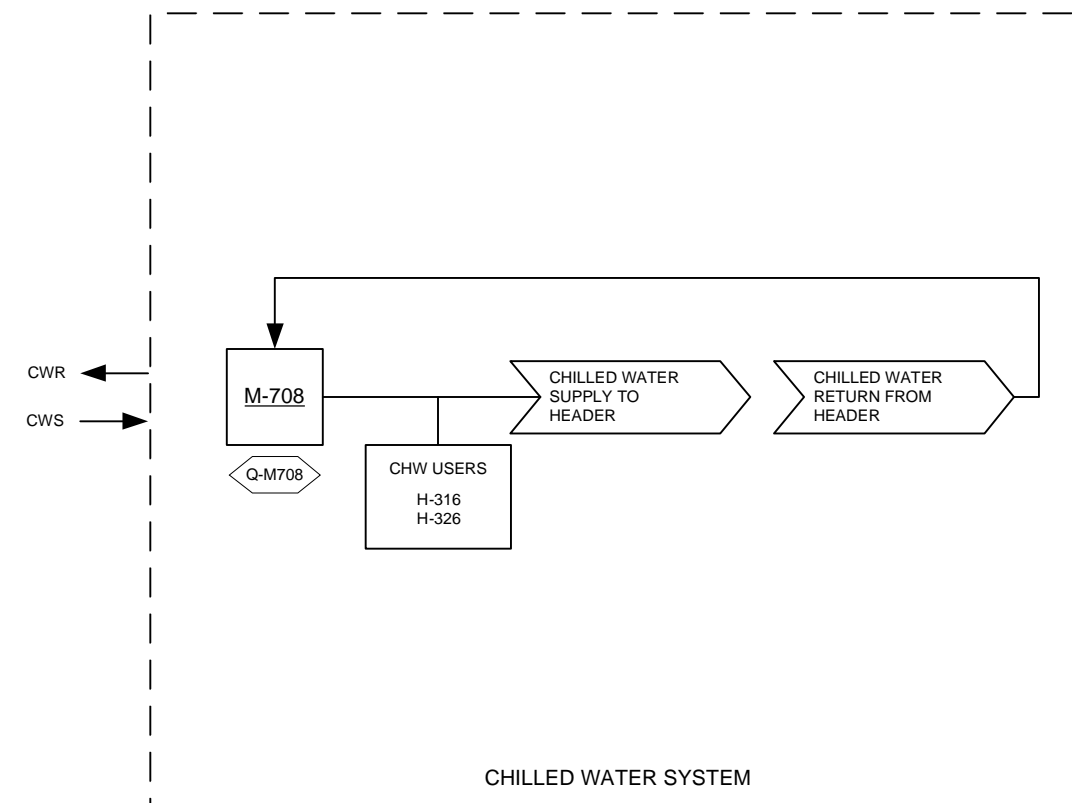
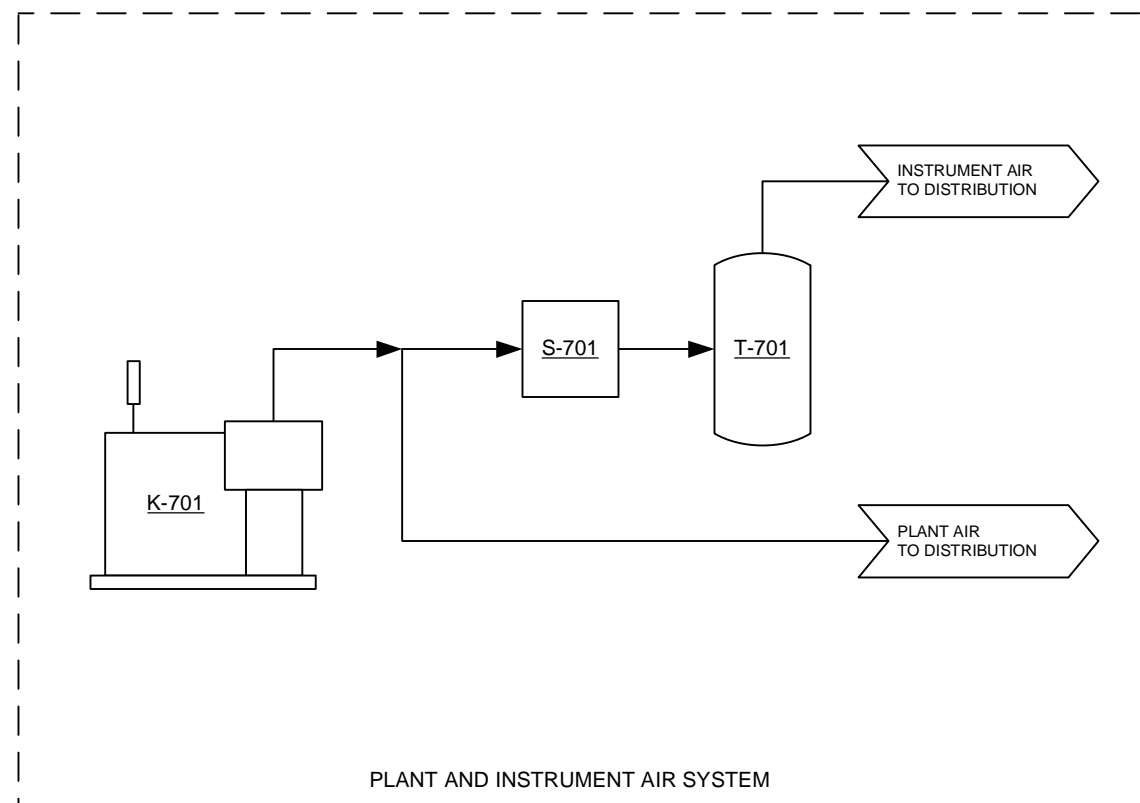
P-792  
DIESEL PRODUCT  
PUMP

T-790  
GASOLINE PRODUCT  
STORAGE TANK

P-790  
GASOLINE PRODUCT  
PUMP

M-710  
PRODUCT  
LOADING RACK

M-708  
CHILLED WATER  
SYSTEM

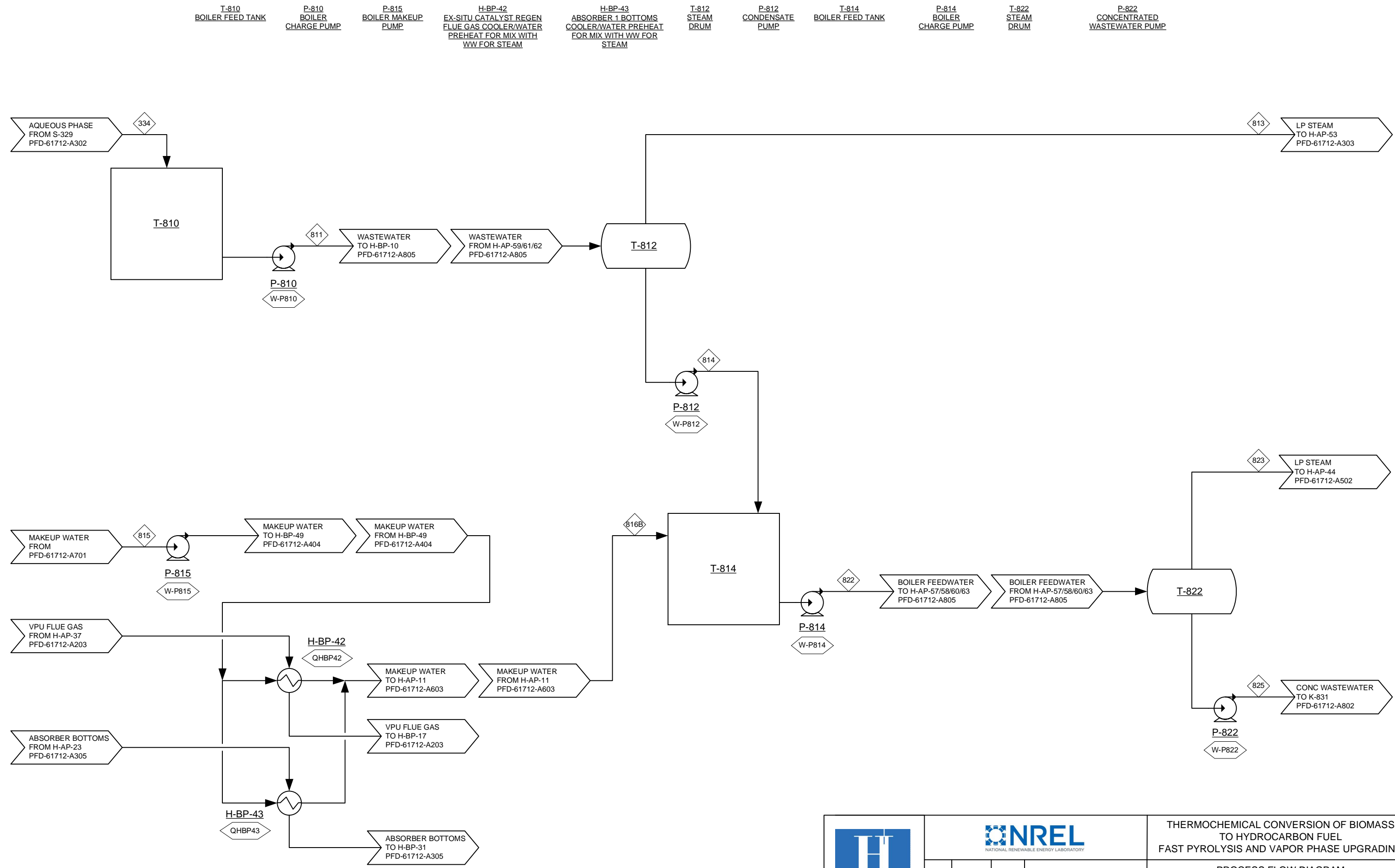


Plot date: 1/29/2015 J:\11A - Process Solutions\30482 MREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712 150128.vsd

				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING																			
	PROCESS FLOW DIAGRAM AREA 700: UTILITIES AND PRODUCT LOADOUT				Project No: 30482.00	Drawing: PFD-61712-A703	Rev: 2																
<table border="1"> <thead> <tr> <th>Rev.</th> <th>Date</th> <th>By</th> <th>Description</th> </tr> </thead> <tbody> <tr> <td>2</td> <td>12/29/14</td> <td>JAR</td> <td>MINOR UPDATES</td> </tr> <tr> <td>1</td> <td>12/12/14</td> <td>DMS</td> <td>ADDED HX NETWORK</td> </tr> <tr> <td>0</td> <td>9/29/14</td> <td>JAR</td> <td>ISSUED FOR DESIGN REPORT</td> </tr> </tbody> </table>	Rev.	Date	By	Description	2	12/29/14	JAR	MINOR UPDATES	1	12/12/14	DMS	ADDED HX NETWORK	0	9/29/14	JAR	ISSUED FOR DESIGN REPORT							
Rev.	Date	By	Description																				
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1	12/12/14	DMS	ADDED HX NETWORK																				
0	9/29/14	JAR	ISSUED FOR DESIGN REPORT																				



Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\_30482 Pyrolysis Ex-Situ PFDs\_61712\_150128.vsd



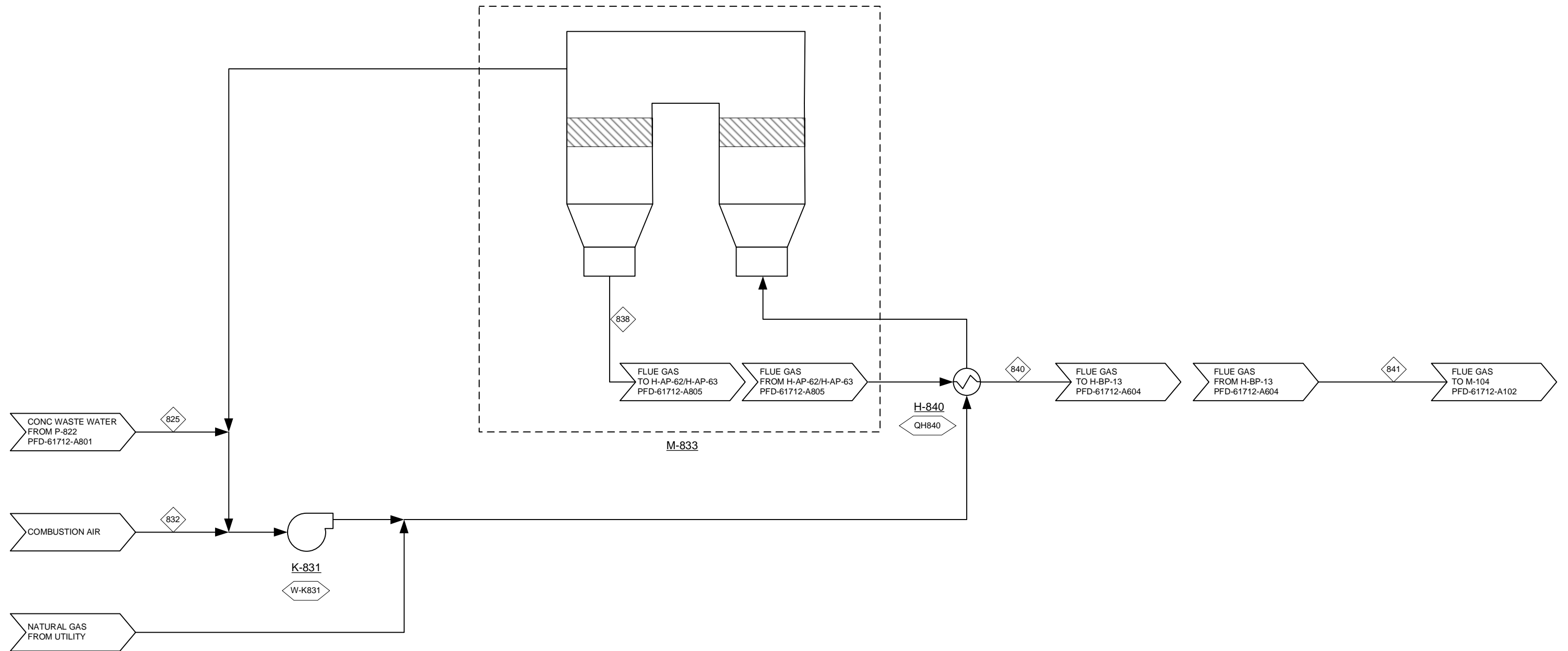
	 NATIONAL RENEWABLE ENERGY LABORATORY			THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING											
	PROCESS FLOW DIAGRAM AREA 800: WASTEWATER MANAGEMENT														
<table border="1"> <thead> <tr> <th>Rev.</th> <th>Date</th> <th>By</th> <th>Description</th> </tr> </thead> <tbody> <tr> <td>1</td> <td>12/12/14</td> <td>DMS</td> <td>ADDED HX NETWORK</td> </tr> <tr> <td>0</td> <td>9/29/14</td> <td>JAR</td> <td>ISSUED FOR DESIGN REPORT</td> </tr> </tbody> </table>	Rev.	Date	By	Description	1	12/12/14	DMS	ADDED HX NETWORK	0	9/29/14	JAR	ISSUED FOR DESIGN REPORT	Project No: 30482.00	Drawing: PFD-61712-A801	Rev: 1
Rev.	Date	By	Description												
1	12/12/14	DMS	ADDED HX NETWORK												
0	9/29/14	JAR	ISSUED FOR DESIGN REPORT												





K-831  
RTO  
BLOWER

M-833  
AQUEOUS REGENERATIVE  
THERMAL OXIDIZER

H-840  
RTO FEED/EFFLUENT  
EXCHANGER

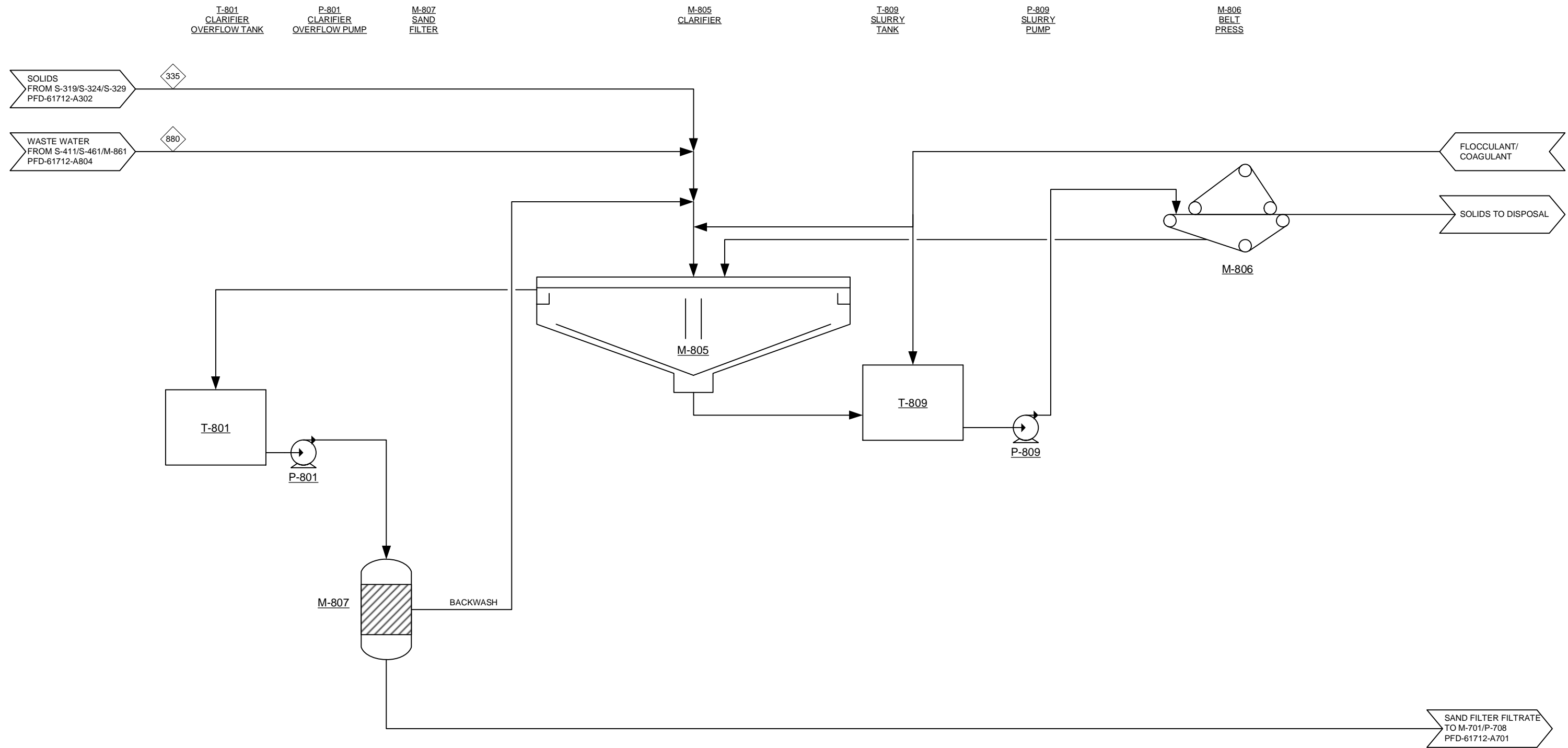




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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING			
	PROCESS FLOW DIAGRAM AREA 800: AQUEOUS RTO				Project No: 30482.00	Drawing: PFD-61712-A802	Rev: 1
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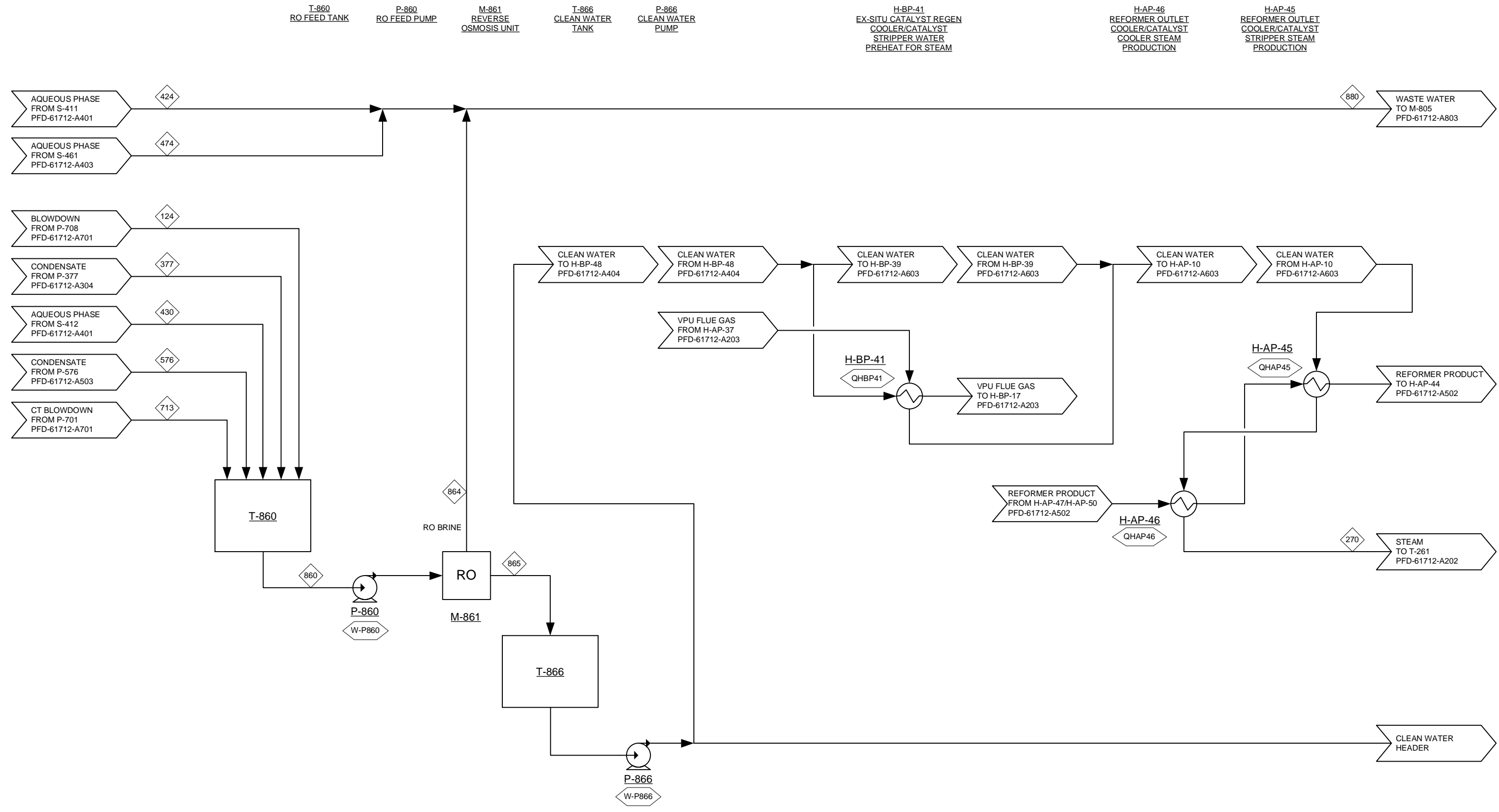




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1	12/12/14	DMS	ADDED HX NETWORK																	
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		Project No:	30482.00	Drawing:	PFD-61712-A803															
		Rev:			2															



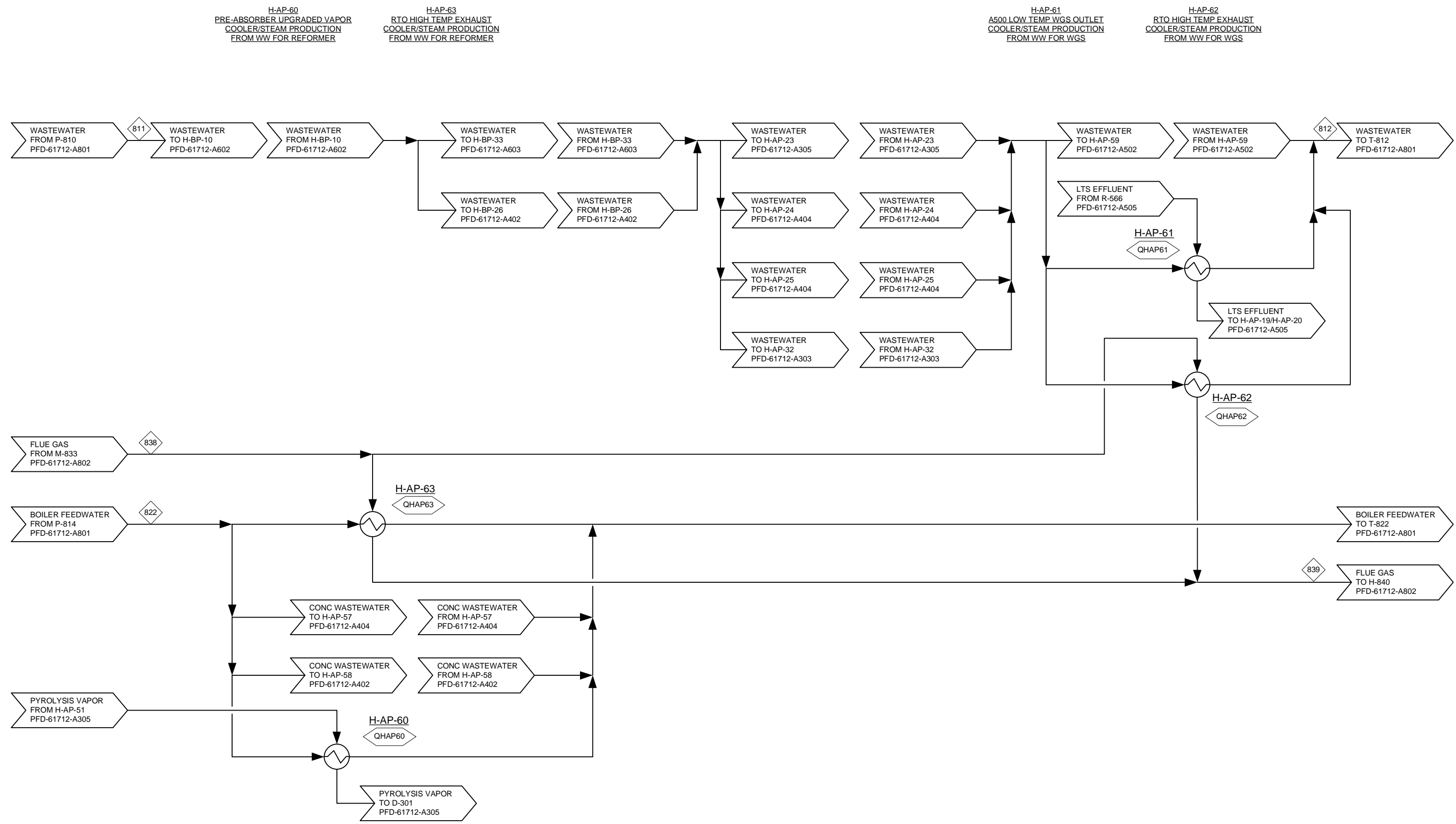
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				THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING		
	PROCESS FLOW DIAGRAM AREA 800: WASTEWATER REVERSE OSMOSIS					
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Plot date: 1/29/2015 J:\1A - Process Solutions\30482 NREL Thermochemical Conv - Design-Model\Drawings\30482 Pyrolysis Ex-Situ PFDs\61712\_150128.vsd



		THERMOCHEMICAL CONVERSION OF BIOMASS TO HYDROCARBON FUEL FAST PYROLYSIS AND VAPOR PHASE UPGRADING		
		PROCESS FLOW DIAGRAM AREA 800: A800 HEAT RECOVERY		
0 Rev.	12/12/14 Date	DMS By	ADDED HX NETWORK Description	Project No: 30482.00 Drawing: PFD-61712-A805 Rev: 0



## Appendix H. Heat Exchanger Costs for the *Ex Situ* Case

HX Name	Description	Belongs to Area	Hot In	Hot Out	Cold In	Cold Out	LMTD	Duty	Pres. Stream 1	Pres. Stream 2	Shell	Tube	Shell Material	Tube Material	Shell Design Pres. (20% Excess, Min. = 50 psig)	Tube Design Pres. (20% Excess, Min. = 50 psig)	U	Area	Equip. Cost (Q1 2009 Basis)	Direct Cost (Q1 2009 Basis)	Ratio (Direct Cost/Equipment)
	Stream 1 /Stream 2		F	F	F	F	ΔT	Btu/h	(psia)	(psia)							Btu/(h r ft <sup>2</sup> °F)	ft <sup>2</sup>	\$	\$	
<b>Network Above Pinch</b>																					
H-AP-7	Reformer Flue Gas Cooler / Reformer Feed High Temp Preheat	A500	1804.2	1134.2	525.6	1400.0	499.5	43,837,566	19	118	Reformer Flue Gas Cooler	Reformer Feed High Temp	CS	CS	50	130	10	8777	165,100.00	326,100.00	1.98
H-AP-8	Char Combustor Flue Gas Cooler / Fast Pyrolysis Fluidizing Gas Preheat	A211	1212.4	309.9	285.0	800.0	138.0	64,162,490	115	125	Char Combustor FG Cooler	FP Fluidizing Gas	CS	CS	120	140	10	46481	804,700.00	1,275,600.00	1.59
H-AP-9	Char Combustor Flue Gas Cooler / Inter-Turbine Steam Reheat	A600	1328.0	1212.4	698.3	1000.0	414.1	8,222,305	115	350	Char Combustor FG Cooler	Inter-Turbine Steam Preheat	CS	CS	120	410	10	1986	45,500.00	146,200.00	3.21
H-AP-10	Boiler Feed Water Blowdown Cooler / Catalyst Stripper Water Preheat for Steam	A600	581.0	309.9	285.0	356.0	90.9	225,383	1336	145	Catalyst Stripper Water Preheat	BFW Blowdown Cooler	CS	SS304L	160	1,590	100	25	13,200.00	129,200.00	9.79
H-AP-11	Boiler Feed Water Blowdown Cooler / Water Preheat for Mix with WW for Steam	A600	581.0	309.9	285.0	350.0	92.5	143,809	1336	155	Water Preheat for Mix	BFW Blowdown Cooler	CS	SS304L	170	1,590	100	16	13,000.00	129,000.00	9.92
H-AP-12	Hydrotreater Outlet Cooler / HT Product to Naphtha Column Preheat	A450	415.5	309.9	285.0	375.0	32.1	3,492,816	1510	48	HT Product	Hydrotreater	SS316	A199-T22 or A199D (2.5 Cr-1 Mo)	50	1,800	80	1361	112,200.00	312,200.00	2.78
H-AP-13	Distillate Column Condenser / HT Product to Naphtha Column Preheat	A450	550.3	490.9	375.0	450.0	107.9	2,912,097	15	48	Distillate Column Condenser	HT Product	SS316	CS	50	50	5	5398	106,900.00	247,500.00	2.32
H-AP-14	A300 WGS Outlet Cooler / A300 Pyrolysis Off-Gas to WGS Preheat	A360	425.0	309.9	285.0	400.0	25.0	4,039,336	84	93	A300 WGS Outlet Cooler	A300 Pyrolysis Off-Gas	A204C	CS	90	100	10	16188	275,400.00	474,300.00	1.72
H-AP-15	A300 WGS Outlet Cooler / A300 WGS Feed Preheat	A360	490.4	425.0	396.8	464.0	27.3	3,382,516	84	91	A300 WGS Outlet Cooler	A300 WGS Feed Preheat	A204C	CS	90	90	10	12411	200,200.00	385,000.00	1.92
H-AP-16	Distillate Product Cooler / HC Product to Naphtha Column Preheat	A450	491.1	309.9	285.0	466.1	25.0	2,373,485	35	48	Distillate product cooler	HC Product	SS316	CS	50	50	80	1189	34,100.00	146,000.00	4.28
H-AP-17	Post-Absorber 1 Vapor Cooler / Char Combustor Air Preheat	A310	358.2	309.9	287.2	336.2	22.4	2,934,814	110	123	Post Absorber 1 Vapor Cooler	Char Combustor Air Preheat	CS	CS	120	130	10	13131	247,500.00	458,100.00	1.85
H-AP-18	Post-Absorber 1 Vapor Cooler / Ex Situ Catalyst Regen Air Preheat	A310	358.2	309.9	285.0	336.2	23.4	2,528,606	110	117	Post Absorber 1 Vapor Cooler	Ex Situ Catalyst Regen Air Preheat	CS	CS	120	130	10	10795	190,300.00	386,900.00	2.03
H-AP-19	A500 Low Temp WGS Outlet Cooler / PSA Off-Gas to Reformer Combustor Preheat	A500	503.0	309.9	285.0	450.0	37.2	4,124,363	101	21	PSA Off-Gas	A500 Low Temp WGS Outlet	CS	CS	50	110	10	11086	170,400.00	353,900.00	2.08
H-AP-20	A500 Low Temp WGS Outlet Cooler / Reformer Combustor Air Preheat	A500	503.0	309.9	285.0	450.0	37.2	5,634,861	101	21	Combustor Air Preheat	A500 Low Temp WGS Outlet	CS	CS	50	110	10	15145	240,900.00	439,300.00	1.82
H-AP-21	A500 Low Temp WGS Outlet Cooler / Natural Gas to Reformer Preheat	A500	540.0	503.0	285.0	500.0	105.0	17,663	101	198	A500 Low Temp WGS Outlet	Natural Gas to Reformer	A204C	CS	110	220	10	17	9,500.00	62,500.00	6.58
H-AP-22	A500 Low Temp WGS Outlet Cooler / Reformer Combustor Gas Preheat	A500	540.0	503.0	285.0	500.0	105.0	100,164	101	21	Reformer Combustor Gas	A500 Low Temp WGS Outlet	CS	CS	50	110	10	95	11,300.00	64,500.00	5.71
H-AP-23	Absorber 1 Bottoms Cooler / WW Preheat for Steam Production	A310	461.2	309.9	285.0	358.6	54.9	1,597,418	133	155	Absorber 1 Bottoms	WW Preheat	CS	SS316	140	170	80	364	22,700.00	112,800.00	4.97
H-AP-24	Hydrotreater Outlet Cooler / WW Preheat for Steam Production	A500	415.5	309.9	285.0	358.6	38.7	3,230,771	1510	155	WW Preheat	Hydrotreater Outlet Cooler	SS316	A199-T22 or A199D (2.5 Cr-1 Mo)	170	1,800	80	1043	95,500.00	299,200.00	3.13
H-AP-25	Distillate Product Cooler / WW Preheat for Steam Production	A450	491.1	309.9	285.0	358.6	64.4	384,860	35	155	Distillate Product Cooler	WW Preheat	CS	SS316	50	170	80	75	14,000.00	82,600.00	5.90
H-AP-26	Reformer Flue Gas Cooler / Inter-Turbine Steam Reheat	A600	1134.2	911.6	698.3	1000.0	170.7	14,562,462	19	350	Reformer Flue Gas Cooler	Inter-Turbine Steam Reheat	CS	CS	50	410	10	8531	168,000.00	328,700.00	1.96
H-AP-27	Reformer Flue Gas Cooler / Distillate Column Reboiler	A450	911.6	819.0	705.0	711.6	153.0	6,062,749	19	20	Reformer Flue Gas Cooler	Distillate Column Reboiler	CS	CS	50	50	35	1132	27,100.00	122,100.00	4.51
H-AP-28	Reformer Flue Gas Cooler / Naphtha Column Reboiler	A450	819.0	741.5	595.8	626.5	168.0	5,072,974	19	40	Reformer Flue Gas Cooler	Naphtha Column Reboiler	CS	CS	50	50	35	863	23,400.00	101,500.00	4.34
H-AP-29	Reformer Flue Gas Cooler / Reformer Combustor Air Preheat	A500	741.5	663.1	450.0	600.0	174.9	5,123,961	19	21	Reformer Flue Gas Cooler	Reformer Combustor Air	CS	CS	50	50	5	5861	88,000.00	227,900.00	2.59
H-AP-30	Reformer Flue Gas Cooler / Reformer Feed Gas Preheat	A500	663.1	651.6	466.8	500.0	173.7	757,539	19	120	Reformer Flue Gas Cooler	Reformer Feed Gas Preheat	CS	CS	50	130	10	436	18,700.00	85,000.00	4.55



HX Name	Description	Belongs to Area	Hot In	Hot Out	Cold In	Cold Out	LMTD	Duty	Pres. Stream 1	Pres. Stream 2	Shell	Tube	Shell Material	Tube Material	Shell Design Pres. (20% Excess, Min. = 50 psig)	Tube Design Pres. (20% Excess, Min. = 50 psig)	U	Area	Equip. Cost (Q1 2009 Basis)	Direct Cost (Q1 2009 Basis)	Ratio (Direct Cost/Equipment)
	Stream 1 /Stream 2		F	F	F	F	ΔT	Btu/h	(psia)	(psia)							Btu/(h r ft <sup>2</sup> *F)	ft <sup>2</sup>	\$	\$	
H-AP-31	Post-Absorber 1 Vapor Cooler / Boiler Feed Water Preheat	A310	358.2	309.9	285.0	340.0	21.4	9,708,179	110	1346	Post Absorber 1 Vapor Cooler	Boiler Feed Water Preheat	CS	SS304L	120	1,600	40	11349	902,000.00	1,982,200.00	2.20
H-AP-32	A300 WGS Outlet Cooler / WW Preheat for Steam Production	A360	425.0	309.9	285.0	358.6	42.3	1,437,623	84	155	A300 WGS Outlet Cooler	WW Preheat	A204C	SS316	90	170	35	971	41,200.00	181,800.00	4.41
H-AP-33	A300 WGS Outlet Cooler / Boiler Feed Water Preheat	A360	425.0	309.9	285.0	340.0	49.0	477,847	84	1346	A300 WGS Outlet Cooler	BFW Preheat	A204C	SS304L	90	1,600	40	244	33,300.00	233,100.00	7.00
H-AP-34	Hydrotreater Outlet Cooler / Boiler Feed Water Preheat	A410	360.0	309.9	285.0	340.0	22.4	1,055,021	1910	1346	BFW Preheat	Hydrotreater Outlet Cooler	SS304L	A199-T22 or A199D (2.5 Cr-1 Mo)	1,600	2,280	80	590	113,700.00	322,700.00	2.84
H-AP-35	Boiler Feed Water Blowdown Cooler / Boiler Feed Water Preheat	A600	360.0	309.9	285.0	340.0	22.4	300,243	1336	1336	BFW Preheat	BFW Blowdown Cooler	SS304L	SS304L	1,590	1,590	100	134	55,300.00	192,900.00	3.49
H-AP-36	Reformer Flue Gas Cooler / Boiler Feed Water Preheat	A600	380.0	309.9	285.0	340.0	31.9	4,583,506	19	1346	Reformer Flue Gas Cooler	BFW Preheat	CS	SS304L	50	1,600	35	4110	327,000.00	875,100.00	2.68
H-AP-37	Ex Situ Catalyst Regen Flue Gas Cooler / Boiler Feed Water Preheat	A261	380.5	309.9	285.0	340.0	32.1	3,939,780	111	1346	Ex Situ Catalyst Regen FG Cooler	BFW Preheat	CS	SS304L	120	1,600	35	3509	283,400.00	830,900.00	2.93
H-AP-38	Ex Situ Catalyst Regen Flue Gas Cooler / Char Combustor Air Preheat	A261	897.2	380.5	336.2	600.0	132.9	15,809,168	111	123	Ex Situ Catalyst Regen FG Cooler	Char Combustor Air	CS	CS	120	130	10	11897	202,900.00	400,100.00	1.97
H-AP-39	Ex Situ Catalyst Regen Flue Gas Cooler / Ex Situ Catalyst Regen Air Preheat	A261	897.2	380.5	336.2	600.0	132.9	13,035,111	111	117	Ex Situ Catalyst Regen FG Cooler	Ex Situ Catalyst Regen	CS	CS	120	130	10	9810	176,300.00	338,000.00	1.92
H-AP-40	Boiler Feed Water Blowdown Cooler / Boiler Feed Water Preheat	A600	500.0	360.0	340.0	465.0	26.8	839,835	1336	1346	BFW Blowdown	BFW Preheat	SS304L	SS304L	1,590	1,600	100	313	84,700.00	314,200.00	3.71
H-AP-41	Hydrotreater Outlet Cooler / Boiler Feed Water Preheat	A410	520.0	360.0	340.0	465.0	34.6	3,372,674	1910	1346	BFW Preheat	Hydrotreater Outlet Cooler	SS304L	A199-T22 or A199D (2.5 Cr-1 Mo)	1,600	2,280	80	1218	197,900.00	524,000.00	2.65
H-AP-42	Reformer Flue Gas Cooler / Boiler Feed Water Preheat	A600	520.0	380.0	340.0	465.0	47.1	9,160,429	19	1346	Reformer Flue Gas Cooler	BFW Preheat	CS	SS304L	50	1,600	35	5557	439,700.00	989,200.00	2.25
H-AP-43	Hydrotreater Outlet Cooler / HC Product to Naphtha Column Preheat	A410	717.4	520.0	466.1	550.0	100.1	1,099,410	1910	48	HC Product	Hydrotreater Outlet Cooler	CS	A199-T22 or A199D (2.5 Cr-1 Mo)	50	2,280	80	137	28,600.00	106,400.00	3.72
H-AP-44	Reformer Outlet Cooler / Reformer Steam Superheat	A500	728.9	644.0	356.2	556.2	225.4	4,505,467	115	135	Reformer Outlet Cooler	Reformer Steam Superheat	CS	SS316	120	150	10	1999	67,000.00	209,700.00	3.13
H-AP-45	Reformer Outlet Cooler / Catalyst Stripper Steam Production	A261	775.4	728.9	356.0	356.0	395.7	2,467,430	115	145	Reformer Outlet Cooler	Catalyst Stripper Steam	CS	CS	120	160	35	178	13,800.00	79,000.00	5.72
H-AP-46	Reformer Outlet Cooler / Catalyst Cooler Steam Superheat	A261	780.5	775.4	355.0	555.0	312.9	269,714	115	140	Reformer Outlet Cooler	Catalyst Cooler Steam	CS	CS	120	150	10	86	12,000.00	66,000.00	5.50
H-AP-47	Reformer Outlet Cooler / Inter-Turbine Steam Reheat	A600	1616.0	780.5	698.3	1000.0	265.0	27,890,753	115	350	Reformer Outlet Cooler	Inter-Turbine Steam Reheat	CS	CS	120	410	10	10525	196,200.00	392,800.00	2.00
H-AP-48	Pre-Absorber Upgraded Vapor Cooler / Steam Superheat	A600	930.9	902.5	580.0	641.3	305.8	5,711,881	115	1326	Pre-Absorber Upgraded Vapor Cooler	Steam Superheat	CS	SS304L	120	1,580	50	374	48,800.00	249,200.00	5.11
H-AP-49	Ex Situ Catalyst Regen Flue Gas Cooler / Steam Superheat	A600	1202.0	897.2	641.3	1000.0	227.9	17,014,851	111	1326	Ex-Situ Catalyst Regen Flue Gas Cooler	Steam Superheat	CS	SS304L	120	1,580	50	1493	125,700.00	528,700.00	4.21
H-AP-50	Reformer Outlet Cooler / Steam Superheat	A600	1616.0	780.5	641.3	1000.0	320.6	16,442,228	115	1326	Reformer Outlet Cooler	Steam Superheat	CS	SS304L	120	1,580	50	1026	85,800.00	488,000.00	5.69
H-AP-51	Pre-Absorber Upgraded Vapor Cooler / Boiler Feed Water Preheat	A310	902.5	690.4	465.0	582.0	270.2	42,704,554	115	1346	Upgraded Vapor Cooler	BFW Preheat	CS	SS304L	120	1,600	40	3951	312,400.00	860,300.00	2.75
H-AP-52	A300 WGS Outlet Cooler / Boiler Feed Water Preheat	A360	637.0	490.4	435.6	465.0	102.4	7,591,348	84	1346	A300 WGS Outlet Cooler	BFW Preheat	A204C	SS304L	90	1,600	40	1853	148,800.00	553,400.00	3.72

HX Name	Description	Belongs to Area	Hot In	Hot Out	Cold In	Cold Out	LMTD	Duty	Pres. Stream 1	Pres. Stream 2	Shell	Tube	Shell Material	Tube Material	Shell Design Pres. (20% Excess, Min. = 50 psig)	Tube Design Pres. (20% Excess, Min. = 50 psig)	U	Area	Equip. Cost (Q1 2009 Basis)	Direct Cost (Q1 2009 Basis)	Ratio (Direct Cost/Equipment)
	Stream 1 /Stream 2		F	F	F	F	ΔT	Btu/h	(psia)	(psia)							Btu/(h ft <sup>2</sup> °F)	ft <sup>2</sup>	\$	\$	
H-AP-53	Pre-Absorber Upgraded Vapor Cooler / A300 WGS Steam Superheat	A310	690.4	466.4	353.8	403.8	186.2	760,513	115	140	Upgraded Vapor Cooler	A300 WGS Steam Superheat	CS	SS316	120	150	10	408	25,100.00	115,100.00	4.59
H-AP-54	Reformer Flue Gas Cooler / Boiler Feed Water Preheat	A600	651.6	520.0	402.2	435.6	161.9	8,608,504	19	1346	Reformer Flue Gas Cooler	BFW Preheat	CS	SS304L	50	1,600	40	1329	106,900.00	509,500.00	4.77
H-AP-55	Boiler Feed Water Blowdown Cooler / Boiler Feed Water Preheat	A600	581.0	500.0	340.0	402.2	169.2	485,893	1336	1346	BFW Blowdown Cooler	BFW Preheat	SS304L	SS304L	1,590	1,600	100	29	27,200.00	163,500.00	6.01
H-AP-56	Pre-Absorber Upgraded Vapor Cooler / Boiler Feed Water Preheat	A310	690.4	466.4	340.0	402.2	196.3	15,578,969	115	1346	Pre-Absorber Upgraded Vapor Cooler	BFW Preheat	CS	SS304L	120	1,600	40	1984	155,100.00	559,900.00	3.61
H-AP-57	Hydrotreater Outlet Cooler / Steam Production from WW for Reformer	A800	717.4	520.0	353.7	361.5	249.2	3,061,157	1910	145	Steam Production	HT Outlet Cooler	CS	A199-T22 or A199D (2.5 Cr-1 Mo)	160	2,280	80	154	27,900.00	106,000.00	3.80
H-AP-58	Distillate Column Condenser / Steam Production from WW for Reformer	A800	550.3	490.9	353.7	361.5	161.6	4,524,433	15	145	Distillate Column Condenser	Steam Production from WW	CS	SS316	50	160	35	800	32,300.00	145,800.00	4.51
H-AP-59	A500 High Temp WGS Outlet Cooler / Steam Production from WW for WGS	A500	835.4	428.0	358.6	359.1	211.2	20,869,597	108	150	A500 High Temp WGS Outlet	Steam Production from WW	A204C	SS316	110	170	35	2823	101,300.00	281,800.00	2.78
H-AP-60	Pre-Absorber Upgraded Vapor Cooler / Steam Production from WW for Reformer	A310	690.4	466.4	353.7	361.5	201.9	28,749,167	115	145	Upgraded Vapor Cooler	Steam Production from WW	CS	SS316	120	160	35	4069	125,300.00	307,100.00	2.45
H-AP-61	A500 Low Temp WGS Outlet Cooler / Steam Production from WW for WGS	A500	540.0	503.0	358.6	359.1	162.0	1,752,794	101	150	A500 Low Temp WGS Outlet	Steam Production from WW	A204C	SS316	110	170	35	309	22,000.00	111,700.00	5.08
H-AP-62	RTO High Temp Exhaust Cooler / Steam Production from WW for WGS	A800	863.4	436.7	358.6	359.1	228.5	4,331,122	22	150	RTO High Temp Exhaust Cooler	Steam Production from WW	CS	SS316	50	170	35	542	26,700.00	139,900.00	5.24
H-AP-63	RTO High Temp Exhaust Cooler / Steam Production from WW for Reformer	A800	863.4	436.7	353.7	361.5	232.8	4,695,177	22	145	RTO High Temp Exhaust Cooler	Steam Production from WW	CS	SS316	50	160	35	576	26,900.00	140,100.00	5.21
<b>Network Below Pinch</b>																					
H-BP-1	A300 WGS Outlet Cooler/Condenser / Boiler Feed Water Preheat 1	A360	218.7	185.0	138.1	175.6	44.9	4,911,418	83	25	WGS Outlet	BFW Preheat 1	A204C	CS	80	50	35	3124	51,200.00	173,100.00	3.38
H-BP-2	Reformer Flue Gas Cooler / Reformer Combustor Air Preheat	A500	309.9	244.8	173.1	285.0	44.3	3,736,136	18	21	Air Preheat	Reformer Flue Gas	CS	CS	50	50	5	16885	173,100.00	353,400.00	2.04
H-BP-3	Post-Absorber 1 Vapor Cooler / Fast Pyrolysis Fluidizing Gas Preheat	A211	309.9	220.0	200.7	285.0	22.0	10,024,571	109	127	FG Preheat	Post Absorber 1 Vapor	CS	SS304L	140	120	10	45578	865,900.00	1,379,600.00	1.59
H-BP-4	A300 WGS Outlet Cooler/Condenser / Pyrolysis Off-Gas Feed to WGS Preheat	A360	218.7	185.0	95.0	200.7	44.7	3,585,841	83	95	WGS Outlet	Pyrolysis Off Gas Feed	A204C	CS	80	100	10	8016	111,900.00	257,900.00	2.30
H-BP-5	Hydrotreater Outlet Cooler / HT Product to Naptha Column Preheat	A450	309.9	175.0	120.4	285.0	37.8	3,812,615	1,508	53	HT Product	HT Outlet Cooler	SS316	A199-T22 or A199D (2.5 Cr-1 Mo)	50	1,790	70	1440	121,900.00	322,100.00	2.64
H-BP-6	Hydrocracker Outlet Cooler / HC Product to Naptha Column Preheat	A450	309.9	175.0	110.0	285.0	41.8	1,527,541	1,908	53	HC Product	HC Outlet Cooler	SS316	A199-T22 or A199D (2.5 Cr-1 Mo)	50	2,270	70	522	56,500.00	206,800.00	3.66
H-BP-7	Low Temp WGS Outlet Cooler/Condenser / PSA Exh. to Ref. Comb. Preheat	A500	213.3	185.0	109.4	199.3	36.5	2,116,466	100	21	PSA Exchanger	Low Temp WGS	CS	A209 (C - 0.5 Mo)	50	110	10	5793	121,900.00	266,000.00	2.18
H-BP-8	Low Temp WGS Outlet Cooler/Condenser / Boiler Feed Water Preheat 1	A500	213.3	185.0	138.1	175.6	42.1	7,255,229	100	25	BFW Preheat 1	Low Temp WGS	CS	A209 (C - 0.5 Mo)	50	110	35	4926	107,000.00	230,700.00	2.16
H-BP-9	Low Temp WGS Outlet Cooler / Reformer Combustor Gas Preheat	A500	309.9	213.3	108.8	285.0	55.5	74,879	100	22	Reformer Combustor Gas	Low Temp WGS	CS	A209 (C - 0.5 Mo)	50	110	10	135	14,000.00	67,400.00	4.81
H-BP-10	Steam Turbine Exhaust Cooler / WW Preheat for Steam Production	A600	234.3	170.0	86.5	174.7	70.9	9,250,080	4	160	Steam Turbine Exhaust	WW Preheat	CS	SS316	50	180	150	870	31,600.00	122,800.00	3.89
H-BP-11	Post-Absorber 1 Vapor Cooler / Boiler Feed Water Preheat 1	A310	250.0	220.0	175.6	232.3	29.0	5,196,218	109	25	BFW Preheat 1	Post Absorber 1 Vapor	CS	SS304L	50	120	35	5117	107,000.00	277,400.00	2.59
H-BP-12	Low Temp WGS Outlet Cooler / Reformer Combustor Air Preheat	A360	309.9	213.3	173.1	285.0	31.9	19,735	100	21	Reformer Combustor Air	Low Temp WGS	CS	CS	50	110	10	62	9,700.00	62,400.00	6.43

HX Name	Description	Belongs to Area	Hot In	Hot Out	Cold In	Cold Out	LMTD	Duty	Pres. Stream 1	Pres. Stream 2	Shell	Tube	Shell Material	Tube Material	Shell Design Pres. (20% Excess, Min. = 50 psig)	Tube Design Pres. (20% Excess, Min. = 50 psig)	U	Area	Equip. Cost (Q1 2009 Basis)	Direct Cost (Q1 2009 Basis)	Ratio (Direct Cost/Equipment)
	Stream 1 /Stream 2		F	F	F	F	ΔT	Btu/h	(psia)	(psia)							Btu/(h r ft <sup>2</sup> *F)	ft <sup>2</sup>	\$	\$	
H-BP-13	RTO Low Temp Exhaust Cooler / Boiler Feed Water Preheat 1	A800	269.1	244.8	175.6	232.3	51.3	490,867	19	25	BFW Preheat 1	RTO Low Temp EC	CS	SS304L	50	50	35	274	16,800.00	102,000.00	6.07
H-BP-14	A300 WGS Outlet Cooler / Pyrolysis Off-Gas Feed to WGS Preheat	A360	309.9	218.7	200.7	285.0	21.3	2,862,490	83	95	WGS Outlet	Pyrolysis Off-Gas Feed	CS	CS	80	100	10	13460	150,600.00	329,000.00	2.18
H-BP-15	Low Temp WGS Outlet Cooler / PSA Exh. to Ref. Comb. Preheat	A500	309.9	213.3	199.3	285.0	18.9	2,019,392	83	25	BFW Preheat	A300 WGS O/L	CS	A209 (C - 0.5 Mo)	50	80	35	3048	68,400.00	190,100.00	2.78
H-BP-16	Char Combustor Flue Gas Cooler / Boiler Feed Water Preheat 1	A211	255.0	244.8	175.6	232.3	41.7	676,950	112	25	BFW Preheat 1	Char Combustor FG	CS	CS	50	120	35	464	17,000.00	81,900.00	4.82
H-BP-17	Ex Situ Catalyst Regen Flue Gas Cooler / Boiler Feed Water Preheat 1	A261	255.0	244.8	175.6	232.3	41.7	534,946	245	25	BFW Preheat 1	Ex-situ Catalyst Regen FG	CS	CS	50	280	40	321	16,100.00	82,200.00	5.11
H-BP-18	Hydrotreater Outlet Cooler / Boiler Feed Water Preheat 1	A410	250.3	193.6	175.6	232.3	18.0	1,937,436	1,508	25	BFW Preheat 1	HT Outlet Cooler	CS	A199-T22 or A199D (2.5 Cr-1 Mo)	50	1,790	100	1076	83,300.00	266,400.00	3.20
H-BP-19	Hydrocracker Outlet Cooler / Boiler Feed Water Preheat 1	A460	250.3	193.6	175.6	232.3	18.0	346,619	1,908	25	BFW Preheat 1	HC Outlet Cooler	CS	A199-T22 or A199D (2.5 Cr-1 Mo)	50	2,270	120	160	29,100.00	132,200.00	4.54
H-BP-20	Post-Absorber 1 Vapor Cooler / Boiler Feed Water Preheat 2	A310	309.9	250.0	235.2	285.0	19.4	10,383,723	109	1,351	PA 1 Vapor Cooler	BFW Preheat 2	CS	SS304L	120	1,610	40	13389	792,100.00	1,803,000.00	2.28
H-BP-21	Char Combustor Flue Gas Cooler / Boiler Feed Water Preheat 2	A211	309.9	255.0	235.2	285.0	22.2	3,635,193	112	1,351	Char Combustor FG	BFW Preheat 2	CS	SS304L	120	1,610	40	4088	234,000.00	788,300.00	3.37
H-BP-22	Ex Situ Catalyst Regen Flue Gas Cooler / Boiler Feed Water Preheat 2	A261	309.9	255.0	235.2	285.0	22.2	2,261,634	108	1,351	Regen Flue Gas	BFW Preheat 2	CS	SS304L	110	1,610	40	2543	144,300.00	695,300.00	4.82
H-BP-23	Hydrotreater Outlet Cooler / Boiler Feed Water Preheat 1	A410	309.9	250.3	175.6	232.3	76.1	2,039,539	1,508	25	BFW Preheat 1	HT Outlet Cooler	CS	A199-T22 or A199D (2.5 Cr-1 Mo)	50	1,790	100	268	36,100.00	133,300.00	3.69
H-BP-24	Hydrocracker Outlet Cooler / Boiler Feed Water Preheat 1	A460	309.9	250.3	175.6	232.3	76.1	364,886	1,908	25	BFW Preheat 1	HC Outlet Cooler	CS	A199-T22 or A199D (2.5 Cr-1 Mo)	50	2,270	100	48	15,800.00	92,500.00	5.85
H-BP-25	Low Temp WGS Outlet Cooler / Boiler Feed Water Preheat 1	A500	309.9	250.0	175.6	232.3	76.0	1,641,492	83	25	A300 WGS Outlet	BFW Preheat 1	A204C	CS	80	50	35	617	19,000.00	96,400.00	5.07
H-BP-26	Naphtha Column Condenser / WW Preheat for Steam Production	A450	298.0	200.2	174.7	285.0	18.5	7,190,523	35	160	WW Preheat	Naphtha Column	SS316	SS316	180	50	35	11097	319,100.00	627,000.00	1.96
H-BP-27	A300 WGS Outlet Cooler / Boiler Feed Water Preheat 1	A360	250.0	218.7	175.6	232.3	28.5	573,334	83	25	A300 WGS	BFW Preheat 1	A204C	CS	80	50	35	574	18,800.00	96,200.00	5.12
H-BP-28	Low Temp WGS Outlet Cooler / Boiler Feed Water Preheat 1	A500	250.0	213.3	175.6	232.3	26.4	1,005,597	100	25	BFW Preheat 1	Low T WGS	CS	A209 (C - 0.5 Mo)	110	50	35	1087	33,500.00	128,700.00	3.84
H-BP-29	Distillate Product Cooler / Boiler Feed Water Preheat 1	A450	309.9	193.6	175.6	232.3	40.8	1,500,727	30	25	BFW Preheat 1	Distillate Product	CS	SS316	50	50	80	460	20,100.00	85,000.00	4.23
H-BP-30	Distillate Product Cooler / HT Product to Naphtha Column Preheat	A450	193.6	175.0	110.0	120.4	69.0	240,551	30	53	Distillate Product	HT product	SS316	SS316	50	50	80	44	11,800.00	82,900.00	7.03
H-BP-31	Absorber 1 Bottoms Cooler / Boiler Feed Water Preheat 1	A310	255.0	193.6	175.6	232.3	20.3	556,211	129	25	BFW Preheat 1	Absorber 1	CS	SS316	50	140	80	343	21,000.00	110,700.00	5.27
H-BP-32	Boiler Feed Water Blowdown Cooler / Recycled Boiler Feed Water Preheat	A600	255.0	193.6	153.4	239.4	26.0	400,090	1,326	30	Recycled BFW	BFW Blowdown Cooler	CS	SS304L	50	1,580	100	154	30,200.00	147,300.00	4.88
H-BP-33	Boiler Feed Water Blowdown Cooler / WW Preheat for Steam Production	A600	309.9	255.0	174.7	285.0	47.3	203,262	1,326	160	WW Preheat	BFW Blowdown Cooler	SS316	SS304L	180	1,580	100	43	19,000.00	141,200.00	7.43
H-BP-34	Absorber 1 Bottoms Cooler / Boiler Feed Water Preheat 1	A310	309.9	255.0	175.6	232.3	78.5	419,621	128	25	BFW Preheat 1	Absorber 1	CS	SS304L	50	140	80	67	13,400.00	82,000.00	6.12
H-BP-35	A300 WGS Outlet Cooler / Boiler Feed Water Preheat 1	A360	309.9	250.0	175.6	232.3	76.0	1,097,460	83	25	BFW Preheat 1	A300 WGS Outlet	CS	A209 (C - 0.5 Mo)	50	80	35	413	20,300.00	85,200.00	4.20
H-BP-36	A300 WGS Outlet Cooler/Condenser / Fast Pyrolysis Fluidizing Gas Preheat	A360	218.7	185.0	159.7	200.7	21.4	4,868,699	82.84	127	WGS Outlet Cooler	FP Fluidizing Gas	A204C	CS	80	140	10	22709	279,400.00	511,900.00	1.83

HX Name	Description	Belongs to Area	Hot In	Hot Out	Cold In	Cold Out	LMTD	Duty	Pres. Stream 1	Pres. Stream 2	Shell	Tube	Shell Material	Tube Material	Shell Design Pres. (20% Excess, Min. = 50 psig)	Tube Design Pres. (20% Excess, Min. = 50 psig)	U	Area	Equip. Cost (Q1 2009 Basis)	Direct Cost (Q1 2009 Basis)	Ratio (Direct Cost/Equipment)
	Stream 1 /Stream 2		F	F	F	F	$\Delta T$	Btu/h	(psia)	(psia)					psig	psig	Btu/(hr ft <sup>2</sup> *F)	ft <sup>2</sup>	\$	\$	
H-BP-37	Boiler Feed Water Blowdown Cooler / Natural Gas to Reformer Preheat	A500	309.9	255.0	60.0	285.0	82.7	15,859	1331	200	Natural Gas	BFW Blowdown	CS	SS304L	230	1580	40	5	9,900.00	72,000.00	7.27
H-BP-39	Boiler Feed Water Blowdown Cooler / Catalyst Stripper Water Preheat for Steam	A600	309.9	255.0	153.4	285.0	54.6	139,187	1331	150	Catalyst Stripper WW	BFW Blowdown	CS	SS304L	170	1580	40	64	13,300.00	80,600.00	6.06
H-BP-40	Ex Situ Catalyst Regen Flue Gas Cooler / Recycled Boiler Feed Water Preheat	A261	309.9	255.0	153.4	239.4	85.2	156,535	107.84	29,696	Recycled BFW	Ex-Situ Catalyst Regen	CS	CS	50	110	35	53	9,400.00	62,100.00	6.61
H-BP-41	Ex Situ Catalyst Regen Flue Gas Cooler / Catalyst Stripper Water Preheat for Steam	A261	309.9	255.0	153.4	285.0	54.6	256,387	107.84	150	Ex Situ Regen Flue	Catalyst Stripper WW	CS	CS	110	170	35	134	13,700.00	68,000.00	4.96
H-BP-42	Ex Situ Catalyst Regen Flue Gas Cooler / Water Preheat for Mix with WW for Steam	A261	309.9	255.0	153.4	285.0	54.6	198,081	107.84	160	Ex Situ Regen Flue	Water preheat	CS	SS316	110	180	35	104	14,600.00	83,600.00	5.73
H-BP-43	Absorber 1 Bottoms Cooler / Water Preheat for Mix with WW for Steam	A310	309.9	255.0	153.4	285.0	54.6	78,505	127.84	160	Water Preheat	Absorber 1 Bottoms	SS316	SS304L	180	140	80	18	10,700.00	84,900.00	7.93
H-BP-44	Absorber 1 Bottoms Cooler / Recycled Boiler Feed Water Preheat	A310	193.6	175.0	60.1	153.4	71.2	168,999	123	29,696	Recycled BFW	Absorber 1 Bottoms	CS	SS304L	50	130	80	30	10,500.00	78,500.00	7.48
H-BP-45	Boiler Feed Water Blowdown Cooler / Recycled Boiler Feed Water Preheat	A600	193.6	170.0	60.1	153.4	69.3	154,167	1331	29,696	Recycled BFW	Boiler Feedwater Blowdown	CS	SS304L	50	1580	100	22	13,000.00	128,700.00	9.90
H-BP-46	Hydrocracker Outlet Cooler / Recycled Boiler Feed Water Preheat	A460	193.6	175.0	60.1	153.4	71.2	114,047	1907.5	29,696	Recycled BFW	HC Outlet	CS	A199-T22 or A199D (2.5 Cr-1 Mo)	50	2270	100	16	12,100.00	88,600.00	7.32
H-BP-47	Hydrotreater Outlet Cooler / Recycled Boiler Feed Water Preheat	A410	193.6	175.0	60.1	153.4	71.2	166,633	1507.5	29,696	Recycled BFW	HT Outlet	CS	A199-T22 or A199D (2.5 Cr-1 Mo)	50	1790	100	23	12,300.00	88,800.00	7.22
H-BP-48	Hydrotreater Outlet Cooler / Catalyst Stripper Water Preheat for Steam	A410	193.6	175.0	61.1	153.4	70.8	277,242	1507.5	150	Catalyst Stripper WW	HT Outlet	CS	A199-T22 or A199D (2.5 Cr-1 Mo)	170	1790	100	39	15,500.00	92,200.00	5.95
H-BP-49	Hydrotreater Outlet Cooler / Water Preheat for Mix with WW for Steam	A410	193.6	175.0	61.2	153.4	70.8	193,593	1507.5	160	Water Preheat for Mix	HT Outlet	SS316	A199-T22 or A199D (2.5 Cr-1 Mo)	180	1790	100	27	13,300.00	91,900.00	6.91
<b>Total</b>								568,440,588											12,000,000	31,624,400	2.64

General Guidelines Used:

1. Steam Turbine Exhaust / WW Preheat considered a water/steam heat exchange and allocated a U of 150 BTU/hr ft<sup>2</sup> F
2. High pressure gas heat exchange , U = 10 BTU/hr ft<sup>2</sup> F
3. Low Pressure gas heat exchange , U=5 Btu/hr ft<sup>2</sup> F
4. Water / Gas (100 psi) heat exchange , U =35 Btu/hr ft<sup>2</sup> F
5. High pressure liquid-liquid heat exchange(~1000 psi), U = 100 Btu/hr ft<sup>2</sup> F
6. Water and distillate product (~100 psi) , U = 80 Btu/hr ft<sup>2</sup> F
7. Pressures (<800 psig: CS; 800-1400 psig: SS304L; >1400 psig A199-T22 or A199D (2.5 Cr-1 Mo)
8. Default Corrosion allowance for Tube (CS): 0.0025 inches(0.06 mm) and Shell (CS) :0.125 inches (3 mm) in ASPEN ICARUS

## **Appendix I. Plant Footprint and Land Cost Calculation From Harris Group Inc.**

**Table I-1. Plant Footprint and Land Cost Calculation From Harris Group Inc.**

	Area	Width	Length	Area	
		ft	ft	ft <sup>2</sup>	acre
1	Truck staging, scales, scale shack, guard shack, etc.	250	500	125,000	2.9
2	Feedstock handling and storage: x2-truck dumps/hoppers, x2 scalping screens/hogs, x2-400' diameter stacker reclaimers, and conveyors	800	1,000	800,000	18.4
3	Feedstock drying and storage: x2-dryers/WESPs/RTOs and x2-dry feedstock silos	200	500	100,000	2.3
4	Pyrolysis island: x2-reactors, x2-regenerators, bed/sorbent media handling w/ silos, ash handling w/ silo(s), air compressors, solids cooler, instrument air system, etc.	125	150	18,750	0.4
5	Vapor phase upgrading island: reactor, regenerator, bed media handling w/ silos, air compressor, solids cooler, steam stripper, instrument air system, etc.	75	100	7,500	0.2
6	Condensers: two absorber condensers, decanters, filters, WGS reactor, PSA, compressor	100	100	10,000	0.2
7	Hydrotreating/hydrocracking reactors, hydrogen compressors	50	100	5,000	0.1
8	Product separation: distillation columns	75	100	7,500	0.2
9	SMR: reformer and PSA	200	200	40,000	0.9
10	Wastewater treatment, boiler water treatment, condensate treatment, DA, steam distribution, power generation, reboiler stripper, RTO, etc.	200	250	50,000	1.1
11	Cooling towers, pumps, etc.	100	150	15,000	0.3
12	Tank farm: product tanks, fuel, chemicals, fire water, process water, etc.	500	500	250,000	5.7
13	Air separation plant, compressors, tanks, etc.	50	50	2,500	0.1
14	Storm water system: retention pond, etc.	200	200	40,000	0.9
15	Electrical feed, transformers, etc.	100	100	10,000	0.2
16	Electrical building	25	100	2,500	0.1
17	Control room	25	50	1,250	0.0
18	Offices, etc.	100	100	10,000	0.2
19	Maintenance shop, maintenance warehouse/yard	200	200	40,000	0.9
20	Parking, roads, etc.	500	500	250,000	5.7
21	Buffer			871,200	20.0
22	Unusable land (topography and environmentally)			1,306,800	30.0
23	Other: space in-between process areas, etc. (10% of process areas and buildings)			153,500	3.5
24	Easement (10% of all above)			411,650	9.5
25	Contingency (10% of all above)			452,815	10.4
			<b>Total</b>	<b>4,980,965</b>	<b>114.3</b>
	Specific Land Cost*	\$/acre	14,000		
	Site Area	acres	114.3		
	<b>Total Land Cost</b>	<b>\$</b>	<b>1,600,861</b>		

\*Specific land cost assumption based on USDA (2012) and Dutta et al. (2011). Basis: 2,000 dry metric tons/day feedstock basis or 2,205 dry short tons/day. Most estimates derived from Dutta et al. (2011).

## Appendix I References

Dutta, A.; Talmadge, M.; Hensley, J.; Worley, M.; Dudgeon, D.; Barton, D.; Groendijk, P.; Ferrari, D.; Stears, B.; Searcy, E.M.; Wright, C.T.; Hess, J.R. (2011). *Process Design and Economics for Conversion of Lignocellulosic Biomass to Ethanol: Thermochemical Pathway by Indirect Gasification and Mixed Alcohol Synthesis*. NREL/TP-5100-51400. Golden, CO: National Renewable Energy Laboratory.

U.S. Department of Agriculture. (2012). "Trends in U.S. Farmland Values and Ownership." Economic Information Bulletin No. (EIB-92). Washington, DC: U.S. Department of Agriculture.

## Appendix J. Reviewer Comments on Draft Design Report and Responses

This appendix presents a summary of reviewer comments from draft versions of the report, issued for peer review in June 2014 and in August 2014. Comments from the peer review panel are summarized below and followed by a response from the authors. Some of the comments are paraphrased along with added context for clarity. Comments were combined when there were commonalities among observations from multiple reviewers. Minor/editorial comments were addressed, but left out of this appendix. The responses also describe any actions taken to address the comments in this final version.

### Area A100: Feed Handling and Drying

1. **Comment:** Feedstock handling capital, including drying and sizing, should be included in the analysis. The \$80/dry ton cost may be too low.

**Response:** Details about feedstock logistics and cost breakdown are included in Jacobson et al. (2014). All the above costs are included in the \$80/dry ton. This report focuses on the conversion aspects and includes the feedstock cost input as an operating expense. Sensitivity analysis showing the impact of more expensive feedstock is included in Figure 15.

2. **Comment:** Use of blended feedstock material can be a challenge in actual plants from a handling perspective. Additional equipment may be necessary.

**Response:** Further experiments and validation efforts led by the Idaho National Laboratory will study the details of feed systems for the blended material.

3. **Comment:** For grinding to 2mm, what portion of it happens within the plant? What is the form of the feedstock and which operations happen onsite. The effect of particle size on conversion needs to be studied.

**Response:** The assumption of the particle size in this report is consistent with Jones et al. (2013). For the 2022 target case presented in this report, it is anticipated that pelletized material will be brought to the plant and crushed on-site before feeding to the reactor. An additional cross-flow dryer for warming up the feed using waste heat is included within plant operations in this design.

4. **Comment:** The low cost of feedstock at \$80/dry ton is partially justified by the use of substantial residue (30%) and waste materials (20%). Such biomass materials come with significant quality/consistency issues that impact operating efficiency. These issues the authors abstract away using the n<sup>th</sup> plant framework. More fundamentally, by assuming that a mature industry with multiple operating plants has been achieved, the authors should recognize that within such a context there will be competition for biomass resources. Such competition implies that the availability of residue/waste at low cost is very questionable. The authors would be on more solid ground in assuming a mature industry uses plantation wood dedicated to feed these plants.

**Response:** As observed by the reviewer, the assumption of diversified material was deliberate for cost reduction purposes. The cost impacts of the inclusion of the various constituents of the blend, at different volumes, were also included by Jacobson et al. (2014).



The marginal cost of each constituent is shown to go up for higher volume demands. The cost of large volumes of plantation wood is expected to be higher than the blended material.

5. **Comment:** One of the startups using catalytic fast pyrolysis technology stated in their public report that their wood yard design were a significant part of their inability to achieve target rates. This area should not be neglected.

**Response:** We included areas for “Feedstock handling and storage” and “Feedstock drying and storage” in our design (shown in Appendix I).

6. **Comment:** I was surprised to see C&D waste as 20 % of the blended feed. C&D waste usually contains significant metal and ash contamination (e.g., iron from nails, gypsum from sheetrock). Is the INL blended feedstock clean of contaminants? If not, those contaminants should be mentioned as a risk to Area 200. Multiple reviewers questioned the impacts of contaminants and additional ash in the blended material (usually much higher than wood), along the same lines as this comment; they expressed their concerns about the impacts of mineral matter/ash on the organic yields.

**Response:** The feedstock logistics design proposed by the Idaho National Laboratory has specifications for ash. They discuss operations for ash removal in order to meet the elemental analysis specifications of the feedstock in Jacobson et al. (2014). In addition there are experimental plans to quantify the impacts of using the blended material on the yields from the various conversion pathways (including those detailed in this report). Findings from these experiments will be factored into future techno-economic assessments.

## Area A200: Fast Pyrolysis and Vapor Upgrading

7. **Comment:** What was the reason for the choice of 120 psia (~8 bars) with a hydrogen partial pressure of approximately 75-95 psia (5-6.6 bars) in the inlet fluidizing gas for the fast pyrolysis reactors? These are not conventional fast pyrolysis or hydrolysis conditions. This assumption should be emphasized upfront, otherwise people do not see that there is a deviation from conventional pyrolysis at near atmospheric conditions.

**Response:** Based on this and similar comments, we made these assumptions very conspicuous in the Executive Summary and the Introduction sections, as well as Section 3.2.1.5 dedicated to this aspect.

8. **Comment:** The liquid yield and oxygen content for the organic phase in this report do not coincide with Figure 1. For that oxygen content the yield would be near 20% and here your yield is near 30%. I understand you are looking at a process that uses hydrogen and elevated pressure, but it would be great if you could state where these yields came from, either experimental data or a projection, somewhere clearly in the Area 200 description. Figure 11 shows that >50% of the LHV is recovered as fuel-range hydrocarbon products in each case. Again, this is very dependent on process yields, so it is good to be very clear on where you obtain those.

**Response:** We have since made it very clear that this design report details target cases for 2022. Figure 1 is reflective of the current state of technology. We have separately developed a state of technology assessment, and initial annual targets leading up to 2022, based on the process designs detailed in this report; those results are expected to be published in BETO’s Multi-Year Program Plan.

9. **Comment:** There were several comments about Figure 1, including (a) reasons for differences among data points and whether they were caused by differences in catalysts or different reaction conditions, (b) the draft version had a discussion using catalyst to biomass ratios, while the figure shows the inverse (biomass to catalyst ratio) on the x-axis, (c) whether the results are for *in situ* or *ex situ*, (d) more clarity in the text surrounding the discussion of the figure.

**Response:** Figure 1 was previously published in a journal article. Details about the individual data points are available in the cited literature. We have modified some of the text around the figure based on reviewer comments. The main purpose of the figure is to show that we tend to lower yields as we deoxygenate the organic product. This is a key challenge for us in meeting our 2022 goals with both high yields and significant deoxygenation. This figure highlights the need for catalyst research and exploring new catalyst materials and chemistry to accomplish our goals.

10. **Comment:** Many comments reflected that the draft version did not sufficiently emphasize that we are showing designs for target cases, rather than the current state of research.

**Response:** Please see the response to Comment 8. Based on this recommendation, the title of this report was modified to include “Research Pathways,” and key table captions were also modified to state that these are 2022 targets.

11. **Comment:** Multiple reviewers of the draft report wanted to see more discussion about catalysts. Their comments included (a) the likely necessity to use catalysts with different functionality compared to zeolites like ZSM-5, which produce aromatics, (b) mentioning new chemistries that can promote lower oxygen at higher yield, (c) queries whether confidentiality constraints were stopping the authors from disclosing more about the catalysts, (d) requests for the inclusion of some catalyst background for the reader to be able to appreciate the relevance of these conversion pathways.

**Response:** Section 3.2.1.6 was added to discuss some of these aspects. Since this report is focused on the process design and techno-economics, we limited the discussion and pointed out review articles as additional resources on this topic.

12. **Comment:** The use of a hot gas filter (HGF) may be necessary, even in the case of a circulating fluidized bed (CFB) *ex situ* reactor. The two preceding cyclones may not be sufficient to remove finer entrained mineral matter that can deactivate catalysts. The current design assumes two cyclones prior to the CFB *ex situ* reactor. It was pointed out that the statement in the draft version about “only a small proportion of fine solids” needed to be qualified.

**Response:** Irreversible deactivation from contaminants is mentioned in the current version. We also mention that an HGF may be necessary based on future experimental data.

13. **Comment:** The draft report used the term ash to refer to all biomass inorganic content. It was pointed out that there is a difference between mineral matter and ash. Ash is the product after biomass combustion.

**Response:** We adopted the suggestion and made changes to the text to reflect this. However, it should be noted that much of the literature on this subject uses the term ash for biomass inorganic content in all contexts, because ash is the eventual measurement of inorganic content.

14. **Comment:** It should be pointed out that mineral matter is contained in the char from the pyrolysis reactor.

**Response:** We added this to the text in Section 3.2.1.

15. **Comment:** Call out the content of char entering the char combustor and mention that the char/sand mixture flowrate has been adjusted to maintain thermal balance so that the heat supplied by char combustion is equal (more or less) to the heat required for the pyrolysis step.

**Response:** In order to further convey this point we added text to say that pyrolysis is endothermic. Char and all other component flow rates are included in the stream summary tables in Appendix G. Percent char produced is shown in Table ES-1.

16. **Comment:** How much coke is deposited on the catalyst in the *in situ* case? FCC catalysts come out of the riser with 1-2% coke.

**Response:** In the 2022 target case there is 1.1% coke on the catalyst leaving the *in situ* catalytic fast pyrolysis reactor. Details are available in the steam summaries in Appendix G.

17. **Comment:** Attrition rates assumed in the draft report were too low.

**Response:** We feel the catalyst replacement rates assumed in the final draft cover this concern adequately. A total of 3.6% of the catalyst inventory is assumed to be replaced per day in both the *in situ* and *ex situ* cases.

18. **Comment:** It was noted that some of the key catalyst performance goals are competing. For example, increased coupling may lead to more liquids, but may also lead to more coke formation. Furthermore, increased liquid yield may decrease hydrogen efficiency.

**Response:** The goal of the research is to overcome these obstacles. Also, the use of separate reactors operating with different catalysts and different reaction conditions will be considered as we consider additional process options in the future.

19. **Comment:** The catalyst cost at \$6,500/ton in the draft seemed 3 to 8 times low.

**Response:** We increased the unit cost of the catalyst three times to \$19,500/ton or \$9.75/lb. Note that the actual cost will depend on modifications made to the catalyst based on research. This unit cost is higher than FCC catalyst costs, which was the basis of our initial assumption of \$6,500/ton or \$3.25/lb. We also allow for 3.6% of the catalyst inventory to be replaced per day. This leaves room for the research to develop less expensive catalysts with higher losses, or more expensive catalysts with lower losses to meet the cost targets.

20. **Comment:** With the recent commercial challenges, it may be difficult to accept the utilization of FCC upgrading equipment (circulating fluidized bed reactors).

**Response:** The research will have to experimentally justify and demonstrate achieving some of the target metrics using circulating fluidized bed reactors. This technology has been successfully scaled up for biomass fast pyrolysis; we chose this option in our design for that reason. The *ex situ* upgrading case will have additional fixed bed options as mentioned in the text.

21. **Comment:** Total capital costs in the initial draft seemed high in both the *in situ* and *ex situ* cases. Some Catalytic Fast Pyrolysis systems have been reported for 50% of the costs shown in the draft report.

**Response:** The equipment costs were since adjusted in the final version, especially for the use of higher than ambient pressures. There were savings from the use of 120 psia pressures because of reduced reactor volumes (estimated by the Harris Group). We were careful to not underestimate the costs, and used higher installation factors of ~4 for the reactor and the regenerator in the final version.

22. **Comment:** For the *ex situ* case the benefit of adding hydrogen to the fast pyrolysis reactor is negligible, so why not add hydrogen only to the *ex situ* vapor upgrading reactor?

**Response:** The reason we chose to add hydrogen to the front end instead of the *ex situ* reactor only was because of concerns about the dilution of hydrogen and lowering the partial pressure. We do need a certain amount of fluidizing gases, so inclusion of hydrogen in the mix allows us to not add other gases for fluidization in the fast pyrolysis reactor.

23. **Comment:** The initial design specified a pressurized (~120 psia) reactor and a near atmospheric combustor, with intermediate lock hoppers in order to lower compression costs for air fed to the combustor. There were many comments about this design, especially with respect to costs and reliability of such a system, and it was recommended that the system should be designed with similar reactor and combustor pressures.

**Response:** The recommendation to operate the reactor and combustor at comparable pressures was adopted in the final design. The electricity credit was reduced because of higher compression requirements, but we agreed that this is a more reliable design.

24. **Comment:** The simplified flow diagrams in the report do not adequately reflect the complexity of the systems described such as solids coolers and lock hoppers (in the previous draft). More details should be presented.

**Response:** Appendix G includes detailed process flow diagrams along with stream tables.

25. **Comment:** How was the 5:1 catalyst to biomass ratio concluded?

**Response:** This is an initial assumption, and will likely be modified with more experimental results. This ratio will depend on the steady state activity of the catalyst, which is affected significantly by the reactor configuration and whether the system is a truly circulating fluidized bed system. Although Figure 1 shows results from different experimental configurations, it indicates that ~6% oxygen content oil can be produced with an approximate 5:1 catalyst to biomass ratio (0.2 biomass to catalyst ratio). As mentioned in this report, significant yield improvements will be necessary via catalyst research to achieve our 2022 yield targets, even as we achieve an oxygen content of 6%. Our choice for this design was influenced by this consideration.

26. **Comment:** In both cases, stripping steam is used to recover additional product. How much extra yield is assumed? How was this concluded? And is it really worth the extra yield to add this extra unit operation?

**Response:** This assumption was consistent with FCC systems where steam helps recover additional hydrocarbons from the catalyst before regeneration. The tradeoff between capital

costs, product recovery, and impacts on catalyst maintenance will need to be assessed experimentally for biomass systems during our research.

27. **Comment:** What is the organic yield and composition (CHON) for both the *in situ* and *ex situ* cases? What is the basis for this yield?

**Response:** The organic liquid yields are shown in Table ES-1, and mass percent C, H, O are shown in Table 6 under Area 300. These are targets to achieve cost-competitive fuels production from biomass by 2022. The yield bases for 2022 were derived using these considerations: (1) organic yield maximization while still allowing reasonable coke and gas losses, (2) the yields needed to be in the range where the process was economically feasible, and (3) the *ex situ* case had the added target for higher diesel-range product.

28. **Comment:** What is the non-condensable gas composition from the *in situ* and *ex situ* reactors?

**Response:** We have included detailed flow diagrams and stream summaries in Appendix G, where the gas composition information is also included.

29. **Comment:** What is the hydrogen consumption in the *in situ* and *ex situ* process?

**Response:** Hydrogen consumption by difference of reactor inlet and outlet gas composition in the *in situ* and *ex situ* 2022 target cases are 1.3 and 1.8 wt.% of dry biomass, respectively. Please note that this consumption can be significantly impacted by water gas shift assumptions. The other metrics such as H/C ratio, oxygen content, and organic liquid yields provided in Table ES-1 are more reflective of the extent of desirable reactions involving hydrogen.

30. **Comment:** Why is the *ex situ* case bio-oil oxygen content lower than in the *in situ* case?

**Response:** The catalyst performance assumptions are more aggressive for the *ex situ* case, based on some of the potential advantages outlined in Table 3.

31. **Comment:** Why is the *in situ* yield (75 gge/ton) lower than the *ex situ* yield (78 gge/ton)?

**Response:** In this 2022 target design, the yield differences are primarily because of the higher losses during the hydrotreating of the *in situ* process bio-oil. The *in situ* process bio-oil has higher oxygen content and losses are estimated based on Figure 8.

32. **Comment:** Why is the catalyst loss rate lower for *ex situ* compared to *in situ*?

**Response:** Although both the *in situ* and *ex situ* cases assume total catalyst replacement rates of 3.6% of the inventory per day, the catalyst (bed solids) inventory itself is assumed to be larger for the *in situ* case (Table 4) because of the disadvantages of the catalyst mixing with bulk solids such as biomass, char, and mineral matter/ash within the reactor, as outlined in Table 3.

33. **Comment:** Add a sensitivity case for 20% oxygen content in the organic liquid with atmospheric pressure and 5 bars pressure, using hydrogen only downstream. Outline the impact on capital costs (because of larger volumes) in such a case.

**Response:** We will consider adding such a case during our future analysis. We could not include the case in this report because of time constraints. We did add a discussion about hydrogen and pressure in Section 3.2.1.5. Even without any consideration of potential

benefits to the chemistry (which will need to be experimentally proven with future catalyst development), we anticipate some negative impacts on the economics because of larger reactors.

34. **Comment:** Show how you can bring down the cost further from less than \$3.5/GGE to \$3/GGE.

**Response:** Figure 15 shows sensitivity cases and the key areas where we can make further impacts. As pointed out by another reviewer, we can optimize the operating scales and related handling of intermediates after some maturation of the technology, and our  $n^{\text{th}}$ -plant assumption *in this regard* may be sub-optimal; economies of scale alone can bring down the cost significantly. There is some conservatism in the assumption of catalyst losses of 3.6% of the inventory per day (especially for the *ex situ* case); this may be another area of further cost reduction.

35. **Comment:** Show sensitivity to the modeled dew point in the condensation train and how much of an impact changes in this temperature impact the process and economics.

**Response:** The reviewer's comment was based on the assumption in the initial design that we can have indirect heat exchange down to the dew point of the pyrolysis vapors. In the final design we assumed direct quench below the dew point to avoid fouling heat exchangers. The impact is shown in sensitivity Case 22 in Figure 15.

36. **Comment:** Discuss the basis for sizing and scaling of the combustor. Parameters that should be discussed include superficial velocity, % of stoichiometric air used, scaling variable used (should be related to superficial velocity).

**Response:** We have added this discussion in Section 3.2.

37. **Comment:** From the perspective of solids carryover to the quench system, it may not be necessary to have a hot gas filter (HGF) provided the cyclone efficiencies match the Particle Size Distribution (PSD) of the catalyst. In this context it may be useful to remove fines from fresh catalyst before introducing into the reactor. Granted some char will carry over, especially for the *in situ* case, but that alone will not necessitate a hot gas filter.

**Response:** Thank you for your valuable insights.

38. **Comment:** Hydrogen embrittlement considerations for the reactors should be mentioned in the text.

**Response:** We have included this along with a reference.

39. **Comment:** It is important to pay close attention to siting, economies of scale, use of merchant hydrogen taking advantage of economies of scale to reduce costs.

**Response:** This is a generic design for a standalone plant at a U.S. location. We do understand that there are numerous advantages to be had from an optimal location, but we did not want to make this design too specific and tied to other considerations; those factors will likely be leveraged more efficiently by commercial entities.

40. **Comment:** The incentives for *ex situ* should be bigger than the *in situ* case, leveraging hydrogen addition; it is less clear whether hydrogen addition will be possible in the *in situ* case. For a yield of 29%, the trend line in Figure 1 in the study design would suggest a pyrolysis oil oxygen level closer to 20 % vs. 10.8% assumed in the study; if these numbers

are confirmed then it seems that the benefits in this process are derived primarily from the introduction of hydrogen.

**Response:** The anticipated benefits from hydrogen addition are larger for the *ex situ* case, as reflected by the more aggressive 2022 targets compared to the *in situ* case. It has been further clarified in this final version of this report that the cases shown here reflect target cases, and not the current state of catalyst performances as reflected by Figure 1. The 2022 case is targeted to significantly improve on the performances shown in Figure 1. The benefits through research is expected from not just the introduction of hydrogen, but also through the use of developed catalysts that are capable of beneficially using the hydrogen at the reaction conditions during vapor upgrading.

41. **Comment:** It is not at all clear why the two cases produce such differing amounts of gasoline vs. diesel. This raises questions about the product distillation curve and the hydrocracker design.

**Response:** Targeted coupling reactions will be one of the objectives of *ex situ* catalyst development. Coupling reactions are expected to allow the production of larger molecules, including more molecules in the diesel range. This is the reason for a larger proportion of diesel in the *ex situ* product as the 2022 target.

42. **Comment:** Is the distillation curve for the 10.5 % oxygen (*in situ*) product assumed to be significantly different than for the 6.4 % (*ex situ*) product? Data from previous work suggested that significant boiling point changes occur below 5% oxygen in the case of fast pyrolysis. Here the oxygen level for the hydrocarbon feed is assumed to be higher than for the hydrotreated product (in the previous cases with 5% oxygen after hydrotreating of raw pyrolysis oil). Why is this assumption made? Is there data to support this?

**Response:** Note that we are not aiming to directly blend the material targeted at 10.5% and 6.4% oxygen for the *in situ* and *ex situ* 2022 cases, respectively, into fuel products. The downstream hydroprocessing is aimed to further reduce the oxygen content to below 1% before it can be considered for blending into gasoline and diesel. The 2022 targets for the final product in this report are close to the low oxygen content (LOC) products characterized by Christensen et al. (2011), which were considered blendable into gasoline and diesel.

43. **Comment:** It is noted that the design calls for the diesel fraction from the hydrotreater to be sent to the diesel pool. Given what is known about the poor quality of pyrolysis oil diesel, we would think it will require upgrading via hydrocracking. Specific data about diesel product quality should be provided, given that a substantial portion of *ex situ* economic advantage derives from producing more diesel and less gasoline range material.

**Response:** As noted in the Conclusions section, product characterization and quality specifications specific to these processes will become important with advances in the research for these pathways. We expect that in the post-2017 timeframe significant attention will be paid to quality aspects and the development of associated targets for refinery integration. This may include targeting the hydrocracking operations, already included in this design, toward better quality products, including the possibility of ring-opening chemistry.

44. **Comment:** The riser diameter on the ex-situ pyrolysis reactor was limited to 1000 tons/day. What limits the riser diameter?

**Response:** The limitation of 1,000 tons/day per fast pyrolysis reactor train was based on biomass feeding constraints and not the riser diameter.

45. **Comment:** FCC units that can operate with only two cyclones on their regenerators do not usually meet U.S. emissions standards for particulate matter. Typically, a wet-gas scrubber (preferred), electrostatic precipitator, or baghouse is required. Perhaps a tertiary separation is not necessary for sand, but one will be required for ZSM-5. A flue-gas scrubber was mentioned with a reverse-osmosis system for the water product, but there was no other description of the equipment.

**Response:** We do not describe the system in the main report because it is mature technology, but have included the source of the scrubber information used for our costs in Appendix A. The information was originally obtained for use in Dutta et al. (2011).

46. **Comment:** Will the regenerators handling ZSM-5 be operated in full or partial-burn mode? Partial burn requires a separate CO boiler.

**Response:** We assumed full burn with 20% excess air, along with an associated catalyst cooler.

47. **Comment:** In the draft version it was mentioned that the *ex situ* catalyst operates in a “more benign reaction environment”. It should be further stated that irreversible catalyst deactivation from impurities such as alkali can be reduced by the upstream removal of solids. In addition it is important to point out the flexibility to operate at different conditions compared to the fast pyrolysis reactor in the *ex situ* approach; this can have advantages in carbon efficiency, higher selectivity to target products and reduced deactivation.

**Response:** Thank you for the valuable comments. All the points were included in this final version.

48. **Comment:** It was not clear if there was a continuous feed of steam (mentioned for stripping the catalyst) to the reactors or a feed to the regeneration cycle.

**Response:** In this conceptual design the stripping steam is fed after the catalyst is separated from the vapors, similar to FCC units. The function is to strip out any volatiles from the catalyst that would otherwise go to the regenerator and be combusted.

49. **Comment:** In terms of deoxygenation, does your model suggest that hydrodeoxygenation pathways would be preferred to decarboxylation / decarbonylation reactions.

**Response:** Carbon efficiency is of prime importance for increasing fuel yields. Unlike in syngas-based processes, any carbon not already incorporated in liquid-range molecules after vapor upgrading (in these *in situ* and *ex situ* conceptual process designs) cannot be reincorporated into liquid phase products. Thus hydrodeoxygenation is the preferred route for deoxygenation to avoid carbon losses as CO and CO<sub>2</sub>.

50. **Comment:** What is meant by “more favorable reaction chemistry” in the context of *ex situ* vapor upgrading?

**Response:** We meant desirable reactions such as hydrodeoxygenation, hydrogenation, and coupling. We have added this to the text.



51. **Comment:** What are the purported benefits of reducing oxygen content to 6.4% in the *ex situ* case? Does this allow dropping into an existing refinery, or does it allow removing extra hydrodeoxygenation units?

**Response:** Compared to raw pyrolysis oil hydrotreating (Jones et al. 2013) where three hydrotreating steps are included in the design, this conceptual process assumes a single step hydrotreater, which is assumed to be made possible by the lower oxygen content in the bio-oil; this will be experimentally verified with progress in research. The 6.4% oil is not deemed suitable for blending into refinery products; it may however be possible to feed this intermediate into a petroleum refinery for further processing (Christensen et al. 2011).

52. **Comment:** Inclusion of a comparison between *in situ* and *ex situ* will be useful.

**Response:** We included this in this final version (Table 3).

53. **Comment:** Need to be consistent with the use of the terms “vapor upgrading” and “vapor phase upgrading”. At one point it says “vapor phase upgrading” is for *ex situ*.

**Response:** We made them consistent in the final version.

54. **Comment:** It was mentioned that the pyrolysis reactor has sizing constraints due to biomass feeding. It is unclear why those constraints are gone just by switching to an *ex situ* configuration. The system is still using a pyrolysis reactor upstream of the *ex situ* reactor. Are you saying 2 pyrolysis reactors feed into 1 upgrading reactor? If so, you have 3 total reactors for *ex situ* and 2 for *in situ*...how does that reduce cost for the *ex situ* system? Please make this clearer.

**Response:** The reviewer correctly pointed out that there are more reactors in the *ex situ* system, hence the total capital costs are higher compared to the *in situ* system. However, the single larger *ex situ* reactor is less expensive compared to the combined cost of two-train reactors necessary for fast pyrolysis (Table 5). The language in the text was modified in an attempt to make this more apparent.

55. **Comment:** Is the inclusion of metals factored into the catalyst costs?

**Response:** We did factor the inclusion of metals into the cost. Also, based on reviewer comments we made significant upward revisions to the assumed catalyst costs for *in situ* and *ex situ* vapor upgrading.

56. **Comment:** The regeneration temperature for zeolites is typically < 650°C.

**Response:** We reduced the regeneration temperature in the versions after the June 2014 draft. The temperature was higher in the June 2014 draft version, based on FCC catalyst regeneration temperatures from literature.

57. **Comment:** Do you have any olefins in the gases? Are they all utilized in coupling reactions? Typically quite significant fractions of olefins are formed.

**Response:** We did not use coupling reactions for light olefins in the gases for the 2022 cases. Additional coupling of olefins can be beneficial to yields.

58. **Comment:** Why is the assumed heat loss lower for the *ex situ* reactor compared to the fast pyrolysis reactors? Is it because of the assumption of a single train for the *ex situ* reactor?

**Response:** Yes, the rationale was lower losses in the single train *ex situ* reactor compared to two trains for the fast pyrolysis reactor.

59. **Comment:** When mentioning “better quality oil” in Figure 1, it should be mentioned that oxygen content alone does not dictate the quality of oil. It is a function of functional groups. For example phenols are preferable to acids. Some catalytic pyrolysis oils still contain some of the reactive species.

**Response:** We added the mention of reactive functional groups to the section around Figure 1.

60. **Comment:** “Efficient hydrogen utilization, which ties into reduced aromatics in the product, reduced coke formation, and greater hydrodeoxygenation to allow higher carbon efficiency”. How is hydrogen efficiency measured?

**Response:** The effectiveness of hydrogen use during vapor upgrading is measured by the combination of the three metrics: H/C ratio, oxygen content, and yield of the organic liquid product.

61. **Comment:** Is there a problem of having hydrogen in the reactor of the circulating fluidized bed (CFB) system with the presence of oxygen in the combustor?

**Response:** Gases and vapors from the reactor do not flow into the combustor side of the CFB system. In a typical system, solids such as char are separated in a cyclone and then sent to the combustor, with a seal created by the solids in a standpipe. The oxygen reacts with the solids and the hydrogen-rich gases on the reactor side should not flow into the combustor.

62. **Comment:** Is stripping supposed to be within the continuous process or is it separate? It doesn't appear on the process flow diagram.

**Response:** Stripping steam is part of the continuous process. It is not shown in the simplified process flow diagrams in the main report. However the detailed process flow diagrams and stream summaries in Appendix G include this information.

63. **Comment:** What types of reactions cause the heat balance in the *ex situ* reactor to be exothermic?

**Response:** Hydrogenation and hydrodeoxygenation reactions are typically exothermic. Product distributions before and after the *ex situ* upgrading reactor can be found in Appendix G.

64. **Comment:** Explain how the capital cost of the fast pyrolysis reactor compares with Ensyn's published values; those were used by Jones et al., 2013.

**Response:** Please see comment 21 for a related response. The costs of the systems in this design are lower because of smaller volumetric flow rates as a result of higher pressures (~6 times Jones et al. 2013). Although a direct comparison is not possible without going back and modifying the design by the Harris Group, a quick check by changing the cost by a factor of 6 (for the larger volume) to the power of 0.5 (scaling exponent) for the reactor and combustor gave an installed cost very close to the one in the Jones et al. 2013 report.

65. **Comment:** “The fluidizing gases are rich in hydrogen because of a deliberate attempt to create a hydrogen-rich atmosphere to impact the chemistry favorably.” Please explain what is

meant by favorable. Is it to reduce coking? At these conditions it is unlikely to cause hydrogenation.

**Response:** Favorable chemistry includes hydrodeoxygenation and reduced coking as near-term targets. Hydrogenation, although difficult, is not impossible. Hydrogenation will be one of the longer-term targets.

66. **Comment:** It is worth adding more information about the chemistry of all the processes considered, especially of the catalytic pyrolysis and catalytic vapor cracking. What kind of products and with what yields can be obtained from those processes. Mass balances for all the stages should be better visible, in addition to tables within the text; suggest providing stream sizes in the process flowsheets.

**Response:** The processes represent 2022 targets. We will develop further understanding of the chemistry with research progress and modify the chemistry accordingly; some of the chemistry assumptions will be specific to catalysts being used. In the simulation we used conversion blocks to represent the key functionalities of hydrodeoxygenation, hydrogenation, and coupling. Detailed stream information is provided in Appendix G of this final version; products and the assumed chemistry can be seen in those stream summaries.

67. **Comment:** It is not quite clear how the size of the pyrolyzers and the vapor cracker were calculated. In Table 4 the weight ratio of the fluidizing gas to biomass is equal to 0.86, which may be too low. Even bubbling beds usually operate at the ratio  $>2$ ; the entrainment of solids requires significantly more gas ( $U_t/U_{mf}=72$ ).

**Response:** Note that the reactor conditions, especially the slightly elevated pressure and gas properties such as density, and drag coefficient (because of the presence of hydrogen) are different from typical fast pyrolysis systems. In addition the reactor dimension has an impact on the velocities. Based on the reviewer's observation, Anna Trendewicz conducted simulations using the model described in Trendewicz et al. (2014) to validate whether the reactor was in entrained flow mode for the conditions assumed for the model in this report; her results showed that we are in the correct regime.

68. **Comment:** Organic yield of 64 wt % (fast pyrolysis intermediate in *ex situ* case) is certainly high, considering you feedstock ash content. My correlation with the ash content of 0.9 wt% gives me 54.2 wt% (based on dry ash free feed).

**Response:** The feedstock ultimate analysis specifications we used are based on woody biomass, and the yield assumption is based on yields reported for such systems and mentioned by Jones et al. (2013). We understand that there are variations in ash within woody biomass samples, which can affect yields. With progress in research the impacts of ash and blended material based on experimental results will need to be factored into the analysis.

69. **Comment:** In the draft report a reference was provided for the design of the combustion section, which is very secondary. A source of the reactor design criteria should be provided.

**Response:** Information about superficial velocity and residence time assumptions for the reactor section was added to the text. The tool described in Worley and Yale (2012) was used by the Harris Group for the reactor design.

## Area A300: Pyrolysis Vapor Quench and Product Recovery

70. **Comment:** The initial draft had an indirect heat exchanger condensation train; multiple reviewers questioned the feasibility of such a design because of potential fouling problems. It was called out that even with 6% oxygen content the product may not be stable enough to allow indirect heat exchange.

**Response:** We modified the conceptual design to include direct cooling using two absorber/condensers (shown as the high temperature absorber/condenser and low temperature absorber/condenser in Figure 6). Indirect cooling was limited to the portion prior to the onset of vapor condensation, and the section after most of the heavy material was removed from vapor stream. Lighter fraction bio-oil was used for condensing the heavy fractions in the first absorber/condenser. The final cooling of the entire lighter fraction occurs in a second absorber/condenser.

71. **Comment:** Pyrolysis vapor fractions condense at different temperatures. The heavier the fraction the higher the temperature. See some of Professor Robert Brown's work for specific fractions. That means that staged coolers upstream of the flash tank will foul. (Note that the initial draft had a flash tank instead of the first absorber/condenser used to knock out the heavy organic material; this comment was based on the initial draft.) Inherent is an assumption that if you add catalyst (*in situ*) or upgrade the vapors (*ex situ*), the product will be more uniform with respect to condensation temperatures; I don't think this will happen.

**Response:** This and other comments were the reason for us to move toward a design with two separate absorber/condensers, first for the heavy fraction and the second for recovering the lighter fraction (shown as the high temperature absorber/condenser and low temperature absorber/condenser in Figure 6).

72. **Comment:** The chilled water heat exchanger cools the process permanent gases. These gases are split into 3 streams (that seems very difficult to accurately control), and the stream directed into the water gas shift reactor with an inlet temperature of 464°F, gases compressed to 214 psia (note temperature and pressure are for the *ex situ* case, and were slightly different in previous draft version). Where does the heat come from for this reactor, is it from steam? The non-condensable gases are also cooled compressed and re-heated. How is the heat provided?

**Response:** The non-condensable gases are split into three streams. One of them is a purge of 1%, which will be a bleed and does not need accurate control. In practice this will be a two-way split between water gas shift (WGS) and recycle, after an initial bleed. This should be doable, especially because you can allow a range of pressure drops on the WGS side because that operation is not affected to any significant extent by slight variations in operating pressure. The heat for the WGS preheat comes from process heat exchange (exchanger network for the *ex situ* case is provided in Appendix H of this final version). The gases are cooled in the absorber/condenser and reheated for WGS; recompression to 214 psia happens before the PSA after cooling of the WGS outlet.

73. **Comment:** (This comment was based on the design in the draft version where the first absorber/condenser for recovering the heavy fraction was not present; instead there was a flash drum after indirect heat exchange.) The dew point of water at 116 psia is 339°F per references. Water will be condensing long before reaching the flash drum temperature of

110°F. Later it is pointed out that there are issues with heavy hydrocarbons present in the Area 200 effluent vapor. “I think you need to plan to cool the effluent to no less than 350°F, which will, unfortunately, push a substantial cooling load into the absorber, adding exchanger surface area and tower diameter. The higher condensation temperature is another challenge introduced in the design by the desire to add hydrogen (at pressure) to the upgrader.”

**Response:** The dew point consideration was the primary reason for changes in the design and the inclusion of two absorber/condensers as mentioned in response to some of the previous comments. The Aspen Plus model predicts a condensation temperature of 466°F for the vapor stream prior to the high temperature absorber/condenser in Figure 6. Note that this is the dew point of the mixture, and not the pure component dew point of any specific compound; condensation is affected by partial pressures of all constituents. Very little water is condensed in the first absorber/condenser (included for knocking out the heavier components); it has a bottom stream temperature of 461°F (*ex situ* 2022 target case). Less indirect heat recovery is now possible because of the inclusion of this design change with a high cut-off temperature (466°F) on indirect heat recovery (as pointed out by the reviewer: “push a substantial cooling load into the absorber”).

74. **Comment:** The filter for removing particulate matter from the liquid hydrocarbon should be placed in front of the oil/water separator, which will increase its size significantly (the draft report for review had the filter only for the organic phase product stream after condensation of the vapor upgraded stream). Otherwise, particulate matter in the oil/water separator will likely form a stable emulsion (rag layer) and prove exceptionally difficult to separate. The oil/water separator might also require pH control, depending on the presence of residual acidic oxygenates and for emulsion control. Process chemicals for such need to be included in your off-sites basis if not already required for water and wastewater treatment.

**Response:** Per this recommendation the entire condensed liquid stream is filtered in this updated final design. Wastewater treatment was significantly modified in the final design, with a separate section (Area 800) for the destruction of organics in the water from the condensers in Area 300. Also, assumed costs for wastewater for the rest of the plant operations were conservative (based on a unit treatment cost for streams that are more difficult to treat). Any additional chemical costs (if necessary) can be absorbed within those treatment costs. Also, from our current experimental results, carboxylic acids are expected to be negligible for organic liquid products with oxygen contents of 15% or less. We assumed stainless steel for most of the equipment to handle anticipated acidity (Appendix A).

75. **Comment:** An understanding of the impurity profile into the water gas shift (WGS) reactor will be important in specifying the catalyst and hence the operating temperature (and hence determining equilibrium limitation on conversion). Copper catalysts are the commercial standard for low temperature water gas shift, but experience short lifetimes in the presence of inorganic impurities such as S and Cl. If impurity levels are high there is the option to use guard beds to absorb these impurities (additional cost). Alternatively, a non-copper catalyst (e.g. iron-based high temperature shift) may be more appropriate, but this would require higher operating temperatures to compensate for the lower activity.

**Response:** The design was modified to have a single step “dirty shift” or sour water gas shift catalyst as mentioned Section 3.3.1 of this version. Operating temperature was higher than a low temperature shift reactor, and a positive 35°F approach to equilibrium was assumed.

76. **Comment:** Are there one or two organic phases? Usually you will form two organic phases, with a top fraction (s.g. < 1) and bottom fraction (s.g. > 1). This is the case even with highly deoxygenated product, although there is less of the bottom phase and maybe better catalysts and processes can eliminate the heavy compounds.

**Response:** The model does not have the capability to predict three liquid phases (two organics and one aqueous with dissolved hydrocarbons). Hence we are working with the total organic liquid predicted. There is potential for improvements in this area with the progress in research.

77. **Comment:** Was there water in the predicted organic phase?

**Response:** There was some water predicted in the organic phase (~0.4% in the *ex situ* version of the simulation). Again this is an area for improvement and we are working on phase equilibrium prediction methods as part of our research.

78. **Comment:** How much steam is fed to the water gas shift reactor in A300?

**Response:** A steam to gas (after subtracting hydrogen) molar ratio of 1.2 was assumed for this sour gas shift design. Appendix G shows stream flows.

79. **Comment:** Effective filtering is needed to prevent fines carryover into downstream organic liquid upgrading.

**Response:** As noted in response to comment 74, filters were included in all liquid streams. We added a note in the text to emphasize their importance.

80. **Comment:** The possibility of fouling the heat exchangers may also be due to physically entrained aerosols sticking on the surface, not just reacting pyrolysis oils.

**Response:** This is another reason we switched to a direct quench absorber/condenser at a relatively high temperature (see comment 73) for the first vapor condensation step.

81. **Comment:** In the previous draft with a flash tank (instead of a heavy organics absorber/condenser in this final version) 92% of the bottoms product was being cooled and pumped in the single absorber/condenser. A reviewer pointed out that one should be aware of the potential high viscosity and the difficulty of pumping the liquid after cooling.

**Response:** In the updated design we only use the light organic liquid from the second absorber/condenser as the quench stream in both the heavy and light fraction absorber/condensers (also called the high temperature and low temperature absorber/condenser in Figure 6 to alleviate this concern). The heavy organic fraction is maintained at a relatively high temperature of 140°F until it is mixed with the lighter organic portion.

## Area A400: Hydroprocessing and Product Separation

82. **Comment:** “85% carbon efficiency for 20% oxygen content, and 98.5% carbon efficiency for negligible oxygen content as is usually the case in petroleum refineries.” Is the yield for the 20% oxygen content feed consistent with current data in the literature?

**Response:** There is limited data currently available for large-scale hydrotreating of organic products in the range of oxygen content of interest in this report. As described in Figure 8, we interpolated carbon efficiencies using the oxygen contents in the feed. Additional data points will become available with further experiments in the coming years. Also, note that the carbon efficiency assumption is consistent (and conservative), with respect to hydrotreating of intermediate oxygen content products within the interpolated range in Figure 8 for products obtained from hydrothermal liquefaction of woody biomass, as interpreted from the data made available by Zhu et al. (2014).

83. **Comment:** “A WHSV of  $0.5 \text{ h}^{-1}$  usually translates to a lower LHSV for most feedstock and catalyst combinations with an example of such conversion provided by Elliott et al.” Are the catalysts used in this work along with yields used in the design basis? If not, what are the catalysts? Multiple reviewers wanted to see specific mention of the types of catalysts assumed for hydrotreating and hydrocracking.

**Response:** Catalyst assumption information was added in Section 3.4.1. Non-precious metal catalysts were assumed for hydrotreating. The preliminary data point from PNNL shown in Figure 8 was obtained using a non-precious metal catalyst.

84. **Comment:** In Section 3.4 of the draft version the introduction of sulfur was mentioned. Do you talk about this anywhere later in the report?

**Response:** Further discussion was added to Section 3.4.

85. **Comment:** Do the number of hydrotreating reactors include swing reactors? This should be stated.

**Response:** Swing reactors were not used in the base case. However, cost sensitivity when using swing reactors for hydrotreating is shown in Case 25 of Figure 15.

86. **Comment:** In the draft version it was mentioned in Section 2.2 that the product was “easier to hydrotreat”. This is presumably true. But the remaining O when oxygen content gets to low levels is actually more difficult to hydrotreat compared to the “easy” O removed early on. The effect of this O on HDN and HDS is unknown (but is probably not good).

**Response:** Based on this and other reviewer comments the assumed hydrotreating severity, both temperature and pressure, were increased in subsequent drafts of this report. Sulfur and nitrogen do not have significant presence in the woody feedstock assumed in this report.

87. **Comment:** Bio-feeds are often high in N, producing  $\text{NH}_3$ . Is this considered?

**Response:** We understand that some biomass feedstocks, such as algae, can contain significant amounts of nitrogen. Woody feedstocks have lower nitrogen content (Table 2 shows our assumption). Ammonia is shown as a product of hydrotreating. Most of the ammonia produced in the pyrolysis and vapor upgrading sections (small amounts may be present, although not included in this report) will likely be removed with the aqueous phase after scrubbing operations in Area 300.

88. **Comment:** Why were the hydrotreating pressures chosen?

**Response:** It was assumed, for the 2022 target cases shown, that the *in situ* case would require higher severity (1,800 psia) and the *ex situ* case 1,500 psia based on their oxygen contents of 10.5% and 6.4%, respectively. These pressures are slightly lower than the

assumption of 2,000 psia in Jones et al. (2013), noting that raw pyrolysis oil has a much higher oxygen content. It is also understood that the pressures may need to be adjusted based on future experimental results. We included sensitivity Case 27 in Figure 15 to show the impact of a higher hydrotreating pressure; the impact is negligible because hydrotreating is a relatively lower cost operation compared to the upstream vapor upgrading (Area 200) in this particular conceptual process design.

89. **Comment:** The amount of hydrogen consumption assumed in the pyrolysis step for both cases is not trivial and seem to be counter to what is intended with this technology. To put these numbers in perspective by expressing them as wt. % hydrogen of pyoil, they would be 2.3 for the in-situ case and 3 for the *ex situ* case. This is compared to about 5.8 for treating fast pyrolysis pyoil to the 0.5% oxygen level.

**Response:** In the final version of this report the values of the weight of *makeup* hydrogen to the weight of bio-oil feed for the hydrotreating reactor in the *in situ* and *ex situ* cases are 6.3% and 3.6%, respectively; this is based on the *pure* hydrogen *makeup*. For hydrocracking, the corresponding values are 10.2% and 3.9% for *in situ* and *ex situ*, respectively. It should be noted that the feed to the hydroprocessing reactors are nearly water free. The aqueous fraction is >50% of the liquid products in Area 300. If the aqueous portion was included in the calculation (for a more direct comparison with the hydrotreating of raw pyrolysis oil from non-catalytic fast pyrolysis, where the reaction water is not removed) then the makeup hydrogen to condensation product ratios for hydrotreating are 2.5% for *in situ* and 1.4% for *ex situ*. We included the ratio of the weight of *chemical* hydrogen consumption to the weight of bio-oil feed to the hydroprocessing reactor in Section 3.4.2; the *chemical* consumptions (shown in Table 9 for hydrotreating and Table 10 for hydrocracking) are lower than the *makeup* ratios mentioned above because the makeup ratios factor purge streams required to maintain the 90 mole % hydrogen purity. All the chemical consumption values are on a water-free basis, and the inclusion of (previously removed) water in the calculations would further lower the ratios. The values shown indicate potentially significant hydroprocessing savings (in the 2022 target case) compared to the 5.8% chemical hydrogen consumption shown for raw pyrolysis oil in Jones et al. 2013; this is to be expected because that was the purpose of vapor upgrading with upstream hydrogen utilization.

90. **Comment:** The basis for the hydrotreater operating conditions selected in the study need to be defined more clearly with respect to the choice of pressures, temperatures and space velocity.

**Response:** As mentioned, we show the values for 2022 target cases in this report. The operating parameters chosen for this design are relatively severe with respect to conventional hydrotreating, although less so compared to the hydrotreating of oils from non-catalytic fast pyrolysis. We will modify assumptions as further data becomes available. Cost sensitivities to some of these parameters are shown in Figure 15.

91. **Comment:** Catalytic Fast Pyrolysis (CFP) will be “easier to treat” by causing less hydrotreating catalyst deactivation and fouling. There are several independent studies asserting that CFP can be processed with significantly less HT catalyst fouling/coking (this has not been quantified however). We agree that this supports the approach in this study i.e. specifically that of deleting the investments for the stabilizer and 1st reactor in the current PNNL fast pyrolysis + HT configuration (successfully operated for 60 days). It is less clear



that one can also reduce the pressure because of this lower coking/fouling property, or argue that the *ex situ* material can be operated at an even lower pressure. In the absence of more specific test data, we would recommend staying with 2000 psia at this stage and treating the option for lower pressures as an optimization opportunity. Also the assumption of a two year catalyst life may be optimistic even in an  $n^{\text{th}}$  plant analysis.

**Response:** We included sensitivity cases for higher pressure, use of swing reactors, and catalyst costs in Figure 15 to allow the reader to assess the impacts of variations suggested by the reviewers.

92. **Comment:** We would recommend that the target product oxygen level from the hydrotreaters be the same for both the *in situ* and *ex situ* cases by adjusting the space velocity. This keeps the hydrocracker design the same for both cases except for volume, and avoids having to make some assumptions about the hydrocracker design. By the time the material is hydrotreated to near 1% oxygen its properties are “petroleum like,” and no unusual hydrocracking conditions should be needed. Another reviewer commented on the higher oxygen content in the feed to the hydrocracker in the previous draft: “I would expect the oxygen content in the resid fraction to be lower than this, and certainly lower than the output of the unit operation above. We have seen the unremoved oxygen from the HT to follow the lower molecular weight species (phenolic oxygen) as some of the higher MW species are formed by condensation where the oxygen is removed as water.”

**Response:** We made this change in the final design per the reviewers’ inputs. The oxygen content at the hydrotreater outlets are 1 wt %.

93. **Comment:** In the case of the hydrotreaters there appears to be a constraint put on the weight and length of the reactors due to logistics. This drives the design to multiple parallel trains of small hydrotreaters. It is not clear what sets these constraints. Single high pressure reactors of significantly larger size are common in the petroleum industry. If this is driven by the vision of remote plants, these plants could be located where these length and weight restrictions would not apply e.g. on a river. Using parallel small reactors sacrifices significant economies of scale that this study could use to improve the economics. A study design with this large number of tiny reactors would not have much credibility with a refiner. Another reviewer stated that the added commentary about transportation limitations to justify the use of smaller reactors was a good addition, given our design decision in the initial draft.

**Response:** We used this feedback to move to single large hydrotreaters in the final design. Multiple smaller hydrotreaters in the initial draft is no longer used. We also removed the commentary about transportation limitations because of this decision.

94. **Comment:** You might want to mention what impurities are expected to be in the purge stream from the hydrotreater.

**Response:** We provided detailed stream summaries in Appendix G of the final version of the report. Assumptions about light gases formed, which constitute the impurities from the hydrotreating and hydrocracking reactors in both the *in situ* and *ex situ* cases, can be gathered from the information provided.

95. **Comment:** You might want to mention that the hydrocracker recycles to extinction any gas oil (heavier than distillate, e.g., three- and four-ring aromatics) fraction.

**Response:** We added this to the text per this suggestion.

96. **Comment:** Both hydrotreater and hydrocracker have two-stage flashes on the reactor effluent. Where does the low-pressure flash vapor go?
- Response:** We included detailed process flow diagrams in Appendix G. All stream destinations can now be traced by the interested reader. In this particular case the high-pressure (HP) flash purge streams go to the pressure swing adsorption (PSA) and the low pressure (LP) one goes to the reformer.
97. **Comment:** A low rate of irreversible catalyst deactivation would make the option for a fixed bed reactor more feasible (assuming this reactor set up would cope with rates of reversible deactivation by carbon laydown). Note also that the use of guard beds may be a strategy in fixed bed operation to minimize the effects of poisoning.
- Response:** Note that we included a sensitivity case in Figure 15 showing the cost impact of using swing reactors. This case should capture the impact of more frequent maintenance activities for reversible deactivation (coke laydown).
98. **Comment:** Hydrotreating catalyst: I'm assuming at some point that a sulfided NiMo (or CoMo) catalyst will be used in this stage of the process. Will there be sufficient sulfur species present in the feed to this reactor to maintain the catalyst in a sulfided state, or do you envisage having to add a sulfiding agent?
- Response:** We have included justification in the text based on the Aspen Plus simulation predictions, which show that we will have sufficient sulfur at steady state to keep the catalyst sulfided.
99. **Comment:** Hydrotreating catalyst: "Price: \$20/lb (2011) based on NREL calculations using metals pricing and costs for manufacturing processes." This cost is a bit on the high side.
- Response:** We retained the \$20/lb in the final report to allow for any cost escalations because of catalyst modifications to handle the quality of oil after vapor upgrading.
100. **Comment:** For hydroprocessing add information about makeup hydrogen, make clear that purge gas goes to the PSA and not reforming, both lb/lb and Carbon/Carbon yields.
- Response:** All these are included in the final version of the report. A related response is included after comment 96.
101. **Comment:** Compare hydrocracker and hydrotreater costs with Jones et al. (2013) report after scaling. Provide sensitivity analysis to show impact of capital cost escalation.
- Response:** A quick comparison was made between the first stage hydrotreater in Jones et al. (2013) and the hydrotreater cost assumed in the *ex situ* case of this report using the ratios of the mass flow rates and a scaling exponent of 0.65 (based on Jones et al. 2013). The reactor cost was higher in the *ex situ* case. It is understood that the two cases are not directly comparable because of differences in the quality of feed to the reactors and also the conversion strategies. Sensitivity Cases 19 and 25 in Figure 15 of this report show the impacts of changes in assumptions.
102. **Comment:** The hydrotreater is modeled to operate at 340°C (inlet temperature). This temperature is low for the material being processed. What is the temperature rise in the hydrocracker given an inlet temperature of 380°C? Usually they get to 400-410°C as the max temperature needed for really low deoxygenation (even with low O&N HTL oil from algae).

I am not sure that you can back off on that temperature even starting with lower oxygen content because of the remaining type of oxygen is just harder to remove.

**Response:** This temperature was increased to 375°C at the inlet with an outlet temperature of 403°C at the outlet. The hydrocracker inlet temperature was also increased to 392°C, with an outlet temperature of 420°C.

103. **Comment:** What is the chemical consumption across the reactor? This is a key metric and difficult to back calculate from the text. Add this to the table. Also, state the basis for hydrogen consumption.

**Response:** Chemical hydrogen consumption per feed to the reactor (on a weight basis) for the hydrotreater is 2.1% for *ex situ* and 2.6% for the *in situ* case; for the hydrocracker it is 3.1% for *ex situ* and 5.4% for the *in situ* case. This was added to the tables in Section 3.4.2. The basis for hydrogen consumption is discussed in Section 3.4.

104. **Comment:** The hydrogen feed to the reactor was 14,174 scf/bbl for the *in situ* case and 9,161 scf/bbl (these numbers reflect updates for this final version for context). How was this chosen?

**Response:** The key factors are reactor temperature control and maintaining 90 mole% purity of the hydrogen feed gas (treat gas). This is discussed in detail in Section 3.4.

105. **Comment:** In the draft version: Process model flow information for hydrotreater based on CHO yields reported: Predicting a 96% carbon yield to the organic liquid product seems too high. Typically a 60 to 65% yield has been achieved with regular (non-catalytic) fast pyrolysis oil that is already a higher average molecular weight. It is possible that catalytic fast pyrolysis oil could have higher yield to non-condensables.

**Response:** The interpretation of 96% based on the information provided in the draft version may not be accurate (because sufficient information was not provided and some gases were included in the reported stream). This assumption was revisited and modified as shown in Figure 8 for the entire hydroprocessing unit (carbon efficiencies of 91% for *in situ* and 94% for *ex situ*). Individual carbon efficiencies for the hydrotreaters can be derived from CHO analysis and mass flow rates provided in Table 8.

106. **Comment:** In the draft version: Hydrocracker yield in Table 8, based on CHO calcs: 99% carbon yield to the organic is also too high. Very unlikely to achieve this with the best of oils. What is the basis for the yields?

**Response:** Similar to previous response for the hydrotreater: The interpretation of 99% based on the information provided in the draft version may not be accurate (because sufficient information was not provided and gases were included in the reported stream). Also, assumptions in this regard were subsequently modified as shown in Figure 8 for the entire hydroprocessing unit (carbon efficiencies of 91% for *in situ* and 94% for *ex situ*). Individual carbon efficiencies for the hydrocracker can be derived from CHO analysis and mass flow rates provided in Table 8.

107. **Comment:** Flow rate to hydrocracker: Is there a reference for this estimate? I would expect that the product from the HT would have less resid type material, due to the tendency for CFP to make smaller molecule hydrocarbons rather than the high MW that comes out of HTL and FP.

**Response:** The 2022 targets in this design reflect intended research improvements to increase diesel-range molecules via coupling reactions. Research efforts will include catalyst development to move toward these targets. As noted in the text the 2022 target for diesel-range molecules are significantly lower for the *in situ* case.

108. **Comment:** Mass of catalyst in the hydrotreating reactor (Table 9): What is meant by “design” and “actual”? and why is actual > design?

**Response:** There is a 70% overdesign as noted in this latest version.

109. **Comment:** Hydroprocessing catalyst price in Table 30: \$10-12/lb (2011) based on NREL calculations using metals pricing and costs for manufacturing processes (comment based on June 2014 draft). This is rather low for hydrotreating catalyst – perhaps should be ~\$20/lb

**Response:** We increased the cost to \$20/lb, although another reviewer pointed out that \$20/lb may be on the high side for catalysts without precious metals.

110. **Comment:** If you could get to 5-10% oxygen in catalytic pyrolysis then the hydrotreating likely would work similarly to hydrotreating HTL. I just wonder what kind of carbon recovery you get through the catalytic pyrolysis step when you have only 5-10% oxygen left. Carbon recovery of hydrotreating of CFP oil with 5-10 wt% O would be similar to that of HTL oil, which could reach 0.92-0.98 g carbon in oil per g carbon in feed. That was observed recently with algae HTL oils. The lower end of that range (0.92) is what is seen with lower lipid algae biocrudes. Since the CFP feedstocks won't have lipid, I'd suggest aiming for the 0.92 g/g yield (or maybe even lower).

**Response:** In the latest version we have a 91% and 94% carbon recovery for the *in situ* and *ex situ* cases with 6.4% and 10.5% oxygen contents, respectively. This is in line with the reviewer comments. Hydroprocessing carbon recovery targets for 2022 for the *in situ* and *ex situ* cases are outlined in Table ES-1.

## Area A500: Hydrogen Plant

111. **Comment:** The hydrogen plant investment costs seem out of line WRT the cost of the hydroprocessing: the ratio of H<sub>2</sub> plant cost/Hydroprocessing cost seems much too high, which again provides a pretty significant economic penalty.

**Response:** The cost was changed to make consistent with Jones et al. (2013). Our initial source had a higher cost estimate.

112. **Comment:** If I read correctly, you're using fuel gas to fire the SMR rather than natural gas. Did you check the adiabatic flame temperature of the fuel gas to ensure that it is capable of providing the radiant heat necessary? My understanding from steam cracking is that high-CO gases cannot provide sufficient temperature to operate a cracking furnace, which runs only a little hotter than an SMR.

**Response:** Aspen Plus predicts that the adiabatic temp can support the SMR. Historically, we have used a minimum fuel combustor temperature of 1,700°F or higher in our simulations (design specification). However, the temperature is higher than 1,750°F for both the *in situ* and *ex situ* cases. There is hydrogen present in the fuel gas mix. Preheating the combustion air after the air blower helps to raise the temperature significantly.

113. **Comment:** PSA – Not all PSA processes for air separation require 6-7 bar pressure. Is the 16-18 bar PSA pressure for H<sub>2</sub> firmly established? Also, it does not appear that hydrogen recycle is required...assumption or based on rigorous review of the process for these conditions?

**Response:** Here is some information from Miller and Stoecker (1989). It is not the most recent publication, but we assume that the general premise for PSAs has not changed. “The driving force for the separation is the impurity partial pressure difference between the feed and the tail gas. A minimum pressure ratio of approximately 4:1 between the feed and tail gas pressure is usually required for hydrogen separations. However, the absolute pressures of the feed and tail gas are also important, particularly to hydrogen recovery. The optimum feed pressure range for PSA units in refinery applications is 200-400 psig. The optimum tail gas pressure is as low as possible. Since vacuum is normally avoided, tail gas pressures between 2 and 5 psig are typically used when high recovery is needed. The 2 psig pressure can be used when the tail gas is to be compressed, and 5 psig can be used when the tail gas is sent directly to fuel burners, as in steam reforming applications.” Our design has ~65% and ~70% hydrogen (volume basis) in the streams fed to the PSA. Recycle is required for low hydrogen concentrations.

## Area A600: Steam System and Power Generation

114. **Comment:** From initial draft version: A portion of the economics is dependent on high electricity production with credit of 21 cents (per kW-hr?), which is too high ... probably closer to 5 cents in most areas where this plant could be located.

**Response:** To clarify the reviewer’s interpretation, the 21 cents credit was per GGE of product and not 21 cents/kWh. The unit credit is 5.85 cents/kWh. The per GGE electricity credit has since been reduced after process modifications to address reviewer comments; the reduction was primarily from the removal of lock hoppers in the circulating fluidized bed reactor systems.

115. **Comment:** You should list the pressure levels for the steam headers. I’m not an expert by any means, but I was surprised at the super-high pressure level of 1321 psia. It might just be my personal experience, but I’m used to seeing levels like 900 or 1500 psig. Steam cracker transfer-line exchangers will produce up at the 1500 psig range. FCC waste-heat boilers and catalyst coolers tend to run more like 900 psig. Regardless, some explanation of the determinant of the SHP header level would be nice.

**Response:** This was used to maximize electricity generation. We had quotes from the mixed alcohol process (Dutta et al. 2011) for these conditions, so we did not want to go any higher since cost quotes are difficult to get. We did not want to go lower because we have sufficient delta T to operate at 1,321 psia in the catalyst coolers. We requested Harris Group to make sure that the catalyst cooler costs reflect this steam pressure.

116. **Comment:** In the previous draft: I found intra-process heat exchangers listed in the equipment lists of Area 600 for both cases but no mention of its need or specifications in the narrative and no listing of the reformer itself.

**Response:** We have provided detailed heat exchanger network information for the *ex situ* case. The heat exchange network is included in Appendix G-2, and details of heat exchangers and costs in Appendix H. The pinch analysis heat exchanger cost line items in the equipment

list in Appendix B were prorated based on duties in specific areas, given that cross exchanges occur across areas and assignment of exchangers to one specific area would be arbitrary. The *in situ* case was scaled from the *ex situ* case using total duty, which we deemed reasonable because the processes are similar.

117. **Comment:** Power Gen – Why 350 psia extraction pressure for the low pressure turbine (LPT)? Was there any sensitivity analysis to this parameter? My experience would have thought this to be significantly lower (<270 psia) in order to max steam cycle thermal efficiency. Nevertheless, no explanation was given as to the 1st stage expansion pressure. The steam cycle efficiency may not change by more than 1% by going lower in extraction stage pressure, but it really depends on how flat the net efficiency vs. LPT inlet pressure curve is. Are the high pressure turbine (HPT) and LPT turbine expansion efficiencies different? They are in real systems.

**Response:** We will study the impact via sensitivity analysis in the future. It was not included in this report because of time constraints; the reviewer pointed out the benefit may be marginal. We do not assume different efficiencies for HPT and LPT; it is good to be made aware of this. We will keep the existing specifications for this report, but retain this comment for future use and modifications.

118. **Comment:** Electricity credit seems to influence also somewhat substantially. Would make sense to evaluate Power Gen cycle efficiency more closely as well as evaluate (if you haven't already) other cycle technology options that might fit.

**Response:** This can be done in the future. However, since the focus of the process is fuels production, most of the biomass energy is targeted toward fuels rather than power and the overall impact of electricity is not as significant. The electricity credit was further reduced to ~4 cents/GGE since the draft version that was reviewed.

## Area A700: Cooling Water and Other Utilities

119. **Comment:** Chilled water is mentioned as a utility for Area 200, and I found the equipment in the equipment list. I found no discussion of the equipment specifications in the narrative, however.

**Response:** We added information in Appendix A. It was derived from Humbird et al. (2011) and the same electricity consumption basis was used in this report.

## Area A800: Wastewater Management and Recycle

120. **Comment:** We were pleased to see that the design includes more definition to the utilities part of the plant. In our view, past studies underestimated these costs, particularly for water treatment.

**Response:** Thank you for the comment.

121. **Comment:** Comment based on previous draft: I think you need a loading rack for wastewater, or at least a pump, pad, and flex hose, since your plan includes shipping wastewater offsite. Additionally the logistics and costs of shipping so much wastewater offsite is significant. The offsite wastewater treatment number of \$0.48/T seems optimistic.

**Response:** Clarification is now provided that we were not planning to ship the wastewater. The portion of wastewater that is most challenging will be handled by the regenerative

thermal oxidizer (RTO). Other wastewater that has known methods of treatment is expected to be treated in the plant vicinity. We assumed an operating cost for this treatment; the assumed cost of \$0.022/gallon was conservative (high) and based on Humbird et al. (2011).

122. **Comment:** Comment based on first draft in June: Discuss what will be the fate of wastewater, aerobic digestion (discuss assumed it will not be toxic). Is this discharged to POTW (publicly owned treatment works)? Please specify type of treatment and amount to be treated. 9% carbon is very high.

**Response:** The wastewater treatment (WWT) strategy was since modified to use an RTO, as described in this version of the report. The wastewater is not sent to POTW; please see discussion in this version about using an RTO for the challenging streams, and on-site WWT for the rest of the wastewater.

## Miscellaneous

123. **Comment:** Is it reasonable to provide costs with the precision of five digits if the uncertainty of yields is more than 20%? Another reviewer suggested reducing the number of significant figures reported.

**Response:** This was done in a few of the tables. Please understand that the report and all the numbers needed to be updated multiple times. We found it easier and less error prone to keep all the figures. We do understand the large uncertainties in our analysis, and the inclusion of significant figures is not a reflection of extreme certainty.

124. **Comment:** A reviewer questioned 0% contributions presented in the energy balance pie charts (Figure 11).

**Response:** We have since included one place of decimal in that pie chart. The numbers presented still reflect rounding to the nearest tenth.

125. **Comment:** A significant amount (~30%) is lost through air-cooled exchangers. Where will the energy come from for the coolers?

**Response:** The air cooled exchangers are driven by electricity and accounted within our simulation. The air cooled exchangers were used to save on water usage, and used for cooling needs down to 140°F, but no lower. Cooling water was used for cooling below 140°F.

126. **Comment:** In the sustainability section there was mention of ZnO and HDS as catalysts in the previous draft. Are they state of the art?

**Response:** We changed the nomenclature to indicate that these are not catalysts for hydroprocessing. They are used for sulfur removal from off-gases prior to the reformer.

127. **Comment:** A reviewer was interested in having enough details to reproduce and model some of the operations in the process.

**Response:** We had not included the detailed stream tables in the review draft. They are now available in Appendix G. We believe the significant details provided in Appendix G will help answer the reviewer's questions.

128. **Comment:** For the sustainability section providing the SimaPro categories applied to the inputs will help with reproducibility of results.

**Response:** The information is provided in Table 25 of this version.

129. **Comment:** It will be helpful to know the assumed composition of all these catalysts for sustainability calculations. Provide the caustic identity.

**Response:** Most of the catalysts are proprietary in nature and company specific. Approximate composition information can be gleaned from the literature. The SimaPro assumptions (including for caustic) are listed in Table 25.

130. **Comment:** Can you provide the boiler feed water chemicals used?

**Response:** Chemicals utilized for boiler feed water and/or steam condensate treatment are an oxygen scavenger like sodium sulfite ( $\text{Na}_2\text{SO}_3$ ) or hydrazine ( $\text{N}_2\text{H}_4$ ) and corrosion inhibitor/neutralizing amine like morpholine ( $\text{C}_4\text{H}_9\text{NO}$ ). Reference Betz Dearborn Water Management Group, 1998.

131. **Comment:** Can you provide the cooling tower treatment chemical used?

**Response:** Chemicals utilized for cooling tower water treatment generally contain proprietary combinations of corrosion inhibitor, oxygen scavenger, pH control and biological fouling mitigation. Typical compounds used in treatment programs are phosphates, azoles, copolymers and zinc. Reference Betz Dearborn Water Management Group, 1998.

132. **Comment:** An additional table showing the fossil energy consumption and GHG emissions breakdown will be relevant for this work.

**Response:** The information is provided in graphical form (Figure 12).

133. **Comment:** On an energy basis and with electricity credits, the GHG emissions at the conversion stage for the *in situ* and *ex situ* cases are negative 2.6 kg CO<sub>2</sub>e/GJ and negative 1.2 kg CO<sub>2</sub>e/GJ. It's not clear to me if this includes total HDO to produce a finished fuel. It would be worth comparing this number against the fossil fuel baseline emissions to show that it meets the 60% reduction target for qualification as an advanced cellulosic biofuel.

**Response:** The conversion step includes all operations included in this process including HDO to finished fuels. The negative values or significant reductions are derived primarily from offsetting electricity from other sources. Comparisons with fossil baseline emissions are also included in this report, with further details in Appendix E.

134. **Comment:** What is the impact of depreciating your plant over 20 years rather than 30? This may find broader acceptance.

**Response:** The impact is shown (included in this version) in Figure 15 as sensitivity Case 12. There is a 4.1% increase in the 2022 target MFSP for the *ex situ* case.

135. **Comment:** The conclusion of *in situ* and *ex situ* selling price being nearly equal at ~\$3.5/GGE is reasonable.

**Response:** Thank you for the comment.

136. **Comment:** Cold biomass can potentially be used for temperature control instead of preheating it. Is it worth the CapEx to heat it? Provide a sensitivity case.

**Response:** While we did not include a sensitivity case, the use of low grade process heat for heating the biomass has positive impacts on the overall process efficiency. The cost of



additional cross flow pellet dryer and a blower are marginal compared to the gains in energy efficiency. This low grade heat would otherwise have no consumers in the process.

137. **Comment:** The title should more accurately reflect the content. These design cases are objectives and not achieved yet.

**Response:** We tried to make it clear in multiple places within the text that these design cases reflect 2022 targets. We also changed the title to say that these are research pathways.

138. **Comment:** A reviewer did not agree with definitive statements in the draft version saying that we can achieve cost-competitiveness based on this design report.

**Response:** We have since modified the statements to make clear that the design case is an outlined pathway, and achievement of catalyst performances outlined in this report is one way to move toward cost-competitiveness of biomass-derived hydrocarbon fuels.

139. **Comment:** Assessment of cost-competitiveness should include consideration of distribution and marketing costs, before the MFSP can be compared to retail pump prices and for claims of cost competitiveness should be advanced. Additional costs are incurred for blending to meet product specifications.

**Response:** We understand the necessity of considering additional costs for marketing, distribution, and blending. The research goals presented are for 2022. We anticipate careful consideration of quality specifications and associated penalties/credits as we develop further understanding via research and obtain experimental results. The aspect of blending is expected to be covered as part of future work. We also show that there are options, such as economies of scale, to significantly improve costs beyond the 2022 target cases outlined here, and some of the other significant impacts shown in Figure 15 can be leveraged to further reduce our minimum fuel selling price (MFSP) and offset additional distribution and marketing costs.

140. **Comment:** The design does not leverage economies of scale that can bring significant benefits. N<sup>th</sup> plant assumptions should also include performance at an efficient scale.

**Response:** We understand that economies of scale can have major impacts as depicted in the sensitivity analysis shown in Figure 15. However, we maintained the design at 2000 dry metric tonnes per day for our base case for consistency and comparison across other pathway design reports funded by BETO. The interested reader can gauge the benefits derived from economies of scale from Case 10 in Figure 15. We also included the reviewers' recommendations for the inclusion of references related to economies of scale.

141. **Comment:** Even with n<sup>th</sup> plant assumptions, capital costs for the process are 6-8 times the cost of new petroleum refinery capacity. Capital efficiency should be significantly improved. It is understood that further contingencies were not included, and favorable process assumptions (e.g. 2 year catalyst life, 90% capacity utilization) were made because of the assumption of n<sup>th</sup> plants. Inclusion of additional contingencies would further reduce capital efficiencies, and contingencies for the current state of CFP development should be 50% more.

**Response:** Biomass conversion processes involve solids handling, use low energy density feedstocks, and are less mature; hence the economics are difficult at this stage. The significant learnings of the petroleum industry through operational improvements for nearly a

century can be achieved only through actual implementations of these technologies by industry. While economies of scale are one way to leverage future improvements in capital efficiency, other significant areas of potential improvements include catalyst and yields, process intensification and performance, and optimization of intermediate streams; these opportunities are even beyond those outlined in this report. Hence the n<sup>th</sup>-plant performance outlined here is one potential way toward feasibility, but many other opportunities remain for further improvements in capital efficiency through actual implementation and learnings. For contingencies, we do understand that pioneer plants require significant additional costs; we have not included pioneer plant analysis in this report because we are studying the potential of the process in a mature stage of development. We agree that pioneer plant studies should include higher contingencies.

**142. Comment:** The authors attribute only a 10% return to invested capital. Moreover, it appears that even this low investment return is “leveraged” – via the use of 60% debt whose interest expense is tax deductible. These assumptions are not attractive to companies. The sensitivity analysis shows that a 15% investment return would raise the MFSP by 15.4% (was slightly higher in the draft for review). Venture capital/private equity will likely seek 20+% returns to offset risks. Studies should include returns which industry would require pushing pioneer scale plants to a mature industry.

**Response:** The financial assumptions for the base case are consistent with other design reports funded by the Bioenergy Technologies Office (BETO), and allow comparison across conversion pathways; they outline a basis for cost-improvement based research. Sensitivities to changes in these financial assumptions are captured in Figure 15. Sensitivity analysis in Figure 15 also shows options to offset the demands for higher returns via further improvements in other areas. We have conducted pioneer plant analysis separately in the past; the purpose of such studies is to address the push toward commercialization and understanding of risks, rather than understanding where the research and development can lead us.

**143. Comment:** It is not clear that the “leveraged economics” have been done correctly – the authors need to provide more detailed and accessible spreadsheets.

**Response:** Detailed discounted cash flow rate of return (DCFROR) and other financial assumptions are included in the appendices of this report. Note that the financial methods have been used in other detailed reports over the years, and have been reviewed by multiple entities, including academic institutions that use our design reports in some of their courses as examples. We believe any major errors in our methods would be noticed and brought to our attention; we do receive comments (including about correctness) from varied sources after the publication of our reports, and we address them. Some of our spreadsheets are available online, and thus have been used and vetted by others.

**144. Comment:** The search for savings on this order of magnitude should drive researchers to look at different and more specific plant locations. The authors’ in-situ and ex-situ plants reside at some generic location geared to Idaho National Lab’s (INL) recent feedstock/logistics work. The location seems to be consistent with “distributed pyrolysis plants” found in other literature, seeing as the plant design self-manufactures hydrogen. It is unclear whether this location permits large scale water-borne transport of chipped biomass. It clearly does not allow co-processing product at an adjacent refinery. This leads the authors to

incorporate a sub-scale 1.4 kbd hydrocracker into the process design. Feeding CFP heavy fractions to a hydrocracker may be the right process solution, but this probably needs to happen within a co-processing approach for CFP to have a reasonable chance at commercialization.

**Response:** We have not considered the co-location scenario in this particular report. With progress in the research we will become better informed about the quality and feasibility of co-processing. An expansion of the scope for location and specific feedstock transportation was not feasible within the time available. Please note that such integrated studies have been conducted in the past (typically after the conversion-specific design report is released). As an example please see Muth et al. (2014).

145. **Comment:** Follow-up work should focus on process designs and locations which facilitate refinery co-processing, large scale/low cost water transport of biomass, and use of the refinery infrastructure e.g. merchant hydrogen. Ex-situ CFP may be well suited to such an approach, seeing as it may produce higher quality blendstocks that still retain some oxygen. Arbogast et al. (2012) contains information about such locations and the economics of and technical requirements for co-processing.

**Response:** Thank you for pointing out the reference. We added a limited discussion for this report based on your comment, mostly alluding to this as potential future work for cost reduction. We do plan to leverage the current study for other scenarios as more data becomes available from the research. We feel that this study is a start within the time we had available to prepare this report, mainly focusing on building process model-based scenarios outlining a potential pathway to feasibility of the technology via research in the coming years.

146. **Comment:** We look forward to seeing the data supporting the very promising CFP yields and oxygen removal assumed in the study. If confirmed, these could significantly improve the overall economics of biomass pyrolysis to fuels. This study design should be very valuable in formulating and monitoring progress of your forward program. It might be useful as part of this study design to: (a) Identify the most economically attractive areas for focus and what “killer” factors need to be overcome. Examples of potential “killer” variables are: (i) Catalyst life & equipment fouling, (ii) Metallurgy corrosion, (iii) Yields derived from batch experiments extrapolated to a continuous process with scaled up reactors, (iv) Product quality and necessary further processing required for introduction into refinery equipment and/or final fuel products, (b) Estimate probabilities of success in key research areas & derived benefits, (c) Provide a single, more extensive summary of key assumptions in the study and a sense of how well they are backed up with data.

**Response:** Thank you for these valuable comments. We are at the early stages of research for these pathways. We will consider these points as more data becomes available; some of these may be futile at this point because of the lack of data and early stages of research. We conduct annual state of technology assessments to track the progress of research. The 2014 assessments, along with our annual improvement targets leading to 2022 are expected to be published soon in BETO’s Multi-Year Program Plan (MYPP). All your points are candidates for consideration with further maturity.

147. **Comment:** In the draft version for review: The error bands quoted in the design write up regarding the AACE classification system were a bit misleading.

**Response:** We removed references to the AACE classification in the final version of the report based on this comment.

148. **Comment:** Could you mention how many model compounds you used?

**Response:** The list of compounds used is available in Appendix F of this version of the report.

149. **Comment:** Based on June 2014 draft: Suggest adding sensitivity analysis for: (a) Upgrading yield, (b) Losses to different products (coke, light gases) (which would give better results), (c) Catalyst cost and cat:biomass ratio, residence time in upgrader, (d) Hydrotreating severity.

**Response:** Sensitivity analyses related to the above were added to the August 2014 and subsequent drafts.

150. **Comment:** How did you calculate the theoretical GGE production and yield (Table ES-2)? Did you just take into account the C and H in the feedstock and calculate how much gasoline and diesel could be made?

**Response:** Section 4.5 describes how we use LHV from the simulation to come up with the GGE values.

151. **Comment:** What composition did you assume for the upgraded products?

**Response:** Stream tables in Appendix G of this version show the compositional (surrogate compounds) assumptions.

152. **Comment:** Given the importance of catalyst performance, it may have been valuable to include a dedicated section devoted to catalyst design.

**Response:** We included a short section (3.2.1.6) on potential vapor upgrading catalysts, primarily referring the reader to other articles. Assumptions regarding hydroprocessing catalysts were also added in Section 3.4. We feel that this design report is focused on techno-economics and we should not interfere with the catalyst researchers' ongoing publications of their work.

153. **Comment:** The sustainability section could benefit from a chart. For example, the chart could compare carbon input/output in the form of feedstock, fuel, char, flue gas.

**Response:** This specific chart for carbon flow is not provided. However, information about biomass energy distribution upon processing (LHV basis) is provided in Figure 11. The carbon efficiencies to products are shown in Figure ES-1 and the information about char is available in the stream tables (Appendix G), along with flue gas information. Almost all the carbon not converted to fuel will eventually show up in the flue gas in the current process design, because excess gases, char, coke, and aqueous carbon are all combusted.

154. **Comment:** Some discussion of potential planned (scheduled maintenance, feedstock supply schedules, planned holidays...) and unplanned (equipment failure, supply disruptions) would be helpful. In particular, there may be interest in knowing whether there are safety/reliability differences between *in situ/ex situ* fast pyrolysis and other technologies. A qualitative assessment of reliability concerns specific to these technologies (coking, reactor operation) would be sufficient.

**Response:** We did not include this discussion in this report. However we will address some of these topics in the future, especially with the maturing of the technology.

155. **Comment:** The PSA hydrogen stream in the figures can be labeled as Excess or Export Hydrogen unless it is also utilized in the process.

**Response:** All hydrogen produced is utilized within the process. Natural gas is imported and steam-reformed when additional hydrogen is required. Surplus process fuel gas, if available, is converted to electricity.

156. **Comment:** Discuss oxygenated species types (phenols are preferred to acids, etc.) after vapor upgrading and condensation.

**Response:** Details about species and stream compositions are included in Appendices F and G of this version of the report.

157. **Comment:** We notice in both this study and the recent PNNL/NREL fast pyrolysis study that the upper size limit for the pyrolysis reactors is set at 1000t/ day due to “biomass feeding constraints”. In our previous (pre-2010) discussions there were considerations of 2000 t/d or larger reactors. What has changed? Is this believed to be a hard upper limit? This will have a significant impact on the economic benefits of economies of scale as we try to move this technology to larger, more economic plants.

**Response:** As mentioned earlier, we have limited this to 1,000 TPD because of anticipated biomass feeding constraints. We have not seen any information thus far about confidence in building larger reactors than this. We also made the same assumption for our indirect gasification studies (Dutta et al. 2011). However, this does not negate future possibility of further scale-up of biomass reactor systems. Note that all the rest of the equipment beyond the initial fast pyrolysis reactor are assumed to have no scaling constraints.

158. **Comment:** We think additional sensitivities and a fuller discussion of what they reveal about where progress is needed, is the way to go. In addition to scale, we think the biomass cost and capital/contingency/return sensitivity discussion is very important to framing the economics and the progress that needs to be made. Framing this properly will spur more aggressive thinking about research possibilities and ultimately more progress.

**Response:** We feel we show many of these sensitivities in Figure 15. Additional sensitivities and providing options around specific (or anticipated) challenges encountered in the future will also be keys to the success of the research on these conversion pathways. As outlined in the Conclusions and Future TEA Work sections of this report, looking into further conversion variations and options will be the next focus of the TEA team.

159. **Comment:** Ultimately, we also think this discussion will drive pyrolysis oil plants away from generic distributed locations with hydrogen self-sufficiency towards larger plants integrated logistically or co-located with refineries. Our 2010 study saw big potential savings from such an approach, and we think researchers and techno-economic analysts should favor this model or say why they choose not to do so.

**Response:** This is definitely an option. However, we feel that it will be premature to propose that as a base case without first gaining a deeper understanding of quality aspects and acceptability of intermediates by petroleum refiners.

160. **Comment:** There seems to be a number of omissions in the offsites. These include: (a) Wood yard or other storage area for feedstock, (b) Warehouse for catalysts, (c) Product tankage for gasoline and diesel, (d) Loading racks (rail or truck) for finished products, (e) Administration building and laboratory. I looked through the equipment lists and didn't see anything like these. I don't think your factors for direct equipment costs cover these. If the feedstock will be supplied in a weatherproof form, then perhaps you need only plot space. If the fresh and spent catalysts are stored in some kind of bulk containers, then perhaps you need only plot space. If you assume colocation at an existing refinery or biorefinery, then you don't need an administration building, laboratory, or loading racks. All of these assumptions need to be stated if valid.

**Response:** The current version provides information about most of these items: (1) we included plant footprint calculations by the Harris Group in Appendix I showing area for storage, (2) warehouse for catalysts is not mentioned specifically; however bed media handling with silos are included in the pyrolysis island and within the equipment list (Appendices A and B), (3) product tanks are included in the equipment list, and land allocated under plant footprint, (4) loading racks are factored into the footprint and included in the equipment list under Area 700, and (5) administrative buildings are included within indirect costs (Table 28) and space is allocated within the footprint. Laboratory space is not specifically mentioned, but will be covered under the category "Offices, etc." in Appendix I. The inclusion of Appendix I should answer most of the remaining queries. We do not assume co-location.

161. **Comment:** I did not find a location basis. Construction in the Midwest will have a different cost than in the Gulf Coast. If you feel the difference is insignificant, then just say so.

**Response:** An average U.S. location is appropriate, given many of our costs are derived from that setup within ACCE.

162. **Comment:** In looking at a number of the variable costs, the base-year data are significantly out of date (BFW chemicals were quoted 23 years ago!). Simply inflating these numbers is risky. I do recognize that VOC rarely drive the sensitivity of the economics, but more contemporary quotations are probably in order

**Response:** We updated most of the costs mentioned (Table 30).

163. **Comment:** Wage rates seem low, especially given the recent run-up in starting salaries for chemical engineers. Given all of the present and anticipated construction on the Gulf Coast, I suspect even the non-professional wages are low.

**Response:** We included a 10% escalation, shown in Table 32.

164. **Comment:** It would be nice to have a comparison basis for the  $n^{\text{th}}$ -plant assumption of 90 % on-stream factor (same as a gasifier or FCC unit?).

**Response:** Refiners have made tremendous improvements in operating reliability of refinery applications as the technologies have matured. John S. Magee states, "It is not uncommon today to have FCC units complete three-to-four-year runs between major turnarounds with nearly 100 percent stream factor" (Magee 1993). Given that solids handling is more challenging, we believe that 90% on-stream factors for an  $n^{\text{th}}$  plant with our conceptual design is not unreasonable.

165. **Comment:** The steam plant was depreciated on a 20-year, 150 % declining balance basis. There is a MACRS schedule for the 20-year asset class. The two are not quite the same since the MACRS schedule reverts to straight-line in year 9.

**Response:** We switched to the 20-year MACRS schedule for the steam plant.

166. **Comment:** I realize that you have been using a leveraged financial basis (debt financing at a lower rate than the IRR) for other studies. Nevertheless, such a basis gives a slight improvement to the economics that has nothing to do with the technology. I don't propose you change it, but perhaps recognizing it in the narrative has merit.

**Response:** Although not mentioned in the main report, we do recognize the slight improvement in the economics over 100% equity with 10% IRR. In the past we provided sensitivity cases showing the impact of the assumption (see Dutta et al. 2011, Figure 16, Case 20). Since we have maintained the same assumption in following BETO-funded reports, we did not explicitly discuss the impact in this report.

167. **Comment:** Calling the discount rate the IRR bothers me a little. Given you are accounting for debt financing separately, it's more like a cost of equity. This is a minor detail, of course.

**Response:** We qualified the text (in this version) in places where IRR was mentioned to also say that this is the discount rate.

168. **Comment:** I realize that you had to use a relatively sparse set of model compounds for the mass and energy balances. Nevertheless, it would have been nice to see some compositional data for selected streams, especially the inputs and outputs of each of the reactors. I would've liked to be able to follow the relative production and destruction of aromatics, in particular.

**Response:** Detailed stream tables and flow diagrams are provided in Appendix G showing model compound flow rates for the 2022 target cases.

169. **Comment:** I found no discussion of product specifications for the gasoline or distillate products. Even if the plant provides only blendstocks and not finished products, the manufacturing targets should be discussed. Since you were hydrotreating the product to remove aromatics, I assume you must've had a target of some kind.

**Response:** Since we are at the early stages of our research, we deliberately limited quality specifications to oxygen content and H/C ratios. Trying to be more specific at this stage without more experimental data would be misleading. We anticipate that there will be significant focus on quality specifications around the 2017 timeframe and beyond with more maturation of the technology.

170. **Comment:** Over time, many chemical processes get optimized to consume (or contain) their byproducts because finding long-term, steady-value dispositions for those byproducts is difficult. This process, given its lack of maturity, carries significant market exposure to placing the electricity and to disposing of wastewater.

**Response:** We agree that these will be important considerations in the future, and our research plans include some of these aspects.

171. **Comment:** The onsite and offsite are around 50/50 of the TIC, depending on case. Given that I think some offsites are missing, the balance will tip decidedly to offsites, which fits for a greenfield project. To be economical, subsequent evolutions of the design will need to

focus on making the design more self-contained. A breakthrough in wastewater treatment is probably required.

**Response:** We tried to include all the major costs, both on-site and off-site. Wastewater treatment was not modeled in detail, but a conservative (high) operating cost was added for that operation. As mentioned in response to another comment, we will have on-site wastewater treatment and there will not be any off-site wastewater shipping requirements.

172. **Comment:** The assumption of using stainless steel in the oil/water separator is probably okay.

**Response:** Thank you for the feedback.

173. **Comment:** Based on personal experience with similar systems, Area 300 will require demonstration at some scale to resolve all of the potential fouling and corrosion issues.

**Response:** We agree that this needs further vetting as experimental results become available.

174. **Comment:** If the RTO technology for wastewater handling finds common and effective use with the kinds of wastewater streams you are producing, then perhaps it will work. If you can cite similar applications where the technology is effective, that would be a good addition.

**Response:** We were able to contact a reputable vendor to talk about the general feasibility of the stream going to the RTO. We changed the concentration based on their initial reluctance to comment on a much more dilute stream going into the RTO.

175. **Comment:** Power requirement tables: An “additional cross-flow dryer” is described in section 3.1 as being within the plant. To avoid questions and confusion, the power consumption should be listed here. The foot note then explains why it’s small. Same comment applies to table 16.

**Response:** Text was added as recommended by the reviewer.

176. **Comment:** Carbon conversion efficiency in reactors is significant. That makes sense relative to Fischer-Tropsch. How aggressive are the reactor performance assumptions on this parameter?

**Response:** The carbon conversion efficiency on the vapor upgrading portion is based on research targets for 2022 (and not the current state of technology). For this process to be successful we have to get to high process efficiencies to justify the capital. This is theoretically feasible because of direct versus indirect liquefaction. However, doing the right chemistry during vapor upgrading using catalysts will be the key to success. We provided a planned trajectory for achieving the targets for inclusion in BETO’s Multi-Year Program Plan document. The hydrotreating efficiency assumptions are shown in Table ES-1 and Figure 8.

177. **Comment:** It will be nice to broaden the work to include technology risk assessment.

**Response:** While technology risk assessments were not part of our goals for this design report, we are mindful of that aspect. We separately did some high level assessments in that regard; advancements in technology readiness are expected with advances in our research.

178. **Comment:** Pinch Analysis: This section seems to report results, not improvements to the heat exchange network (HEN) design. Certainly one immediate conclusion is that higher pressure cold streams would lower HX irreversibility. Are the cold stream phase change



streams in the composite diagrams primarily associated with the steam cycle? If so, certainly more could be done to improve cycle efficiency. Utility HX duties were mentioned but not shown (called out) in the composite curve figures. What are their magnitudes and how are they provided? Was there any attempt at HEN redesign?

**Response:** Higher pressure in the steam system would help, but we decided to settle on the 1,350 psia for the steam production based on quotes we had from previous reports. We understand that steam turbine system designs/fabrication change and costs get significantly higher with much higher pressures. As you probably inferred, the near horizontal line on the cold side is associated with phase change for steam and moving this up can improve process efficiency at the cost of capital associated with larger heat transfer area requirements, as well as any changes in costs of the steam turbines. There are other cold streams in the process such as air preheat (where going to a very high temperature may not be recommended). We did change the air preheat and reformer preheat temperatures to some extent and saw changes in efficiencies, hydrogen production, natural gas requirement, electricity production, etc. Most of the other streams are pegged to process requirements for specific unit operations. So any optimization will be limited by these constraints. We typically take out the utilities to balance the hot and cold streams. The utilities use is usually determined by the pinch point and approach temperatures on the side below the pinch. We keep adding utilities until the side below the pinch appears feasible. We provided duties for all exchangers (see Appendices G and H).

179. **Comment:** Follow-up to previous comment and response: Okay, seems like you have the right price point vs. steam pressure picked out. But at some point in the future, it might be good to know what the marginal cost of increasing pressure is, as the net benefit might be worth it. Further, given the temperature differences in the composite diagram, I think there is room there for an economic lowering of the pinch in the phase change HX section(s). The main point is that there is an optimal tradeoff between HX surface area and life cycle costs. Huge  $dT$ 's don't necessarily pay off, since operating efficiency gains are very important to operating cost reductions (vs. capital) over the life cycle of the plant. Here a true Pinch Analysis effort with HEN re-design (or exergy analysis) might make a difference.

**Response:** We do the heat exchanger network (HEN) at the end of the project after we freeze the models because of the very high levels of effort required for processes of this size. Results are shown in Appendix H. However, we do not modify the steam pressure in an iterative fashion, primarily because we do not have the resources to get actual quotes for various turbine systems to do detailed cost sensitivity with steam pressure. Also, since electricity is not our primary product, we anticipate a minimal impact. Also, we do the HEN manually to avoid proposing a spaghetti and physically infeasible network, usually created by commercial software (unless they are well constrained). As mentioned earlier, we decided to go with a steam pressure which we felt was reasonable and for which we had costs available. We would definitely like to bump up the efficiencies since this is very apparent in the sections where the hot and cold curves diverge significantly, and the steam system is the only major operation where we can change specifications without violating process condition requirements. Again, the objective of this design is to focus on the biomass conversion aspects with reasonable recovery of process heat, which we believe we have accomplished here. Pushing for optimization to higher efficiencies in the steam system with increased pressure will be a different exercise if further resources are available.

## Appendix J References

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