TECHNICAL REPORT

Biomass to Gasoline and Diesel Using Integrated Hydropyrolysis and Hydroconversion

Reporting Period:
April 1, 2010 through December 1, 2012

DOE Award Number:
U.S. DOE Award DE-EE-0002873

Revised:
December 28, 2012

Prepared For:
U.S. Department of Energy

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Executive Summary

Cellulosic and woody biomass can be directly converted to hydrocarbon gasoline and diesel blending components through the use of integrated hydropyrolysis plus hydroconversion (IH^2). The IH^2 gasoline and diesel blending components are fully compatible with petroleum based gasoline and diesel, contain less than 1% oxygen and have less than 1 total acid number (TAN). The IH^2 gasoline is high quality and very close to a drop in fuel.

The DOE funding enabled rapid development of the IH^2 technology from initial proof-of-principle experiments through continuous testing in a 50 kg/day pilot plant.

As part of this project, engineering work on IH^2 has also been completed to design a 1 ton/day demonstration unit and a commercial-scale 2000 ton/day IH^2 unit. These studies show when using IH^2 technology, biomass can be converted directly to transportation quality fuel blending components for the same capital cost required for pyrolysis alone, and a fraction of the cost of pyrolysis plus upgrading of pyrolysis oil. Technoeconomic work for IH^2 and lifecycle analysis (LCA) work has also been completed as part of this DOE study and shows IH^2 technology can convert biomass to gasoline and diesel blending components for less than $2.00/gallon with greater than 90% reduction in greenhouse gas emissions. As a result of the work completed in this DOE project, a joint development agreement was reached with CRI Catalyst Company to license the IH^2 technology.

Further larger-scale, continuous testing of IH^2 will be required to fully demonstrate the technology, and funding for this is recommended. The IH^2 biomass conversion technology would reduce U.S. dependence on foreign oil, reduce the price of transportation fuels, and significantly lower greenhouse gas (GHG) emissions. It is a breakthrough for the widespread conversion of biomass to transportation fuels.

Project Objectives

The project goal was to rapidly demonstrate a new, economical technology that integrates hydropyrolysis (pyrolysis carried out in a pressurized hydrogen atmosphere) and hydroconversion, for the direct conversion of biomass into fungible fuels such as gasoline and diesel. This technology utilizes our domestic renewable biomass resources to create transportation fuels, sufficient in quantity and quality to substantially reduce our reliance on foreign crude oil. Thus, this technology offers a path to genuine energy independence for the U.S., along with the creation of a significant amount of new U.S. jobs to plant, grow, harvest, and process biomass crops into fungible fuels. Commercialization of this technology will also reduce U.S. GHG emissions from transportation fuels made through this process by 90% compared to present levels.

Compared to other processes that employ biomass to create fungible fuels, for example, fast pyrolysis plus upgrading, IH2 offers three key technical and economic advantages:

1. No external source of hydrogen or methane is required for upgrading.
2. A high quality fungible hydrocarbon product which has low TAN and low oxygen content is directly produced.
3. Capital and operating costs are lower than other biomass-to-fuel technologies.

The first two advantages translate directly into the third advantage, better economics, which ensures rapid commercialization after the technology demonstration phase.

The IH^2 process consists of a pressurized fluidized-bed first stage reactor for hydropyrolysis, followed by a hydroconversion step, which further removes oxygen from the biomass and fully converts the biomass to gasoline and diesel products. Light gas from the hydroconversion step is separated and sent to a steam reformer which produces the hydrogen used in the process. With this integration, and using the proper processing conditions, the process is self sufficient as it requires no external source of methane or hydrogen. The specific objectives of the work will be to demonstrate or provide the following:

1. Produce gasoline and diesel fuels containing less than 2% oxygen
2. Generate enough C1-C3 gas to internally produce all of the hydrogen required by the process
3. Quantify yields and material balances for all products
4. Update LCA and techno-economic analyses required for commercialization
5. Generate design information to provide reliable process scale up to 1 t/d demonstration or 2000 t/d commercial size
6. Demonstrate the utility of the process for converting a variety of feedstocks including wood, corn stover, and algae into gasoline and diesel fuels.
7. Establish process operability and catalyst stability in a continuous, 50 kg/day pilot plant.

The IH^2 project was initially funded for the preparatory research and development (R&D) and preliminary engineering of a 1 ton/day and 2000 t/d IH^2 pilot plant. A project extension was later funded which allowed testing of the IH^2 process in a 50 kg/day pilot plant in order to determine catalyst stability and costs.

Process Overview

A simplified process flow diagram of the IH^2 process is shown in Figure 1.

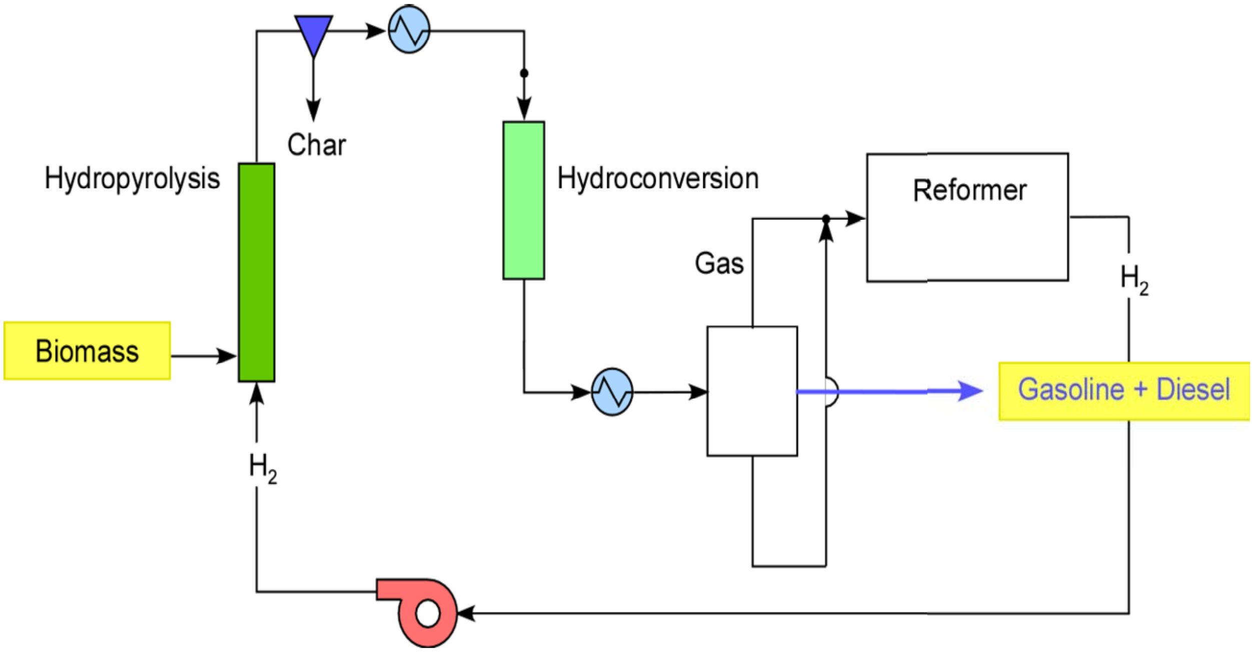


Figure 1—The IH2 system, showing overall process flow.

Biomass is converted to gas and liquid in the presence of hydrogen in a pressurized fluid-bed hydropyrolysis stage, and the vapor from this stage is directed to a second stage hydroconversion unit which removes oxygen and produces deoxygenated gasoline and diesel products. The liquid is condensed and the C_3- gas from the process is sent to an integrated steam reformer. By running at the proper conditions with the proper catalyst, the hydrodeoxygenation and decarboxylation reactions are balanced so the H_2 required for hydropyrolysis and hydroconversion is produced in the steam reformer. The hydropyrolysis and hydroconversion processes are exothermic and produce high levels of steam. The process steps are carried out at almost the same pressure except for pressure drops through the vessels, so the energy required to compress hydrogen and recirculate it back to the first stage is available from steam produced in the process.

IH^2 Project Team

Our Integrated BioRefinery (IBR) project team, shown in Figure 2, was well suited to successfully complete the project tasks and ultimately commercialize the IH^2 technology.

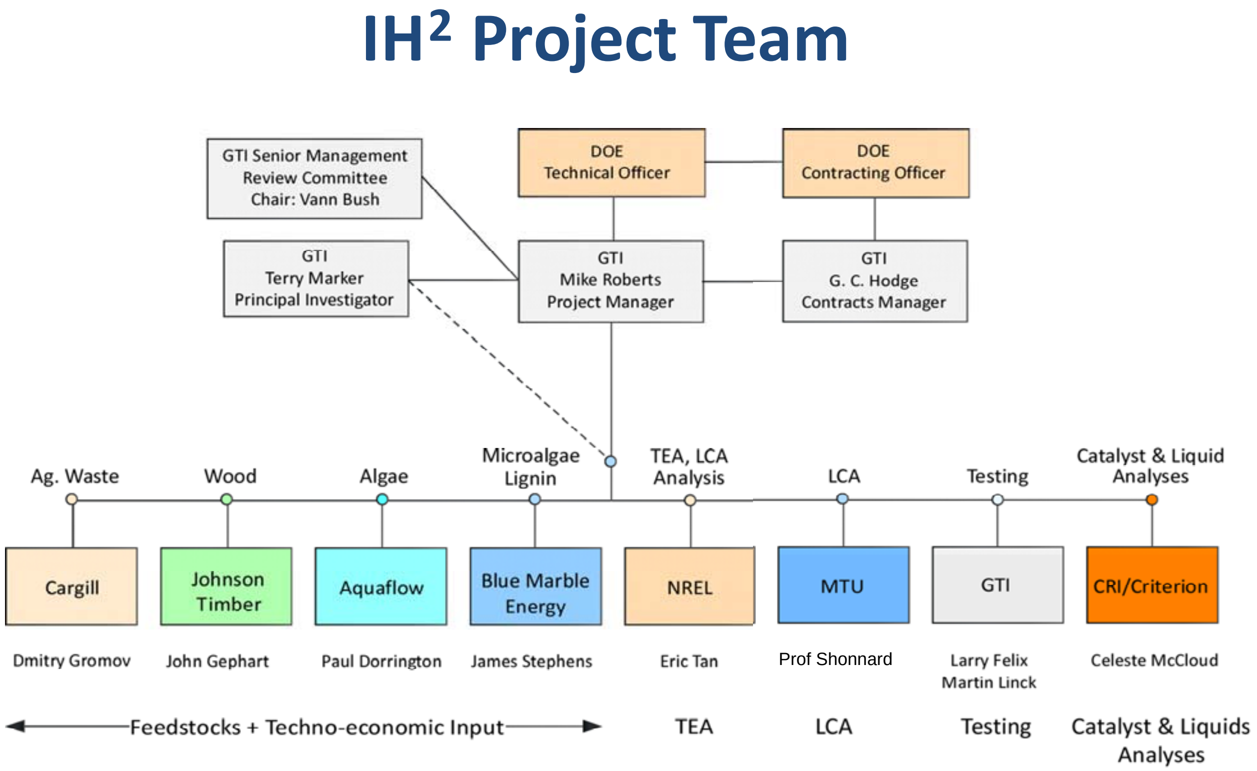


Figure 2—Project Team

The team included experts from the agricultural industry (Cargill), forest industry (Johnson Timber), microalgae industry (Aquaflow), and macroalgae industry (Blue Marble Energy) who all have a stake in commercializing new technology for converting their feedstocks into fungible fuels. The National Renewable Energy Laboratory (NREL) is another key team member who updated the technoeconomic analyses, and collaborated in the LCA. The updated LCA has been performed by Professor Shonnard of MTU after obtaining input from GTI, Cargill, Johnson Timber, Aquaflow, and Blue Marble Energy.

A key team member is CRI Catalyst Company (CRI) who has developed and provided the catalysts used in the IH^2 development. CRI signed joint development and licensing agreements with GTI to commercially offer the IH^2 technology.

In addition to the IH^2 team members, subcontractors CBI (Chicago Bridge and Iron) and Zeton, shown in Figure 3, were used for the preliminary engineering design for the 1 ton/day pilot plant and the 2000 ton/day commercial IH^2 plant.

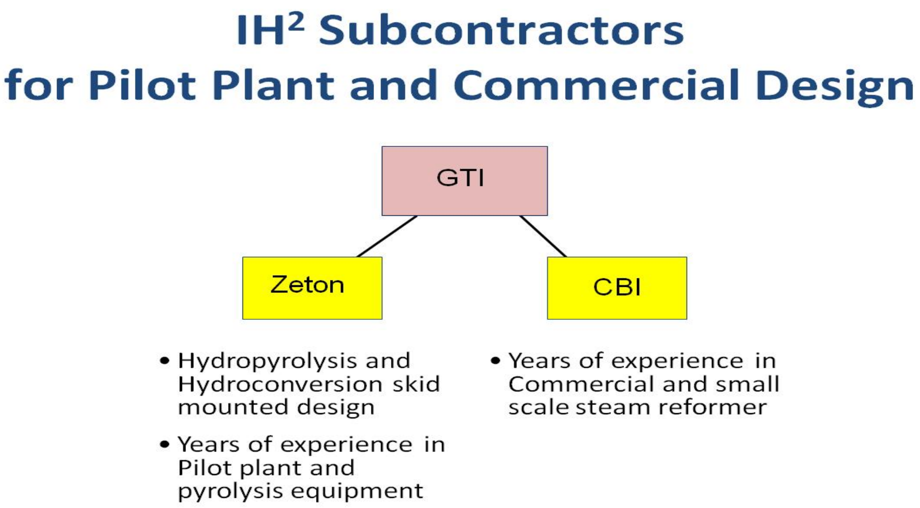


Figure 3 - Subcontractors

IH^2 Project Tasks and Timeline

GTI applied for full Integrated Biorefinery(IBR) funding, which included the construction and operation of a 1 ton/d IH^2 pilot plant. However GTI was only funded for Phase 1 of the IBR project which consisted of preparatory R&D, preliminary engineering of a 1 ton/day pilot plant and 2000 ton/day

commercial unit, and a technoeconomic and LCA update for the IH^2 technology. A simplified version of the project timeline is shown in Figure 4. The project task list is shown in Table 1.

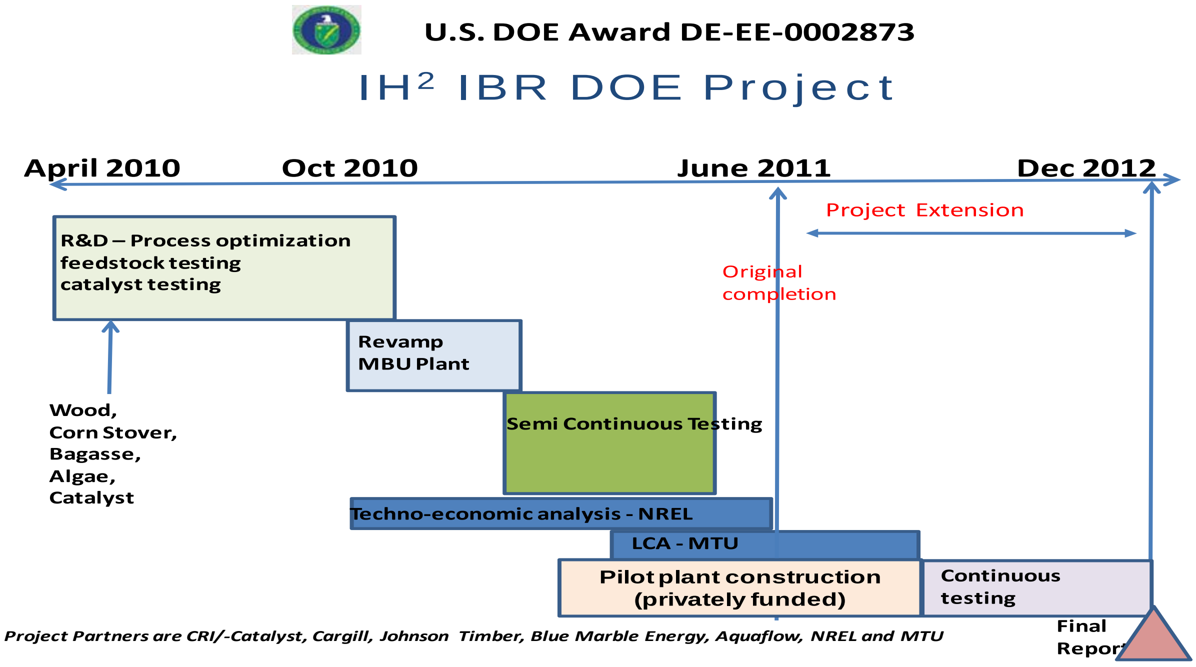


Figure 4—IH^2 Project Timeline

Table 1—Project Task List (extension tasks shaded)

0	Integrated Biorefinery Project - 3-4
A.	DOE Core
B.	Preparatory R&D
B.1	Procure Feedstocks
B.2	Prepare Bench-Scale Unit
B.3	Initial BSU Scoping Tests
C.	Preliminary Biorefinery Process Flow Diagram
C.1	Preparation of Process Flow Diagram
C.2	HYSYS Simulation Update
C.3	Define Facilities Requirements for IBR
C.4	Preliminary Design Package for IBR
C.5	Preparation of Test Plan for IBR
C.6	Preliminary NEPA Documentation
C.7	Preliminary RMP
C.8	Financial Readiness
D.	Life Cycle Analysis
E	Technoeconomics
F.	Management and Reporting
G	Preliminary Detailed Engineering
H	Feedstock Procurement and Preparation-50 kg/d
I	Pilot Plant Testing-50 kg/d
J	Catalyst Testing-50 kg/d
K	Product Testing and Characterization-50 kg/d
L	Management and Reporting-50 kg/d

Preparatory R&D

Although the IH^2 project applied for a full pilot plant funding, the IH^2 project was initially only funded for phase 1 of the IBR and later secured additional funding for longer term IH^2 testing using a 50kg/d IH^2 pilot plant (built through outside funding).

IH^2 Bench Testing

In the catalytic hydropyrolysis and hydroconversion experiments, a bubbling fluidized bed of catalyst was used and the biomass was fed in a continuous fashion. In this way, very rapid heat of the biomass occurs when it is mixed with the catalyst. Initial experiments with this laboratory unit were typically run for 3 hours with a 1 micron filter in the reactor, so the reactor accummulated char over time. Typical biomass feed rates were 5 g/min. Hydropyrolysis weight hourly space velocity (WHSV) was in the range of 0.5-2.0. At the end of a test, the system was taken apart, the feed and product weighed, and the material balance was completed.

The initial reactor system is shown in Figure 5.

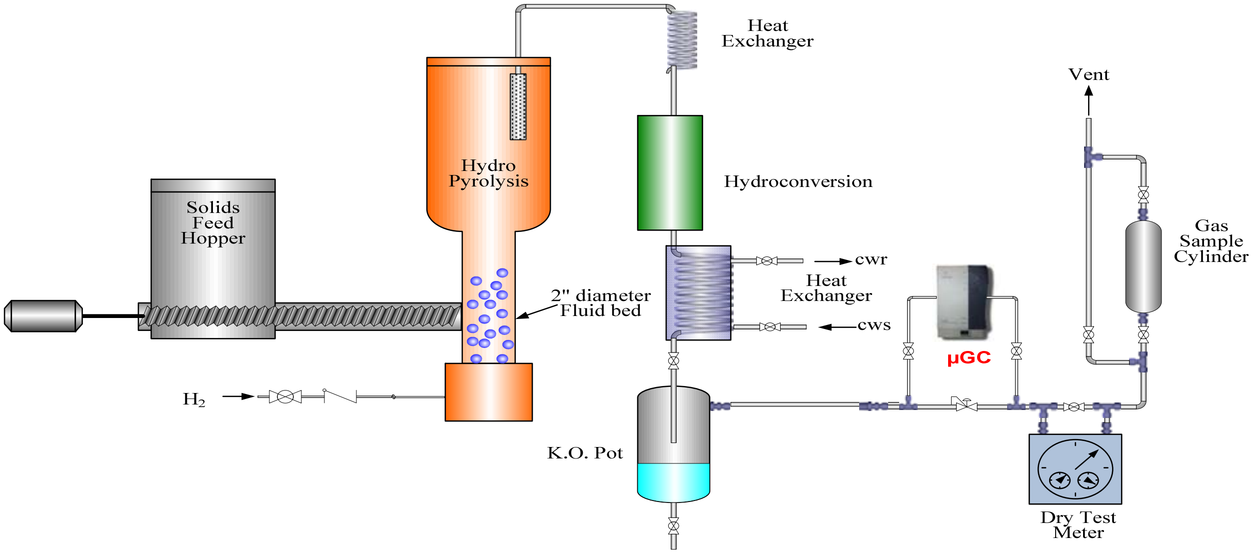


Figure 5—IH^2 Initial Proof-of-Principle Laboratory Unit

Modifications were made to the laboratory IH^2 system to enable the char to be continuously removed from the reactor and taken overhead to a filter assembly, where it was collected separately from the catalyst. The improved laboratory unit is shown in Figure 6. This improvement allowed semi-continuous testing. The reactor ran all day, was shut down overnight, and restarted the next morning with the same catalyst in the reactor. Using this system, continuous catalyst-char separation was demonstrated. This laboratory unit also allowed tests to run over several days to show catalyst stability over a 3 day test period.

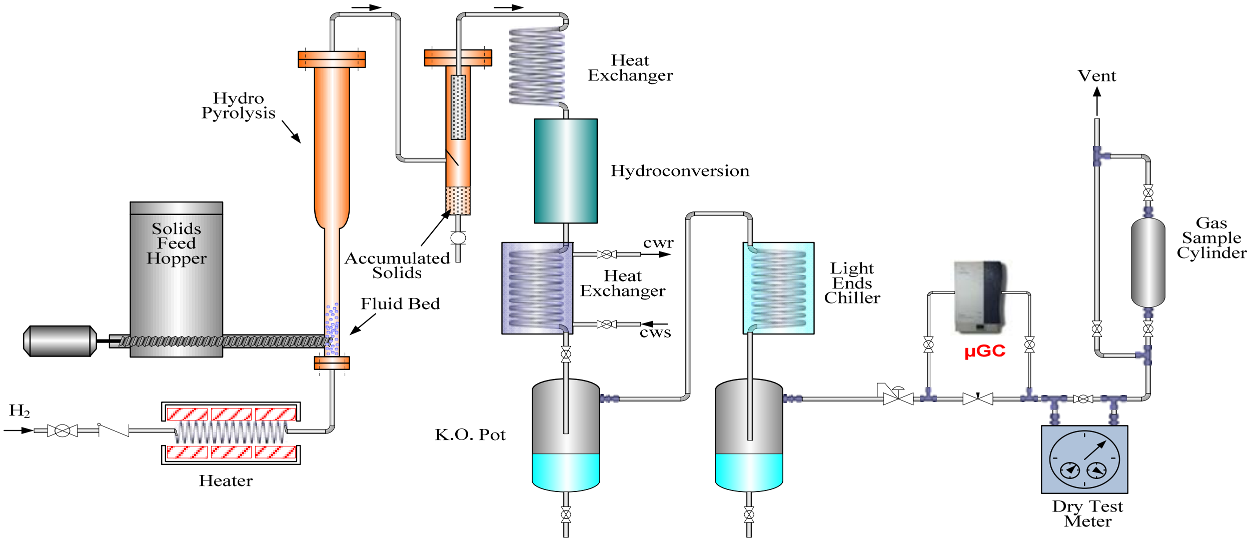


Figure 6—Improved IH^2 Pilot Plant with Continuous Char removal

This system could also be run with the second reactor by-passed in order to gather data on only the hydropyrolysis section. The goal of the IH^2 experiments was to determine the yields and product quality from a variety of biomass feedstocks.

In order to achieve good separation of biomass and catalyst in catalytic hydropyrolysis, the biomass is smaller than the catalyst and less dense as well. The mechanism of first stage catalyst char separation which we have demonstrated in the laboratory unit is shown in Figure 7.

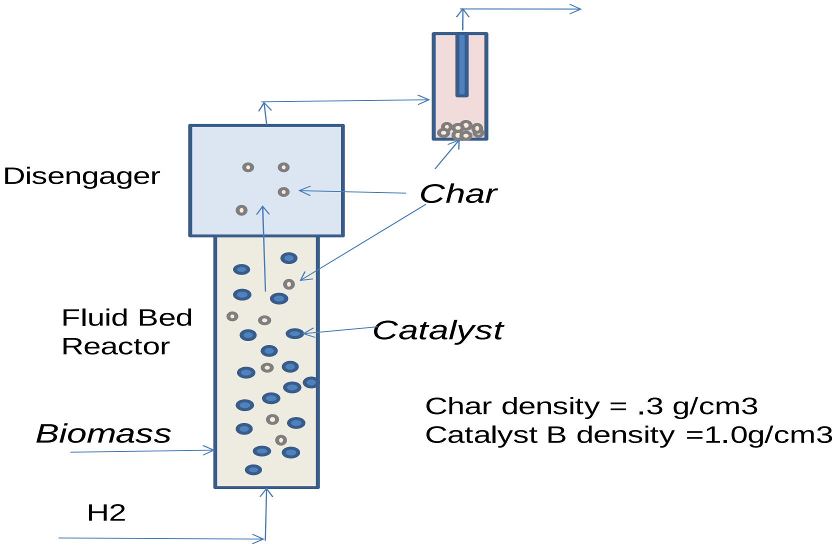


Figure 7—Mechanism of char-catalyst separation

Feedstocks:

A number of feedstocks were tested in the IH^2 system. Feedstock analysis is shown in Table 2.

Table 2—Biomass Feedstock Analysis

	Wood (mixed)	Wood maple	Lemna derived	Aquaflow algae	Bagasse	Macro algae	Corn-stover
Feed wt % C	49.7	50.2	46.3	43.1	43.1	34.0	40.2
Feed wt % H	5.8	6.2	5.8	6.1	5.0	4.43	5.0
Feed wt % O	43.9	42.9	35.7	20.4	35.3	23.6	35.7
Feed wt % N	0.11	.11	3.7	6.5	.34	4.6	1.0
Feed wt % S	0.03	.03	0.3	0.7	.10	1.9	0.05
Feed wt % Ash	0.5	.5	8.2	23.1	16.2	29.4	18.1
Feed wt % moisture	5.6	5.5	7.2	5.9	3.4	6.9	6.5
Feed H/C	1.40	1.40	1.50	1.70	1.39	1.56	1.49
% Lignin	29.5	26.4	21.3	48.9	26.0	22.9	20.9
%Arabinan	1.2	0.6	1.1	1.7	1.3	3.8	2.8
%Galactan	2.4	1.4	2.0	1.7	1.1	4.6	2.0
%Glucan	42.3	41.3	22.0	4.0	42.8	8.5	36.8
%Xylan	13.9	15.5	6.0	0.9	23.4	3.9	21.3
%Mannan	4.5	2.4	.6	2.2	0.0	0.3	0.3

Wood feed was a mixed feed of 68% hardwood and 32% softwood, which represents a low-cost blend of available wood feeds in the upper Midwest of the U.S. It was obtained from Johnson Timber and is representative of wood feed available for the Flambeau River Falls gasification project.

Lemna was obtained from Petroalgae and was a lemna which had been extracted to remove much of the protein from the structure. The extracted lemna protein is sold as animal feed, while the remaining solid lemna (called lemna derived biomass) was used as feed for the IH^2 process.

The microalgae was a wastewater algae biomass with low lipid content obtained from Aquaflow. It was collected from sewage ponds in New Zealand. This sample of algae is widely mixed and there are up to 27 Chlorophyta, 6 diatoms, 1 dinoflagellate, 11 cyanobacteria, 7 Euglenophycota, 1 Euglenozoa and numerous unidentified small flagellates and unicellular algae. The macroalgae was a natural ocean seaweed harvested from the ocean by Blue Marble algae. All of the microalgae and macroalgae used in these studies was naturally occurring.

The bagasse and cornstover were obtained from Cargill. The bagasse had to be pelletized in order to be fed into the reactor.

The biomass varied in size. Initial wood tests were done with 450-1000 micron biomass. Later semi-continuous tests were done with wood less than 200 micron, which was sized so as to quickly react and be carried through the catalyst bed, where the char was collected on the process filter.

All the specialty catalysts used in these tests were manufactured by CRI. Tests were also run with alumina and inert ceramic in the first stage to show the effect of an inert heat carrier instead of a catalyst in the hydropyrolysis step. The catalyst was sized in order to fluidize in the pilot plant equipment.

Experimental Results:

The experimental results are shown in Tables 3, 4, 5, 6 and 7. Table 3 shows IH^2 processing results using a lemna feed. Table 4 shows the IH^2 processing results for cornstover, bagasse and algae feeds. Table 5 shows the IH^2 processing results with a wood feed. Table 6 shows hydropyrolysis results with no second stage using a wood feed. Table 7 shows the results of extended 3 day IH^2 test runs in semi-continuous mode using a wood feed.

These tests demonstrate that the IH^2 processing of a variety of biomass directly produces high quality light hydrocarbon gasoline and diesel fuels or blending components at high yields. The IH^2 liquid products have low levels of oxygen, and low TANs. The hydropyrolysis step alone, reduced liquid hydrocarbon oxygen content to less than 4% under optimal conditions, as shown in Table 6. The liquid yields from wood were 28-25 wt% under optimal processing conditions, while algae gave the highest liquid yields at 46 wt%. No other process has ever shown the ability to directly convert biomass to high quality liquid transportation fuels at such high yields.

The weight recovery relative to the dry moisture-free biomass fed (which is shown) is always greater than 100% since it includes the hydrogen which is added to the structure. Hydrogen uptake varied with conditions and catalyst and ranged from 2-6%. All experiments were run at mild conditions with temperatures in the first stage from 340-470 °C and temperature in the second stage from 370-400 °C. Pressures were 14 to 23 bar.

There was no increase in pressure drop or signs of coking on the 1 micron filter in the hydropyrolysis pilot plant because the hydropyrolysis products are stable hydrocarbons. In contrast, filters in pyrolysis service(1) typically coke up rapidly and show an increasing pressure drop over time, reflecting pyrolysis product reactivity and the tendency to coke.

In hydropyrolysis, the liquid products are condensed and the hydrocarbon phase floats cleanly on top of a separated water phase. IH^2 product is shown in Figure 8. This contrasts with the single phase mixture of pyrolysis oil and water mixture produced from typical pyrolysis work shown in figure 9 which generally is collected via quench.

Figure 8—IH^2 Liquid Product from Wood -Top phase hydrocarbon, bottom phase water

Figure 9—Pyrolysis Oil – Picture from Ensyn Website

Initial hydropyrolysis tests were run for 2-4 hours. In the initial laboratory unit configuration, the bed filled up with char and the feeder held low amounts of feed. The improved laboratory unit had an external filter so char could be collected separately from the catalyst. The 5/25 test (Table 7) using the improved reactor configuration was run for 18 hours with continuous char removal by restarting the test over a period of 3 days and running for 6 hours each day. The 6/27 test (Table 7) was run for 20 hours over 3 days. The liquid product from the 5/25 eighteen hour test and 6/27 twenty hour test contained less than 1% oxygen indicating good catalyst stability over the longer test period.

Table 3—Lemna IH^2 experiments

	10/16	**11/ 0**	**12/3**	**12/9**	**12/15**
Feed	lemna	lemna	lemna	lemna	lemna
Hydropyrolysis catalyst	CRI-4211	CRI-4211	CRI-4201	CRI-4201	CRI-4211
Hydroconversion catalyst	CRI-4202	CRI-4202	CRI-4202	CRI-4202	CRI-4202
hours with biomass feed	2.3	2.1	2.9	3.1	2.2
Wt% recovery (relative to biomass)	93.8	99.4	96.8	102.4	104.3
% C recovery	99	105	100	110	99.0
Wt% C4+ liquid yield (MAF)	27.2	23.3	22.0	32.0	29.5
Wt% C1-3 yield (MAF)	10.8	9.6	4.3	4.5	16.5
Wt% CO_2 yield (MAF)	7.4	10.5	15.4	8.8	7.4
Wt% CO yield (MAF)	5.7	9.4	6.5	6.2	7.8
Wt% char yield (MAF)	16.9	17.1	21.3	17.6	3.2
Wt% water yield (MAF)	35.5	32.9	31.9	34.1	41.3
Wt% H_2 added MAF (calc)	3.5	2.7	1.3	3.2	5.6
Wt% H_2 available from reforming C1-C3 and CO	3.4	3.4	1.7	1.7	5.2
Liquid Analysis					
Wt% Oxygen	<.5	<.5		<.5	<.3
Wt% Carbon	85.59			84.62	85.58
Wt% Hydrogen	14.10			13.70	14.17
Wt% Nitrogen	.37			1.23	.24
Wt% Sulfur	.04			.005	.01
Density	.75			.77	.74
% Gasoline C4-345	59			63	73
% Diesel 345F +	41			37	27
TAN (total acid number)	.3			.2	.3
RON of condensed gasoline	84			86	85
H/C	1.98			1.94	1.99
Hydrocarbon Gas Analysis					
Wt% methane	19.7	21.4		18.86	27.71
Wt% ethane	41.5	40.3		37.79	36.87
Wt% propane	38.8	38.3		42.55	35.42
Water Analysis					
pH	12	12		10	10
% nitrogen	Nm	Nm	Nm	Nm	Nm
% carbon	5.0	4.0		4.0	5.1
% sulfur	Nm	Nm	Nm	Nm	Nm
% ammonia	6.2	5.2		5.8	6.7

Table 4—Bagasse, Cornstover, Micro, and Macro Algae IH^2 Experiments

	1/18	**9/28**	**9/30**	**10/04**	**12/30**	**1/13**
Feed Type	Bagasse	Cornstover	Micro Algae	Micro Algae	Seaweed Algae	Seaweed Algae
Hydropyrolysis catalyst	CRI-4211	CRI-4211	CRI-4211	CRI-4211	CRI-4211	CRI-4211
Hydroconversion catalyst	CRI-4202	CRI-4202	CRI-4202	CRI-4202	CRI-4202	CRI-4202
Hours with biomass feed	2.25	3.0	2.7	2.9	1.9	2.3
Wt% recovery (relative to biomass)	106.7	102.8	95.5	104.4	92.9	101.2
%C recovery	104	95.1	96	95	88.4	115.2
Wt% C4+ liquid yield (MAF)	28.6	20.6	46.3	46.6	36.1	26.9
Wt% C1-3 yield (MAF)	20.4	13.2	12.8	13.0	10.5	11.3
Wt% CO_2 yield (MAF)	7.1	7.4	-	-	2.4	2.3
Wt% CO yield (MAF)	9.9	9.3	7.4	7.4	6.7	9.1
Wt% char yield (MAF)	6.8	13.9	5.2	1.1	6.0	22.9
Wt% water yield (MAF)	33.3	39.7	32.2	37.1	42.4	31.5
Wt% H_2 added MAF (calc)	6.1	4.2	3.9	5.2	4.1	3.9
Wt% H_2 available from reforming C1-C3 and CO	6.4	4.3	4.1	4.2	3.4	3.8
Liquid Analysis						
Wt% Oxygen	<.5	.3	0.3	1.8(by dif)	0.54	0.62
Wt% Carbon	85.61	87.62	85.37	84.2		86.11
Wt% Hydrogen	13.57	11.87	13.58	13.58		13.13
Wt% Nitrogen	.03	.14	.76	.89	.28	.09
Wt% Sulfur	.21	.07	.03	.03	.22	.05
Density	.81	.82	.79	.78	.78	.82
% Gasoline C4-345	75	70	53	52	52	64
% Diesel 345F +	25	30	47	48	48	36
TAN (total acid number)	.7	.67	.3	.7	.32	.95
RON of condensed gasoline	nm	85.2	81.5	82.9	89.3	83.0
H/C	1.90	1.62	1.91	1.94		1.83
Hydrocarbon Gas Analysis						
Wt% methane	28.9	32.3	28.1	30.0	24.2	28.8
Wt% ethane	41.2	36.3	38.1	37.4	36.5	36.9
Wt% propane	29.9	31.3	33.9	32.4	39.3	34.3
Water Analysis						
pH	10	10	11	12	12	10
% nitrogen	.98	1.56	9.48	9.81	6.9	6.9
% carbon	1.39	.82	4.35	2.43	5.61	8.1
% sulfur	.10	.09	.82	1.04	.52	.73
% ammonia	1.0	1.4	7.3	7.4	6.9	7.1

Table 5—Wood IH^2 Experiments

	1/7	**2/11**	**2/16**	**4/28**	**5/4**	**8/23**
Feed	Mixed wood	Mixed wood	Mixed wood	Mixed wood	Mixed wood	Mixed wood
Hydropyrolysis catalyst	CRI-4211	CRI-4211	CRI-4201	CRI-4201	CRI-4201	CRI-4211
Hydroconversion catalyst	CRI-4202	CRI-4202	CRI-4202	CRI-4202	CRI-4202	CRI-4202
Hours of biomass fed	2.3	3.2	3.4	3.4	3.3	3.3
Wt% recovery (relative to biomass)	108.9	106.6	102.2	104.0	103.5	106.3
%C recovery	106.5	100.7	99.6	98.6	100.4	101.0
Wt% C4+ liquid yield (MAF)	28.1	26.4	22.7	22.9	26.0	25.8
Wt% C1-3 yield (MAF)	15.8	18.1	12.0	13.0	13.0	14.5
Wt% CO_2 yield (MAF)	4.2	9.7	10.6	10.1	6.5	7.4
Wt% CO yield (MAF)	10.1	9.9	11.0	10.1	11.6	6.5
Wt % char yield (MAF)	10.7	6.8	14.4	14.4	12.5	13.4
Wt% water yield (MAF)	37.0	34.7	32.8	33.0	34.4	37.0
Wt% H_2 added MAF (calc)	6.0	5.7	3.5	3.6	4.1	4.6
Wt% H_2 available from reforming C1-C3 and CO	5.1	5.8	4.1	4.4	4.5	4.5
Liquid Analysis						
Wt% Oxygen	<.3	.7	<.3	.35	<.3	<2.2
Wt% Carbon	86.54	88.37	88.27			85.25
Wt% Hydrogen	13.13	12.96	11.86			11.45
Wt% Nitrogen	.4	.04	.05			.06
Wt% Sulfur	.03	.01	.006			.01
Density	.76	.78	.84			.86
% Gasoline C4-345	75	78	66			66
% Diesel 345F +	25	22	34			34
TAN (total acid number)	0.25	0.23	0.36			0.33
RON of condensed gasoline	90	91	88			86
H/C	1.82	1.75	1.61			1.61
Hydrocarbon Gas Analysis						
Wt% methane	38.5	36.2	33.1	29.9		25.7
Wt% ethane	34.1	35.6	38.2	40.8		46.1
Wt% propane	27.4	28.2	38.7	29.4		28.2
Water Analysis						
pH	10	9	9	10		8
% nitrogen	na	na	na	.25		0.13
% carbon	2.24	0.52	0.64	.32		0.19
% sulfur	0.3	0.07	0.03	,01		0.01
% ammonia	0	.4	0	.27		0.13

Table 6—Wood IH^2 Experiments – No second stage

	2-25	**5-21**	**3/9**	**3/11**	**3/15**
Feed	Mixed wood	Mixed wood	Mixed wood	Mixed wood	Mixed wood
Hydropyrolysis catalyst	CRI-4201	CRI-4201	CRI-4211	CRI-4201	alumina
Hydroconversion catalyst	None	None	None	None	None
Hours with biomass fed	3.9	2.8	3.4	2.1	2.0
Wt% recovery (relative to biomass)	107.7	103.1	104.8	96.6	87.3
%C recovery	98.8	97.9	104.0	93.8	82.1
Wt% C4+ liquid yield (MAF)	24.1	24.1	25.1	24.6	14.4
Wt% C1-3 yield (MAF)	12.5	11.7	15.4	7.4	4.8
Wt% CO_2 yield (MAF)	10.7	12.1	6.7	12.1	13.5
Wt% CO yield (MAF)	11.2	9.4	9.4	8.3	9.6
Wt% char yield (MAF)	12.7	14.9	14.0	19.4	27.3
Wt% water yield (MAF)	32.4	30.5	34.1	29.9	30.6
Wt% H_2 added MAF (calc)	3.7	2.7	4.6	1.4	0.1
Wt% H_2 available from reforming C1-C3 and CO	4.3	4.0	5.0	2.7	2.0
Liquid Analysis					
Wt% Oxygen	2.6	3.81	0.48	7.74	14.34
Wt% Carbon	86.97	87.24	87.22	82.29	77.42
Wt% Hydrogen	11.37	8.67	11.97	9.59	11.70
Wt% Nitrogen	.1	.25	.04	.07	.05
Wt% Sulfur	.03	.03	na	na	.04
Density	.85	1.02	.82	.95	1.02
% Gasoline C4-345	68	39	64	35	24
% Diesel 345F +	32	61	36	65	76
TAN (total acid number)	0.35	0.33	.50	.5	Na
RON of condensed gasoline	89	89	87	89	87
H/C	1.56	1.19	1.65	1.40	1.81
Hydrocarbon Gas Analysis					
Wt% methane	26.2	34.4	32.0	35.4	45.9
Wt% ethane	33.3	25.5	39.0	18.2	16.9
Wt% propane	15.7	14.6	28.3	8.1	6.4
Wt % ethylene	9.0	9.0	,2	15.3	12.4
Wt% propylene	15.8	16.5	.5	23.0	18.3
Water Analysis					
pH	9	7	9	8	4
% nitrogen	na	.11	.19	.08	.07
% carbon	1.08	1.07	.29	.42	2.4
% sulfur	.03	<.01	.04	.01	.01
% ammonia	.2	.09	.2	.04	.04

Table 7—Wood IH^2 Experiments—Extended Testing Time

	5/11	**5/25**	**6/27**
Feed	maple	maple	maple
Hydropyrolysis catalyst	CRI-4211	CRI-4211	CRI-4211
Hydroconversion catalyst	CRI-4202	CRI-4202	CRI-4202
Hours with biomass fed	6.0	18.4	20
Wt% recovery (relative to biomass)	104.3	103.9	108
%C recovery	99.7	98.6	104.7
Wt% C4+ liquid yield (MAF)	27.5	27.9	26.1
Wt% C1-3 yield (MAF)	18.1	15.6	18.5
Wt% CO_2 yield (MAF)	7.1	10.3	7.7
Wt% CO yield (MAF)	7.3	6.0	8.0
Wt % char yield (MAF)	8.0	8.7	9.3
Wt% water yield (MAF)	37.6	36.1	36.3
Wt% H_2 added MAF (calc)	5.7	4.6	5.9
Wt% H_2 available from reforming C1-C3 and CO	5.6	4.8	5.7
Liquid analysis			
Wt% Oxygen	<.3	<1.0	<.5
Wt% Carbon	87.72	87.43	88.82
Wt% Hydrogen	11.87	10.86	11.18
Wt% Nitrogen	<0.5	.01	.01
Wt% Sulfur	.08	.01	.06
Density	.80	.80	.79
% Gasoline C4-345	79	77	68
% Diesel 345F +	21	23	32
TAN (total acid number)	0.71	.6	.43
RON (research octane number- calc from PIANO) of condensed gasoline	89	88	87
H/C	1.62	1.48	1.51
Hydrocarbon Gas Analysis			
Wt% methane	31.5	31.3	31.2
Wt% ethane	41.8	42.0	41.2
Wt% propane	27.7	26.8	27.6
Water Analysis			
pH	10	9	9
Wt % nitrogen	0.27	.14	.16
Wt % carbon	0.5	.6	.3
Wt % sulfur	0.03	.05.	.01
Wt % ammonia	0.23	na	.16
Char analysis			
Wt %C		78.46	78.66
Wt %H		3.50	3.55
Wt %N		.37	.46
Wt %ash		11.7	9.4
Bulk density, g/cm^3		.25	.23
Heating value, kcal/kg		7060	7266
BET surface area m^2/g		16.7	14.4

In most cases, enough hydrogen can be produced by reforming the CO and light C1-C3 hydrocarbon gas product to make the required hydrogen. However, when hydrogen is not in balance it can be equalized (balanced) by increasing the reactor temperature to make more light ends and less char. The percent C1-C3 hydrocarbon gas yield goes up as hydropyrolysis temperature goes up as shown in Figure 10 and the percent char yields go down as hydropyrolysis temperature goes up as shown in Figure 11.

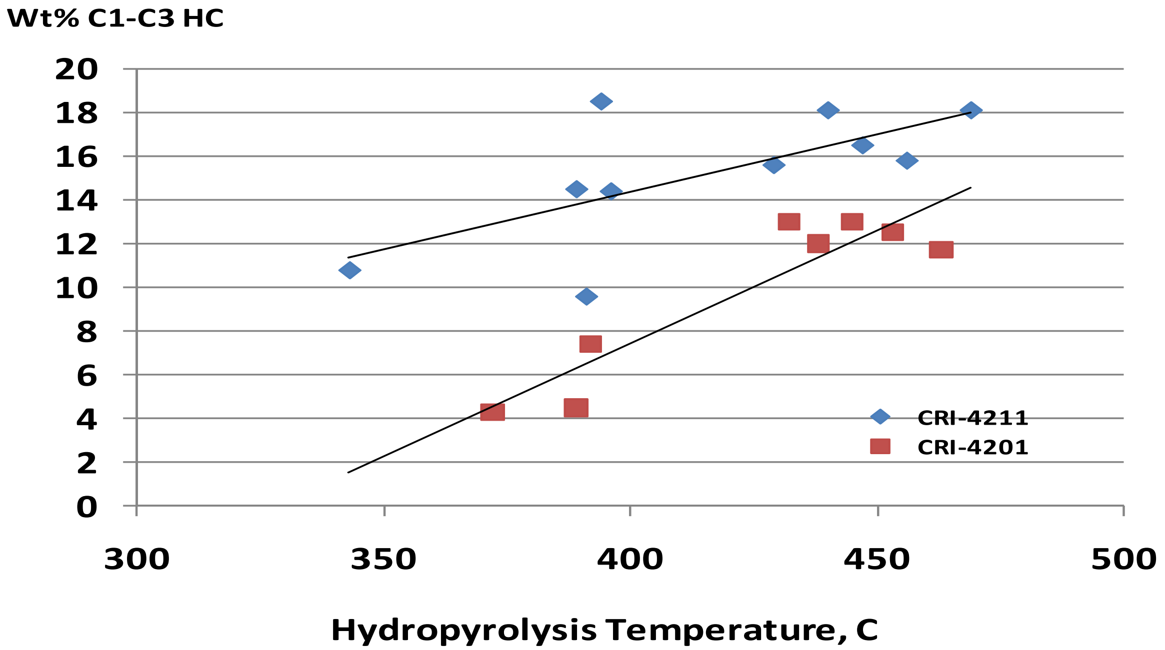


Figure 10—Wt% C1-C3 Hydrocarbons versus Hydropyrolysis Temperature.

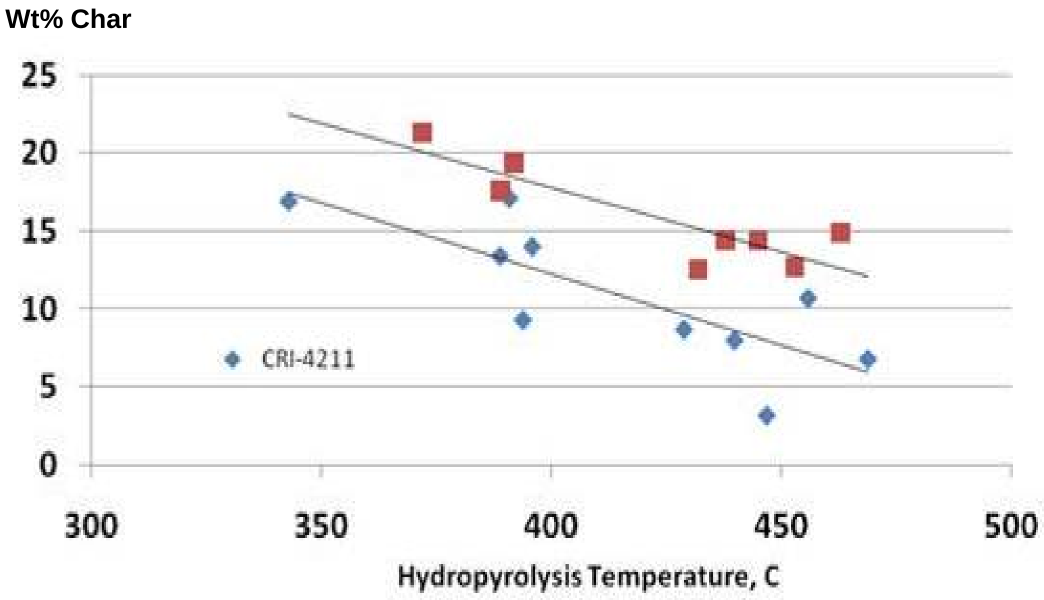
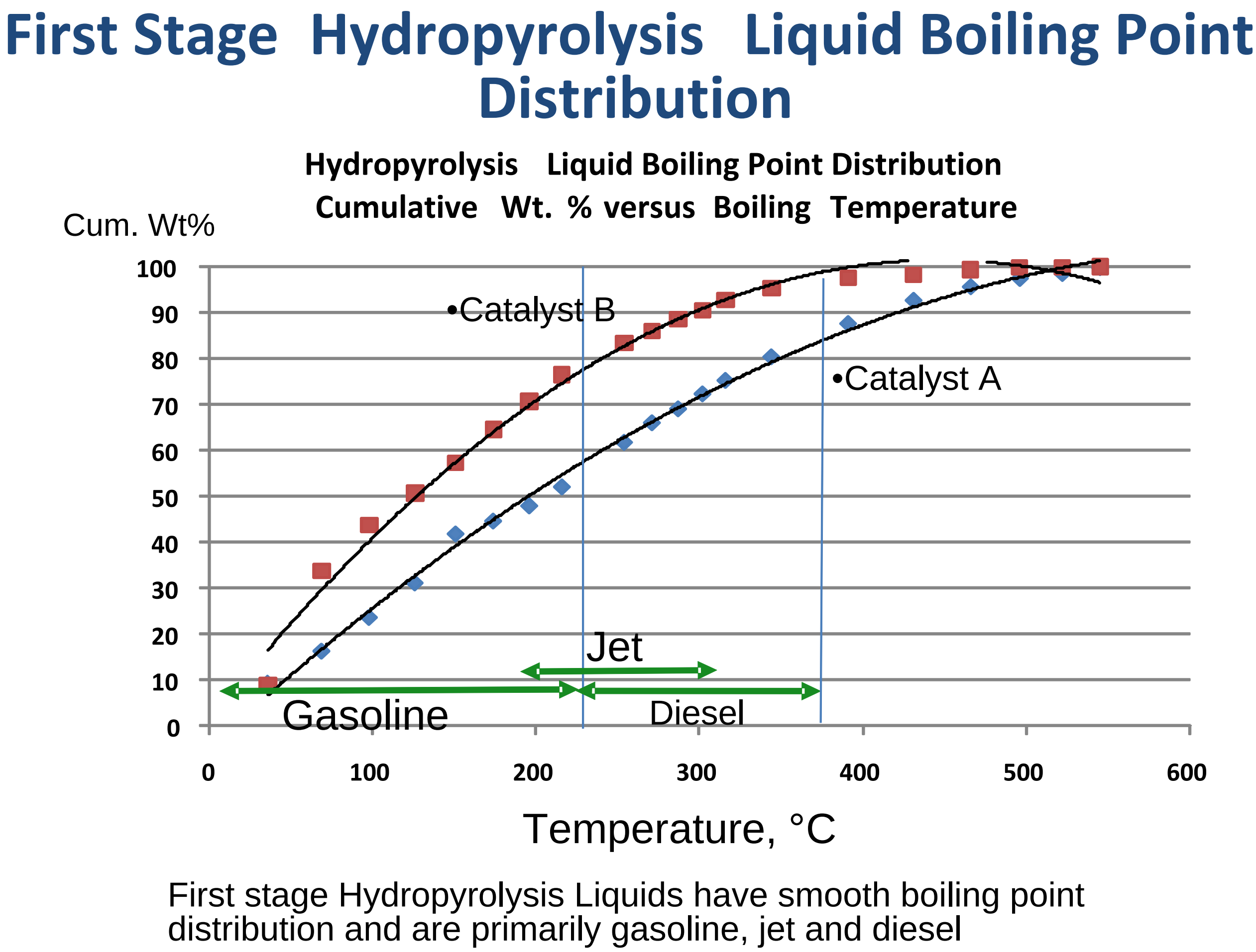


Figure 11—Wt% Char versus Hydropyrolysis Temperature

The experiments in Table 6 were run with only the first stage hydropyrolysis step and no second stage is present. With an active catalyst such as CRI-4211 or CRI-4201 at an elevated temperature, most of the oxygen was removed in the first stage. However, when CRI-4201 was used at a low temperature or when a base alumina was used, low oxygen removal occurred, high char yields were obtained and product liquid yields were decreased. These test results indicate the catalyst choice has a big effect. With an active catalyst, most of the oxygen removal is done in the first stage hydropyrolysis step, and the second stage acts primarily as a polishing step.

Data on boiling point distribution from 2/25 and 3/9 is shown in Figure 12 which shows that hydropyrolysis liquids have a smooth boiling distribution primarily in the gasoline, jet, and diesel range.



First Stage Hydropyrolysis Liquid Boiling Point Distribution

First stage Hydropyrolysis Liquids have smooth boiling point distribution and are primarily gasoline, jet and diesel

Figure 12—Boiling Point Distribution of Hydropyrolysis Liquids

Because of the unstable and reactive nature of pyrolysis oil, no boiling point information is available for pyrolysis oil since it decomposes and cokes during distillation. However, it is possible to compare the average molecular weight of pyrolysis oil with that from the 1st stage catalytic hydropyrolysis. Figure 13 shows pyrolysis oil has a much higher molecular weight than the 1st stage catalytic hydropyrolysis product. Fresh pyrolysis oil has an average molecular weight of 530 and aged pyrolysis oil molecular weight increases to 740 even when stored at 37C(2). IH^2 product has an average molecular weight 158-215 depending on the catalyst and conditions used.

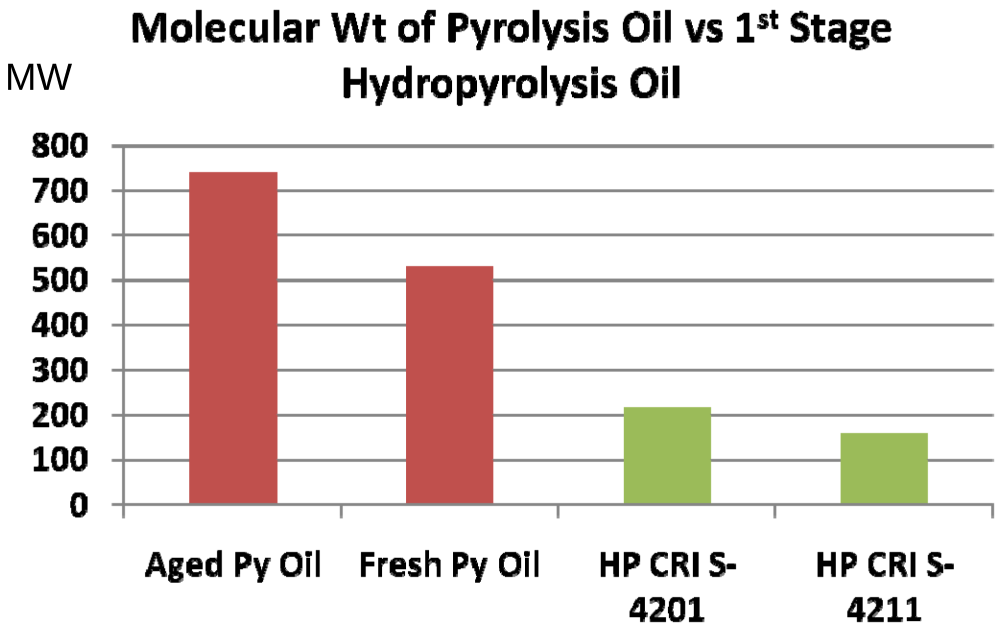


Figure 13—Comparison of Average Molecular weight of Pyrolysis oil versus IH^2 Product

A comparison of typical liquid yields from different feedstocks is shown in Figure 14. Yields are strongly affected by feedstock H/C ratio and those feeds with higher hydrogen to carbon ratio tended to give higher liquid yield than those with low H/C ratio. This effect is shown in Figure 15.

	Wood	Lemna	Aquaflow Micro Algae	Bagasse	Blue Marble Macro Algae	Corn Stover
Feed % C	49.7	46.3	43.1	43.1	34.0	40.2
Feed %H	5.8	5.8	6.1	5.0	4.43	5.0
Feed %O	43.9	35.7	20.4	35.3	23.6	35.7
Feed %N	0.11	3.7	6.5	.34	4.6	1.0
Feed %S	0.03	0.3	0.7	.10	1.9	0.05
Feed % Ash	0.5	8.2	23.1	16.2	29.4	18.1
Feed H/C	1.40	1.50	1.70	1.39	1.56	1.49
Typical % C_4 + Liquid Yield (MAF)	**25-28**	**30**	**46**	**30**	**35**	**21**
C_4+ Gallon/Ton MAF	**85**	**100**	**157**	**100**	**119**	**67**
% Oxygen	**(BDL)**	**(BDL)**	**(BDL)**	**(BDL)**	**(BDL)**	**(BDL)**
TAN #	**<1**	**<1**	**<1**	**<1**	**<1**	**<1**

Figure 14—Typical IH^2 Liquid Yields from Various Feedstocks

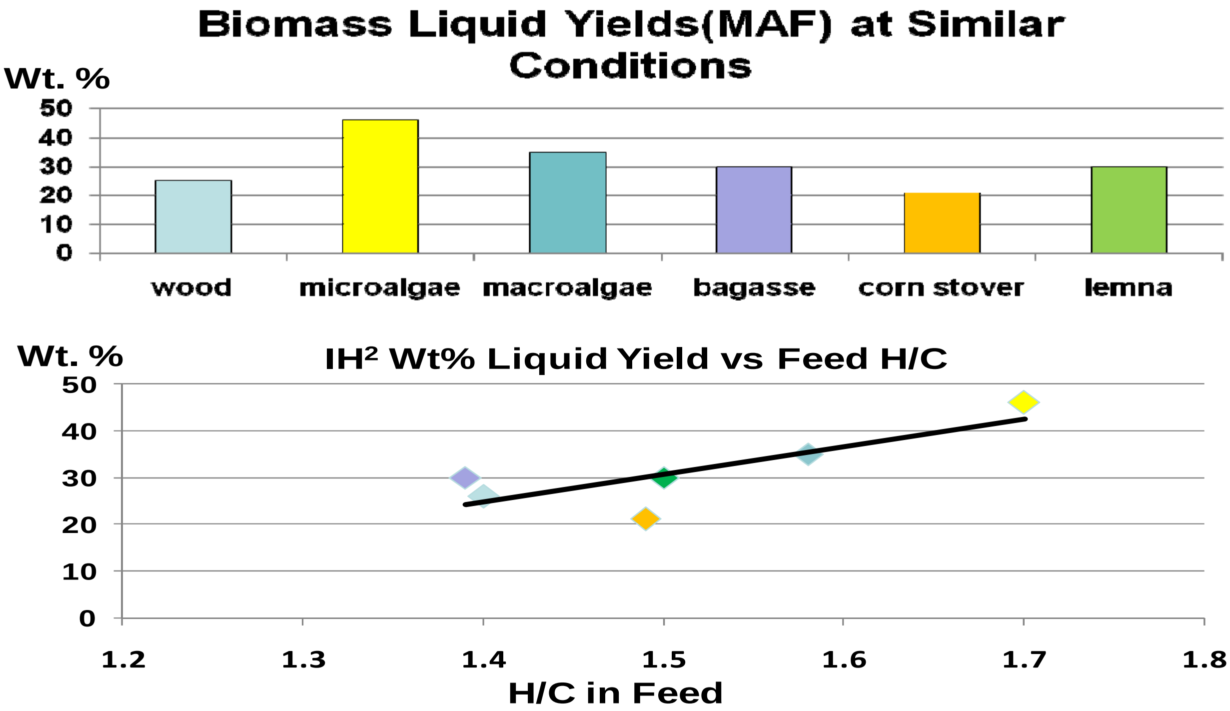


Figure 15—Comparison of Liquid Yields from different feedstocks

Some liquid samples were further analyzed by cutting up the liquid composites into gasoline, diesel and vacuum gasoil cuts. These data are shown in Table 8.

Table 8—Typical Analysis of Cuts of IH^2 Liquid

Component	Gasoline from wood (IBP-220 C)	Gasoline from lemna (IBP-220 C)	Gasoline from algae (IBP-220 C)	Diesel from wood (220-360 C)	Diesel from lemna (220-360 C)	Diesel from algae (220-360 C)
Wt % Oxygen	<1	<1	<1	<1	<1	<1
TAN	<.6	<.05	.08	<.6	<.05	.07
RON (calc)	87	86	82			
Cetane index				22	40	51
H/C molar ratio	1.70	1.83	1.92	1.30	1.64	1.79
Wt ppm Sulfur	52	66	108	52	151	46
Wt ppm Nitrogen	162	12500	7820	634	20600	9630
PIONA vol% aromatics	37	29	25			

Comparison of the distillation of the gasoline cut of typical petroleum and IH^2 gasoline is shown in Figure 16. IH^2 gasoline has a continuous boiling point distribution similar to petroleum gasoline and meets all gasoline boiling point specifications. As shown in Figure 17, IH^2 gasoline contains the same types of components as petroleum gasoline but has fewer olefins and more naphthenes. The IH^2 gasoline from wood has more aromatics and naphthenes than the algae, which has almost equal distributions of paraffins, isoparaffins, naphthenes and aromatics.

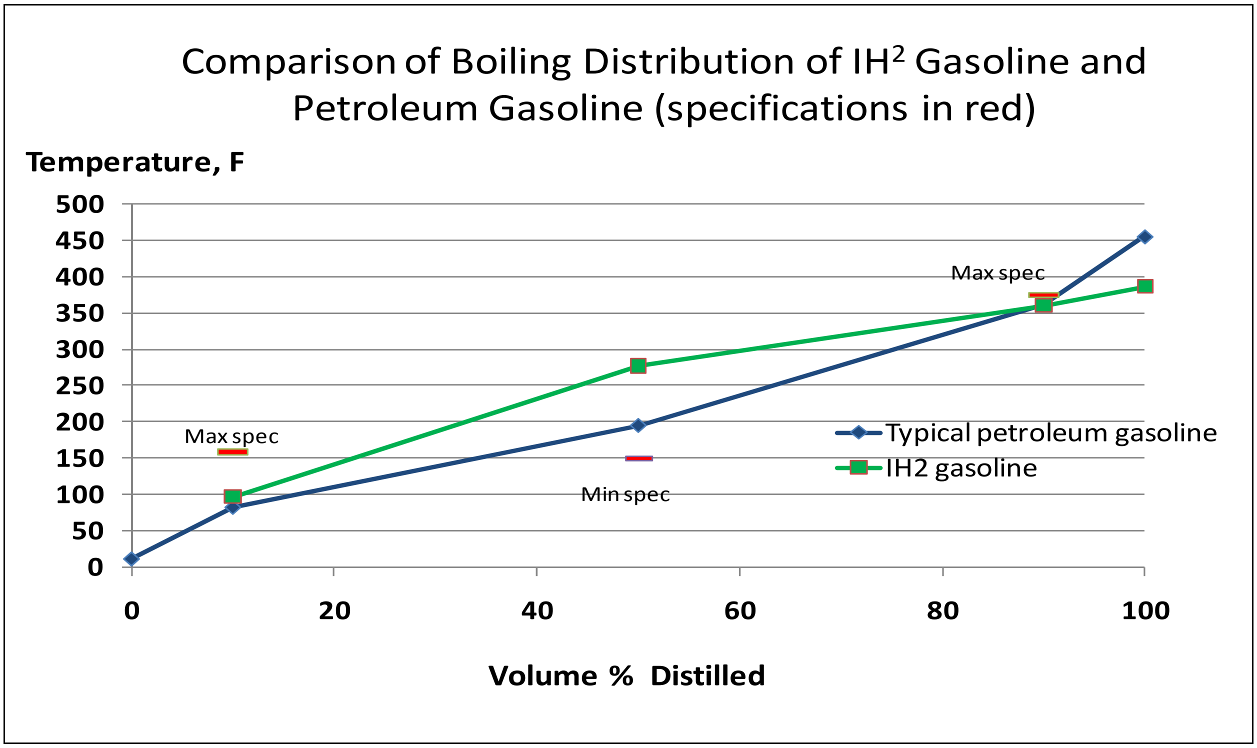


Figure 16—Comparison of the Boiling Range of Typical Petroleum gasoline and IH^2 Gasoline

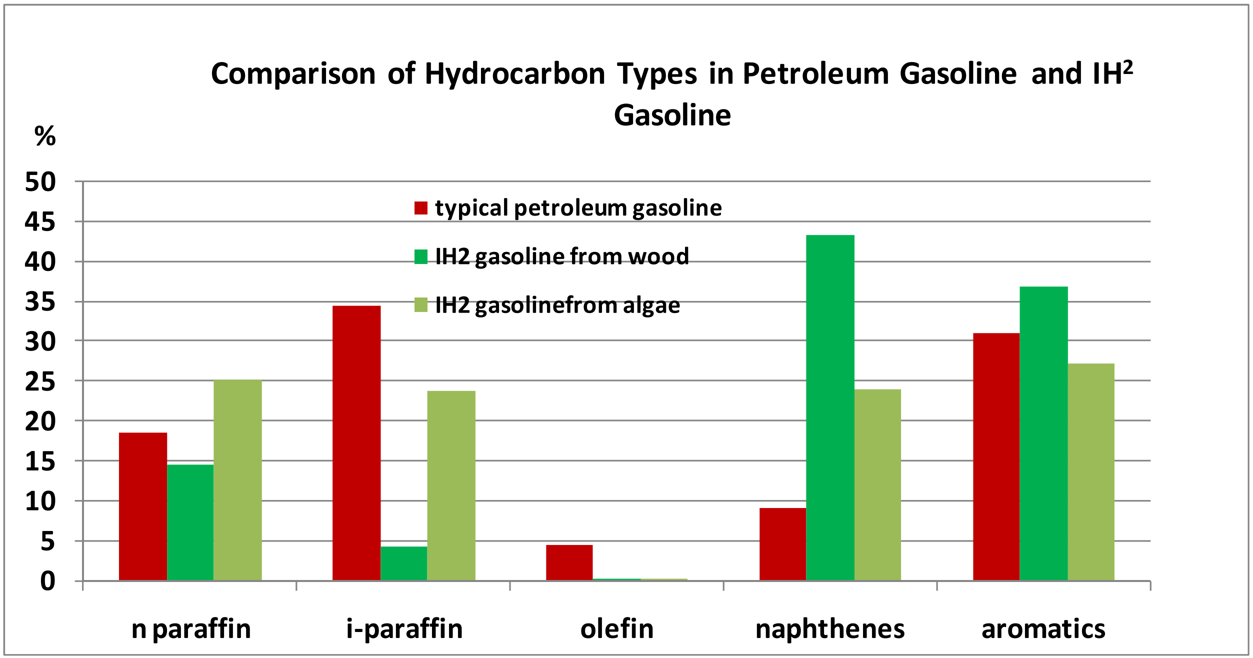


Figure 17—Hydrocarbon Type Compaison for Petroleum Gasoline and IH^2 Gasoline

As shown in Figure 18, IH^2 gasoline also has a higher RON than typical regular gasoline before the ethanol is added, so will have no trouble making gasoline octane requirements once it is blended with ethanol.

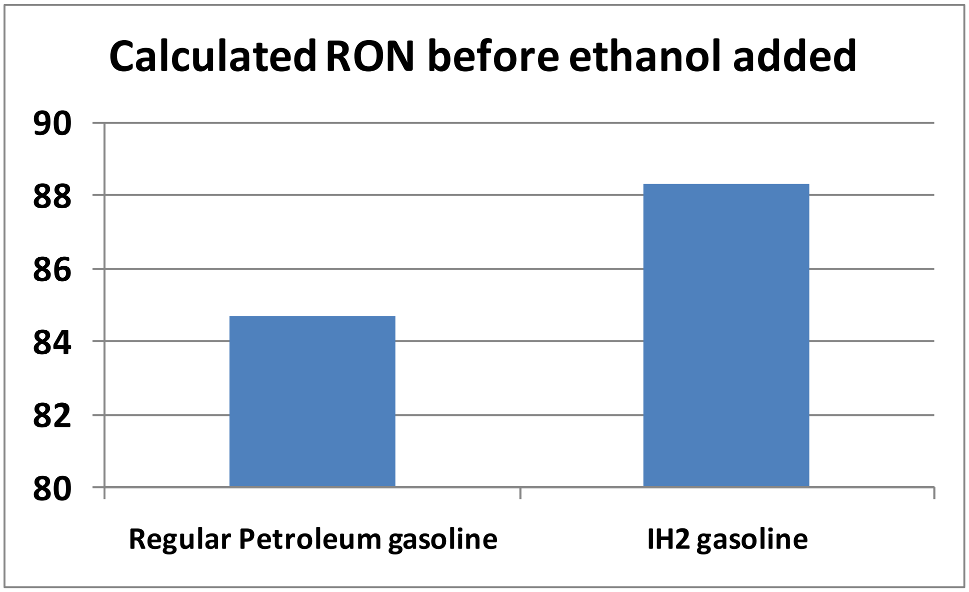


Figure 18- Calculated RON before ethanol added

Because of the high nitrogen content of the lemna, some additional tests were done with new catalyst formulations to reduce nitrogen in product liquids for high nitrogen feeds. The results of these additional tests are shown in Table 9. These tests show the potential of catalyst to adjust product properties in IH^2. The advantage of a catalytic hydropyrolysis is there is flexibility to adjust product properties by adjusting catalyst and conditions.

Table 9—Effect of Alternative Second Stage Catalyst

2nd stage catalyst	1st Generation	New	1st Generation	New
feedstock	wood	wood	lemna	lemna
%C	89.29	87.64	85.58	85.67
%H	11.29	12.99	14.17	14.32
%N	< 0.01	< 0.01	0.24	< 0.01
%O	< 1	< 1	< 1	< 1
Density, gm/cc	0.78	0.75	0.74	0.75
H/C	1.58	1.78	1.99	2.01

Modeling

Modeling Introduction:

A model of the IH^2 process has been developed in HYSYS© to evaluate the expected overall commercial process. Additional work is planned in the future to add components, but the model as is shows the basics of the flow diagram and energy balances.

Heats of Formation and Reaction:

The HYSYS model uses hypothetical components to represent cellulose and lignin since neither these components nor wood are present in the HYSYS database. As such, the heats of reaction are then automatically calculated by HYSYS based on the heats of formation. A good check of the system is to compare heats of formation of the HYSYS hypothetical components with those in the literature.

Table 10—Heats of Formation of Components

INPUT	Literature BTU/lb	HYSYS Component name	HYSYS BTU/lb
Cellulose		Hypo20000	-2004
Cellulose		Hypo20001	-2051
Lignin		Hypo20002	-1069
Wood	-2081 to -2480 avg= -2225	Blended mixture of hypothetical components	-1840
Hexane	-838		-838
Decane	-756		-756
H_2O	-6886		-6886
Methane	-2015		-2015
CO_2	-3851		-3851
Carbon	0		0

Table 11—Model Wt% Yields

INPUT	HYSYS model	exp 5-4
Wood	100	100
Hydrogen	4.2	4.1
OUTPUT		
C4+Liquid	25.0	26.0
CO_2+CO	19.6	18.1
H_20	34.9	34.4
C1-C3 hydrocarbons	13.4	13.0
Carbon	11.2	12.5
Total	104	104

Table 12—Heat of Reaction Comparison for Yields

INPUT	Calculated Heat of reaction from literature	HYSYS heat of reaction
BTU/lb wood	-1141	-1200

The HYSYS heats of reaction are in reasonably good agreement with the literature. Pyrolysis of biomass is a mildly endothermic reaction whereas hydropyrolysis and hydroconversion are very exothermic reactions.

Model Reactions:

The HYSYS model is based on a number of model reactions of the hypothetical components. These reactions are shown in Appendix F. Additional components will be added as the model is improved.

Table 13—Structure of Hypothetical Components

	Hypo 20000	Hypo20001	Hypo20002
Molecule	cellulose	cellulose	lignin
MW	324	648	166
Formula	$C_{12}H_{20}O_{10}$	$C_{24}H_{40}O_{20}$	$C_9H_{10}O_3$
%C	44.4	44.4	64
%H	6.2	6.2	6
%O	49.4	49.4	29
% in wood	37	37	26

Catalyst Attrition Tests

The catalyst attrition tests were done in a Plexiglas fluidization reactor pictured in Figure 19.

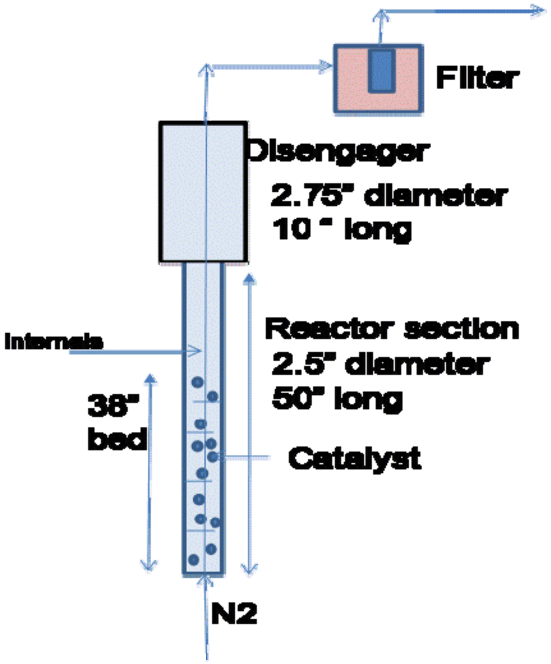


Figure 19—Diagram of Attrition Test Unit

In the attrition tests, the catalyst is placed in the bed and then nitrogen is sent through the Plexiglas system to fluidized the catalyst particles. The attrition, or the amount of material which is collected in the over head filter, is weighed each hour over a period of several days. For these tests 1/16" catalyst support was used since the actual catalyst was not yet available. Spherical support was used for these tests since spherical catalyst has a lower attrition in fluidized bed than irregularly shaped catalyst pills.

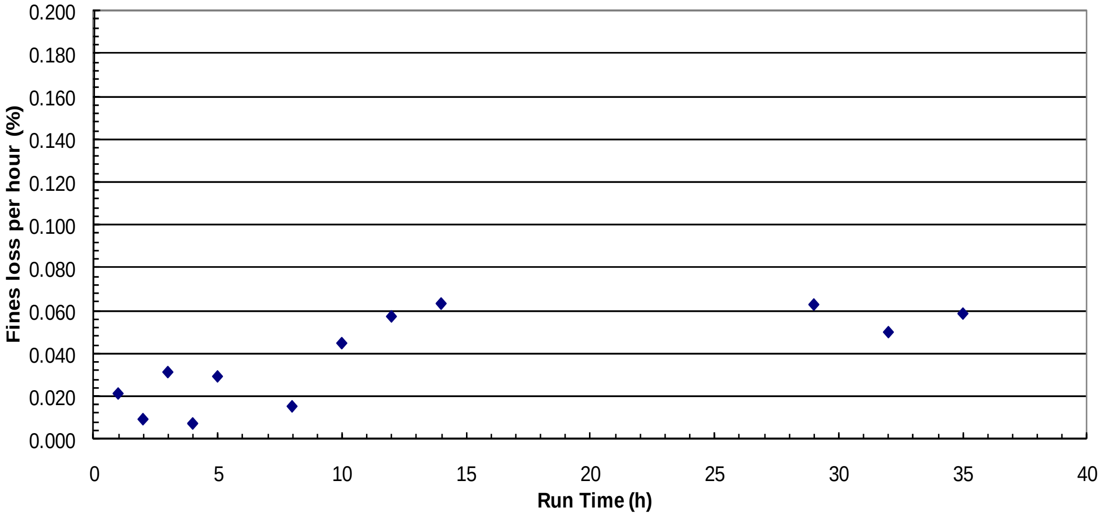


Figure 20—Attrition Rate

The results as expressed in percent fines loss per hour and appears to steady out at around 0.06%fines/hour = 10%fines/week. In general, it has been reported(3) the attrition M (in wt%/hr) in fluidized beds is

$$M=C*p_f*U^3*(Lc/Dc)^{.78}$$

Where U is the velocity in ft/sec, (Lc/Dc) is the bed height/diameter, p_f is the density of the gas and C is a constant related to the hardness of the catalyst particle. These tests should be a good predictor of catalyst attrition under actual process conditions. Proprietary catalyst internals are used in the reactor to prevent slugging. These internals will also be present in the pilot unit and the commercial design to prevent slugging.

Technoeconomic update

The original IH^2 economics had been done by starting from pyrolysis technoeconomic studies from NREL and others, adding the cost of the hydrogen plant and hydrotreating reactor and subtracting the cost of the pyrolysis regenerator and quench system (equipment which is not in the IH^2 design). The same feed preparation is used for IH^2 as is used in pyrolysis .

Updated technoeconomics were done by NREL based on an IH^2 HYSYS model which was used with ICARUS to estimate the cost of the individual pieces of equipment. Specialty equipment such as the reactors were scaled up based on standard and proprietary engineering design principles for fixed bed hydrotreaters and fluid bed hydropyrolysis..

A summary of the finalized NREL report information is shown in Tables 14, 15, 16 and 17. The entire report is included in Appendix A.

Table 14—Installed Costs for a 2000t/day IH^2 unit

Process Area	**Installed Costs $ Million 2007 basis**
Feed Handling and Drying	4.72
Hydropyrolysis and hydroconversion	17.71
Absorption tower	0.44
Distillation Tower	3.99
Sour Water Stripper	0.96
Amine Scrubber	1.43
Ammonium Sulfate Production	2.71
Hydrogen Plant	44.04
Utilities and Cooling Water	7.40
Equipment Contingency	29.20
Total	112.64

Table 15—Total Capital Investment IH^2, $Million

Total Purchase Equipment Cost (TPEC)	**82.55**
Installation Factor	1.365
Total Installed Costs	112.64
Other Direct Costs	
Land (not depreciated)	1.61
Site Development (4% of ISBL)	4.11
Total Direct Costs (TDC)	118.36
Indirect Costs	
Prorated Expenses (10% of TDC)	11.67
Home Office and Construction Fees (20% of TDC)	23.35
Field Expenses (10% TDC)	11.67
Project Contingency (30% TDC)	35.02
Other Costs (Start-up and Permits) (10% TDC)	11.67
Total Direct Costs (80% TDC)	93.40
Fixed Capital Investment	211.76
Working Capital	21.01
Total Capital Investment	232.77

Table 16—Fixed Operating Costs IH^2 Plant

	2007 salary	# positions	2007 costs	$MM/yr	Cents/gal fuel
Plant manager	147,000	1	147,000		
Plant engineer	70,000	1	70,000		
Maintenance supervisor	57,000	1	57,000		
Lab manager	56,000	1	56,000		
Shift supervisor	48,000	5	240,000		
Lab technician	40,000	2	80,000		
Maintenance technicians	40,000	16	640,000		
Shift operators	48,000	20	960,000		
Yard employees	28,000	12	336,000		
Clerks and secretaries	36,000	3	108,000		
Total salaries		62	2,694,601	2.69	4.42
Overhead and benefits			2,424,601	2.42	3.98
Maintenance			4,202,991	4.20	6.90
Insurance and taxes			1,471,047	1.47	2.42
Total Fixed Operating Costs				10.79	

Table 17—Process Engineering Analysis-2000 dry metric tonnes Biomass per day

Minimum Fuel selling price (MFSP)	$1.60 per gallon
Contributions feedstock	$ 0.91 per gallon
Operating costs	$0.16 per gallon
Capital Charges and taxes	$0.54 per gallon
Delivered feedstock cost	$71.97 (includes drier and sizing capital)
Internal Rate of Return after Tax	10%
Equity Percent of Total Investment	40%

The NREL technoeconomic study shows that IH^2 technology has excellent economics.

Cargill studied the integration of IH^2 into an existing corn ethanol plant. For the cornstover case, with 20% feed moisture, it was estimated 180,000 lb/hr of export steam could be produced from the IH^2 process. Cargill studied the advantages of integrating this steam in with a dry grind ethanol plant. They concluded this integration could be attractive at reducing the CO_2 emissions for ethanol production as shown in Figure 21.

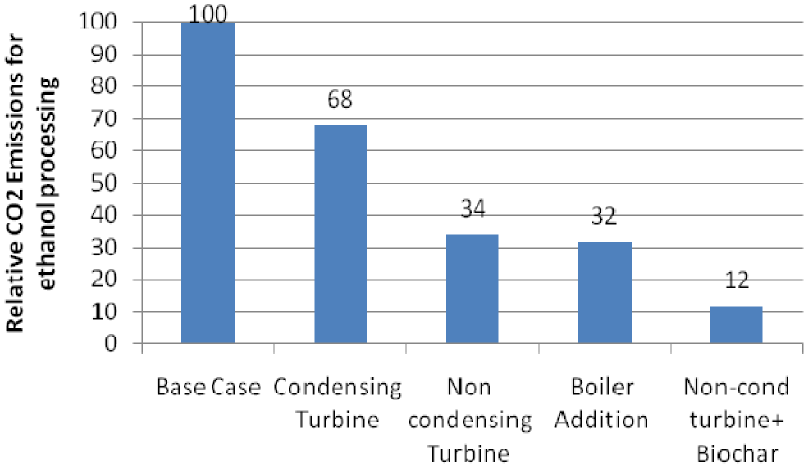


Figure 21—Relative CO_2 Emissions for Ethanol Processing Utilizing integration with IH^2 steam

Besides energy, there are other opportunities to integrate the IH^2 process with ethanol production, including utilization of char to produce steam or as a fertilizer.

LCA update

The initial LCA of IH^2 technology was based on preliminary yield estimates and done by Dr. Shonnard of MTU. A much more detailed LCA was done utilizing input from the project partners and was done by Edwin Maleche of MTU under Dr. Shonnard's guidance as part of the DOE project.

The result are very favorable, showing IH^2 is a excellent conversion technique for wood from an LCA perspective, giving over 90% GHG reduction and easily qualifying IH^2 fuels as advanced biofuels (50% reduction required).

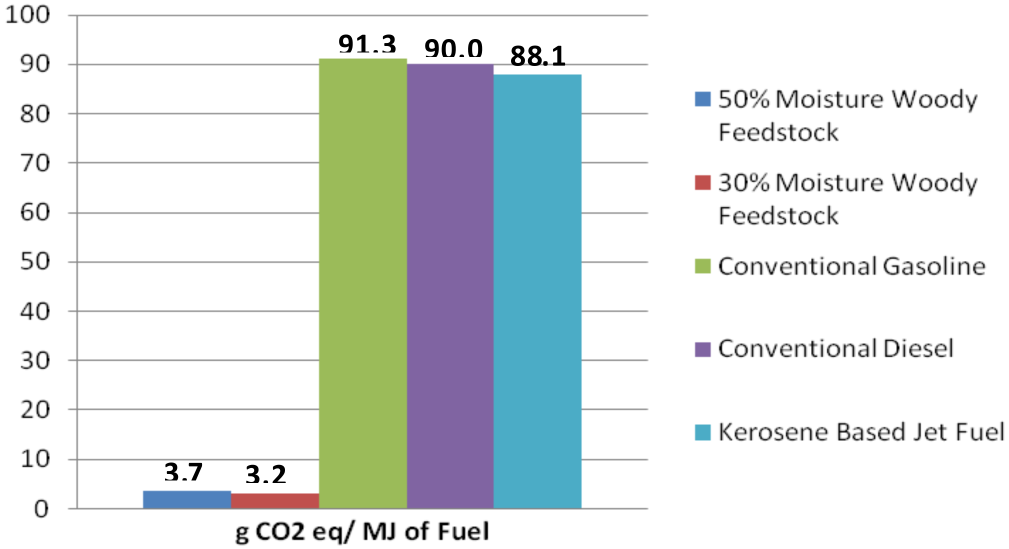


Figure 22—Results of IH^2 fuel for the 50% and 30% moisture woody feedstock green house gas emissions results saving compared to petroleum fuels Well-to-Wheels (WTW)

Dr. Shonnard's MTU team also finished an analysis of the LCA for IH^2 using a cornstover feed. The results are also very favorable showing IH^2 is an excellent conversion technique for cornstover from an LCA perspective, giving over 90% greenhouse gas reduction and easily qualifying IH^2 fuels as advanced biofuels (50% reduction required).

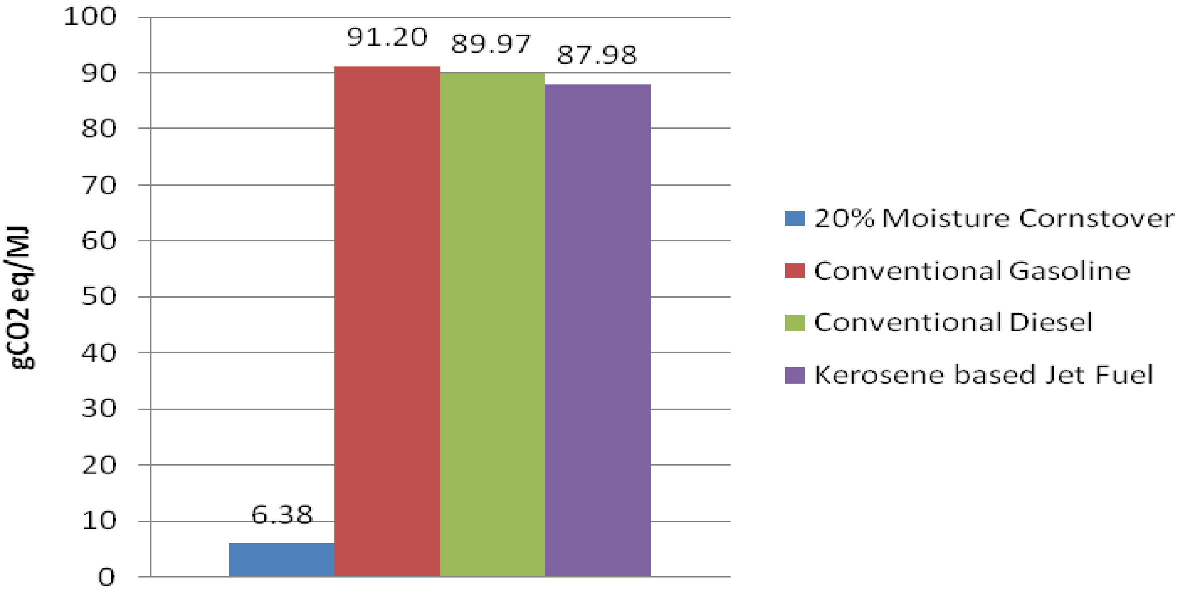


Figure 23—Results of IH^2 fuel for 20% moisture cornstover feedstock green house gas emissions results saving compared to petroleum fuels WTW

IH^2 has extremely favorable LCA with low GHG emissions. The entire overall LCA report can be found in Appendix B.

Preliminary Engineering

Preliminary engineering was done on the costs of building a 1 ton/day pilot plant and a 50 kg/day continuous pilot plant. Zeton designed the hydropyrolysis-hydroconversion section of the 1 ton/d pilot plant and CBI designed the SMR plant to produce H_2 from the C1-C3 gases from IH^2. Table 18 shows the cost estimate for a 1 ton/day IH^2 pilot plant.

Table 18—Cost Estimate for 1 ton/day IH^2 Pilot Plant

Section	$MM	Source
Hydropyrolysis and Hydroconversion	4.3	ZETON
H_2 production	4.0	CBI
Total	8.3	

Zeton also developed a cost estimate and preliminary engineering design for a continuous 50 kg/day pilot without the steam reformer section. This estimate came in at $1.8MM. This unit was funded privately and was built by Zeton. The 50 kg/day pilot plant was installed at GTI and used for the continuous testing segment of this project. The detailed preliminary engineering for both the 1 ton/day and 50 kg/day unit are found in Appendix C.

Continuous Pilot Plant tests

The continuous 50 kg/day pilot plant was delivered to GTI on Sept 20, 2011. Pictures of the new pilot plant are shown in Figures 24-27.

Figure 24—New 50 kg/d IH^2 Pilot Plant - lifted into place

Figure 25—IH^2 Pilot Plant being slid into place

Figure 26—IH^2 Control Room

Figure 27—50 kg/d IH^2 pilot plant-overall look

The goal of the pilot plant was to convert the IH^2 semi-continuous batch process to a continuous process, show IH^2 process operability, generate more IH^2 products, and show catalyst stability. The pilot plant construction was paid for with private funds. Shakedown was funded via U.S. DOE Award DE-EE-0004390. The shakedown of the pilot plant took longer than expected and cost more than expected primarily because of mechanical problems. Key issues were problems with leaking valves, which were solved by using metal sealed valves, and problems feeding and transporting biomass and char, which were solved by adding mechanical stirrers to the feed and char removal system. Improvements were also required in the automated safety systems to better display key alarms and facilitate automatic shutdown in case of leaks.

Once shakedown operations were completed, continuous pilot plant testing began, progressing from 8 hour/day operation to 16 hour/day operation to 24 hour/day operation over the space of a few weeks. The quality of the IH^2 liquids from continuous operation were quite high as shown in Figure 28, 29 and Table 19.

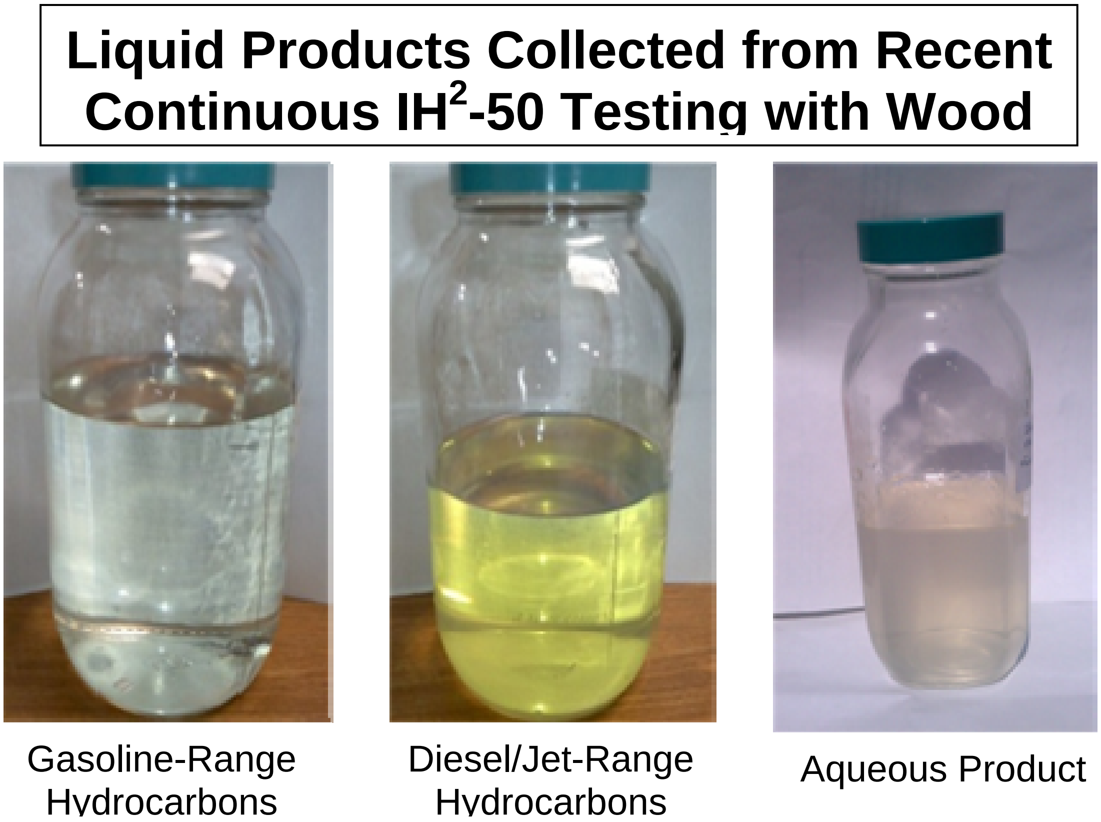


Figure 28—Liquid products from IH^2

Table 19 - Typical Analysis of IH^2 Liquids from Continuous Pilot Plant Testing with Wood feed

Wt% C	88.96
Wt% H	10.83
Wt% S	<0.1
Wt% N	<0.1
Wt% O	<1
TAN	<0.05
Wt% Gasoline	70
Wt % Diesel	30

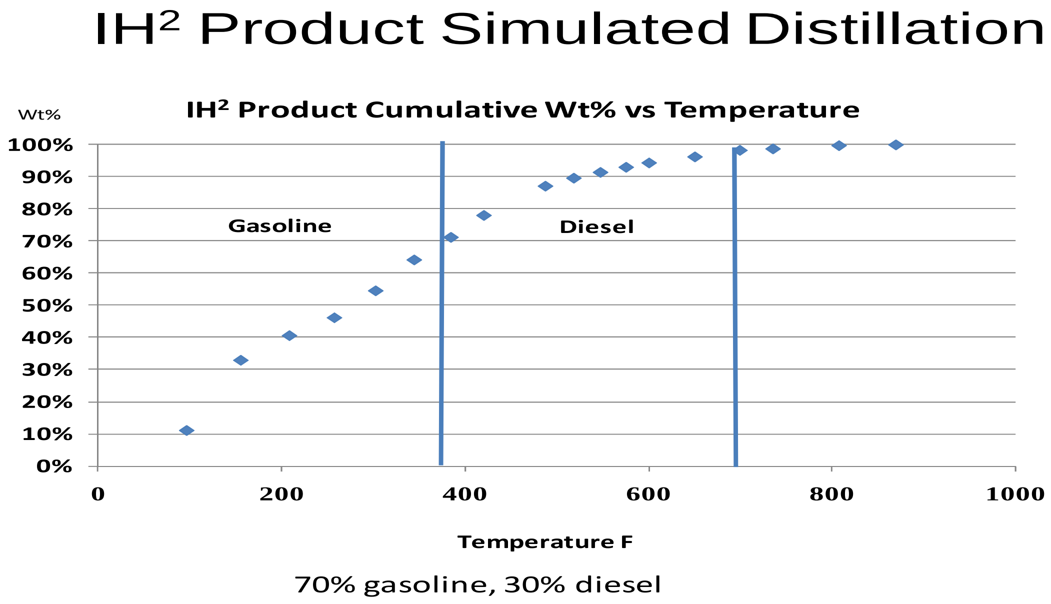


Figure 29—IH^2 Liquid Product from Wood Simulated Distillation

The yields from the bench scale testing and continuous testing were consistent as shown in Table 20.

Table 20—IH^2 Yield Comparison, Wood feed, MAF

	Bench scale test	50 kg/day continuous
% C4+ Liquid hydrocarbon	26	26
% water	36	36
% char	13	14
% C1-C3	13	15
% $CO+CO_2$	17	14
Total	105	105

The pilot plant was operated to get daily yields, material balances, and product analysis so that product quality and yields could be monitored versus time. Data from the pilot plant versus hours on stream is shown in Figures 30-36.

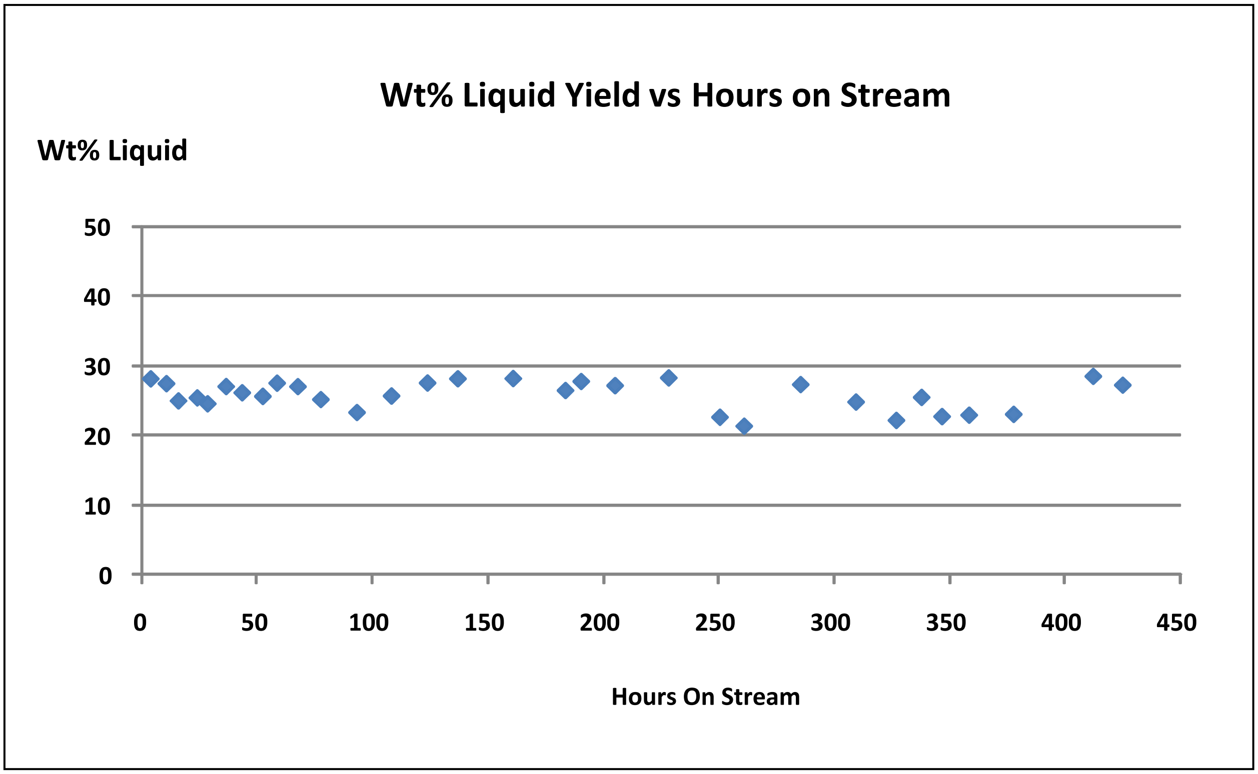


Figure 30—Wt% Hydrocarbon Liquid Yield versus Hours on Stream (wood feed)

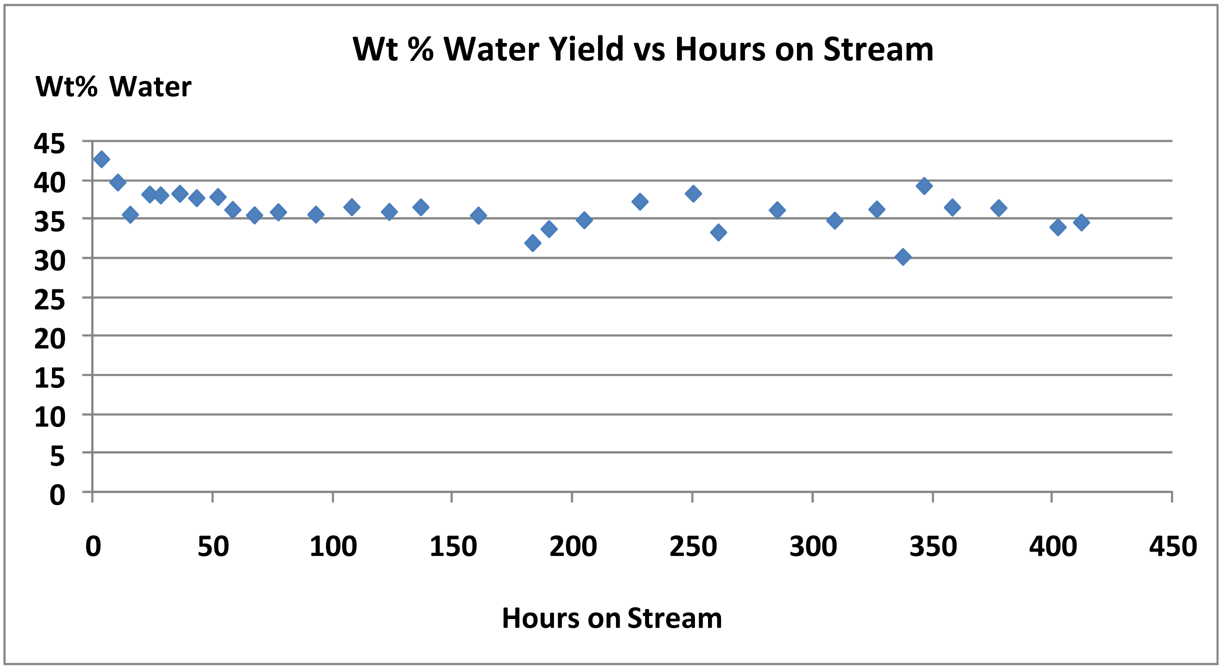


Figure 31—Wt% Water Yield versus Hours on Stream(wood feed)

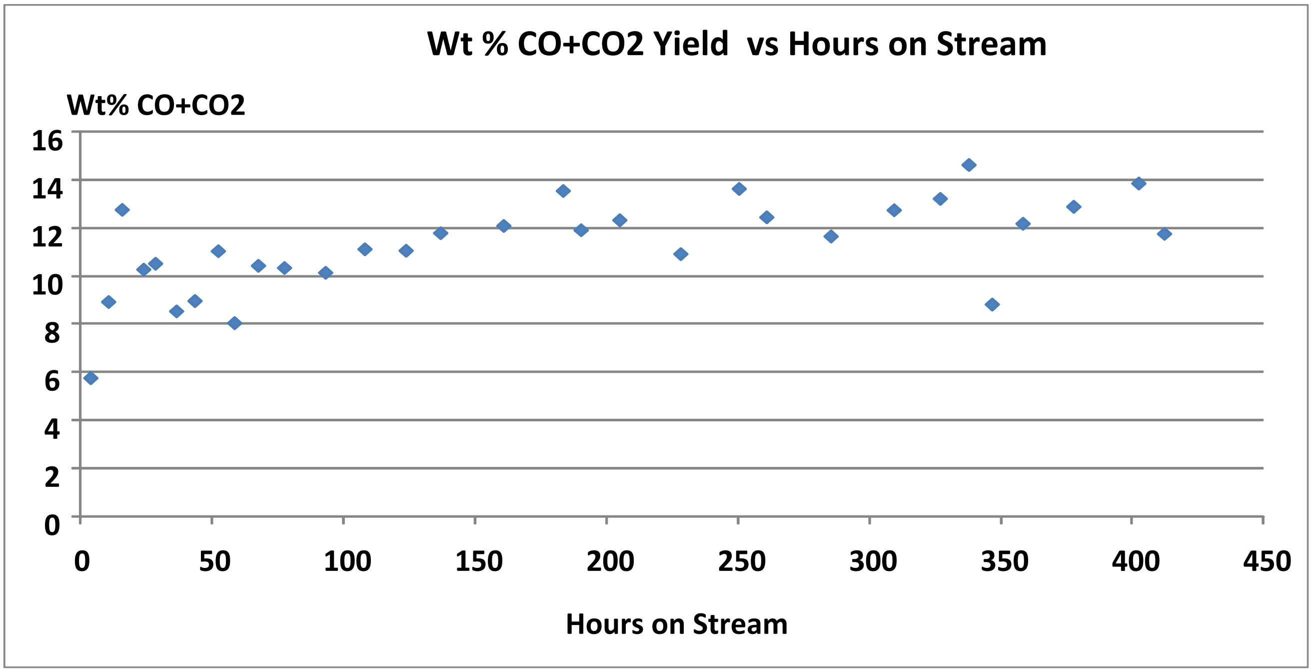


Figure 32—Wt% CO+CO$_2$ Yield versus Hours on Stream(wood feed)

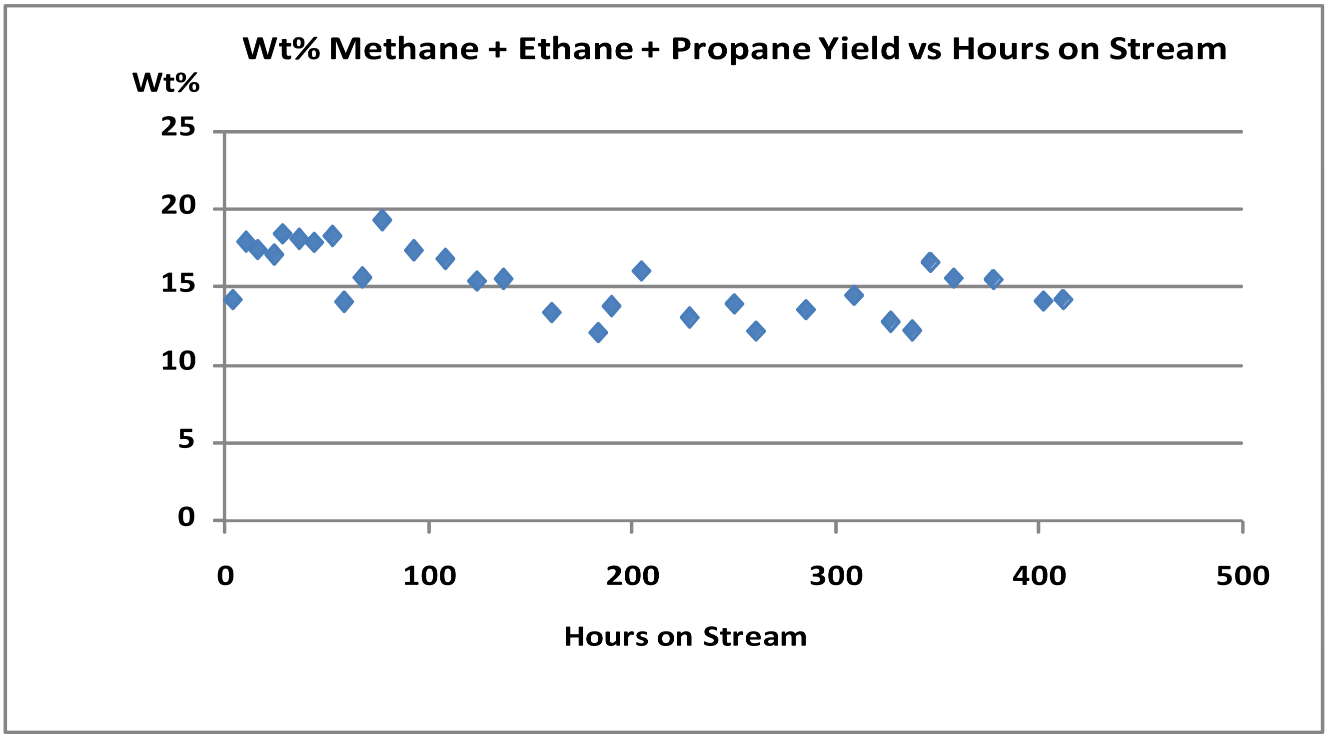


Figure 33—Wt% Methane +Ethane +Propane Yield versus Hours on Stream (wood feed)

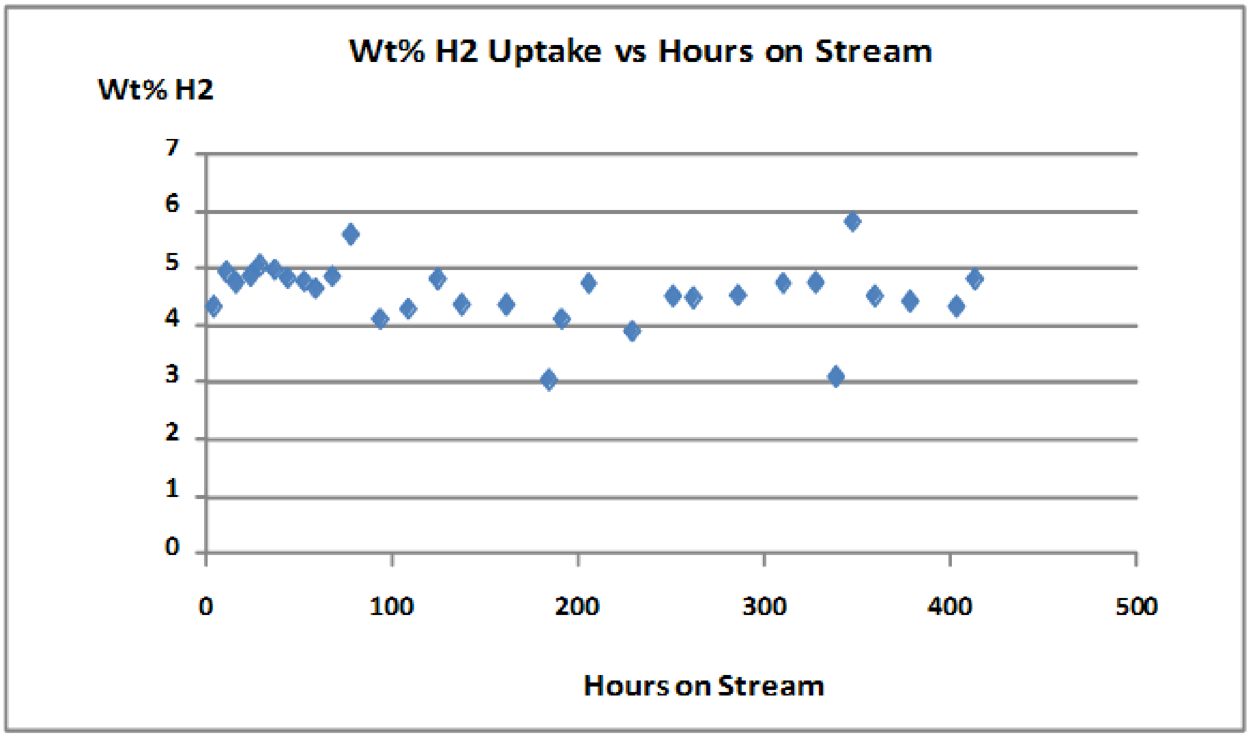


Figure 34—Wt% H_2 Uptake versus Hours on Stream

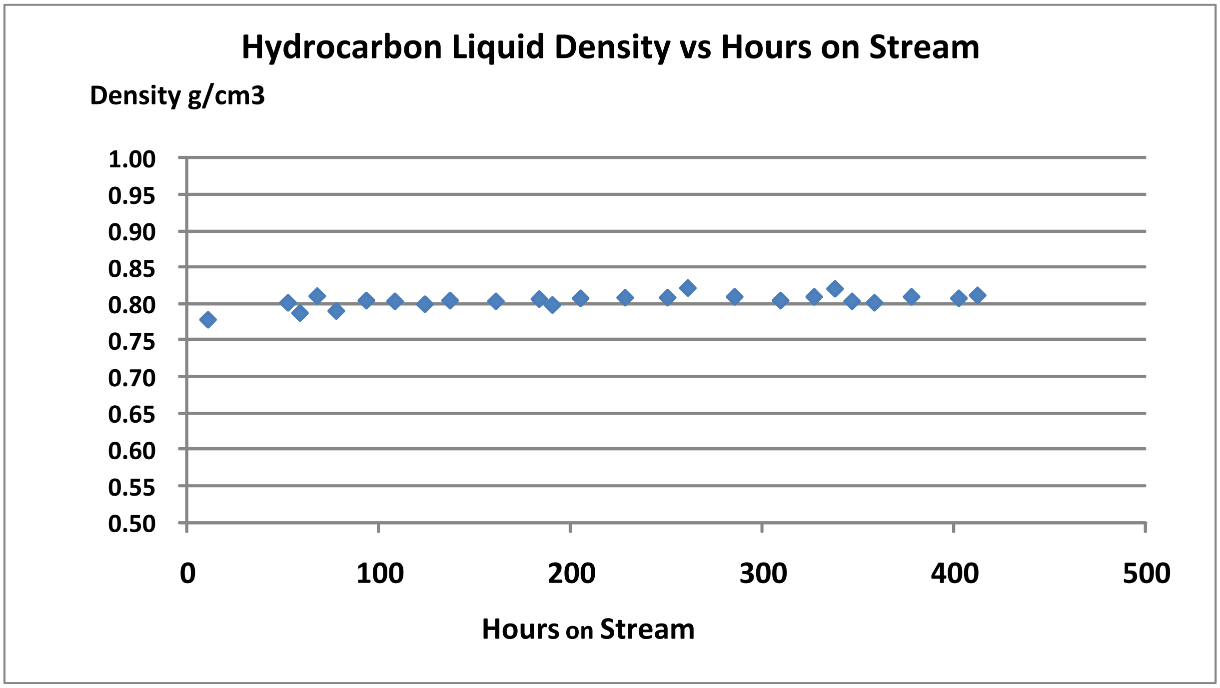


Figure 35—Hydrocarbon Product Density versus Hours on Stream

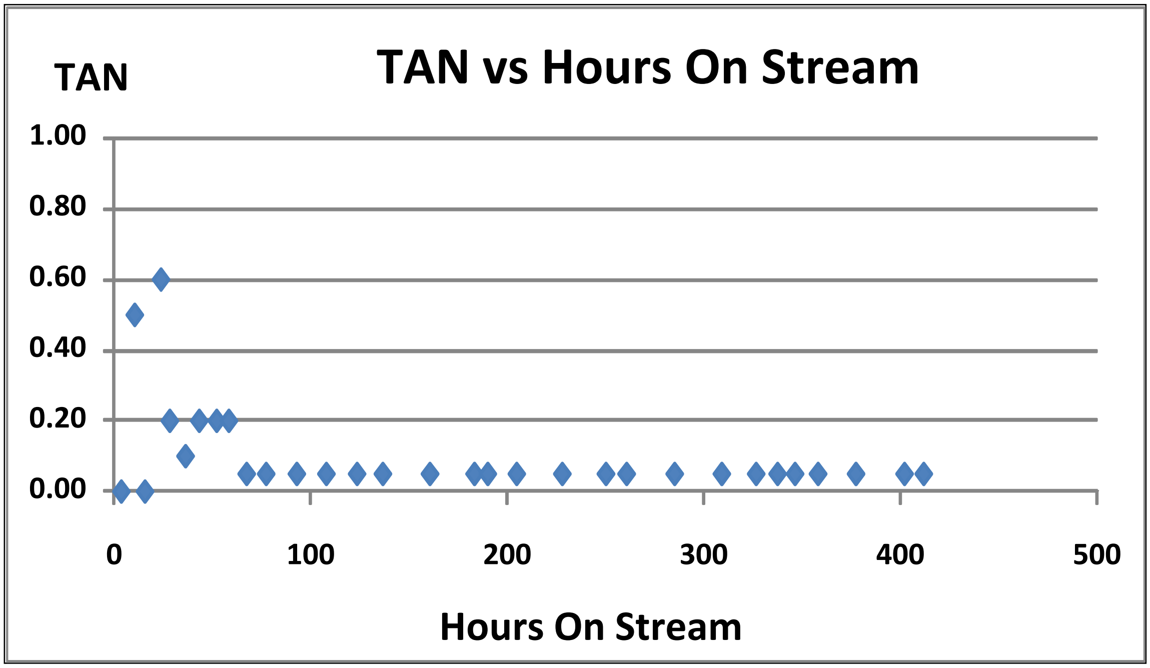


Figure 36—TAN versus Hours on Stream (wood feed)

The percent oxygen in the products was always less than 1% throughout the test. In general, the system shows very stable operation. CRI fractionated 25 gallons of the IH^2 liquids into a gasoline, jet, and heavy diesel cuts. These were then compared with the results from typical petroleum derived gasoline jet and diesel. Table 21 shows the weight % of each cut.

Table 21—Wt% of IH^2 Fractions from Wood

	Wt%
Gasoline IBP-390F	72.2
Jet 390-535F	19.5
Heavy Diesel 535-700F	8.3
Total Diesel 390-700F	27.8

Table 22 compares the properties of the IH^2 gasoline to typical gasoline. The IH^2 gasoline is very similar to petroleum gasoline but has a higher octane, and a slightly higher Reid Vapor Pressure (RVP).

Table 22—Gasoline Fraction Comparison

	Typical Fossil Gasoline (no ethanol)	IH^2 Gasoline from Wood
% C	86.9	87.9
% H	13.1	12.1
Bromine Number	9.4	0
Wt % n - paraffins	18.5	10.9
Wt % I - Paraffins	34.4	4.5
Wt % Aromatics	31.0	25.4
Wt % Napthenes	9.1	31.0
Wt % Oxygenates	0.09	0.0
Reid Vapor Pressure @100°F	8.8	9.5
Calc Octane Number	84.7	88.3
Density	0.722	0.761

Future Work

Additional continuous testing with wood, cornstover, and lemna is planned under U.S. DOE Award DE-EE-0004390. This testing will provide additional information on catalyst life and stability using a variety of feedstocks. After that project is completed, further R&D work to gather information for process and kinetic modeling and the effect of particle sizes and residence time would be highly desirable. Additionally a scale up to a 1 ton/day size or larger demonstration scale would be recommended to provide further confidence and reduce risk for scale up to full commercial scale.

Conclusions

Gas Technology Institute has developed a new breakthrough catalytic technology,IH^2, for thermochemically converting biomass directly into gasoline, jet, and diesel fuels. Initial testing has demonstrated and validated the conceptual and technical basis of this process. Larger scale 50 kg/day continuous testing has shown the operability and practicality of the IH^2 process over a 400+ hour test. LCA, completed by MTU, has shown the hydrocarbon fuel products from the IH^2 process reduce GHGs by greater than 90% compared to the comparable fossil fuels. NREL has completed technoeconomic studies which show the low capital cost for the IH^2 technology and the potential to make gasoline, jet, and diesel at less than $2.00/gallon.

The IH^2 technology when fully commercialized has the potential to be a game-changing technology, by reducing U.S. dependence on foreign crude, creating U.S. jobs and producing high quality and low-priced transportation fuels from U.S. grown biomass resources.

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Appendix A — NREL Technoeconomic Analysis

NREL National Renewable Energy Laboratory

A national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy

Innovation for Our Energy Future

Technical Memorandum

To:	Gas Technology Institute
Title:	Techno-economic Analysis of the Integrated Hydropyrolysis and Hydroconversion Process for the Production of Gasoline and Diesel Fuels from Biomass
Author:	Eric C. D. Tan
Platform:	Analysis Report
Date:	May 23, 2011

Summary

Techno-economic analysis is a methodology that has been used to guide the research and development of lignocellulosic biofuels production processes at NREL for over two decades. The purpose of this study is to develop a techno-economic model for assessment of GTI's integrated hydropyrolysis and hydroconversion process (IH^2) for producing gasoline and diesel fuels from woody biomass. The minimum fuel selling price (MFSP) was calculated using a discounted cash flow rate of return analysis (DCFROR) and was determined to be \$1.60/gal, in 2007 dollars. The annual fuel production rate is 60.9 million gallons and the total capital investment (TCI) was estimated to be \$232.8 million.

Keywords: Techno-economic analysis, biomass, minimum fuel selling price, integrated hydropyrolysis and hydroconversion process (IH^2)

Introduction

GTI has developed a novel process—integrated hydropyrolysis and hydrovonversion process (i.e., IH^2)—to covert lignocellulosic biomass into transportation fuels. IH^2 was reported to be a promising technology as the process is capable of converting biomass directly to fungible gasoline and diesel fuels or blending components [1-3]. NREL has worked with GTI on the techno-economic analysis of producing gasoline and diesel fuels via IH^2. NREL has developed a detailed economic cash flow analysis of the IH^2 process using Excel Spreadsheets. Material balance data from the HYSYS process model from GTI were used to size certain process equipment for the purposes of developing capital and operating costs. NREL has also consulted and worked closely with GTI to choose financial assumptions most appropriate for this project.

Process Overview

Schematic representation of the IH^2 process is shown in Figure 1. The detailed description of the process can be found in GTI reports, e.g., ref. [1]. Briefly, the process is carried out in two integrated stages: hydropyrolysis and hydroconversion. Hydropyrolysis is a catalytic exothermic reaction and is completed in a fluid bed in the presence of hydrogen. This is immediately followed by a second stage hydroconversion step. The hydroconversion step catalytically removes oxygen present in the hydropyrolysis effluent (a partially deoxygenated pyrolysis liquid) and produces gasoline and diesel boiling range liquid products. In addition to the liquid products, the process also produces a gaseous mixture comprising CO and light hydrocarbon gases (C_1-C_3). The light gases are reformed in a steam reformer to produce hydrogen. The onsite hydrogen production meets the IH^2 demand and no additional hydrogen is required. The by-products of the process are char, high pressure steam, and ammonia/ammonium sulfate (not shown in Figure 1). Ammonia and hydrogen sulfide in the process condensate are stripped and oxidized to make ammonium sulfate which can be used as a fertilizer.

METHODS AND ASSUMPTIONS

In process economics analysis, the first step is to determine the total equipment cost based on process simulation results. The total capital investment (TCI) is then computed from the total equipment cost. Next, variable and fixed operating costs are determined. With these costs, a discounted cash flow analysis is performed to determine the minimum fuel selling price (MFSP) required to obtain a zero net present value (NPV) with a finite internal rate of return (IRR). Details on how to determine each of these costs and the assumptions made in completing the discounted cash flow analysis are described below.

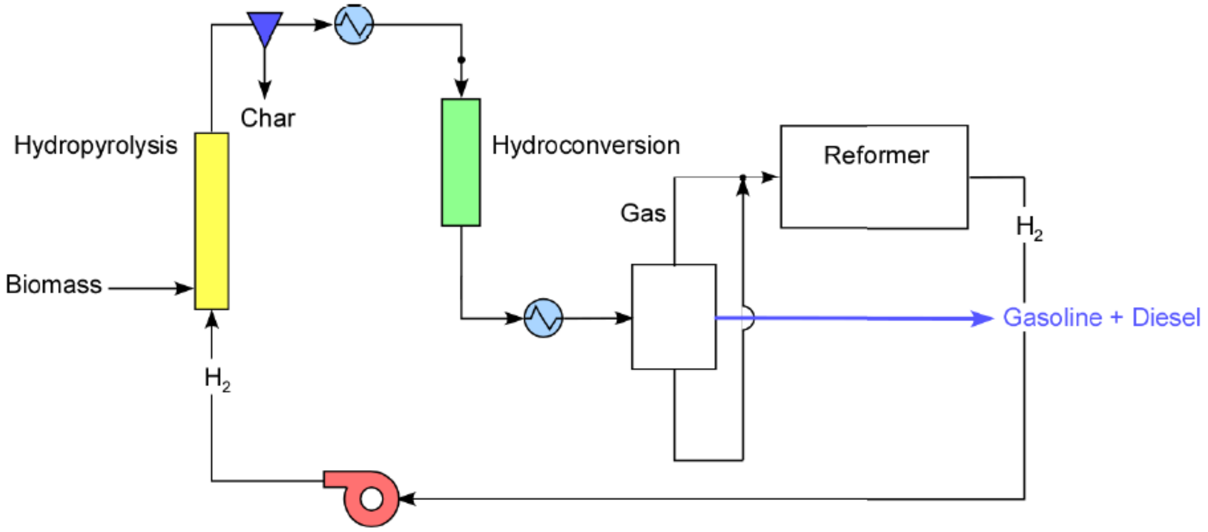

Figure 1. Overall process flow diagram of IH^2 system [1]

Equipment Costs

All costs were projected in 2007 dollars.

Capital costs were developed from a variety of sources. Capital costs for some common equipment items (e.g., tanks, pumps, vessels) were based on recent NREL studies [4-7] or estimated using Aspen Icarus Process Evaluator (Aspen IPE). Unit operations that used well-known technology that can be purchased as modular packages (i.e., hydrogen plant) used the overall cost for the package. Additionally, GTI also provided capital costs for certain equipment (e.g., high pressure feeder, ammonia sulfate system). Equipment cost details can be found in Appendix A.

The capital cost for the feedstock handling area is the high pressure feeder system. Capital costs associated with woody feedstock handing such as screening and grinding are included in the feedstock cost [8].

In this study, a single train of hydropyrolysis reactor is used. This is an appropriate assumption for an nth plant techno-economic analysis.

The equipment costs were developed assuming a minimum of sparing. In general, each pump has a spare, but other unit operations were designed without redundancy.

To account for any miscellaneous equipment left out of the analysis, uncertainty in the analysis due to its early stage of development, as well as the conceptual nature of the analysis, a contingency factor of 35% was applied to project the total equipment costs. This is based on an earlier NREL report on the techno-economic analysis for a large-scale pyrolysis oil production, in which a 35% contingency factor was adopted for the total equipment cost estimation [9]. Table 1 summarizes the installed equipment costs for a 2000 dry tonne per day plant by unit area.

Table 1. Installed Equipment Costs

Process Area	Installed Cost in 2007$
Feed Handling & Drying	$4,723,341
Hydropyrolysis & Hydroconversion	$17,707,759
Absorption Tower	$439,000
Distillation Tower	$3,992,341
Sour Water Strippper	$964,942
Amine Scrubber	$1,431,796
Ammonium Sulfate Oxidizer	$2,748,201
Hydrogen Plant	$44,035,558
Cooling Water & Other Utilities	$7,396,641
Equipment Contingency (35%)	$29,203,853
Totals	**$112,643,432**

All hydrogen demand for the IH^2 process can be met by the onsite hydrogen production. The budgetary cost estimate of the hydrogen plant was done by CB&I for GTI. The hydrogen plant is essentially the conventional steam methane reforming plant (SMR). Instead of supplying natural gas to the SMR, the feed for the present hydrogen plant is exclusively the C1-C3 from the downstream of the hydroconversion reactor, one of the unique features of IH^2.

As integrated hydropyrolysis and hydroconversion process (IH^2) is a novel process, the present estimated capital costs for its non-standard equipment (e.g., the hydropyrolysis and hydroconversion) are subject to change. IH^2 is in many ways different than the conventional fast pyrolysis process [1]. For instance, while the fast pyrolysis is endothermic, IH^2 is highly exothermic. Furthermore, as opposed to fast pyrolysis, IH^2 does not require quenching. Thus, the costs of the existing commercial pyrolysis systems are not directly applicable to IH^2 system.

Another area that may change the current techno-economic analysis result is the feedstock drying. Before entering to the hydropyrolysis reactor, feedstock drying is required. This is a very important step for thermochemical processes. The woody feedstock is dried from 30% to 10% moisture level. A key assumption for biomass drying is made in this TEA study. It is assumed that the heat from the hydrogen plant furnace flue gas can be used to dry the biomass feed. Feed biomass is typically dried with hot flue air from char combustor. With the current assumption, not only the significant capital cost on char combustor can be avoided but also a large by-product credit from char can be gained (MM$4.96 per year in this study).

Total Capital Investment

Once the total equipment cost (Table 1) has been determined, the next step is to add several other items to determine the total capital investment (TCI). Site development and warehouse costs are based on the inside-battery-limits (ISBL) equipment costs (excluding the cooling water and other utilities) and are considered part of the total direct cost (TDC). Project contingency, field expenses, home-office engineering and construction activities, as well as other costs related to construction are computed relative to the TDC and give the fixed capital investment (FCI) when summed. The sum of FCI and the working capital for the project is the TCI. Table 2 summarizes the total installed equipment cost and the associated factors proposed based on industry standards. For the current level of design knowledge, the capital cost estimate is considered to be at the conceptual level.

Variable Operating Costs

Variable operating costs were determined based on raw materials, waste handling charges, and by-product credits incurred only during the process operation. Quantities of raw materials used and by-products produced were provided by GTI. The by-product selling prices were also made available by GTI. Table 3 summarizes the variable costs, both on a per-year and per-gallon of fuel basis. The woody feedstock cost used in this study is $71.97/dry US ton based on 2012 targets [8]. Note that with 30% water content, the corresponding cost per wet ton is $50.38. The hydropyrolysis catalyst for the fluidized bed hydropyrolysis reactor has an attrition rate of 8% per week. The operating costs for the catalyst makeup and disposal are included in the variable operating cost calculation. All other catalysts (e.g., hydroconversion, reforming, and water-gas shift catalysts) are with certain life time and were amortized in the discounted cash flow rate of return calculation. As mentioned earlier, the current design assumed the feedstock can be dried with flue gas from hydrogen production plant. Consequently, char produced in the hydropyrolysis reactor that contains decent heating value can be sold as a by-product. The other major by-product is the export steam. The amount of the export steam strongly depends on the final overall process optimization and integration and will have a direct impact on the variable operating costs. Sensitivity analyses were not performed to investigate several cost uncertainties.

Fixed Operating Costs

Fixed operating costs are generally incurred in full whether or not the plant is producing at full capacity. These costs include labor and various overhead items. Many of the assumptions on fixed operating costs follow NREL 2011 thermochemical conversion platform design report [7] and/or Peters and Timmerhaus [10]. Table 4 shows the recommended number of employees and associated salaries and overhead and benefits.

Discounted Cash Flow Analysis and the Minimum Selling Price of Fuel

The economic analysis consists of first estimating the total capital investment, variable operating costs, and fixed operating costs, then calculating a minimum fuel selling price (MFSP) using a discounted cash flow rate of return analysis (DCFROR). The discounted cash flow analysis is calculated by iterating the selling cost of fuel until the net present value of the project is zero.

This analysis requires that the discount rate, depreciation method, income tax rates, plant life, and construction start-up duration be specified.

While two products are produced (gasoline and diesel blendstocks), they are combined and referred to as a single “fuel” product for simplicity. All MFSP calculation are performed and reported on a combined product basis.

Table 2. Total Capital Investment

Total Purchaseed Equipment Cost (TPEC)			**$82,548,787**
Installation Factor			1.365
Total Installed Cost (TIC)			**$112,643,432**
Other Direct Costs			
Land (Not Depreciated)			$1,610,000
Site Development	4.0%	% of ISBL	$4,106,319
Total Direct Costs (TDC)			**$118,359,751**
Indirect Costs		% of TDC	
Prorated Expenses		10.0%	$11,674,975
Home Office & Construction Fees		20.0%	$23,349,950
Field Expenses		10.0%	$11,674,975
Project Contingency		30.0%	$35,024,925
Other Costs (Start-Up & Permits)		10.0%	$11,674,975
Total Indirect Costs		**80.0%**	**$93,399,801**
Fixed Capital Investment (FCI)			**$211,759,552**
Working Capital	10.0%	of FCI (ex Land)	$21,014,955
Total Capital Investment (TCI)			**$232,774,507**

Table 3. Variable Operating Costs

	Raw Material	lb/hr	Costs $/ton	MM$/yr (2007$)	cents/gal of fuel (2007$)
	Feedstock - Wood Chips (30% moisture content)	262455	50.38	55.60	91.31
	Hydropyrolysis Catalyst (makeup)	52.89	14,000.00	2.72	4.47
	BFW Makeup	231900	0.20	0.23	0.38
	Cooling Tower Water Makeup	1322344	0.20	1.31	2.14
	BFW Chemicals	1.6233	2,800.00	0.03	0.05
	Cooling Tower Water Chemicals	0.66	2,000.00	0.01	0.01
	Diesel Fuel	70.89	805.89	0.24	0.39
	MDEA Makeup			0.03	0.04
Subtotal				**60.16**	**98.80**
Waste Streams					
	Char/Ash	0	32.66	0.00	0.00
	HyPro Catalyst Disposal	52.89	32.66	0.01	0.01
	WWT Cost	84976	0.48	0.20	0.33
Subtotal				**0.21**	**0.35**
By-Product Credits					
	Char	23876	42.00	4.96	8.15
	Ammonia +Ammonium Sulfate Slurry	606	350.00	1.05	1.72
	Export Steam	79442	17.76	5.22	8.57
Subtotal				**6.01**	**9.87**
Total Variable Operating Costs				**54.36**	**89.27**

For this analysis, the minimum fuel selling price (MFSP) was calculated using discounted cash flow rate of return (DCFROR) analysis based on a 10% rate of return, 40% equity financing, and modified accelerated cost recovery system (MACRS) depreciation. It assumes nth plant costs, i.e., discounts extra costs associated with first of a kind plant. The details of the economic assumptions are listed in Table 5. The parameters were based on NREL design reports [6,7]. The discount rate (which is also the internal rate of return (IRR) in this analysis) of 10% and the plant lifetime of 30 years were in turn based on the recommendation in Short et al. [10] on how to perform economic evaluations of renewable energy technologies for DOE. These financial parameters serve merely as a reference point from which to examine other economic sensitivities.

Table 4. Fixed Operating Costs

	2007 Salary	# Positions	2007 Cost	MM$/yr (2007$)	cents/gal of fuel (2007$)
Plant Manager	$147,000	1	$147,000		
Plant Engineer	$70,000	1	$70,000		
Maintenance Supr	$57,000	1	$57,000		
Lab Manager	$56,000	1	$56,000		
Shift Supervisor	$48,000	5	$240,000		
Lab Technician	$40,000	2	$80,000		
Maintenance Tech	$40,000	16	$640,000		
Shift Operators	$48,000	20	$960,000		
Yard Employees	$28,000	12	$336,000		
Clerks & Secretaries	$36,000	3	$108,000		
Total Salaries		**62**	**$2,694,001**	**2.69**	**4.42**
Overhead and Benefits			$2,424,601	2.42	3.98
Maintenance			$4,202,991	4.20	6.90
Insurance & Taxes			$1,471,047	1.47	2.42
Total Fixed Operating Costs				**10.79**	**17.73**

The resulting minimum ethanol selling price of the fuel is $1.60/gal (2007$). The complete discounted cash flow summary worksheet is shown in Table 6. The annual fuel production rate is 60.9 million gallons and the total capital investment is $232.8 million.

Parameters that clearly have impact on MFSP include biomass cost, catalyst cost, catalyst life time, catalyst attrition rates, fixed capital cost, fuel yield, and by-product yields and by-product values or selling prices. Sensitivity analysis on these parameters is warranted.

According to the methodology of Cran [12], the expected accuracy of the TCI analysis is +/- 25%. Since the detail of equipment list (as well as the equipment cost) is still evolving, it is more probable that the TCI will go up rather than down significantly. With the uncertainty of +25%, the impact on the cost of fuel would be a high of $1.75/gal.

Two-train hydropyrolysis system

The overall impact of replacing a single-train hydropyrolysis reactor system with a two-train system on the MFSP was also determined. The fluid bed hydropyrolysis system (including hydropyrolysis reactor, cyclone, catalyst cooler) is modeled with two equal but smaller systems. The two-train capacity is 2x 50% of the single-train case, and the 96% on-stream time assumption for the single-train case is also used here. The two trains are then combined back into a single train for the hydroconversion process. For a two-train hydropyrolysis system, the MFSP is found to be $1.63 per gallon. This is a mere 2% higher than the single-train case ($1.60/gal) and falls within the range of the uncertainty ($1.75/gal for +25%). Table 7 presents the comparison between a single-train and two-train hydropyrolysis system. The fixed capital investment per annual gallon for the two-train system is 4% higher than the single-train system, $3.62 and $3.48 per gallon, respectively.

Table 5. Discounted Cash Flow Analysis Parameters

Plant life	30 years
Discount rate	10%
General plat depreciation	Modified Accelerated Cost Recovery System (MACRS)
General plant recovery period	7 years
Federal tax rate	35%
Financing	40% equity
Construction period	3 years
First 12 months' expenditures	8%
Next 12 months' expenditures	61%
Last 12 months' expenditures	31%
Working capital	10% of total capital investment
Plant Operating Hours per Year	8410
On-Stream Percentage	96%
Start-up time	3 months
Revenues during start-up	50%
Variable costs incurred during start-up	75%
Fixed costs incurred during start-up	100%

Conclusions

This techno-economic study looked at the cost of producing gasoline and diesel range fuels (collectively referred as fuel) from woody feedstock via the integrated hydropyrolysis and hydroconversion (IH^2) process. Based on the current analysis, the fuel can be produced from wood chips at $1.60 per gallon (in 2007$). The annual fuel production is 60.9 million gallons. The total capital cost is estimated to be $232.8 million.

Before the first IH^2 commercial plant is built, various technical challenges are likely. Future techno-economic studies could shed light on advantages and disadvantages of different system designs and assumptions. Results provided in this report can serve as the baseline for future comparison.

Table 6. DCFROR Summary Sheet in 2007 Dollars

Process Engineering Analysis for Gasoline and Diesel from Wood

2,000 Dry Metric Tonnes Biomass per Day
All Values in 2007$

Minimum Fuel Selling Price (MFSP)	**$1.60**	**per Gallon**
Contributions: Feedstock Costs	$0.913	per Gallon
Operating Costs & Credits	$0.163	per Gallon
Capital Charges & Taxes	$0.528	per Gallon
Green Fuel Production at Operating Capacity	60.9	MM Gallons per Year
Green Fuel Product Yield	78.82	Gallons per Dry US Ton Feedstock
Delivered Feedstock Cost	$71.97	per Dry US Ton (Includes Most Capital Up to Throat of Gasifier)
Internal Rate of Return (After-Tax)	10.0%	
Equity Percent of Total Investment	40.0%	

Capital Costs	
Feed Handling & Drying	$4,720,000
Hydropyrolysis & Hydroconversion	$17,710,000
Absorption Tower	$440,000
Distillation Tower	$3,990,000
Sour Water Strippper	$960,000
Amine Scrubber	$1,430,000
Ammonium Sulfate Oxidizer	$2,750,000
Steam Reformer (SMR)	$44,040,000
Cooling Water & Other Utilities	$7,400,000
Total Installed Equipment Cost (TIC)	$112,640,000
Land (115 acres at $14000 per acre)	1,600,000
Site Development	4,110,000
(% of ISBL)	4.0%
Indirect Costs & Project Contingency	93,400,000
(% of TIC)	82.9%
Fixed Capital Investment (FCI)	211,759,552
Working Capital	21,014,955
Total Capital Investment (TCI)	232,774,507
Total Installed Equipment Cost per Annual Gallon of Green Fuel Product	1.85
Fixed Capital Investment per Annual Gallon of Green Fuel Product	3.48
Loan Interest Rate	8.0%
Loan Term (Years)	10
Plant Operating Hours per Year	8410
On-Stream Percentage	96.0%

Operating Costs (¢ / Gallon Product)	
Feedstock	91.3
Natural Gas	0.0
Catalysts	4.5
Other Raw Materials	3.0
Waste Disposal	0.3
Electricity	0.0
Fixed Costs	17.7
Co-Product Credits	-9.3
Capital Depreciation	17.3
Average Income Tax	5.9
Average Return on Investment	29.6

Operating Costs ($ / Year)	
Feedstock	$55,600,000
Natural Gas	$0
Catalysts	$2,720,000
Other Raw Materials	$1,840,000
Waste Disposal	$210,000
Electricity	$0
Fixed Costs	$10,790,000
Co-Product Credits	-$6,010,000
Capital Depreciation	$10,510,000
Average Income Tax	$3,620,000
Average Return on Investment	$18,040,000

Specific Operating Conditions		
Feed Rate	Dry Tonnes / Day	2,000
	Dry Tons / Day	2,205
Feedstock Cost	$ / Dry Ton	$71.97

Table 7. Costs of Fuel Production from Single-train and Two-train Designs

	Hydropyrolysis Reactor	
BC Refinery Scale (Dry MT/Day)	Single-Train	Two-Train
Minimum Fuel Selling Price (MFSP)	$1.60	$1.63
Total installed cost ($MM)	$113	$117
Total project investment ($MM)	$233	$243
Fuel production (MM gal/yr)	60.9	60.9
Fuel yield (gal/dry ton)	78.8	78.8
Fixed Capital Investment/Annual Gallon	$3.48	$3.62

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Appendix B — MTU—LCA Analysis

Sustainable Technologies Laboratory

Sustainable Futures

Michigan Technological

Carbon Footprint Analysis of IH^2 Biofuels

DOE Contract Number: DE-EE0002873

Final Report

Date submitted: January 23, 2012
To: Terry Marker, Gas Technology Institute, Des Plaines, IL

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Executive Summary

Gas Technology Institute (GTI) has developed an innovative process for the conversion of woody biomass into hydrocarbon liquid transportation fuels in the range of gasoline and diesel. The process for this conversion is referred to as "Integrated Hydropyrolysis and Hydroconversion, IH^2". The environmental impacts of producing and using these new renewable liquid fuels are largely unknown, and therefore, MTU was contracted to conduct a cradle-to-grave life cycle assessment (LCA) of these new biofuel products. In addition, several biomass feedstocks were included in the scope of the requested LCA, because it is anticipated that the IH^2 will be able to accommodate a variety of biomass feedstocks. Biomass types for this LCA were diverse representing feedstocks from forest, agricultural, and aquatic environments. These biomass types include algae (microalgae), bagasse from a sugar cane-producing location such as Brazil or extreme southern US, corn stover from a Midwest US location, forest feedstocks from a northern Wisconsin location. Inputs for the production, preparation, delivery, and storage of these biomass feedstocks were provided by several industrial partners in this project, as discussed later in this report. From this input data, we conducted a LCA of just the biomass production system from the "field" to the input of the IH^2 process. These analyses were useful to not only compare and contrast different feedstocks for biofuel production, but also to recommend steps to reduce the environmental impacts of such feedstock production systems. This report contains a preliminary LCA of IH^2 biofuels based on input data for the production and delivery of biomass feedstocks to a future biofuel facility, and also based on inputs for the IH^2 process provided by GTI.

The main research objectives for this report are;

1. Conduct a cradle-to-gate LCA of different biomass feedstocks for IH^2 biofuel production.
2. Conduct a cradle-to-grave LCA of IH^2 biofuels produced from different biomass feedstocks.

Alternative bio-based transportation fuels have the potential to decrease climate change emissions from vehicular transportation. The magnitude of this emission reduction can best be determined using the methods of life cycle assessment (LCA) by considering the entire life cycle of the new biofuel product from biomass cultivation through conversion to biofuel product, and use in vehicles. The methods for LCA put forth by the International Organization for Standardization (ISO, 2006) were followed in this analysis.

The purpose of this report is to evaluate the cradle-to-grave life cycle assessment (LCA) of the Gas Technology Institute (GTI) Integrated Hydropyrolysis and Hydroconversion (IH^2) production chain, including the production of input feedstocks and use of output IH^2 biofuels. The goal is to compare environmental impacts of IH^2 biofuels to equivalent fossil fuels in order to determine savings of emissions, but along this path, intermediate results for each biomass feedstock will be generated and compared to each other. The scope of this LCA will be from cradle-to-grave and the impacts of concern are greenhouse gas (GHG) emissions. The functional unit for biomass feedstocks and IH^2 biofuels will be 1 dry metric and 1 MJ of energy, respectively. The input data for these LCAs will be organized by the scale of production; 1 dry metric ton for biomass inputs, and for IH^2 biofuels production, 2,000 moisture and ash-free (MAF) metric tons/day facility. The LCA results for IH^2 biofuels were generated by dividing the

LCA emissions by the total energy content in MJ of IH^2 biofuel produced each day from the facility. This biofuel production changed depending on the specific biomass input feedstock input to the facility, as shown in the main report.

A life cycle diagrams describing one of the IH^2 biofuel production systems is presented in Figure ES1 for forest feedstocks. Fuels, electricity, lubricants, and grease are common inputs for each of the feedstock production stages because of the presence of machines for biomass collection and equipment for pumping algae solutions (microalgae) and for size reduction (bagasse, stover, and forest feedstocks). Fertilizers are required for stover feedstocks because this feedstocks is produced from intensive agricultural practice which involved application of inorganic and organic fertilizers. When stover is collected off of the land, the nutrients are removed with them and must be replaced for successful subsequent crop production. At the IH^2 conversion to biofuels stage, inputs of catalysts, electricity, and other chemicals are included, and outputs of co-products steam, ammonia, and ammonium sulfate are produced. Diesel fuel for transportation of IH^2 biofuels to locations of blending into fossil fuel stocks is included, and consideration is given to transport to filling stations and also for emissions of greenhouse gases from vehicle use of the biofuels.

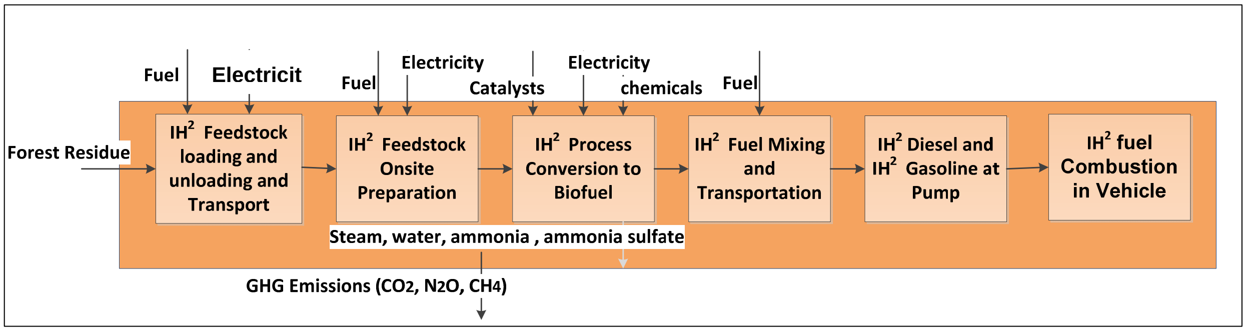

Figure ES1. Life cycle diagrams for production of IH^2 biofuels from biomass feedstocks.

Inputs to each stage of the IH^2 biofuel life cycle shown in Figure ES1 are included in the main report. In this Executive Summary, only the key comparative results will be presented, starting with the GHG emissions per dry metric ton of biomass produced and delivered to the IH^2 production facility. A second key result to be presented in the Executive Summary will be a comparison of IH^2 biofuels produced from each of the four key biomass feedstocks to petroleum fuels.

Table ES1 shows a comparison between each of the biomass feedstocks based on 1 dry metric ton. There is a large difference between the GHG emissions per dry metric ton biomass for these feedstocks. Microalgae is highest because of the dilute concentration of microalgae (300 g/m^3), and the large moisture content of microalgae to be transported (80%) compared to other biomass feedstocks (corn stover 20%, bagasse 20%, forest resources 30% or 50%). Corn stove is next highest due mostly from the inclusion of fertilizer replacement inputs that were not included for bagasse (because of lack of information) and forest resources (because fertilizers are not used for cropping of this biomass in the wild). The main sections of this report will highlight the main causes for these biomass feedstock emissions on an input-by-input basis.

Table ES1. GHG emissions for different biomass feedstocks for IH^2 biofuels production from agricultural, forest, and marine locations.

IH^2 Biomass Feedstock Type	GHG Emissions (kg CO_2 eq. / dry mt biomass)
Microalgae (US Grid Electricity)	657
Cane Bagasse	27
Corn Stover	67
Forest Resources	59

A comparison of IH^2 biofuels to fossil fuels is shown in Figure ES2 for base case inputs. The GHG emissions are cradle-to-grave including combustion of biofuels. Final transportation of IH^2 biofuel from production facility to blending locations and from blending to filling stations are not included in Figure ES2, but the effects of these stages are explored in the full report (their impacts are negligible). All IH^2 biofuels except for microalgae reduce GHG emissions compared to petroleum of over 90%, easily qualifying these fuels to count toward the Renewable Fuels Standard (RFS). Microalgae IH^2 biofuels could qualify if electricity is from renewable sources such as biomass, hydro, nuclear, or wind power.

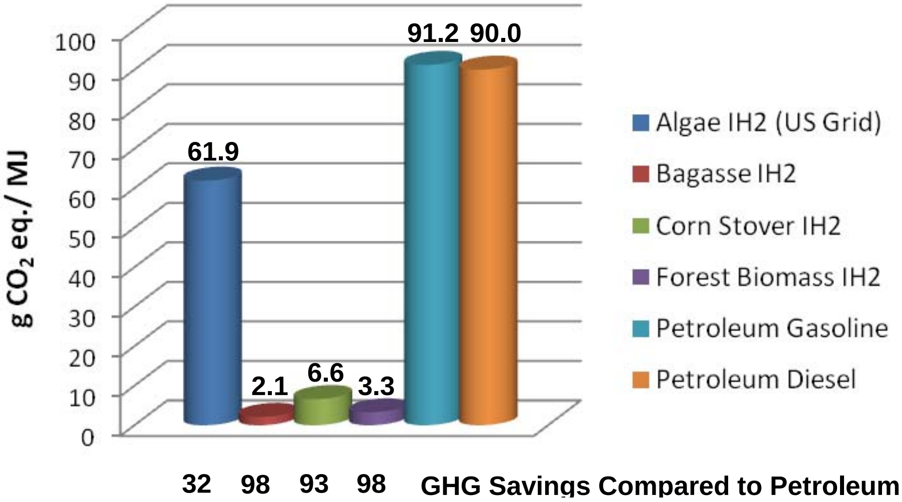

Figure ES2. Comparison between IH^2 biofuels produced from different biomass feedstocks with petroleum gasoline and diesel. Savings of GHG emissions compared to petroleum fuels is shown.

In addition to these differences in GHG emissions for IH^2 biofuels from several biomass feedstocks, there are also differences in biofuel production yields. Table ES2 shows yields of IH^2 Biofuels from microalgae, cane bagasse, corn stover, and forest feedstocks. Microalgae IH^2 biofuels exhibit the highest yields, nearly double the productivity of the other biomass feedstocks. Composition of biomass is likely the reason for these large differences in yields. For example, many species of microalgae contain significant oil, which contains fewer oxygen atoms and more hydrogen atoms per molecule. In such cases, a higher percentage of the starting biomass is expected to exit the process as biofuel as opposed to CO_2, H_2O and other minor co-products. The yields in Table ES2 also impact area productivity, that is, the quantity of biofuel produced per unit area of surface of land or water per year. Area productivity is also affected by biomass productivity per unit surface area per year. Combining both of these productivities will result in a key indicator of overall biofuel production efficiency.

Table ES2. Yield of IH^2 Biofuels from 2,000 Moisture and Ash Free (MAF) Metric Tons (mt) of Biomass.

IH^2 Biofuel from Different Biomass Types	Yield of IH^2 Gasoline (mt)	Yield of IH^2 Diesel (mt)	Total IH^2 Biofuel Yield (mt)
Microalgae	448	448	996
Cane Bagasse	432	140	572
Corn Stover	320	200	520
Forest Resources	320	200	520

The results in this study represent a limited life cycle assessment that touched on one indicator of sustainability, greenhouse gas emissions and savings of those emissions compared to petroleum fuels. It is highly recommended to revisit this LCA when IH^2 conversion data is obtained on pilot or commercial scales. Results from such future studies can help refine IH^2 biofuel system impacts leading to more efficient production of this promising biofuel. Future studies should also include other sustainability indicators for which little is known from this new transportation production system, including land use change emissions, water quantity and quality, emissions of other air pollutants, worker safety, community impacts from biomass transport, and employment. These expanded studies are particularly important when attempting to understand impacts of large-scale dissemination and implementation of this new renewable transportation fuels technology.

1. Introduction

Gas Technology Institute (GTI) has developed an innovative process for the conversion of woody biomass into hydrocarbon liquid transportation fuels in the range of gasoline and diesel. The process for this conversion is referred to as “Integrated Hydropyrolysis and Hydroconversion, IH^2”. The environmental impacts of producing and using these new renewable liquid fuels are largely unknown, and therefore, MTU was contracted to conduct a cradle-to-grave life cycle assessment (LCA) of these new biofuel products. In addition, several biomass feedstocks were included in the scope of the requested LCA, because it is anticipated that the IH^2 will be able to accommodate a variety of biomass feedstocks. The biomass feedstocks include algae (microalgae), sugar cane bagasse, corn stover, and forest feedstocks from a location in the Upper Midwest (Wisconsin). This report contains a preliminary LCA of IH^2 biofuels based on input data for the production and delivery of biomass feedstocks to a future biofuel facility, and also based on inputs for the IH^2 process provided by GTI.

1.1 Background on the IH^2 Process

A process flow diagram of the IH^2 process is shown in Figure 1. A detailed description of the IH^2 process can be found in GTI publications such as in Marker et al. (2009). The process is carried out in two sequential yet integrated stages at moderate pressure (250-500 psi); hydropyrolysis and hydroconversion. Briefly, the process is carried out in two integrated steps: hydropyrolysis and hydroconversion. The first step is an exothermic catalytic fast hydropyrolysis reaction carried out in a fluid bed reactor at moderate hydrogen pressure. The product vapors from the first step are carried to the second conversion step, a hydrodeoxygenation reactor operating at essentially the same pressure as the first hydropyrolysis reactor. The hydrogen required for the IH^2 process is produced in a reformer using C1-C3 co-products, and therefore no external hydrogen source is needed, such as H_2 from steam reforming of methane. Other by-products of the process are char, high pressure steam, and ammonia / ammonium sulfate (not shown in Figure 1). Ammonia and hydrogen sulfide in the process condensate are stripped and oxidized to make ammonium sulfate which can be used as a fertilizer.

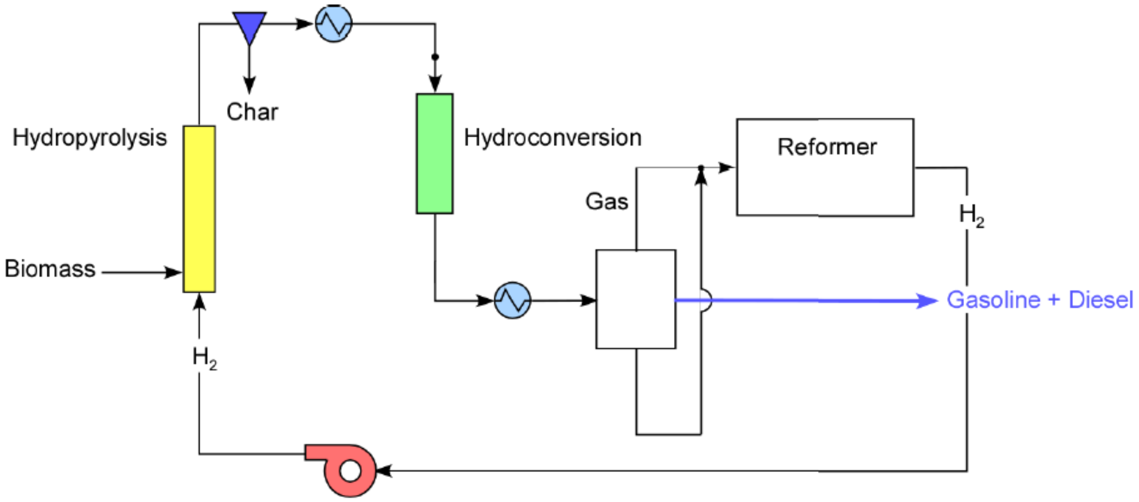

Figure 1.1 Process flow diagram of IH^2 process (Marker et al., 2009)

1.2 Background on Feedstocks

Biomass types for this LCA were diverse representing feedstocks from forest, agricultural, and aquatic environments. These biomass types include algae (microalgae), bagasse from a sugar cane-producing location such as Brazil or extreme southern US, corn stover from a Midwest US location, forest feedstocks from a northern Wisconsin location. Inputs for the production, preparation, delivery, and storage of these biomass feedstocks were provided by several industrial partners in this project, as discussed later in this report. From this input data, we conducted a LCA of just the biomass production system from the “field” to the input of the IH^2 process. These analyses were useful to not only compare and contrast different feedstocks for biofuel production, but also to recommend steps to reduce the environmental impacts of such feedstock production systems.

1.3 LCA Research Objectives

The main research objectives for this report are;

3. Conduct a cradle-to-gate LCA of different biomass feedstocks for IH^2 biofuel production.
4. Conduct a cradle-to-grave LCA of IH^2 biofuels produced from different biomass feedstocks.

The following sections of this report will provide details on the LCA methods used, on the input data included in the analysis, and on the greenhouse gas emissions of IH^2 biofuels. Comparisons will be made to petroleum fuels with respect to savings of GHG emissions over the IH^2 biofuel life cycle.

2. LCA Methods

Alternative bio-based transportation fuels have the potential to decrease climate change emissions from vehicular transportation. The magnitude of this emission reduction can best be determined using the methods of life cycle assessment (LCA) by considering the entire life cycle of the new biofuel product from biomass cultivation through conversion to biofuel product, and use in vehicles. The methods for LCA put forth by the International Organization for Standardization (ISO, 2006) were followed in this analysis. The main steps in conducting a life cycle assessment are as follow, and further details on each step will appear later in this report.

- Life cycle goal and scope and functional unit definition
- Life cycle inventory analysis
- Life cycle impact assessment
- Life cycle interpretation

2.1 Goal and Scope and Functional Unit

The purpose of this report is to evaluate the cradle-to-grave life cycle assessment (LCA) of the Gas Technology Institute (GTI) Integrated Hydropyrolysis and Hydroconversion (IH^2) production chain, including the production of input feedstocks and use of output IH^2 biofuels. The goal is to compare environmental impacts of IH^2 biofuels to equivalent fossil fuels in order to determine savings of emissions, but along this path, intermediate results for each biomass feedstock will be generated and compared to each other. The scope of this LCA will be from cradle-to-grave and the impacts of concern are greenhouse gas emissions. The functional unit for biomass feedstocks and IH^2 biofuels will be 1 dry metric ton and 1 MJ of energy, respectively. The input data for these LCAs will be organized by the scale of production; 1 dry metric ton for biomass inputs, and for IH^2 biofuels production, 2,000 moisture and ash-free (MAF) metric tons/day facility. The LCA results for IH^2 biofuels were generated by dividing the LCA emissions by the total energy content in MJ of IH^2 biofuel produced each day from the facility. This biofuel production changed depending on the specific biomass input feedstock input to the facility, as shown in the subsequent sections.

2.2 Life Cycle Diagram and System Boundary

The life cycle diagrams describing each IH^2 biofuel production system is presented in Figure 2.1 for microalgae, sugar cane bagasse, corn stover, and forest feedstocks. Each diagram has similarities and subtle differences, especially in the feedstock production stage, the first stage on the left of each diagram. Fuels, electricity, lubricants, and grease are common inputs for each of the feedstock production stages because of the presence of machines for biomass collection and equipment for pumping algae solutions (microalgae) and for size reduction (bagasse, stover, and forest feedstocks). Fertilizers are required for stover feedstocks because this feedstock is produced from intensive agricultural practice which involved application of inorganic and organic fertilizers. When this feedstock is collected off of the land, the nutrients are removed with and must be replaced for successful subsequent crop production. At the IH^2 conversion to biofuels stage, inputs of catalysts, electricity, and other chemicals are included, and outputs of co-products steam, ammonia, and ammonium sulfate are produced. Diesel fuel for transportation of IH^2 biofuels to locations of blending into fossil fuel stocks is included, and consideration is given to transport to filling stations and also for emissions of greenhouse gases from vehicle use of the biofuels.

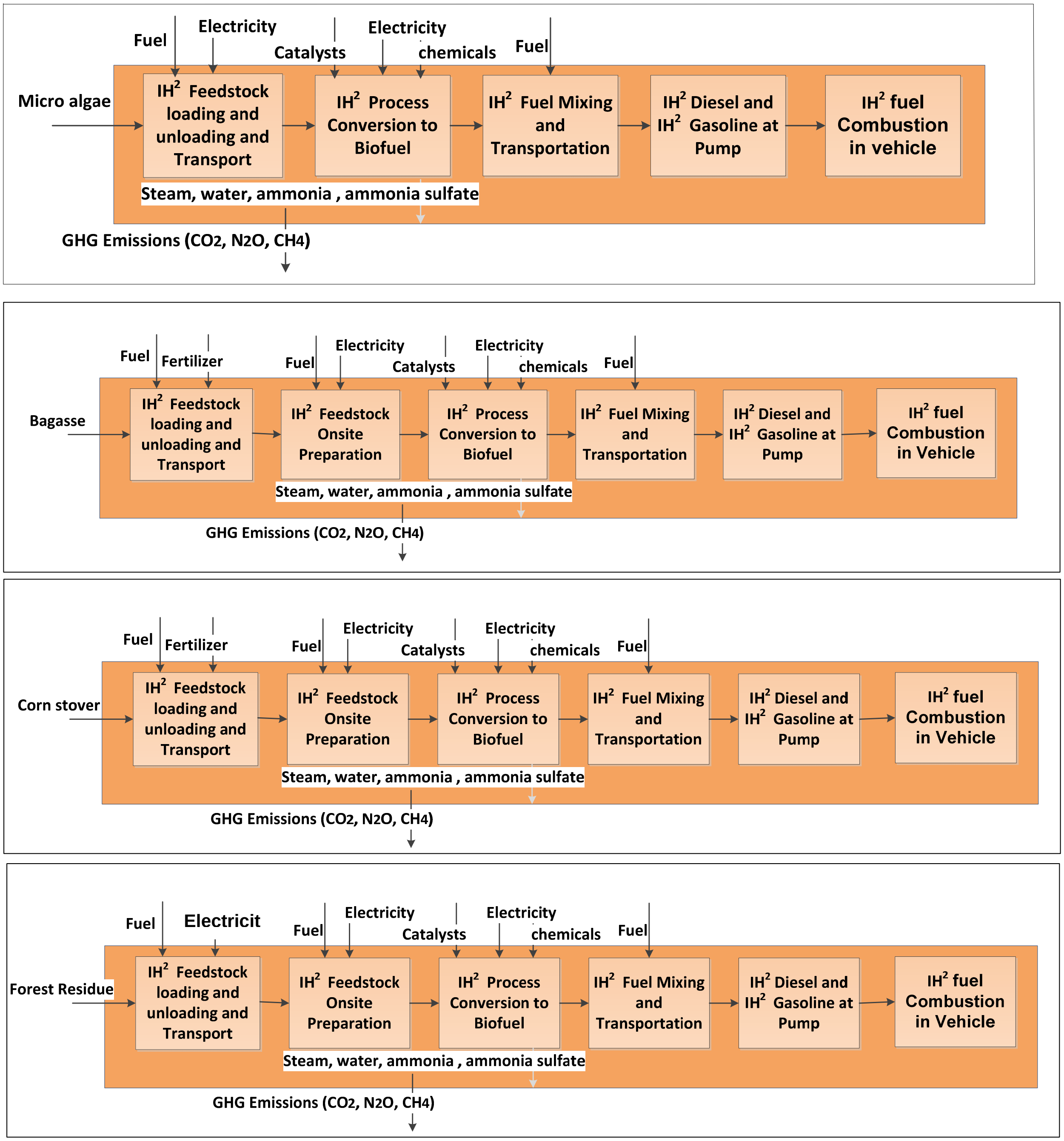

Figure 2.1 Life cycle diagrams for production of IH^2 biofuels from different biomass feedstocks.

The next section will present tables of input data for production of biomass feedstocks and also of IH^2 biofuels produced from these feedstocks.

3. Life Cycle Inventory

The life cycle inventory is the list of emissions associate with each input to the IH^2 biofuel life cycle. The total inventory is the sum of emissions for all of the inputs. The inventory of emissions resides within specific input-specific ecoprofiles in the ecoinvent database in SimaPro 7.2, the LCA software tool used in this study. For example, if diesel fuel is one input to the biomass feedstock production stage, an ecoprofile in the ecoinvent database in SimaPro 7.2 has a list of emissions inventory data for the production of this diesel fuel. We created a diesel combustion emission ecoprofile with an emission factor of 3.17 kg CO_2 / kg petroleum diesel combusted based on stoichiometry. Similarly, other ecoprofiles were used for other life cycle inputs such as transport by road (includes combustion emissions of diesel fuel), for fertilizer inputs, chemicals used, and catalysts. These inventories have data for calculation of many categories of environmental impact, but in this study the primary and sole category of interest is greenhouse gas emissions and global warming. The emissions inventory of the greenhouse gases CO_2, N_2O, CH_4, refrigerants, and solvents is therefore of primary interest. This study did not include the N_2O emissions associated with nitrogen (N) fertilizers allocated to corn stover and cane bagasse production because the removal of N with these biomass feedstocks will have the effect of reducing N_2O emissions compared to the business-as-usual case (feedstocks left on the land to decompose and emit N_2O). This emissions reduction is compensated for when additional N fertilizer is applied to the subsequent corn and sugar cane crops in equal amounts. This assumption is justified based on “Tier 1” emission factors used in the Intergovernmental Panel on Climate Change (IPCC) (Eggleston et al., 2006).

3.1 Inputs for Biomass Feedstock Production

3.1.1 Inputs for Microalgae Production

Table 3.1 below shows the algae production inputs used for the life cycle assessment for the Aquaflow Bionomic Corporation (ABC). This data was obtained from a spreadsheet provided by ABC based on Blenheim site Power assuming 100 g algae/m^3 cell density. The data was then divided into different sections. The first section was the raw material section which includes use of fertilizers which are all provided by the sewage plant or natural water body. The second section is the Pump Shed, which includes the supply and the discharge pumps; 5 electric motors whose energy use is measured in kWh/kg dry algae recovered. The third section is the New Harvest Unit. This section contributes much of the energy and is a total of 6 motors. The fourth section is the De-watering process section where several activities take place including removal of excess water by draining and rising which is done using electrical motors. The other important activity that takes place in this section, is use of chemical additives to agglomerate the algae at the dewatering stage to enhance the harvesting process. Lastly is the transportation to the IH^2 processing which is assumed to be done over a 100 km distance. The moisture in the algae was taken into account for this transport step assuming 80% moisture content.

The main inputs in Table 3.1 for the LCA analysis of the GHG emission was the electricity used by the motors at the pump shed section and new harvest unit section. Greenhouse gas emissions per kWh of electricity used were obtained from the US Environmental Protection Agency eGRID website assuming a U.S. average grid (US EPA, 2011) in the base case analysis. The emissions in this eGRID database are for electricity production only and do not include upstream process of production of primary energy (coal, etc.). To account for this, 10% extra emissions were added for these upstream processes. These additional emissions were arrived at after review of several electricity generation ecoprofiles in the ecoinvent database in SimaPro. The data provide by the ABC in Table 3.1 was divided by three so as to get the algae cell density of 300 g algae/m^3 because the original data was for 100 g algae/ m^3 cell density.

Table 3.1: Data inputs for algae cultivation, harvesting, and transport for Aquaflow Bionomic Corporation. Basis is 1 dry metric ton microalgae and 100 g algae / m^3.

Life Cycle Stage	**Items Used**	**Amounts**	**Comments**
Raw Material Productions	Fertilizer	N/A	N/A
Harvesting of Algae			
	Electricity for separation		
	Hydraulic oil	negligible	
	Lubrication oil	negligible	
Pump shed	Motor(1)	10 kWh	per mt of dry algae
	Motor(2)	100 kWh	per mt of dry algae
	Motor (3)	500 kWh	per mt of dry algae
	Motor(4)	800 kWh	per mt of dry algae
	Motor(5)	100 kWh	per mt of dry algae
New Harvest units	Motor(6)	100 kWh	per mt of dry algae
	Motor(7)	100 kWh	per mt of dry algae
	Motor(8)	40 kWh	per mt of dry algae
	Motor(9)	40 kWh	per mt of dry algae
	Motor(10)	20 kWh	per mt of dry algae
	Motor(11)	20 kWh	per mt of dry algae
De-watering	Motor(12)	80 kWh	per mt of dry algae
	Motor(13)	20 kWh	per mt of dry algae
0.076 ton/ton of dry algae	Chemical additives		
	Fuel		
Conveyance of Algae	Electricity		
Transport		100 km	

3.1.2 Inputs for Bagasse Production

Bagasse is considered a waste from the sugar or cane ethanol production process, and in this analysis it is assumed available with no environmental burden from its production. However, environmental impacts accumulate from bagasse handling in the IH^2 biofuels production life cycle. The step wise process of bagasse handling as a feedstock includes loading, transportation, and unloading to the IH^2 facility. The first stage involves using a diesel powered front loader to transfer bagasse into trucks for transport. The second stage is the transportation stage, where the bagasse is transported using a 16-32 ton truck to be delivered to the IH^2 facility. The third stage is the unloading of the bagasse to IH^2 facility storage, and finally loading into the IH^2 facility.

The main inputs in Table 3.2 are for loading/unloading and for transportation, which involves the use of 16-32 ton trucks to the IH^2 facility. The bagasse may be ground to decrease the size so as to have the desirable size for the IH^2 processing. The first stage is the loading of unbaled bagasse using front loaders directly from the bagasse piles at sugar milling factory onto trucks. There are three such loading/unloading steps and this is the cause of the factor of 3 in the inputs of Table 3.2 for diesel fuel. The factor of 1.1 converts from short tons, the basis for the input data from Morey et al. (2010), to metric tons, and the factor of 1.45 accounts for the field moisture content of the bagasse, assumed to be 45%. The Morey et al. (2010) study was on corn stover, but the steps in the feedstock supply chain and equipment used are very similar to the bagasse supply chain, and therefore the use of this source of input data is justified. Drying of bagasse prior to entering IH^2 reactors is not included in this input data, but is included in the IH^2 process analysis section. There is not factor of 3 for lubricating oils because the input value includes this already. Emissions for combustion of diesel fuel is included in the analysis for loading / unloading steps using stoichiometric factor of 3.17 kg CO_2 / kg diesel combusted. Diesel volume in gallons was converted to kg by using a density of 0.85 kg diesel / L diesel and converting between gallons and liters.

Table 3.2: Inventory data for bagasse loading, transportation, and unloading on a basis of 1 dry metric ton of feedstock.

Life Cycle Stage	Inputs	Units
Loading and unloading		
Diesel fuel	0.04625*3*1.1*1.45	gallons/ton
Lubricating oil	0.00089*1.1*1.45	gallons/ton
Transportation (assume 100 km distance)		
Transport, lorry 16-32t, EURO3/RER S	100	tkm

3.1.3 Inputs for Corn Stover Production

Corn stover feedstock production includes collection from the fields, loading, transportation, unloading, and fertilizer replacement to the fields to compensate for nutrients removed with the stover. The first stage in Figure 1 involves diesel-powered stalk shredder equipment used for shredding of the corn stover. Then the stover is collected, which involves raking and baling, and processed into round bales. Next is stover loading, where the round bales are lifted and moved using a front loader onto trucks for transportation. Then, the corn stover is transported and delivered to the IH^2 facility, and then finally unloaded to the storage area.

This analysis assumes 70% corn stover removal per unit land area with collection every other year that corn is grown, resulting in an average stover removal of 35% of area per year. This leads to more efficient, and less costly collection process and less soil compaction than harvesting of 35% of the corn stover each year. Lastly this analysis assumes that there is nutrient replacement to the corn stover harvested fields. Fertilizers rich in nitrogen, phosphate and potassium are used to replenish the nutrients lost from the field so as to have adequate nutrients for the growth of the next corn crop.

Table 3.3 shows LCA inputs for corn stover handling from the corn field to the IH^2 process as obtained from a recent research article (Morey et al., 2010; Maleche et al. 2011). One of the key inputs is the nutrient replacement. The replacement fertilizers used are diammonium phosphate, ammonia solution, and potassium sulfate. The main diesel input in this process is during the stover collection stage, which involves stalk shredding, raking and baling. The stalk shredding occurs after harvesting of the corn and involves decreasing the size of the stalks by use of a mechanical shredder, which is diesel powered. The shredding is done so as to increase the volume of harvested corn stover and facilitate drying to the target moisture content of 15-20%. The shredded corn stover is then raked using a diesel powered machine. Lastly the stover is baled into round bales for easy handling and transport. The collection stage is the most critical step due to finding the suitable time period for the shredding, racking and round bailing of the corn stover with 15-20% moisture. The third main stage is the transportation stage, in this stage the stover in the form of round bales is loaded onto and transported by truck (25-ton). The last stage in this process is the unloading of stover bales to storage, and then loading of stored stover into the IH^2 process. Transport distance by truck to the IH^2 facility from the field is on average 30 miles (Morey et al. 2010).

Table 3.3: Inventory data for the corn stover with a basis of 1 dry metric ton of feedstock. Each fuel and lubricant entry in this table is divided by 0.85 to convert to dry basis.

Life Cycle Stage	**Inputs**	**Units**
Collection		
Stalk Shredding		
Lubricating oil	1.29E-03	gallons
Diesel fuel	0.222	gallons
Raking		
Lubricating oil	3.53E-04	gallons
Diesel fuel	0.053	gallons
Baling		
Lubricating oil	1.29E-03	gallons
Diesel fuel	0.225	gallons
Bale moving		
Lubricating oil	2.35E-03	gallons
Diesel fuel	0.424	gallons
Loading		
Diesel fuel	0.134	gallons
Lubricating oil	1.53E-03	gallons
Transportation		
Diesel	0.408	gallons
Lubricating oil	2.47E-03	gallons
Unloading		
Diesel fuel	0.134	gallons
Lubricating oil	1.53E-03	gallons
Nutrients Replacement		
Ammonia	9.42	kg
Diammonium phosphate	2.9	kg
Potassium sulfate	12.7	kg

3.1.4 Inputs for Timber Resources Production

Mr. John Gephardt has developed a model of timber resource procurement for northern Wisconsin on behalf of Johnson Timber Company (JTC) and provided information on the quantities of fuel, lubricants, and electricity based on the amount of feedstock delivered per day. This model was based on a wide range of available woody feedstock that were identified around a site located in Park Falls, Wisconsin. Types of feedstock included are: logging residues; un-merchantable timber; un-marketable timber; marketable timber; and mill residues. Each feedstock type has unique requirements in their collection, transport, and processing needs. Within any one type, quantities were available at differing distances to Park Falls. Based on the delivered costs for each feedstock the JTC model selects a blend of feedstock which would result in the lowest possible total costs for each plant size that was evaluated. The price of diesel fuel was included as a variable in the model. This allowed the model to take into account how the blend of feedstock in the output would be influenced as diesel prices change.

The stepwise process of wood and forest residue production in JohnsonTimber Company is illustrated in the flow sheet below in Figure 3.1. The first stage is the collection of resources from the forest. The processes involved in this stage include skidding and cutting of the biomass from the forest to the required length for transportation, roadside chipping and debarking, and loading of the round wood, slabs and chips using a log loader and chip dumps. The second stage is road transport in which the round wood, bark, sawdust, slabs, fuel rods, and woodchips are transported for processing to the IH^2 facility. The last stage is the processing stage. In this stage size reduction occurs whereby there is conversion of the round wood and other sized biomass into chips small enough for the IH^2 process. This stage also includes the use of grinders which can be either stationary (electrical powered) or mobile (diesel powered). In this analysis the grinders are assumed to be either stationary or mobile and are electric-powered according to information from Mr. Gephardt. In the last stage we have the mixing loaders which are used to blend the various types of feed stock which use screens to remove the oversized materials to the IH^2 process.

The JTC model was used to evaluate biomass inputs rates ranging from 50 to1,750 dry short tons/day. Figure 3.2 shown below illustrates how the percentages of hardwoods and softwoods changed with increasing plant size. Within the supply area, hardwoods comprise approximately 70% and softwoods 30% of the available feedstock. The higher percentage of hardwood at the smaller plant sizes is the result of low valued hardwood residues available from an adjacent pulp and paper mill. For the study plant sizes of 500 dry short tons/day and 1,000 dry short tons/day of feedstock were selected for evaluation. The feedstock selected for each plant sized was values were chosen from an economic stand point. Figure 3.3 shows the distribution of total diesel fuel among feedstock collection, transportation, and processing (chipping). Above 1,000 dry short tons/day, there is not much change in total diesel consumption per dry short ton.

Table 3.4 and 3.5 show the wood and forest residue production inputs used for the life cycle assessment for the Johnson's Timber Company. This data was based on an assumption of $3.00 and $6.00 per gallon of diesel fuel in two separate scenarios. This data was divided into different sections. The first section involved the raw material collection which includes the use of lubricants, fuel, grease, hydraulic fluid, and gasoline. The second main section is the transportation which includes the use of lubricants and fuel. The third main section is the yard processing section. In this section several activities take place including wood chipping, screening, and conveying. These inputs include electricity for running the motors, and fuel and

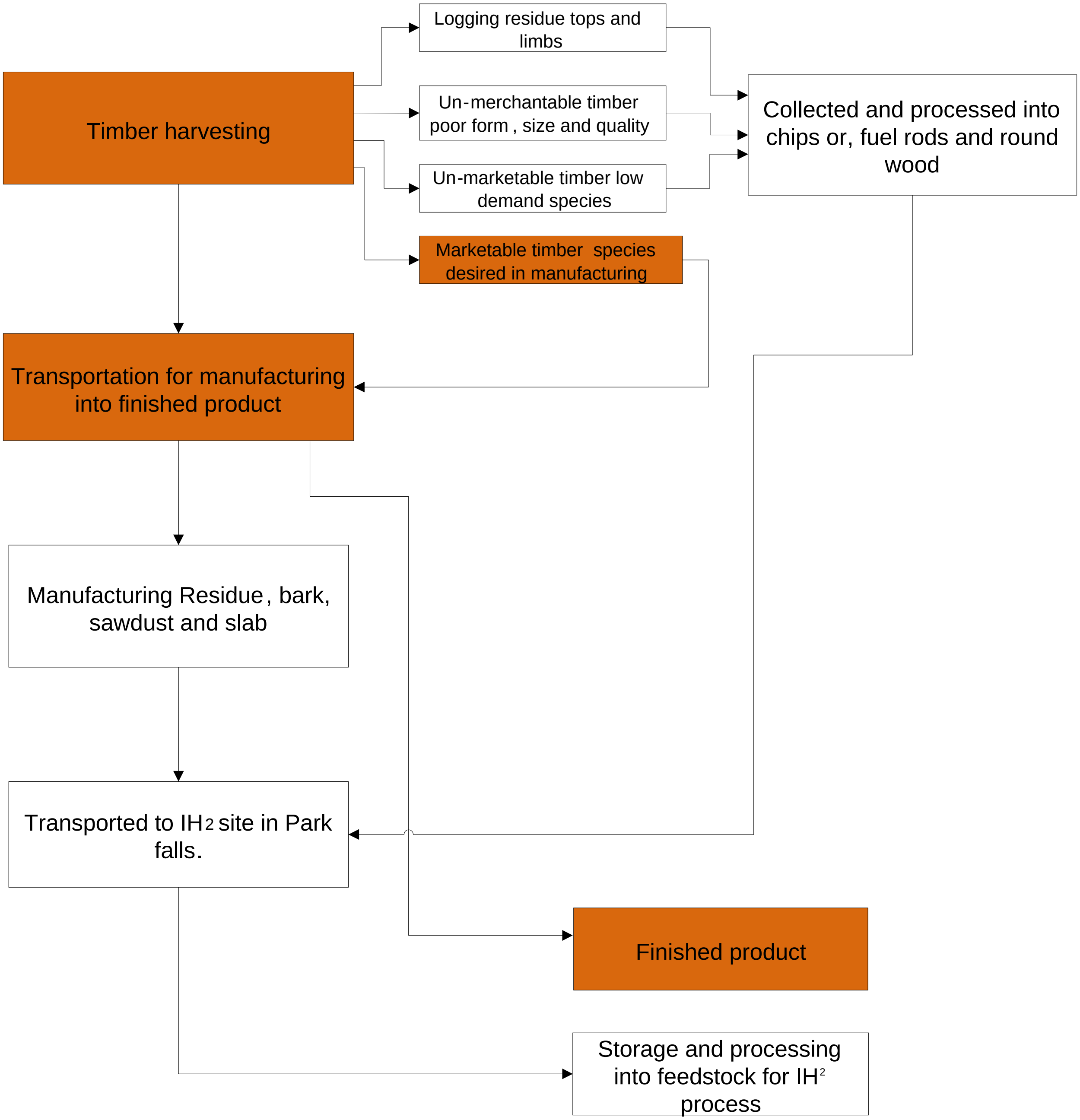

Figure 3.1: Process flow diagram for wood and forest residue production from Johnson Timber Company. The shaded boxes represent steps which are not included in the analysis presented here.

Lubricants inputs for the different yard equipment.

The main data inputs in Table 3.4 and 3.5 are the diesel used for the collection and transportation of the wood to the IH^2 processing plant. Lubricants and hydraulic oil values were assumed based upon the diesel consumption estimates provided by Mr. Gephardt on behalf of JTC. The fertilizer and other additives are assumed to be negligible because no use of these inputs occurs for timber cultivation. The main biomass feed stock inputs are underutilized round wood sources and the

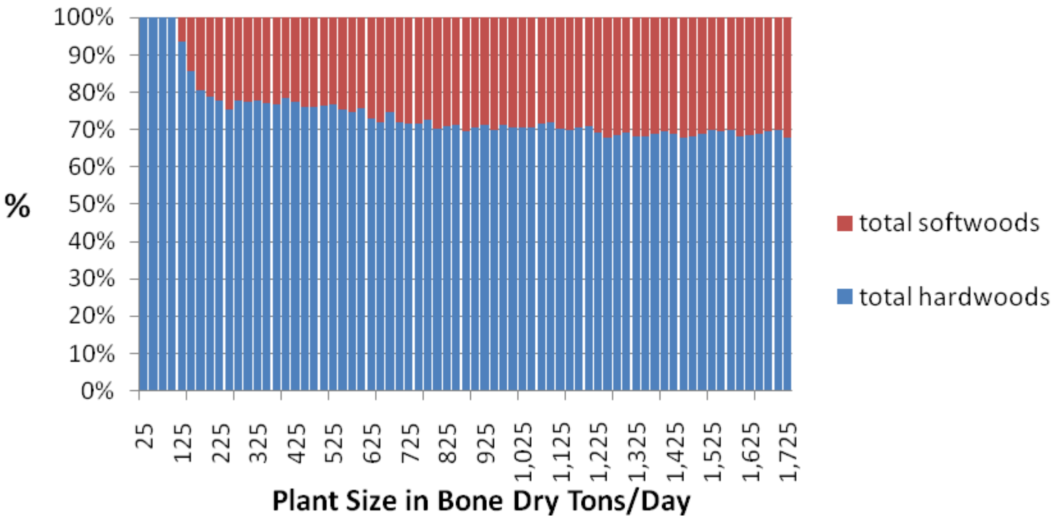

Figure 3.2: The percentages of hard wood and soft wood used as the feed stock input with varying plant size.

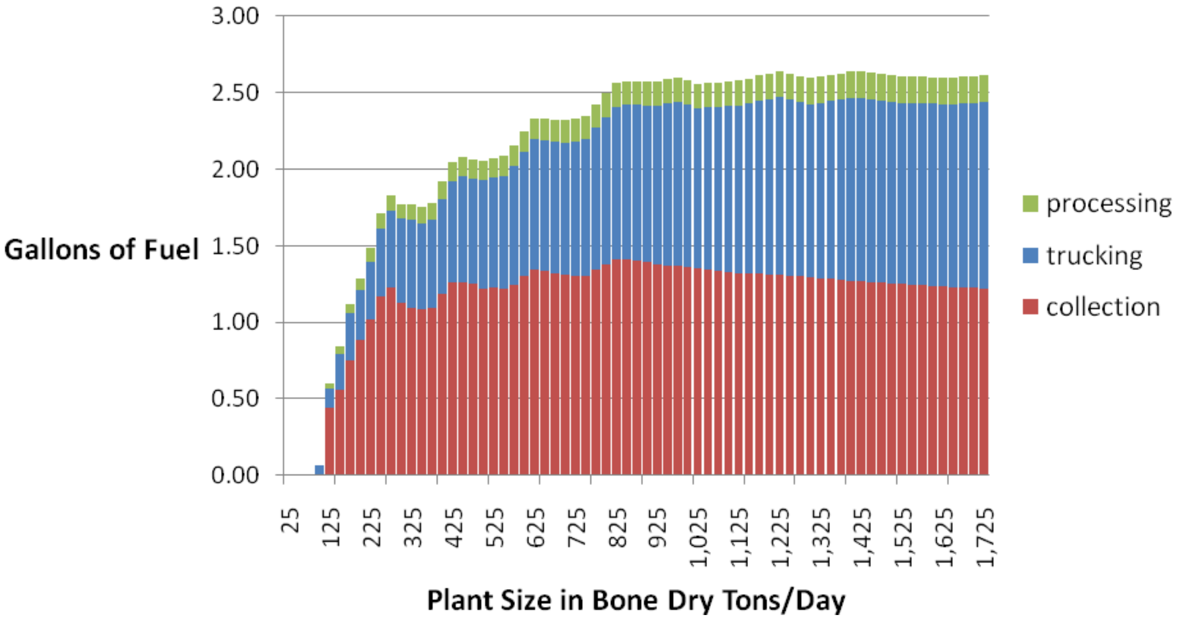

Figure 3.3: Diesel fuel consumption for collection, trucking, and processing as a function of biomass input rate.

Table 3.4: Data inputs for wood and forest residue raw material collection, transportation and yard processing based on 1 dry short ton biomass with an assumption of $3 per gallon of diesel fuel.

Life Cycle Stage	Items Used	Amounts 500 dry tons/day	Amounts 1000 dry tons/day
Collection (Raw material Inputs)	Diesel	1.220 gallons	1.360 gallons
	Lubricating oil	0.014 gallons	0.018 gallons
	Grease	0.038 gallons	0.048 gallons
	Hydraulic fluids	0.014 gallons	0.018 gallons
	Gasoline	0.039 gallons	0.050 gallons
Transportation	Diesel	0.707 gallons	1.059 gallons
	Lubricating oil	0.014 gallons	0.017 gallons
	Hydraulic fluids	0.014 gallons	0.018 gallons
	Tubes of grease	0.038 gallons	0.048 gallons
Yard processing	Diesel	0.126 gallons	0.160 gallons
	Lubricating oil	0.016 gallons	0.016 gallons
	Hydraulic oil	0.016 gallons	0.016 gallons
	Tubes of grease	0.043 gallons	0.043 gallons
(note: US average grid)	Electricity	29.8 kWh	29.8 kWh

Table 3.5: Data inputs for wood and forest residue raw material collection, transportation and yard processing based on 1 dry short ton biomass with an assumption of $6 per gallon of diesel fuel.

Life Cycle Stage	Items Used	Amounts 500 dry tons/day	Amounts 1000 dry tons/day
Collection (Raw material Inputs)	Diesel	1.047 gallons	1.197 gallons
	Lubricating oil	0.013 gallons	0.017 gallons
	Grease	0.038 gallons	0.048 gallons
	Hydraulic fluids	0.014 gallons	0.018 gallons
	Gasoline	0.039 gallons	0.050 gallons
Transportation	Diesel	0.678 gallons	0.914 gallons
	Lubricating oil	0.014 gallons	0.017 gallons
	Hydraulic fluids	0.014 gallons	0.018 gallons
	Tubes of grease	0.038 gallons	0.048 gallons
Yard processing	Diesel	0.122 gallons	0.160 gallons
	Lubricating oil	0.016 gallons	0.016 gallons
	Hydraulic oil	0.016 gallons	0.016 gallons
	Tubes of grease	0.043 gallons	0.043 gallons
(note: US average grid)	Electricity	29.8 kWh	29.8 kWh

non-commercial tree species, since they are undesirable in the manufacturing of traditional forest products**.** Lastly the other main biomass feedstock inputs are forest residues which include tops, limbs and fuel rods. The fuel rods are defined as the round woods that do not meet the size and quality standards for traditional forest products and examples of this are the oversized and undersized stems from saleable and unsaleable trees.

In this inventory the second major input is the electricity used for the size reduction which is used in the electric motors of the stationary chipper. The materials which require high energy for size reduction are the sawmill slabs, fuel rods, and round woods which go through extensive processing for the size reduction. The main equipment used in the yard is the stationary chipper, conveyor system, over size screen, secondary hog and chip dumps. On the other hand, there are materials which do not require a lot of energy for size reduction due to be ready to use or being available in fairly small size particles.

3.2 Inputs for IH^2 Biofuels Production

3.2.1 Inputs for Microalgae IH^2 Biofuels Production

Table 3.6 shows the IH^2 facility inputs and outputs provided for the life cycle assessment. The data was obtained from Terry Marker (GTI) and was based on a 2,000 dry metric ton/day plant. This data was based on an assumption of 20% moisture content of the microalgae biomass feedstock that enters the IH^2 process after being dried from 80% moisture. The data was divided into different sections. The first section includes product yields in which the two main products were the IH^2 renewable diesel and gasoline. The second main section is the raw materials which encompassed the dry biomass and total catalyst which includes the catalyst used for hydropyrolysis and hydroconversion. This catalyst is used for removing all oxygen. Other inputs in this section are the cooling water chemicals plus the boiler feed water chemicals (BFW). The third main section is the utilities section electricity used to run the IH^2 process and natural gas used for drying of the algae. The fourth section is the waste products section which has CO_2 in exhaust that is produced from the reformer. Lastly there is the co-product section which includes water produced from the IH^2 processes, ammonia and ammonia sulfate, which are all mixed in specific ratios so as to produce fertilizers for sale. These co-products results in a GHG reduction credit for the IH^2 life cycle using a displacement allocation. Input tables are similarly organized for other feedstock-specific IH^2 inputs below.

The inventory data from Table 3.6 was input to SimaPro, the LCA software tool used for this evaluation. This input data is shown in Table 3.6, organized by major life cycle stage. In the results section, GHG emissions will be reported for each of the major life cycle stages. Each of the inputs shown in Table 3.6 was multiplied by an energy allocation factor (EAF) which was calculated to be 1 so that the inventory would be apportioned to the main products (renewable diesel and gasoline) as well as the co-products, steam exported from the IH^2 process. The energy allocation factor was calculated using a methodology to be presented next. GHG emissions for the electricity used in the IH^2 process were the US average grid (eGRID, 2011) using an ecoprofile in the ecoinvent™ database in SimaPro. The eGRID emissions are from the site of the power plant only, and do not include upstream and transmission loss effects. In order to compensate for this, the eGRID emissions were multiplied by a factor of 1.1 twice; once for upstream processes (10% additional inventory) and a second time for transmission losses (10% loss assumed).

Table 3.6: Aquaflow Bionomic IH^2 inputs and outputs inventory for 80% moisture microalgae feedstock reduced to 20% moisture. Basis: 1 day operation of 2,000 MAF metric ton/day feedstock plant operation.

Feed stock type	Units	Amounts
Product yields		
IH^2 Gasoline	mt/day	448
IH^2 Diesel	mt/day	448
Raw material		
Dry Biomass (MAF)	mt/day	2000
Total catalysts used	lb/day	761
BFW chemicals	lb/day	85.44
MDEA makeup	lb/day	3.41
Utilities		
Electricity required	kWh	256*24
Natural gas for drier (to decrease algae moisture)	mt/day	538
Waste products		
Char +ash	mt/day	274
CO2 exhaust	mt/day	1030
Co-products(credits)		
Water	mt/day	8830
Ammonia	mt/day	168
Ammonium sulfate	mt/day	48

3.2.2 Inputs for Bagasse IH^2 Biofuels Production

Table 3.7 shows the IH^2 facility inputs and outputs for the life cycle inventory of bagasse biofuels. The data was provided by Terry Marker (GTI) and was based on a 2,000 metric ton (MAF) of bagasse input/day plant with feedstock moisture of 45%. The data was divided into different sections, similar to those described in section 3.2.1. The factor of 2 appearing converts inputs to the basis of 2,000 MAF mt/day from the original set of data for a 1,000 mt/day facility.

The export steam was calculated in two different scenarios

i) Char is burned to produce steam.

ii) Char is a co-product and exported from the product system.

Both of these scenarios affect the energy allocation calculation as shown below in section 4.2.

The bagasse was dried from 45% moisture to 20% moisture to enhance size reduction and IH^2 conversion. The energy for drying was supplied by steam generated by the exothermic reactions occurring in the hydropyrolysis and hydroconversion reactions and was accounted for in the energy balance calculations which yielded the net steam exported (provided by GTI).

The input data from Table 3.7 was entered into SimaPro 7.2, the LCA software tool used for this evaluation. Each of the inputs shown in Table 3.7 was multiplied by an energy allocation factor (EAF) which was 0.897 in the scenario where char is burned and 0.724 in the scenario which

Table 3.7: IH^2 inputs and outputs for the 45% moisture bagasse feedstock. Basis is 1 day operation of 2,000 moisture and ash free (MAF) metric ton/day plant operation.

Feed stock type	**Units**	**Amounts**
Product yields		
IH^2 Gasoline	mt/day	216*2
IH^2 Diesel	mt/day	70*2
Raw material		
Dry Biomass (MAF)	mt/day	2000
Total catalysts used	Ib/day	761.04
BFW chemicals	Ib/day	85.44
MDEA makeup	Ib/day	3.41
Utilities		
Electricity required (US average grid)	kWh	256*24
Diesel fuel (used by Vermeer HG 200grinder)	Ib/day	26,389
Waste products		
Char +ash	mt/day	167*2
CO_2+ hydrogen exhaust	mt/day	785*2
Co-products(credits)		
Water	Ib/day	3,616,200
Ammonia	mt/day	3.3*2
Ammonium sulfate	mt/day	3.3*2
Boiler feed water*	Ib/day	2,841
export steam(steam driven compressor)char product made	Ib/day	690,768
export steam(steam driven compressor)char burned	Ib/day	3,225,120

char is considered as a co-product. The inventory is allocated to the main products (IH^2 diesel and gasoline), and the co-products, ammonia and ammonium sulfate, provide an environmental impact credit in this analysis. The energy allocation factor was calculated using a methodology to be presented in section 4.2.

3.2.3 Inputs for Corn Stover IH^2 Biofuels Production

Table 3.8 shows the IH^2 facility inputs and outputs provided for the life cycle assessment. The data was obtained from Terry Marker (GTI) and Eric Tan (NREL) and was based on a 2,000 dry metric ton/day plant based on an assumption of 20% moisture content of the corn stover biomass feedstock. The data was divided into different sections as shown previously.

The input data from Table 3.8 was entered to SimaPro 7.2, the LCA software tool used for this evaluation. Each of the inputs shown in Table 3.8 was multiplied by an energy allocation factor (EA factor) which was calculated to be 0.755 so that the inventory would be apportioned to the main products (renewable diesel and gasoline) as well as the co-products, steam exported from the IH^2 process.

Table 3.8: IH^2 inputs and outputs inventory for the 20% moisture corn stover feedstock. Basis is 1 day operation of 2,000 moisture and ash free (MAF) metric ton/day plant operation.

Feed stock type	Units	Amounts
Product yields		
IH^2 Gasoline	mt/day	320
IH^2 Diesel	mt/day	200
Raw material		
Dry Biomass (MAF)	mt/day	2000
Total catalysts used	mt/day	0.35
BFW chemicals	mt/day	0.019378
MDEA makeup	mt/day	0.000773
Utilities		
Electricity required (US average grid)	kWh	256*24
Diesel fuel (used by Vermeer HG 200grinder)	mt/day	11.968
Waste products		
Char +ash	mt/day	260
CO2 exhaust	mt/day	1107.2
Co-products(credits)		
Water	mt/day	160
Ammonia	mt/day	15.6
Ammonium sulfate	mt/day	9.8
Boiler feed water*	mt/day	2,841
export steam(steam driven compressor)600psi,700	mt/day	3,734

3.2.4 Inputs for Forest Resources IH^2 Biofuels Production

Table 3.9 shows the IH^2 facility inputs and outputs provided for the life cycle assessment for the Johnson Timber Company’s forest feedstock. The inventory data was obtained from Terry Marker (GTI) and Eric Tan (NREL) and was based on a 2,000 dry metric ton/day IH^2 plant with feedstock dried to moisture of 10%. This data was based on an assumption of 30% and 50% feedstock moisture for two separate scenarios. This data was divided into different sections, similar to Table 3.3 in section 3.2.1.

The inventory data from Table 3.9 was input to SimaPro, the LCA software tool used for this evaluation. In the results section, GHG emissions will be reported for each of the major life cycle stages. Each of the inputs shown in Table 3.9 was multiplied by an energy allocation factor (EAF) so that the inventory would be apportioned to the main products (IH^2 diesel and gasoline) as well as the co-products, ammonia and ammonium sulfate. The energy allocation factor was calculated using a methodology to be presented next. GHG emissions for the electricity used for the grinding and the IH^2 process were the US average grid.

Table 3.9: Forest resources IH^2 inputs and outputs inventory for the 30% moisture and 50% moisture feedstock. Basis: 1 day of operation of 2,000 dry metric ton/day facility.

Inputs	**Units**	**Wood residue**
Product yields		
IH^2Gasoline	lb/day	29,386.67*24
IH^2 diesel	lb/day	18,366.7*24
Raw material		
Dry Biomass	lb/day	183,666.67*24
Total catalysts	lb/day	31.71*24
Cooling Tower chemicals	lb/day	0.60*24
BFW chemicals	lb/day	1.78*24
Utilities		
Electricity (US average grid)	kWh	260*24
Electricity for feedstock sizing (US average grid)	kWh	230.74*24
Diesel fuel (assumed rate 10 gal/hr)	lb/day	7.09*24
Waste products		
Hydrogen	lb/day	1507.67*24
Co-Products (credits, or allocation)		
Water	lb/day	14,682.44*24
$CO_2 + H_2$	lb/day	95,782.2
Ammonia (credit)	lb/day	1,338.66*24
Ammonium sulfate (credit)	lb/day	239.64*24
Export steam driven compressors (30%moisture) (allocation)	lb/day	268,007*24
Export steam driven compressors (50% moisture) (allocation)	lb/hr	133,020

4. Energy Allocation

Energy allocation (EA) was applied in order to distribute the system environmental burdens among all products and co-products in the IH^2 biofuel production chain. The EA method includes an energy balance utilizing material flows and lower heating values (LHV) for each co-product from the IH^2 biofuel conversion stage. No co-products were generated in any other stage for all of the feedstocks considered in this study. The following sections describe the calculations made to determine energy allocation factors (EA factor) to be applied to allocate environmental impact to the main IH^2 biofuel products. The EA factor was applied to all inputs in every life cycle stage to the IH^2 biofuels production system. Energy allocation is an energy balance around the IH^2 process where co-products are produced. We wish to know what fraction of total output of energy from the process is contained in IH^2 biofuels. Energy can be carried out of the process in various forms; IH^2 biofuels, steam, and char co-product. As a quality check on these energy balance calculations, we also attempted to balance the total input energy from the input biomass to the IH^2 conversion process, with all output energy streams. Our attempts to do this from the data provided by GTI yielded energy balances that did not close perfectly, but the output energy was lower than the input energy by 5-20% for most feedstocks. Although this is not perfect data quality, such a result is consistent with energy losses from the process in the form of waste heat which was not quantified. In summary, we feel that the data quality was of sufficiently high quality to proceed with the final analyses.

The (EA) factor was obtained by using the equations below whereby the denominator represents the total energy out from all products and numerator is energy content of the IH^2 gasoline and IH^2diesel.

$$EA_{micro\ algae} = \frac{Energy\ \ Out\ (gasoline + diesel)}{Total\ Energy\ out}$$

4.1 Microalgae IH^2 Biofuels

When the individual inputs are included the above equation transforms into;

20% Moisture Content Micro algae

$$EAF = \frac{\overbrace{\left(44\frac{MJ}{kg}*4.48\times10^{8}\frac{kg}{day}\right)}^{gasoline}+\overbrace{\left(44\frac{MJ}{kg}*4.48\times10^{8}\frac{kg}{day}\right)}^{diesel}}{\underbrace{\left(44\frac{MJ}{kg}*4.48\times10^{8}\frac{kg}{day}\right)}_{gasoline}+\underbrace{\left(44\frac{MJ}{kg}*4.48\times10^{8}\frac{kg}{day}\right)}_{diesel}} = 1$$

4.2 Bagasse IH^2 Biofuels

When the individual inputs are included the above equation transforms into;

20% moisture content bagasse with char as a product

$$EAF = \frac{\overbrace{\left(44\frac{MJ}{kg}*432981.82\frac{kg}{day}\right)}^{gasoline}+\overbrace{\left(44\frac{MJ}{kg}*140318.18\frac{kg}{day}\right)}^{diesel}}{\underbrace{\left(44\frac{MJ}{kg}*432981.82\frac{kg}{day}\right)}_{gasoline}+\underbrace{\left(44\frac{MJ}{kg}*140318.18\frac{kg}{day}\right)}_{diesel}+\underbrace{\left(26.8\frac{MJ}{kg\ char}*334789\frac{kg}{day}\right)}_{char}\underbrace{\left(1.9848\frac{MJ}{kg\ steam}*313988\frac{kg}{day}\right)}_{steam}} = 0.724$$

20% moisture content bagasse with char burned

$$EAF = \frac{\overbrace{\left(44\frac{MJ}{kg}*432981.82\frac{kg}{day}\right)}^{gasoline}+\overbrace{\left(44\frac{MJ}{kg}*140318.18\frac{kg}{day}\right)}^{diesel}}{\underbrace{\left(44\frac{MJ}{kg}*432981.82\frac{kg}{day}\right)}_{gasoline}+\underbrace{\left(44\frac{MJ}{kg}*140318.18\frac{kg}{day}\right)}_{diesel}+\underbrace{\left(1.9848\frac{MJ}{kg\ steam}*1468964\frac{kg}{day}\right)}_{steam}} = 0.897$$

The lower heating values (LHV) of the fuels, steam, and char were obtained from existing databases in the MTU LCA group

4.3 Corn Stover IH^2 Biofuels

When the individual inputs are included the above equation transforms into;

20% moisture content corn stover with char burned

$$EAF = \frac{\overbrace{\left(44\frac{MJ}{kg}*3.64\times10^{5}\frac{kg}{day}\right)}^{gasoline}+\overbrace{\left(44\frac{MJ}{kg}*2.0\times10^{5}\frac{kg}{day}\right)}^{diesel}}{\underbrace{\left(44\frac{MJ}{kg}*3.64\times10^{5}\frac{kg}{day}\right)}_{gasoline}+\underbrace{\left(44\frac{MJ}{kg}*2.0\times10^{5}\frac{kg}{day}\right)}_{diesel}+\underbrace{\left(1.9845\frac{MJ}{kg\ steam}*3.734\times10^{5}\frac{kg}{day}\right)}_{steam}} = 0.755$$

4.4 Forest Resources IH^2 Biofuels

For the two different feedstock moisture scenarios, the energy allocation factor equations are as seen in the equations below. The Low Heating Value of the hydrogen was obtained from literature Grohmann et al. (1984), while the LHV for the wood biomass was obtained from other literature.

30%moisture feedstock

$$EA\ factor = \frac{\overbrace{\left(44\frac{MJ}{kg}*3.2\times10^{5}\frac{kg}{day}\right)}^{gasoline}+\overbrace{\left(44\frac{MJ}{kg}*1.99\times10^{5}\frac{kg}{day}\right)}^{diesel}}{\underbrace{\left(44\frac{MJ}{kg}*3.2\times10^{5}\frac{kg}{day}\right)}_{gasoline}+\underbrace{\left(44\frac{MJ}{kg}*1.99\times10^{5}\frac{kg}{day}\right)}_{diesel}+\underbrace{\left(1.9845\frac{MJ}{kg\ steam}*2.92\times10^{5}\frac{kg}{day}\right)}_{steam}} = 0.798$$

50% moisture feedstock

$$\mathrm{EA\ factor} = \frac{\overbrace{\left(44\frac{\mathrm{MJ}}{\mathrm{kg}}*3.2\times10^{5}\frac{\mathrm{kg}}{\mathrm{day}}\right)}^{\mathrm{gasoline}}+\overbrace{\left(44\frac{\mathrm{MJ}}{\mathrm{kg}}*1.99\times10^{5}\frac{\mathrm{kg}}{\mathrm{day}}\right)}^{\mathrm{diesel}}}{\underbrace{\left(44\frac{\mathrm{MJ}}{\mathrm{kg}}*3.2\times10^{5}\frac{\mathrm{kg}}{\mathrm{day}}\right)}_{\mathrm{gasoline}}+\underbrace{\left(44\frac{\mathrm{MJ}}{\mathrm{kg}}*2.0\times10^{5}\frac{\mathrm{kg}}{\mathrm{day}}\right)}_{\mathrm{diesel}}+\underbrace{\left(1.9845\frac{\mathrm{MJ}}{\mathrm{kg\,steam}}*1.45\times10^{5}\frac{\mathrm{kg}}{\mathrm{day}}\right)}_{\mathrm{steam}}} = 0.888$$

5. Life Cycle Impact Assessment

The inventory data were converted to greenhouse gas impacts using the IPCC GWP 100a method in SimaPro 7.2. This method converts emissions of greenhouse gases into equivalent emissions of CO_2 by employing global warming potentials (GWP). The GWP of CO_2 is 1, for CH_4 = 25, and for N_2O is 298. Other greenhouse gases are also included in this analysis, including solvents and refrigerants that accompany ecoprofiles resident in SimaPro and called into the analysis with the material and energy inputs.

5.1 Microalgae IH^2 Biofuel

The results from the SimaPro analysis were arrived at by dividing the 1-day impact results by the total energy content of the IH^2 biofuels produced (39,424,000 MJ/day), or multiplying by the reciprocal which was 2.54E-8 of a day/MJ. This calculation is shown equations below.

$$\frac{1}{IH^2\ gasoline + IH^2\ diesel}$$

$$\frac{1}{(19{,}712{,}000\ MJ/day) + (19{,}712{,}000\ MJ/day)} = 2.54E - 8\ day/MJ$$

Doing this converted the GHG emissions from a 1 day basis to 1 MJ IH^2 biofuel basis.

5.2 Bagasse IH^2 Biofuels

The results from the SimaPro analysis were arrived at by dividing the 1-day impact results by the total energy content of the IH^2 biofuels produced (25,225,200 MJ/day), or multiplying by the reciprocal which was 3.96E-8 of a day/MJ. This calculation is shown equations below.

$$\frac{1}{IH^2\ gasoline + IH^2\ diesel}$$

$$\frac{1}{(19{,}051{,}200\ MJ/day) + (6{,}174{,}000\ MJ/day)} = 3.96E - 8\ day/MJ$$

Doing this converted the GHG emissions from a 1 day basis to 1 MJ IH^2 biofuel basis. A comparison of the GHG results for IH^2 biofuels is compared to the life cycle GHG emission for petroleum gasoline, diesel, and aviation fuel.

5.3 Corn Stover IH^2 Biofuels

The results from the SimaPro analysis were arrived at by dividing the 1-day impact results by the total energy content of the IH^2 biofuels produced (22,880,000 MJ/day), or multiplying by the reciprocal which was 4.37E-8 day/MJ. This calculation is shown equations below.

$$\frac{1}{IH^2\ gasoline + IH^2\ diesel}$$

$$\frac{1}{(14{,}080{,}000\ MJ/day) + (8{,}800{,}000\ MJ/day)} = 4.37E - 8\ day/MJ$$

5.4 Forest Feedstocks IH^2 Biofuels

The results from the SimaPro analysis were arrived at by dividing the 1-day impact results by the total energy content of the IH^2 biofuels produced (22,880,000 MJ/day), or multiplying by the reciprocal which was 4.37E-8 day/MJ. This calculation is shown equations below.

$$\frac{1}{IH^2\ gasoline + IH^2\ diesel}$$

$$\frac{1}{(14{,}080{,}000\ MJ/day) + (8{,}800{,}000\ MJ/day)} = 4.37E - 8\ day/MJ$$

6. Life Cycle Assessment Results

6.1 Microalgae Biomass and IH^2 Biofuel Results

6.1.1 Microalgae Biomass Production

The results obtained from this analysis are grouped into four main sections: i. Algae Production Pump Shed ii. Algae Production New Harvest Units, iii. Algae Production Dewatering, and iv. Algae Transport. Figure 6.1 shows the GHG emissions per dry metric ton algae produced assuming 300 g algae/m^3 cell density. The Pump Shed stage emits the largest amount of emissions, followed by Algae Production Dewatering, Algae Transport, and Algae New Harvest Units. Table 6.1 shows the effects of primary energy type on the electricity impacts of producing algae. Coal electricity emits the largest amount of emissions, followed by US average grid and natural gas, with renewable electricity emitting the least.

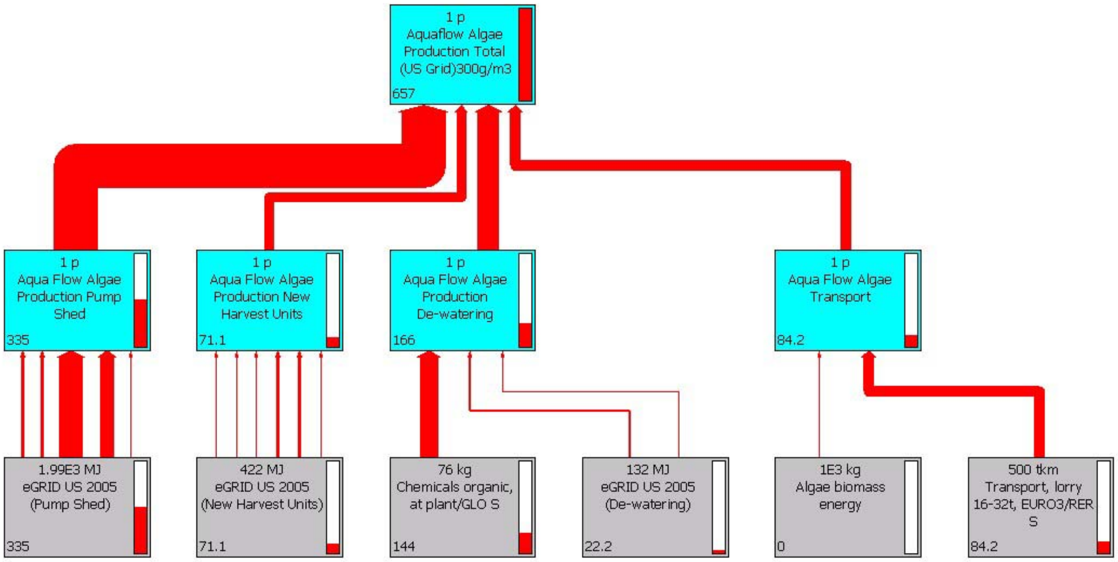

Figure 6.1 Greenhouse gas emissions per dry metric ton algae biomass (657 kg CO_2 eq. / metric ton algae) assuming average US grid electricity.

Table 6.1 Effect of Electricity Type (Primary Energy) on GHG Emissions of Algae

Algae Production Electricity Type	**GHG Emissions (kg CO_2 eq. / dry mt algae)**
Coal	1030
US Grid Average	657
Natural Gas	656
Geothermal	286
Biomass	258
Nuclear	236
Wind	235
Hydro	231

6.1.2 Microalgae IH^2 Biofuel Production and Use

The inputs listed in Table 3.2 were entered into a project in SimaPro in order to determine the greenhouse gas emissions per MJ of IH^2 biofuels produced and used in vehicles. Figure 6.2 shows the total GHG emissions of .0619 kg CO_2 eq./MJ IH^2 biofuels, or 61.9 g CO_2 eq./MJ. To place these emissions into perspective, petroleum gasoline has life cycle GHG emissions of 91.2 g CO_2 eq./MJ. This IH^2 biofuel result was obtained assuming US average grid electricity used for algae feedstock production and also for electricity use during IH^2 biofuel production (IH^2 processes in Figure 6.2). The largest contributor to emissions is algae feedstock production and transport to the IH^2 facility, followed by IH^2 processes for producing biofuels. Natural gas combusted for drying algae from 80% to 20% is the largest single cause of GHG emissions and electricity use for algae harvesting and dewatering is also a major cause for emissions. The emission credits from co-products ammonia and ammonium sulfate total about 20% of the net GHG emissions. The GHG results in Figure 6.2 include effects of biofuels combustion, but do not include transport of IH^2 biofuels to blending locations for mixing into petroleum fuel stocks, nor from the blending location to filling stations. The latter step is considered negligible based on prior experience with biofuel life cycles, and therefore is omitted from this study.

Electricity type has a large impact on GHG emissions as shown in Table 6.1, and similarly has a large effect on IH^2 biofuel emissions as shown in Table 6.2. When coal electricity is used, emissions are highest at 82.8 g CO_2 eq./MJ and are least when a renewable power source is used such as hydroelectric power; 37.9 g CO_2 eq./MJ. There is a very strong influence of electricity type on these GHG results. When mode of transportation from IH^2 facility gate to blending location assuming 100 km distance is explored, there is very little difference between the transport modes.

Table 6.2 Effect of Electricity Type on IH^2 Biofuel GHG Emissions

Algae IH^2 Biofuel Life Cycle: Effect of Electricity Type (No IH^2 Biofuel Transport to Blending)	**GHG Emissions (g CO_2 eq. / MJ)**
Coal	82.8
US Average Grid	61.9
Hydro	37.9

Table 6.3 Effect of Transport Mode to Blending Location on IH^2 Biofuel GHG Emissions. Electricity Type is US Average Grid Power.

Algae IH^2 Biofuel Life Cycle: Effect of IH^2 Biofuel Transport Mode	**GHG Emissions (g CO_2 eq. / MJ)**
Road	62.2
Rail	61.9
Pipeline	61.9

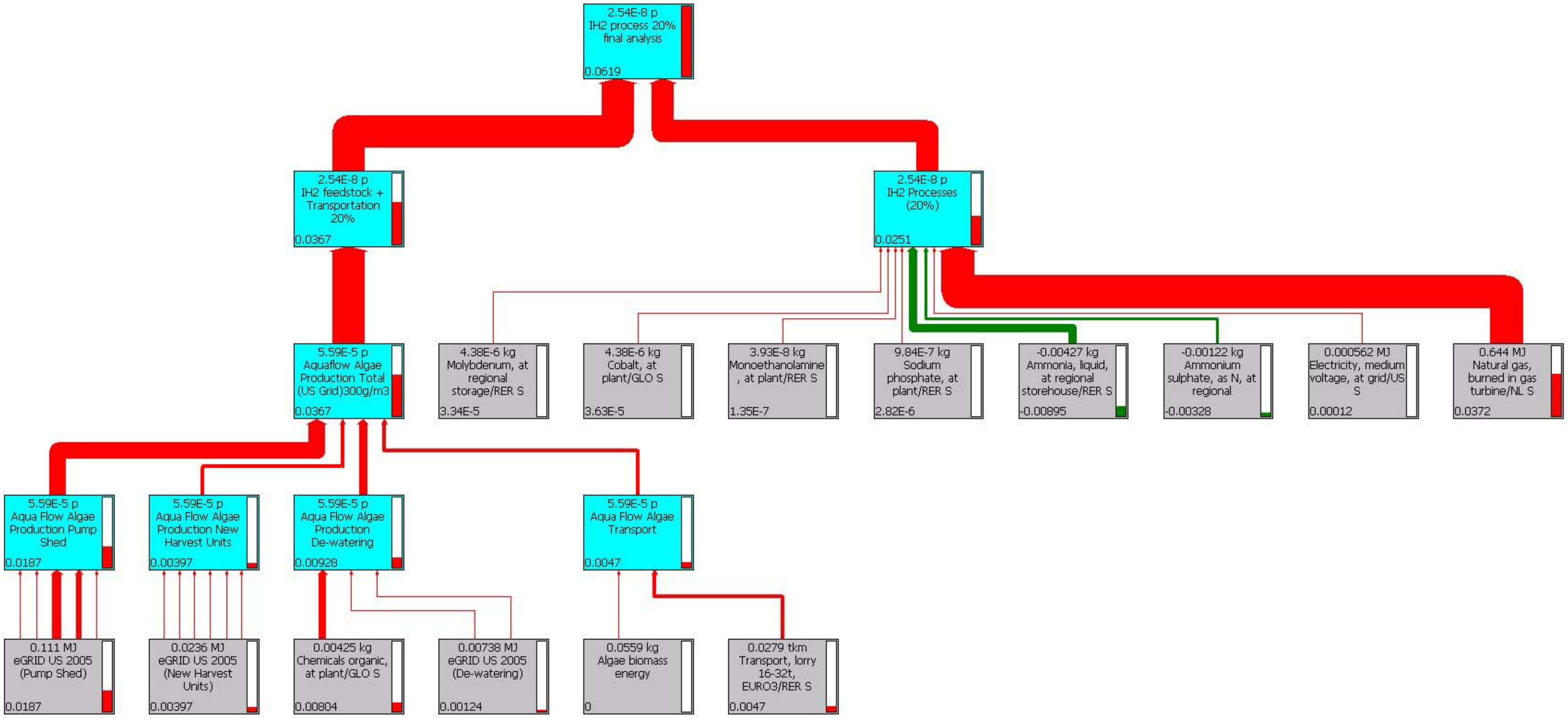

Figure 6.2 Network diagram for microalgae IH^2 biofuels emission of GHGs (kg CO_2 eq./MJ IH^2 biofuels). Red lines show relative magnitude of greenhouse gas impacts while green lines show credits due to co-products of production. Line width corresponds to magnitude of impact or credit.

6.1.3 Discussion of Microalgae IH^2 Biofuel LCA Results

Savings of GHG emissions of IH^2 biofuel compared to petroleum fuels is shown in Figure 6.3. IH^2 biofuels in this comparison are produced using coal, US grid, and hydro power, and savings of GHG emissions compared to petroleum gasoline are 8%, 32%, and 58%, respectively. It is clear from these results that significant savings of emissions are only possible when renewable power is utilized for algae harvesting and dewatering. However, further reductions in GHG emissions is still possible if a renewable energy source could be found for the natural gas required for drying the algae biomass from 80% - 20%. Possible candidates could be landfill gas, anaerobic digester gas, and solar drying.

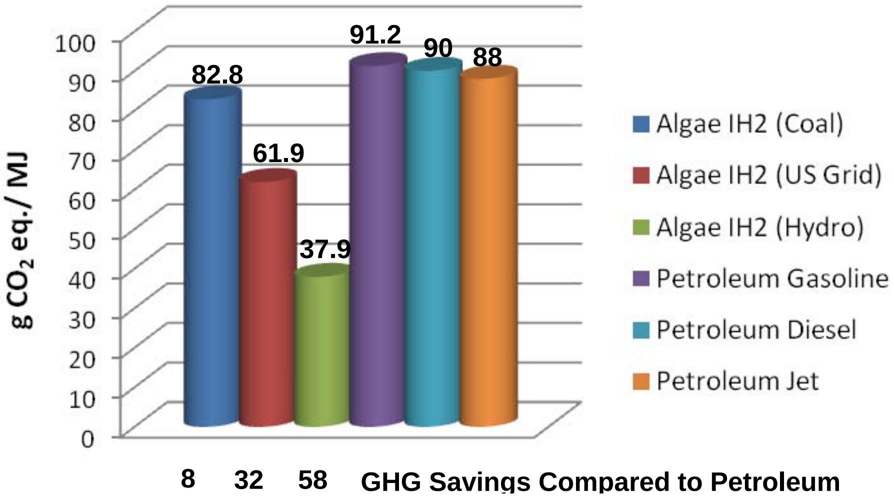

Figure 6.3 Savings of GHG emissions relative to petroleum fuels for algae IH^2 fuels.

6.2 Bagasse Biomass and IH^2 Biofuel Results

6.2.1 Bagasse Biomass Production

The main categories of the bagasse handling which are considered for the LCA analysis were i) bagasse transportation ii) bagasse loading and unloading, and iii) bagasse energy. Figure 6.4 below shows the greenhouse gas emissions per dry metric ton for loading, unloading, and transportation to a IH^2 unit 100 km distance from the sugarcane milling factory. The total GHG emissions are 27.1 kg CO_2 eq. per dry metric ton bagasse. The largest contributor to this total is the transportation process. The bagasse transportation is equivalent to 24.40 kg CO_2 eq. per dry metric ton secondly is the loading and unloading of the bagasse which is very low at 2.65 kg CO_2 eq. per dry metric ton which is about 15% of the total emissions.

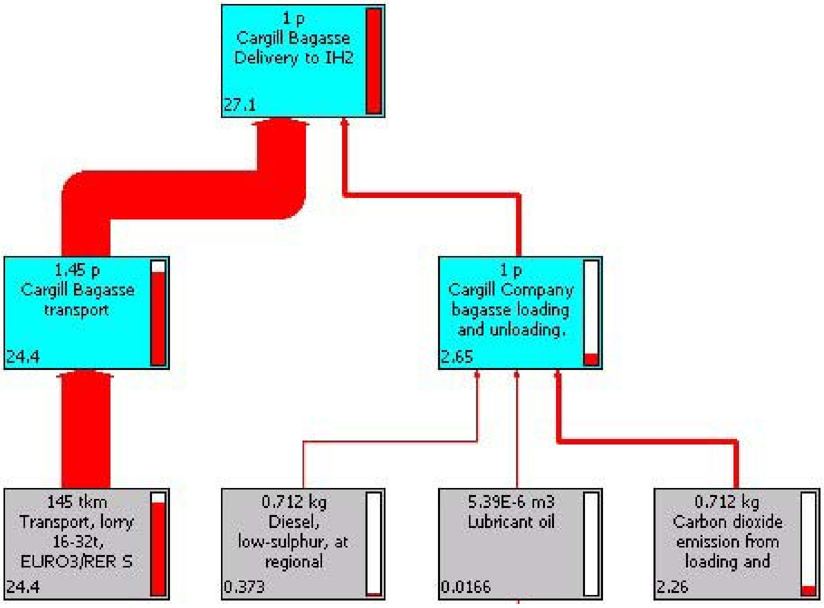

Figure 6.4: Network diagram with magnitudes of GHG emissions from Bagasse handling to the IH^2 process (kg CO$_2$ eq./dry mt bagasse).

6.2.2 Bagasse IH^2 Biofuel Production and Use

The total GHG emissions for this feedstock where the **char is burned** for steam production, is 2.6 g CO_2 eq /MJ of IH^2 fuel produced, as shown in the Figure 6.5. The IH^2 feedstock handling and transportation accounts for most of the emissions, which is 1.92 g CO_2 eq /MJ of IH^2 fuel produced. The lowest emissions are from the IH^2 process which is a credit of -0.892 g CO_2 eq /MJ of IH^2 fuel produced, due to the emissions credits from ammonia and ammonium sulfate co-products. These emission credits were obtained from ecoprofiles in the ecoinvent database in SimaPro 7.2. The IH^2 feedstock onsite preparation is 1.57 g eq CO_2/MJ of IH^2 fuel produced.

The total GHG emissions for bagasse feedstock for **char as a product scenario** is 2.1 g CO_2 eq /MJ of IH^2 fuel produced, as shown in the Table 6.4. These results are very similar to the char burned case except slightly lower because of the lower EA factor (.724).

Table 6.4: GHG emissions for the IH^2 process with bagasse feedstock

Life Cycle Stages	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**
IH^2 Feedstock Transportation	1.55
IH^2 Feedstock Onsite Preparation	1.27
IH^2 Process	-0.72
Total GHG Emissions	**2.1**

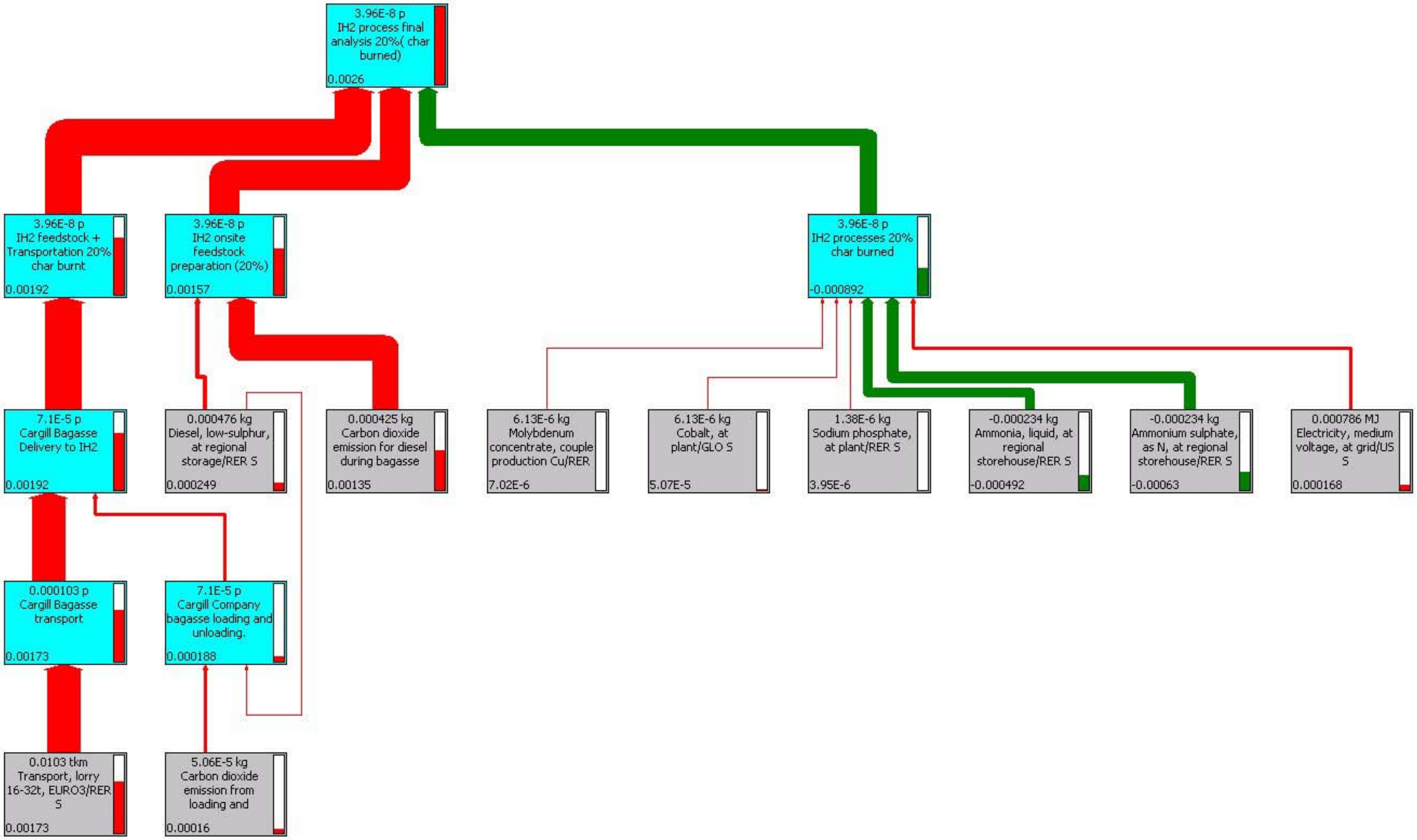

Figure 6.5 Network diagram for bagasse IH^2 biofuels emission of GHGs (kg CO_2 eq./MJ IH^2 biofuels). Red lines show relative magnitude of greenhouse gas impacts while green lines show credits due to co-products of production. Line width corresponds to magnitude of impact or credit.

In Table 6.5 are results obtained from the different IH^2 biofuel transportation modes for the char burned base case. The different modes of transport were: a) Rail b) Road c) Pipeline. The IH^2 biofuel transportation distance from facility to filling station is 100 km. For this short distance, there is little effect of IH^2 biofuel transport to blending stations.

Table 6.5: GHG emissions for the IH^2 process bagasse showing effects of 100 km transport of IH^2 fuel to blending stations by different transport modes

Life Cycle Stages	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**
	Base case (char product)	**Base case (char burned)**	**Road transport**	**Rail transport**	**Pipeline transport**
IH^2 Feedstock and Transportation	1.55	1.92	1.92	1.92	1.92
IH^2 Feedstock Onsite Preparation	1.27	1.57	1.57	1.57	1.57
IH^2 Process	-0.72	-0.89	-0.89	-0.89	-0.89
IH^2 biofuel Transportation	-	-	0.17	.044	.018
Total GHG Emissions	**2.1**	**2.6**	**2.77**	**2.65**	**2.62**

In this scenario an estimation was made of the effects of different transportation distances on GHG emissions from the location of the IH^2 biofuel production facility to different blending sites using **road transport**. We will use the same distances as in the Johnson Timber IH^2 LCA report for this bagasse analysis.

The transportation distances to the various blending sites are shown in Table 6.6. The results obtained from the different transportation locations of the IH^2 biofuel are shown below in Table 6.7.

Table 6.6: Distances to different blending sites being considered

Different blending locations	**Distances**
Scenario 1	147 miles
Scenario 2	202 miles
Scenario 3	277 miles
Scenario 4	392 miles

From Table 6.7 below, the GHG emissions contribution from the IH^2 biofuel transport section varies with the IH^2 biofuel transportation distances for bagasse feedstocks. There is not much effect of distance to blending facility, even for the longest regional distance of 392 miles, on the total GHG emissions for bagasse IH^2 biofuels.

Table 6.7: GHG emissions for production and transportation of IH^2 biofuel produced assuming a 20% moisture bagasse feedstock to different blending sites

Life Cycle Stages	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**
IH^2 Road Transport Distance	147 miles	202 miles	277 miles	392 miles
IH^2 Feedstock and Transportation	1.92	1.92	1.92	1.92
IH^2 Feedstock Onsite Preparation	1.57	1.57	1.57	1.57
IH^2 Process	-0.89	-0.89	-0.89	-0.89
IH^2 biofuel Transportation	0.28	0.39	0.53	0.75
Total GHG Emissions	**2.88**	**2.99**	**3.13**	**3.35**

6.2.3 Discussion of Bagasse IH^2 Biofuel LCA Results

A comparison was conducted between the GHG emissions of IH^2 biofuels from bagasse biomass emissions to the emissions from convectional petroleum gasoline, diesel, and jet fuel shown in Figure 6.6 below. These emissions from the bagasse IH^2 biofuels are relatively low compared to the data from National Energy Technology Laboratory (NETL, 2008). Savings of GHG emissions compared to petroleum fuels is approximately 97%, easily qualifying these biofuels as adavanced biofuels according to the Renewable Fuels Standard (50% reduction required).

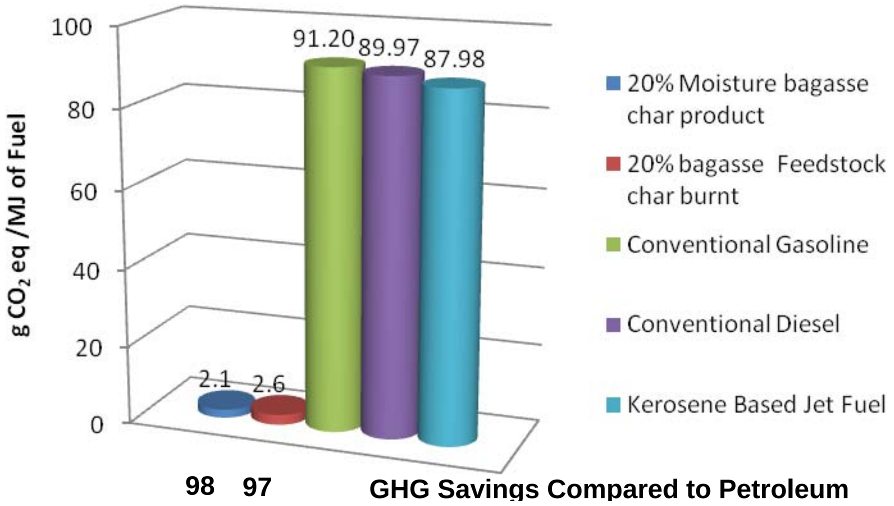

Figure 6.6: Results of IH^2 fuel for bagasse feedstock ghg emisisons results savings compared to petroleum fuels (no transport step to blending was included here-negligible effect).

6.3 Corn Stover Biomass and IH^2 Biofuel Results

6.3.1 Corn Stover Biomass Production

The main categories of the corn stover production system which are considered for the LCA analysis were i. fertilizer replacement, ii. corn stover collection, iii. corn stover transportation, and iv. corn stover loading and loading. Figure 6.7 shows the greenhouse gas emissions per dry metric ton of fertilizer replacement, collection, loading, unloading and transported to a IH^2 unit 48 km (30 mi.) distant from the corn stover fields. The total GHG emissions are 66.8 kg CO_2 eq. per dry metric ton corn stover biomass. The largest contributor to this total is the fertilizer replacement, followed by collection, transport, and loading/unloading.

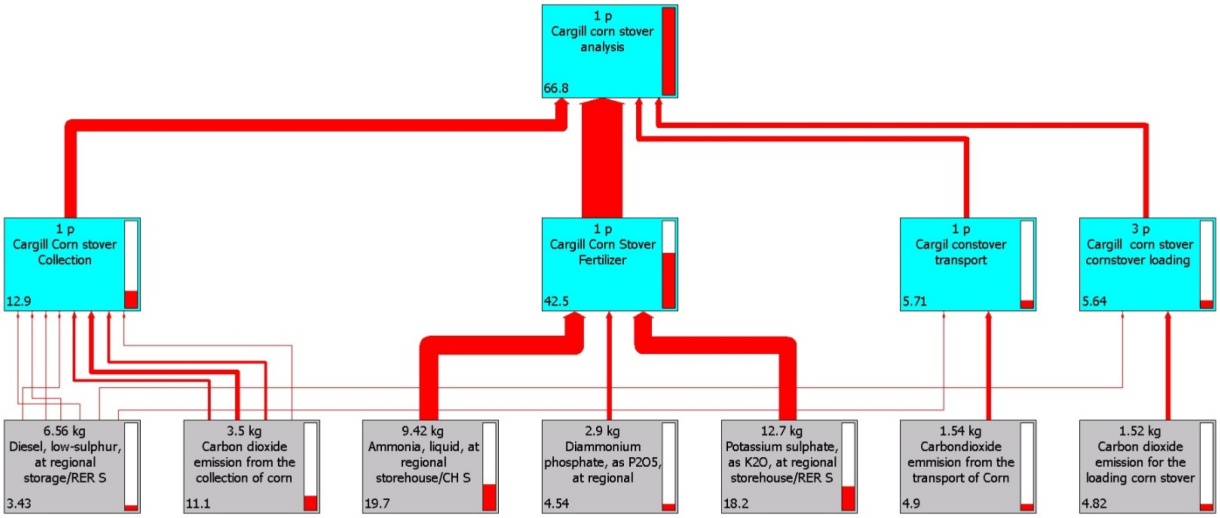

Figure 6.7 Network diagram with GHG emissions from Corn Stover collection, loading, transport, and fertilizer replacement (kg CO_2 eq./dry mt stover).

6.3.2 Corn Stover IH^2 Biofuel Production and Use

The total GHG emissions for corn stover IH^2 biofuel where the **char is burned** for steam production is shown in a network diagram in Figure 6.8. The largest emission is from corn stover production, followed by size reduction, and with a credit for co-products ammonia and ammonium sulfate. Several IH^2 biofuel transportation scenarios were studied assuming 100 km distance to locations of blending into petroleum fuel stocks; a) rail, b) road, and c) pipeline. Table 6.8 shows the results from these scenarios. Road transport adds about 5% to these base case emissions, but rail and pipeline transport contribute negligibly to the total emissions.

In another scenario an estimation was made of the effects of different transportation distances on GHG emissions from the location of the IH^2 biofuel production facility to different blending sites using **road transport**. We will use the same distances as in the Johnson Timber IH^2 LCA report for this bagasse analysis. The transportation distances to the various blending sites are shown in Table 6.6. The results obtained from the different transportation locations of the IH^2 biofuel are shown below in Table 6.9. As in the bagasse case, there is not much effect of distance to blending facility, even for the longest regional distance of 392 miles, on the total GHG emissions for corn stover IH^2 biofuels.

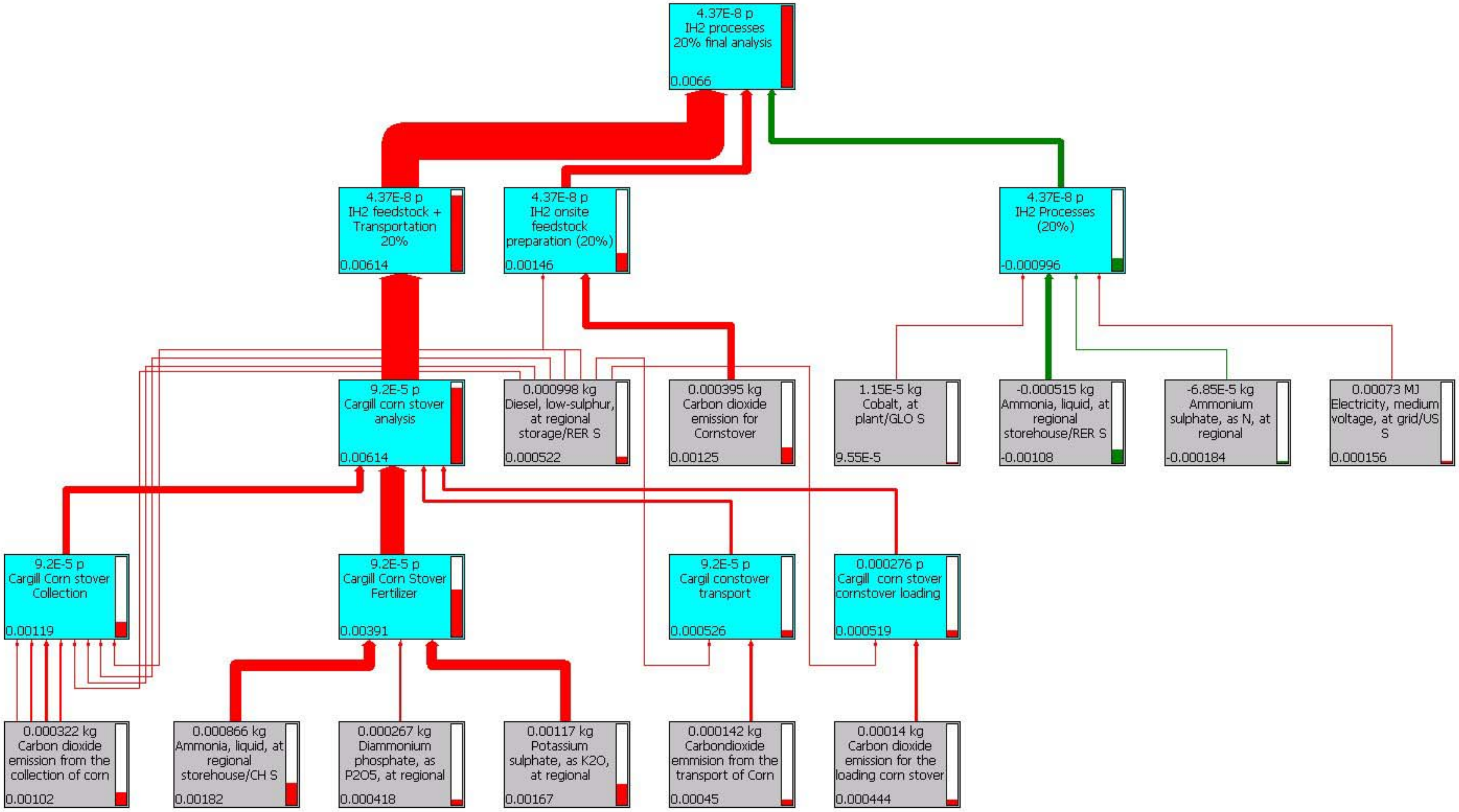

Figure 6.8 Network diagram for corn stover IH^2 biofuels emission of GHGs (kg CO$_2$ eq./MJ IH^2 biofuels). Red lines show relative magnitude of greenhouse gas impacts while green lines show credits due to co-products of production. Line width corresponds to magnitude of impact or credit

Table 6.8: GHG emissions for the IH^2 process with 20% moisture feedstock corn stover

Life Cycle Stages	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**
	Base case (no IH^2 fuel transport)	**Road transport**	**Rail transport**	**Pipeline transport**
IH^2 Feedstock and Transportation	6.14	6.14	6.14	6.14
IH^2 Feedstock Onsite Preparation	1.46	1.46	1.46	1.46
IH^2 Process	-0.996	-0.996	-0.996	-0.996
IH^2 biofuel Transportation	-	0.38	0.09	0.04
Total GHG Emissions	**6.60**	**6.98**	**6.69**	**6.64**

Table 6.9: GHG emissions for production and transportation of IH^2 biofuel produced considering a 20% moisture corn stover feedstock to different blending sites

Life Cycle Stages	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**
IH^2 Road Transport Distance	147 miles	202 miles	277 miles	392 miles
IH^2 Feedstock and Transportation	6.14	6.14	6.14	6.14
IH^2 Feedstock Onsite Preparation	1.46	1.46	1.46	1.46
IH^2 Process	-0.996	-0.996	-0.996	-0.996
IH^2 biofuel Transportation	0.56	0.77	1.06	1.50
Total GHG Emissions	**7.16**	**7.37**	**7.66**	**8.10**

6.3.3 Discussion of Corn Stover IH^2 Biofuel LCA Results

A comparison was conducted between the GHG emissions of IH^2 biofuels from corn stover biomass emissions to the emissions from convectional petroleum gasoline, diesel, and jet fuel shown in Figure 6.9. These emissions from the corn stover IH^2 biofuels are relatively low compared to the data from National Energy Technology Laboratory (NETL, 2008). Savings of GHG emissions compared to petroleum fuels is approximately 93%, easily qualifying these biofuels as adavanced biofuels according to the Renewable Fuels Standard (50% reduction required).

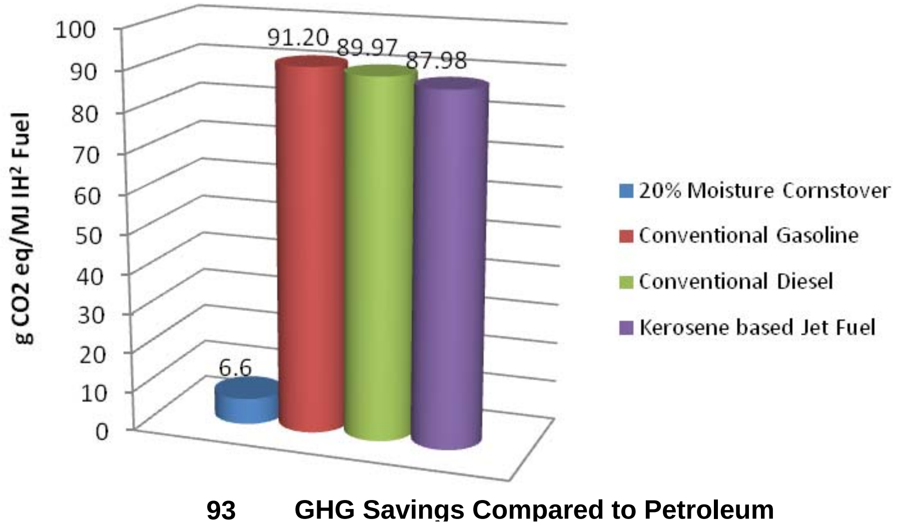

Figure 6.9: Results of IH^2 fuel for corn stover feedstock GHG emisisons results savings compared to petroleum fuels (no transport step to blending was included here-negligible effect).

6.4 Forest Resources Biomass and IH^2 Biofuel Results

6.4.1 Forest Resources Biomass Production

The results obtained from this analysis are grouped into three main sections: collection, transportation and yard preprocessing. Figure 6.10 shows a network diagram of the GHG impacts of these three sections on the basis of 1 dry metric ton assuming a 1,000 dry metric ton / day facility. The largest source if GHG emission is electricity consumed for size reduction of the biomass. Diesel fuel for biomass collection is the next largest, followed by diesel fuel for transportation.

Two sets of results were obtained, one for the 500 and 1,000 dry metric ton/day plants assuming diesel fuel costs of $3/gallon, and another assuming $6/gallon. These results are shown in Tables 6.10 and 6.11. The general trends are that emissions increase for the larger feedstock supply and for lower fuel prices. The reasons for these trends are that larger distances are needed for transport for the larger supply need, and for higher fuel prices, this favors collection of higher cost resources closer to the facility. These economic tradeoffs are possible with the forest procurement model provided by Mr. Gephardt, and the environmental tradeoffs are provided by the LCA.

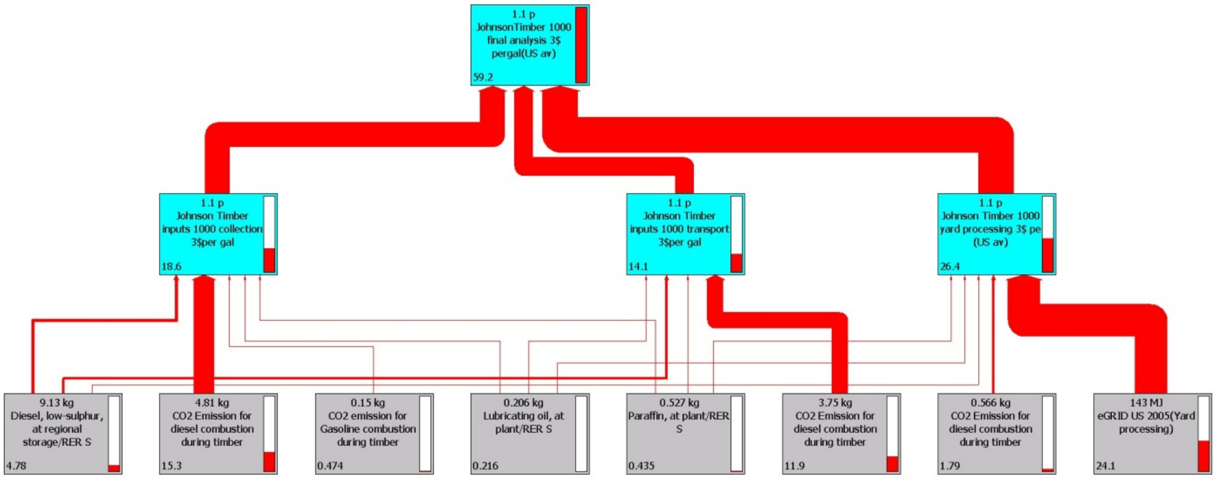

Figure 6.10 Network diagram with GHG emissions from Forest Feedstock collection, transport, and preprocessing (kg CO_2 eq./dry mt forest resources) assuming a 1,000 dry metric ton/day and \$3/gallon diesel fuel.

Table 6.10: Greenhouse Gas Emissions per dry metric ton/day of wood and forest residues collected, transported, and processed on-site. Impacts of all greenhouse gases were converted to CO_2 equivalents using Global Warming Potentials (GWP). Plant sizes of 500 and 1000 dry metric ton/day input feedstock considering electrical energy from US average grid as the yard processing energy source and assumption of \$3 per gallon of diesel fuel used.

	GHG Emissions (kg CO_2 eq./dry metric ton) for 500 dry metric ton per day plant	**GHG Emissions (kg CO_2 eq./dry metric ton) for 1000 dry metric ton per day plant**
Diesel low sulfur at regional storage	3.8	4.78
Gasoline production (unleaded)	0.09	0.11
Lubricating Oil	0.18	0.22
Grease (Paraffin)	0.37	0.44
Hydraulic Oil (White spirit)	0.15	0.18
eGRID US 2005 (yard processing)	24.1	24.1
CO_2 emission for diesel combustion (during timber transportation)	9.4	15.3
CO_2 emission for diesel combustion (during timber collection)	17.7	13.90
CO_2 emission for gasoline combustion(during timber Transportation)	0.37	0.47
Total	**52.1**	**59.2**

Table 6.11: Greenhouse Gas Emissions per dry metric ton/day of wood and forest residues collected, transported, and processed on-site. Impacts of all greenhouse gases were converted to CO_2 equivalents using Global Warming Potentials (GWP). Plant size of 500 and 1000 dry metric ton/day input feedstock considering electrical energy from US average grid as the yard processing energy source and assumption of $6 per gallon of diesel fuel used.

	GHG Emissions (kg CO_2 eq./dry metric ton) for 500 dry metric ton per day plant	**GHG Emissions (kg CO_2 eq./dry metric ton) for 1000 dry metric ton per day plant**
Diesel low sulfur at regional storage	3.42	4.21
Gasoline production (unleaded)	0.08	0.11
Lubricating Oil	0.17	0.21
Grease(Paraffin)	0.37	0.44
Hydraulic (White spirit)	0.15	0.18
eGRID US 2005 (yard processing)	24.1	24.1
CO_2 emission for diesel combustion (during timber transportation)	9.0	10.3
CO_2 emission for diesel combustion (during timber collection)	11.7	13.4
CO_2 emission for gasoline combustion(during timber Transportation)	0.36	0.47
Total	49.4	55.2

6.4.2 Forest Resources IH^2 Biofuel Production and Use

A network diagram showing contributions to GHG emissions of IH2 biofuels produced from 30% moisture content forest biomass is displayed in Figure 6.10. The largest emissions are from feedstock collection, transportation and size reduction (4.14 g CO_2 eq/MJ). Impacts from IH2 conversion process are very small, and an environmental credit is realized from co-products produced. Net GHG emissions are 3.25 g CO_2 eq/MJ.

When 50% moisture content forest feedstocks are input to the IH^2 facility, GHG emissions are slightly higher as shown in Table 6.12. Slightly larger emissions are a result of a higher EAF applied in this case because a smaller amount of co-product steam is produced compared to the 30% moisture content case.

Table 6.12: GHG emissions for the IH^2 process with 50% moisture feedstock content.

Life Cycle Stages	**GHG Emissions (g CO2 eq./MJ of IH^2 fuel)**
IH^2 Feedstock Transportation	4.61
IH^2 Process	-0.99
Total GHG Emissions	**3.62**

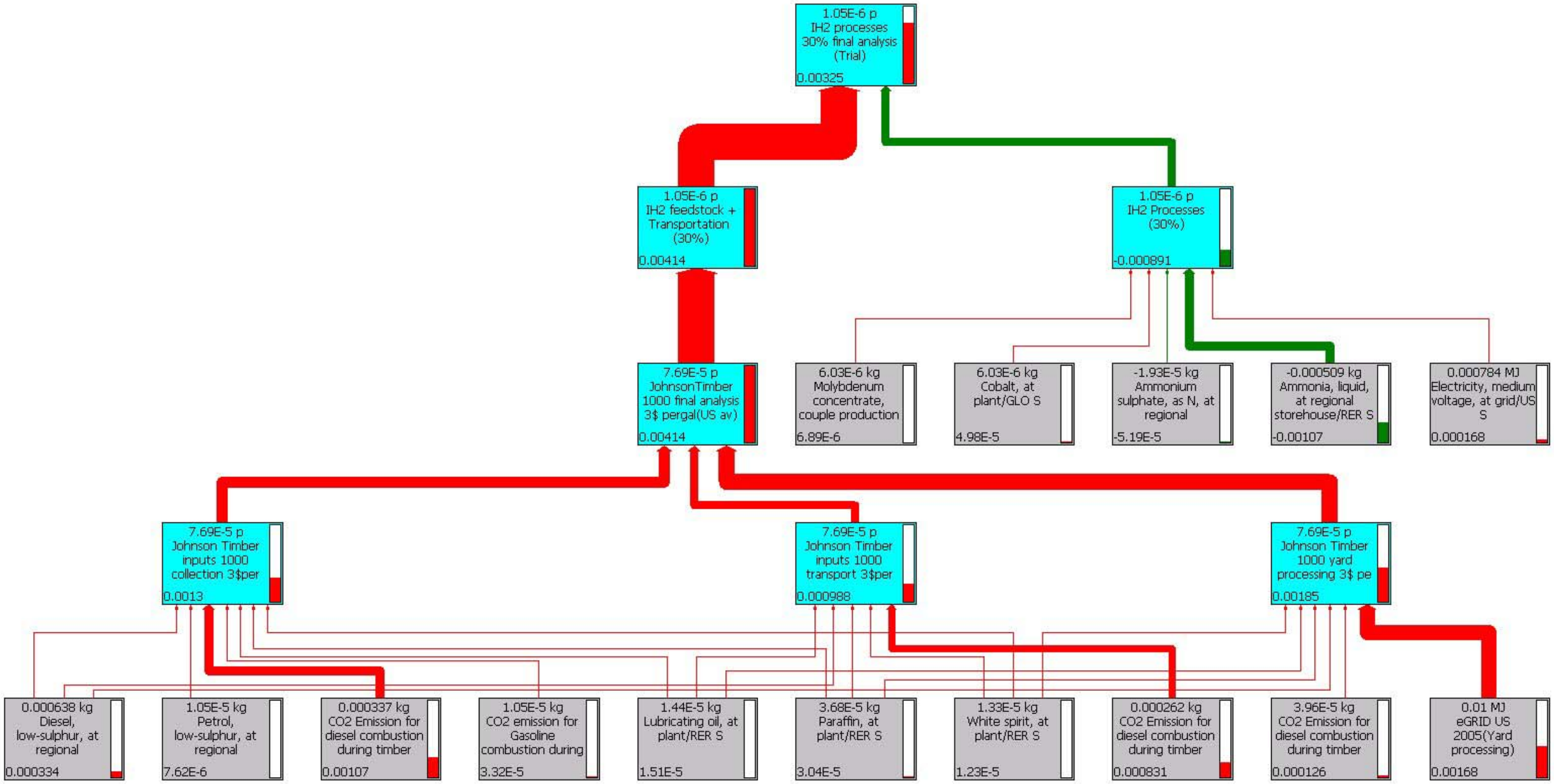

Figure 6.11 Network diagram for forest resources IH^2 biofuels emission of GHGs (kg CO$_2$ eq./MJ IH^2 biofuels). Red lines show relative magnitude of greenhouse gas impacts while green lines show credits due to co-products of production. Line width corresponds to magnitude of impact or credit.

Transportation scenarios to deliver IH^2 biofuel to a blending station located 100 km away using different modes of transport was studied. Table 6.13 contains these results. Road transportation has the highest impact, rail intermediate, and pipeline is the lowest. The effect of biofuel transport to blending locations is minimal.

Table 6.13: GHG emissions for the IH^2 process with 30% moisture forest resources assuming 100 km transport of IH^2 biofuel by different modes

Life Cycle Stages	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**
	Base case (no IH^2 fuel transport)	**Road transport**	**Rail transport**	**Pipeline transport**
IH^2 Feedstock and Transportation	4.14	4.14	4.14	4.14
IH^2 Process	-0.89	-0.89	-0.89	-0.89
IH^2 biofuel Transportation	-	0.35	0.11	0.03
Total GHG Emissions	**3.25**	**3.60**	**3.36**	**3.28**

More transport scenarios were studied by varying distance to blending locations assuming road transport. These distances were obtained by considering several blending facility locations in the Upper Midwest in the region surrounding Park Falls, WI, as shown in Table 6.14. GHG emissions for these transport scenarios are presented in Table 6.15. Even for the longest distance, additional emissions are only slightly larger than 1 g CO_2 eq/MJ.

Table 6.14: Estimated distances for different blending locations

Different blending locations	**Distances**
Minneapolis, MN	147 miles
Green Bay, WI	202 miles
Milwaukee, WI	277 miles
Chicago, IL	392 miles

6.4.3 Discussion of Forest Resources IH^2 Biofuel LCA Results

A comparison was conducted between the GHG emissions of IH^2 biofuels from forest biomass emissions to the emissions from convectional petroleum gasoline, diesel, and jet fuel shown in Figure 6.9. These emissions from the forest resource IH^2 biofuels are relatively low compared to the data from National Energy Technology Laboratory (NETL, 2008). Savings of GHG emissions compared to petroleum fuels are approximately 96% for both the 30% and 50% moisture content biomass-based fuels, easily qualifying these biofuels as adavanced biofuels according to the Renewable Fuels Standard (50% reduction required).

Table 6.15: GHG emissions for production and transportation of IH^2 biofuel produced considering a 30% moisture forest residue feedstock for Johnson Timber Incorporated to different blending sites

Life Cycle Stages	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**	**GHG Emissions (g CO_2 eq./MJ of IH^2 fuel)**
IH^2 Road Transport Distance	147 miles	202 miles	277 miles	392 miles
IH^2 Feedstock and Transportation	4.14	4.14	4.14	4.14
IH^2 Process	-0.89	-0.89	-0.89	-0.89
IH^2 Biofuel Transportation	0.51	0.70	0.96	1.36
Total GHG Emissions	**3.76**	**3.95**	**4.21**	**4.61**

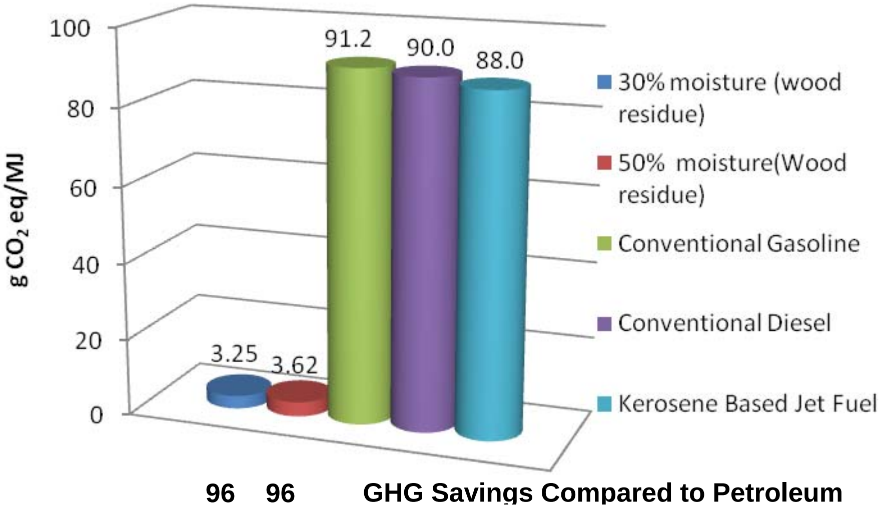

Figure 6.12 Results of IH^2 fuel for forest feedstock GHG emisisons savings compared to petroleum fuels (no transport step to blending was included here-negligible effect).

7. Conclusions and Recommendations

The purpose of this report was to evaluate the cradle-to-grave life cycle assessment (LCA) of the Gas Technology Institute (GTI) Integrated Hydropyrolysis and Hydroconversion (IH^2) production chain, including the production of input feedstocks and use of output IH^2 biofuels. This report contains a preliminary LCA based on input data for the production and delivery of biomass feedstocks to a future IH^2 biofuel facility, and also based on inputs for the IH^2 process provided by GTI. Alternative bio-based transportation fuels, such as the IH^2 biofuels, have the potential to decrease climate change emissions from vehicular transportation. The goal is to compare environmental impacts of IH^2 biofuels to equivalent fossil fuels in order to determine savings of greenhouse gas (GHG) emissions, but along this path, intermediate results for each biomass feedstock were generated and compared to each other. The functional unit for biomass feedstocks and IH^2 biofuels was 1 dry metric and 1 MJ of energy, respectively.

The main conclusion from this study is that GHG emissions for production and use of IH2 biofuels from a variety of feedstocks (microalgae, cane bagasse, corn stover, forest resources) are very small compared to comparable petroleum fuels, with the possible exception of fuels derived from microalgae. Savings of GHG emissions per MJ of transportation fuels between 93-98% are typical of IH^2 biofuels produced from most of the studied biomass species (cane bagasse, corn stover, and forest resources). Explorations of IH^2 biofuel transport modes (truck, rail, pipleline) and transport distances had very little effect on overall system GHG emissions. Microalgae produced using renewable electricity for collection and dewatering helped lower GHG emissions and increase savings above 50% compared to petroleum fuels, but the large energy burden of drying the high moisture microalgae feedstock (80% moisture) continues to be a challenge to approach the savings for bagasse, stover, and forest resources IH^2 biofuels.

In addition to these differences in GHG emissions for IH^2 biofuels from several biomass feedstocks, there are also differences in biofuel production yields. Table ES2 shows yields of IH^2 Biofuels from microalgae, cane bagasse, corn stover, and forest feedstocks. Microalgae IH^2 biofuels exhibit the highest yields, nearly double the productivity of the other biomass feedstocks. Composition of biomass is likely the reason for these large differences in yields. For example, many species of microalgae contain significant oil, which contains fewer oxygen atoms and more hydrogen atoms per molecule. In such cases, a higher percentage of the starting biomass is expected to exit the process as biofuel as opposed to CO_2, H_2O and other minor co-products. The yields in Table ES2 also impact area productivity, that is, the quantity of biofuel produced per unit area of surface of land or water per year. Area productivity is also affected by biomass productivity per unit surface area per year. Combining both of these productivities will result in a key indicator of overall biofuel production efficiency.

The results in this study represent a limited life cycle assessment that touched on one indicator of sustainability, greenhouse gas emissions and savings of those emissions compared to petroleum fuels. It is highly recommended to revisit this LCA when IH^2 conversion data is obtained on pilot or commercial scales. One topic of future interest might be LCAs of mixtures of these feedstocks for IH^2 biofuel production; for example mixtures of microalgae and forest residue resources. Results from such future studies can help refine IH^2 biofuel system impacts leading to more efficient production of this promising biofuel. Future studies should also include other sustainability indicators for which little is known from this new transportation production system, including land use change emissions, water quantity and quality, emissions of other air pollutants, worker safety, community impacts from biomass transport, and employment. These expanded studies are particularly important when attempting to understand impacts of large-scale dissemination and implementation of this new renewable transportation fuels technology.

Table ES2. Yield of IH^2 Biofuels from 2,000 Moisture and Ash Free (MAF) Metric Tons (mt) of Biomass.

IH^2 Biofuel from Different Biomass Types	Yield of IH^2 Gasoline (mt)	Yield of IH^2 Diesel (mt)	Total IH^2 Biofuel Yield (mt)
Microalgae	448	448	996
Cane Bagasse	432	140	572
Corn Stover	320	200	520
Forest Resources	320	200	520

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Appendix C — ZETON and CBI Preliminary Engineering

Zeton Inc. Budgetary Cost Estimate
Supply Of A Hydropyrolysis Demonstration Plant

Gas Technology Institute, Des Plaines, IL

Budget Quotation No. 804-4 February 22, 2011

1 Scope of Work

The scope of work for the supply of the 1 ton per day Hydropyrolysis Demonstration Plant is defined by the Process Flow Diagrams (804-4-001, 804-4-002, 804-4-003 Rev. B) provided with this quote, as well as by the clarifications described in this document.

2 Clarifications

The following clarifications and assumptions apply to Zeton's budgetary cost estimate.

2.1 General

- An allowance has been made for instrumentation, manual and automatic valves.
- Vessel, pipe and tube insulation has not been included in this quotation. Insulation can be installed on-site following re-assembly of the skids.
- Feed storage, handling/conveying to our feed bin, grinding/size classification and drying are excluded from the cost, as they are assumed to be supplied by the wood processing site
- Zeton has assumed that the packaged steam reformer system will be supplied by others, and will be located outside of Zeton's skids.
- Additional equipment that will be required but has not been included in the cost estimate are for the following systems: flare and flare knock-out, vacuum pump and knock-out to de-gas biomass prior to pressurizing the lock hopper, instrument air, utility nitrogen, chilled water (including mechanical refrigeration unit), condensate/BFW quality water, cooling water.

2.2 Equipment specifications

- Equipment sizing has been based on simulation data provided by GTI, unless otherwise specified in the sections below.
- A 25% over-design margin has been added to the simulation flow rates for equipment sizing. This does not correspond to any increase in capacity of the plant: it is merely a factor of conservatism in the flows used for sizing purposes.
- Properties required for equipment sizing have been obtained using ChemCad software. Stream composition data from the simulation have been used as input. At this time, Zeton has not evaluated the accuracy of the resulting properties.
- Equipment design conditions will be as indicated on the Process Flow Diagrams.
- Materials of construction will be Carbon Steel, 304/L or 316/L Stainless Steel as indicated on the Process Flow Diagrams.

- Dimensions obtained from preliminary equipment sizing have been indicated on the Process Flow Diagrams.

2.2.1 Solids Handling

- A bio-mass day bin/volumetric feeder (S-101), lock hopper (V-105), gravimetric feeder (S102) and screw feeder (S-104) have been included to feed the bio-mass into the Hydropyrolysis reactor.
    - S-101 has been sized for a hold-up time of 1 day.
    - S-102 has been sized for a hold-up time of 1 hour.
    - V-105 has been sized for hold-up time of 15 minutes.
    - Sizing of these items has been based on a biomass bulk density of 10 lbs/ft3.
- A lock hopper (V-108) and gravimetric feeder (S-103) have been included to feed catalyst into the Hydropyrolysis reactor. The same screw feeder as for biomass feeding will be used to feed the catalyst.
    - S-103 has been assumed to have a 50 L capacity.
    - V-108 has been assumed to be ¼ the size of the biomass lock hopper V-105.
- Both gravimetric feeders will be installed inside pressure bells (V-106, V-107). The pressure bells have been sized to fit the gravimetric feeders.
- Zeton has assumed that char removal will be accomplished with a cyclone (CY-121). To size the cyclone, it has been assumed that the solids to be removed are in the quantity of the carbon and calcium amounts indicated in the simulation stream data.
- Soot filters (F-125, F-126) have been included to clean the gas before it enters the Hydroprocessing reactor. These are the flexible mesh type, including a blow-back hydrogen reservoir, of the sort considered for the pilot plant but on a larger scale.

2.2.2 Reactors

- Reactor sizes have been based on information provided by GTI.

2.2.3 Compressor & Blower

- The hydrogen recycle compressor (C-151) has been assumed to be a single stage rod-sealed non-lubricated piston type compressor of cast iron/carbon steel materials, similar to that used in the pilot plant. The compressor will be designed to provide 75 psi of pressure difference to the gas stream.
- A variable speed blower (B-138) has been included to drive ambient air through the prereactor cooler.

2.2.4 Heat Exchangers

- A cross-exchanger (HE-137) will be used to heat recycle hydrogen and cool hydroprocessing reactor effluent. This will be a shell & tube, NEN type exchanger. This exchanger has been sized to minimize the sizes of the electric heater HE-113 and the cooler HE-135 and hence improve the energy efficiency of the process. This approach also decreases the equipment cost of the plant at the demonstration scale.
- An electric heater (HE-113) will be used to heat recycle hydrogen exiting the cross exchanger to the desired reaction temperature.

- The heat exchangers that will be used to cool the product streams (HE-135, HE-143) will be shell and tube, NEU type exchangers.
- The pre-reactor cooler (HE-136) will be a double pipe air cooler.
- A spill-back exchanger (HE-154) has been included for the hydrogen recycle compressor.

This will be a welded plate type exchanger.

2.2.5 3-Phase Separators

- Vertical separators have been chosen since there is a large amount of vapour to be separated from a small amount of liquid in both 3-phase separators (V-141, V-142).
- A baffle will be used keep the liquid separation section calm to promote the separation. There will be a pipe within the separator to allow the liquid in the feed stream to flow down to the heavier liquid phase. There will be another pipe to bring any trapped gas below the baffle plate back up to the vapour section.
- A droplet diameter of 50 micron and a droplet residence time of approximately 3 minutes have been assumed for liquid-liquid separation.
- Typically a boot would be used since the volume of liquid is small. If a boot is not used, the hold-up time to get thick enough liquid layers for easy draw-off would be substantial. However, with a boot, the dispersion band thickness increases. If long hold-up times (45 minutes – 2 hours) are acceptable, better separation is possible without the boots. Otherwise boots will be required to shorten the hold-up times. This detail does not affect the plant cost at the required level of precision for the estimate, but is provided for future consideration.

2.2.6 Vessels

- The char chamber (V-123) has been sized for a hold-up time of 2 hours.
- The ash collection chamber (V-114) has been sized to have a volume equal to that of the Hydropyrolysis reactor.
- The soot chamber (V-127) has been assumed to have the same size as the ash collection chamber.
- The char waste tank (V-128) has been sized for a hold-up time of 1 day, based on char flow from the char chamber.
- The water stabilizer (V-162), heavy product stabilizer (V-161) and light product stabilizer (V-163) have each been sized for a hold-up time of 1 day.

2.3 Structural and Layout

- The preliminary layout study indicates that this plant will include 4 vertical modules, 2 with dimensions 12 ft x 12 ft x 48 ft, and 2 with dimension 12 ft x 12 ft x 36 ft.
- In addition, a stair tower will be included.
- Frames will be constructed from rectangular hollow structural steel (HSS) and will be welded and painted rather than galvanized and bolted.
- The plant will be designed for an outdoor location and it has been assumed that there will be enough plot space to accommodate the modules and stair tower listed above.

2.4 Utilities

The following utilities are required at the battery limits of Zeton's skids. Systems to provide the utilities are not in Zeton's scope.

- Cooling water will be required for HE-154 and for the cooling coil on V-123.
- Clean tempered condensate or treated boiler feedwater at a temperature of at most 70oF will be required for HE-135. A flow rate of around 35,000 lb/hr will be required assuming a 5 degree temperature rise. Tempered condensate is recommended instead of cooling water in this exchanger to minimize fouling. Fouling would be an issue in the NEU type exchanger where the tube bundle is non-removable. Depending on available cooling water temperatures, the tempered condensate system may consist of a pump and cooling water indirect exchanger, or may require a mechanical refrigeration unit. The alternative would be to shift duty to the downstream chilled water/glycol exchanger. The pump and exchanger or mechanical refrigeration unit are not included in this cost estimate.
- Ethylene glycol at a temperature of at most 22oF will be required in HE-143. A flow rate of around 9000 lb/hr will be required assuming a 5 degree temperature rise. The associated glycol/water recirculation/mechanical refrigeration unit is not included in this cost estimate.
- Utility nitrogen for padding, purges etc. will be required.

2.5 Electrical & Controls

- General purpose electrical area classification has been assumed for this plant by virtue of outdoor ventilation, in all areas except the vicinity of the product hydrocarbon collection vessels. The area classification around the product receivers is assumed to be Class I, Division 2, Groups C and D.
- The plant will be designed within the guidelines of the National Electrical Code for the area classification noted above.
- 480 V 3 phase and 120/208 V 3 phase power will need to be provided to the skids.
- A single control system for both process controls and safety interlocking has been assumed.

3. Preliminary Timeline:

Once a site is selected, a typical schedule for such a project is indicated below:

- 12-14 weeks for Basic Engineering (leading to +/-10% cost estimate and detailed schedule)
- 12-15 months for Detailed Design, Procurement and Fabrication (subject to deliveries of long lead items from sub-vendors)
- 3-4 weeks for Factory Testing
- 1-2 weeks for Preparation for Shipping

4. Budgetary Cost Estimate and Terms: US$ 3,700,000 +/-30%

Price is estimated in US Dollars, FOB Burlington, ON. Local taxes and duties not included. Price includes detailed engineering, procurement, fabrication, factory testing, and preparation for shipping.

Milestone Payment Schedule:

1. 10% payment due upon issue of order

2. 30% payment due upon ordering of long lead items (pressure bells, feeders, cyclone, hot gas filters, reactors, vessels, heat exchangers, heater, compressor)
3. 20% upon fabrication of skid structure
4. 30% completion of manufacturing at Zeton’s Burlington, ON facility
5. 10% upon shipping from Zeton’s Burlington, ON facility

Invoices will be submitted for each of the above milestones. Invoices are payable within thirty (30) days after the date thereof.

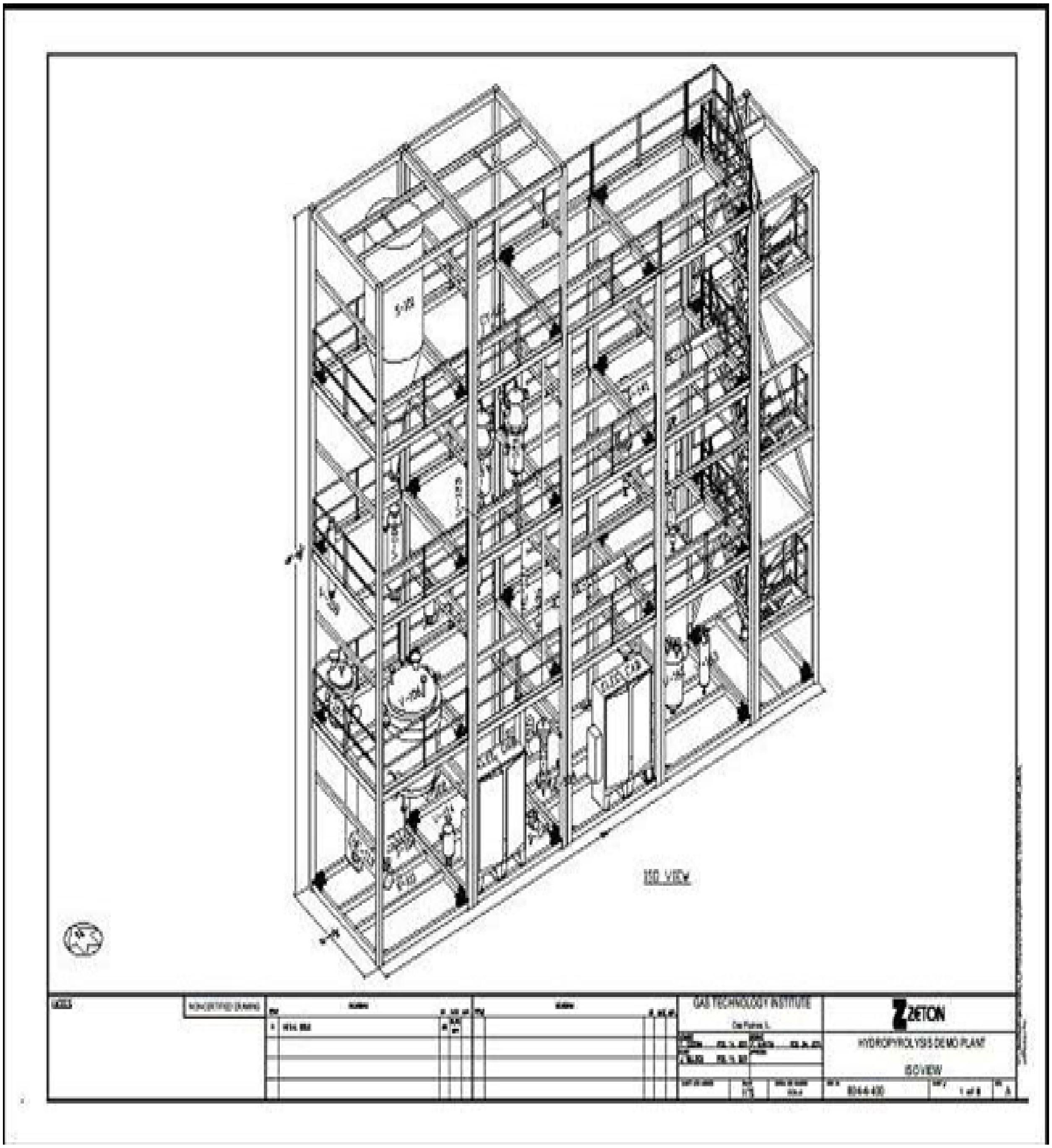
5. General Qualifications:

Zeton Inc. is a private company specializing in the custom design and manufacturing of automated, modular processing systems. These systems include laboratory units, pilot plants, demonstration plants, and modular commercial production plants. The corporation's personnel have gained considerable experience from the design and construction of over 650 pilot and modular commercial plants. This includes specialized experience in the design of reactors and control systems, knowledge of reliable suppliers of the equipment and instrumentation and control elements required, as well as experience in the manufacturing, testing, debugging and commissioning of pilot plants.

Zeton's staff consists of chemical engineers, mechanical engineers, electrical and control system engineers, as well as electrical and mechanical technicians. All personnel are experienced in their particular area of contribution towards Zeton's projects and are capable of effective execution of pilot plant design, construction, testing, installation and commissioning. In addition, the project engineers are experienced in providing efficient project management.

Zeton takes full responsibility for detailed engineering design, instrumentation and control system design, procurement, construction, installation, start-up and operator training. Most of the systems we have built are automated using computer based control, PLCs or DCSs.

Zeton uses a modular design and construction approach for its pilot plants. This gives our systems the flexibility required for process changes and development. Modules can easily be changed, replaced or added as the needs of the unit develop. Modular construction also reduces the project cost and schedule, and the installation and start-up period for the plant.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ISO VIEW
1 of 8
A

CBI Hydrogen Plant

1.0 Introduction

2.0 Design Basis

3.0 Process Description

4.0 Equipment Summary

This Technical Specification defines a conceptual hydrogen plant design by CB&I for Gas Technology Institute to be installed as part of their biomass to diesel demonstration unit.

CB&I's design is the result of a thorough evaluation of the needs and requirements for this project. CB&I has given careful consideration to selection of the design needed to provide an optimum process plant. This effort has resulted in an engineering design optimized to give an economical capital investment, low operating and maintenance requirements, and ease and flexibility of operation.

CB&I's design incorporates special engineering techniques developed during its fifty-six years' experience in the design, construction, and operation of hydrogen and carbon monoxide plants. To date, CB&I has provided over 175 of these plants around the world.

The design basis is to provide an efficient plant producing high purity hydrogen product from biomass gas.

Specifications for biomass feed and fuel gas, hydrogen product, and utilities are listed below:

2.1 Biomass Gas Feed and Fuel (Normal Composition)

Component	**Volume Percent**
Hydrogen	73.06
Methane	6.38
Ethane	3.40
Propane	2.32
n-Butane	0.15
n-Pentane+	0.02
Carbon Monoxide	8.53
Carbon Dioxide	6.14
Total	100.0
Hydrogen Sulfide, ppmv max	2
Pressure, psig min	420.3
Temperature, °F	110

* SCFD—'Standard Cubic Feet per Day'—wherein conditions of measurement are 60 °F and 14.7-psia.

2.2 Hydrogen Product

Hydrogen Purity, vol% min	99.9
Impurities, max	
CO, ppmv	10
CO_2, ppmv	10
CH_4, vol%	0.01
Pressure, psig*	400
Temperature, °F*	110

* Product compression is by others. Therefore, the above guaranteed product temperature and pressure are measured at the product compressor inlet.

2.3 Utilities

The following utilities are required at plant Battery Limits:

a. Electric power
   4160 V, 3-phase, 60 Hz
   480 V, 3-phase, 60 Hz
   120 V, 1-phase, 60 Hz
b. Cooling water supply at 80 °F and 75-psig min, 110 °F max return.
c. Nitrogen at 80-psig for startup and purging
d. Instrument air at 60-psig, oil free, -40 °F dew point, is required for the PSA only; the rest of the plant requires 40-psig, oil free, -40 °F dew point
e. Deionized BFW Makeup: Boiler feed water at 100 °F and 50-psig min.

The quality of boiler feed water makeup should be consistent with standards of the American Boiler Manufacturer's Association and the ASME Research Committee on Water in Thermal Power Systems.

Based on these standards, CB&I's estimate of minimum water quality requirements for a 464-psig steam system are given below. An average blowdown rate of five (5%) percent is utilized.

Dissolved Oxygen (mg/L, max before oxygen scavenger addition)	0.007
Carbon Dioxide (mg/L as free titratable CO2)	none
Total Iron (mg/L – Fe)	0.030 max
Copper (mg/L – Cu)	0.020 max
Total Hardness (mg/L – $CaCO_3$**)**	0.20 max
pH Range at 25 °C	7.5 – 10.0
Nonvolatile TOC (mg/L – C)	0.5 max
Oily Matter (mg/L)	0.5 max
Free Chlorine (mg/L)	below detectable limits
Sulfur (mg/L)	none
Silica (mg/L – SiO_2)	0.8 max

Total Alkalinity (mg/L – $CaCO_3$)	5 max
Specific Conductance (micromho/cm at 25 °C)	50 max
Total Solids (mg/L)	50 max
Suspended Solids (mg/L)	3 max

2.4 Ambient Conditions

Barometric Pressure, psia	14.31
Temperature, °F	
Vessel Design MDMT	-20
Combustion Air	80
Relative Humidity, %	80

Process steps are as follows:

1. Compression and Feed Pretreatment
2. Reforming
3. Shift Conversion
4. Process Gas Cooling
5. Hydrogen Purification
6. Heat Recovery and Steam Generation

Compression and Feed Pretreatment

Biomass gas is supplied at 110 °F and 420-psig minimum. A required amount is sent to the #1 PSA hydrogen purification system, V-101 A-H. The waste gas from V-102 is compressed to 458-psig in the Offgas Feed Compressor, C-101. The compressor discharge is heated to 750 °F in the Feed Preheater, E-102.

The heated gas from E-102 is fed to the Hydrodesulfurizer, V-103, where the catalyst bed saturates any olefins in the feed, converts sulfur compounds to hydrogen sulfide, and adsorbs the H_2S.

Reforming

The desulfurized gas is mixed with steam and superheated to 800 °F in the Reformer Feed Preheat Coil, E-104. The feed mixture then passes through catalyst filled tubes in the Reformer, H-101. In the presence of nickel catalyst, the feed reacts with steam to produce hydrogen and carbon oxides by the following reactions:

$$C_nH_m\,(g) + nH_2O\,(g) + \text{heat} \;=\; nCO\,(g) + (m/2+n)\,H_2\,(g) \qquad (1)$$

$$CO\,(g) + H_2O\,(g) \;=\; CO_2\,(g) + H_2\,(g) + \text{heat} \qquad (2)$$

The first reaction is the reforming reaction; the second is the shift reaction. Both reactions produce hydrogen. Both reactions are limited by thermodynamic equilibrium. The net reaction is endothermic. These reactions take place under carefully controlled external firing.

Shift Conversion

The process gas stream leaves the Reformer at 1,550 °F and is cooled to 675 °F by the Process Steam Generator, E-101. The gas is then fed to the Shift Converter, V-104, which contains a bed of copper promoted iron-chromium catalyst. Most of the incoming carbon monoxide is shifted to carbon dioxide and hydrogen by the following reaction:

$$CO\ (g) + H_2O\ (g) \quad = \quad CO_2\ (g) + H_2\ (g) + \text{heat}$$

Process Gas Cooling

The Shift Converter effluent process gas is cooled in the Feed Preheater, E-102, and the Process Gas Cooler, E-103. Process condensate is separated in the Condensate Separator, V-105. The gas is then sent to the #2 PSA hydrogen purification system, V-109 A-H.

Hydrogen Purification

The pressure swing adsorption (PSA) system is automatic, thus requiring minimal operator attention. The system operates on a repeating cycle having two basic steps: adsorption and regeneration.

During the adsorption step, feed gas flows through adsorbents, which are granular materials that selectively attract and hold (adsorb) feed gas impurities, thus producing high purity hydrogen product. The feed flow continues until the on-stream bed is loaded with impurities. At that time, a new adsorber is switched on-stream and the loaded adsorber is regenerated.

During regeneration, the impurities are desorbed which prepares the bed for the next adsorption cycle. Desorption consists of a step-wise depressurization, followed by purge. The adsorber vessel is then repressurized and returned to service.

Waste gas from the #2 PSA system is sent to the Reformer where it provides most of the fuel requirement. Makeup fuel is provided by biomass fuel gas.

High purity hydrogen from the #2 PSA is combined with the #1 PSA hydrogen and delivered to battery limits at 110 °F and 400-psig.

Heat Recovery and Steam Generation

Thermal efficiency of the plant is optimized by recovery of heat from the Reformer flue gas stream and from the effluent process gas stream. This energy is utilized to preheat Reformer feed gas and generate steam for reforming, shift conversion, and degasification.

Boiler feedwater makeup is received from offplot at 100 °F, 50-psig, and mixed with the process condensate from the V-105. The combined stream is sent to the stripping section of the Deaerator, V-108, for degasification. Stripping steam is provided by the vapor from the Steam Drum, V-106. The deaerator product water is pumped by the BFW pumps, P-101 A,B and sent to the BFW Preheat Coil, E-106, where it is heated and sent to the Steam Drum, V-106.

The Steam Drum serves the Process Steam Generator, E-101, and the Steam Generation Coil, E-105, which produce steam at 464-psig.

A larger portion of the steam from the Steam Drum is fed to the Reformer as process steam; some is used in V-108 as stripping steam. The remainder is recycled back to the process at the inlet of the Process Gas Cooler, E-103. The steam system blowdown is sent to the Blowdown Drum, V-107.

Heat is recovered from the flue gas by preheating the feed gas in E-104, generating steam in E-105, and preheating the boiler feedwater in E-106. The cooled flue gas is discharged to the atmosphere via the Induced Draft Fan, F-101.

Reformer

Item No.	Quantity	Description
H-101	1	Reformer–The reformer is a vertical, cylindrical unit of carbon steel construction, with steel supports, peep doors, access door, service platform for access to catalyst tubes, adjustable burner with air register, electric ignition pilot system, free-floating catalyst tubes, nickel steam-hydrocarbon reforming catalyst, flanged stainless steel inlet and outlet grids, off-take manifold and outlet connectors, inlet manifold, and trombone inlet connectors. The reformer is provided with ceramic fiber refractory insulation of the roof and wall, block insulation and high temperature castable for the floor. The reformer top is designed to allow continuous coolant air flow across the supports. The catalyst tubes in the firebox are designed in accordance with CB&I standard design practices for 100,000 hours minimum stress to rupture. The catalyst tubes are designed to allow ready access and easy removal of the catalyst.

Waste Heat Recovery

The waste heat recovery system consists of the following components. All heat transfer equipment will be fabricated and stamped to comply with ASME Boiler and Pressure Vessel Codes as applicable. Piping will be in accordance with B31.1 or B31.3, as applicable.

Item No.	Quantity	Description
E-101	1	Process Steam Generator - Horizontal fire tube exchanger with a carbon steel shell and 1.25 Cr – 0.5 Mo tubes, refractory lined carbon steel inlet and outlet channels and inlet tubesheet, and ceramic inlet ferrules. The special design shell-and-tube exchanger includes an internal bypass allowing positive outlet temperature control.
E-104	1	Feed Preheat Coil – Horizontal convection coils with carbon steel tubes installed in an internally insulated carbon steel housing.
E-105	1	Steam Generation Coil – Horizontal convection coils with carbon steel tubes installed in an internally insulated carbon steel housing.
E-106	1	BFW Preheat Coil – Horizontal convection coils with carbon steel tubes installed in an internally insulated carbon steel housing.
V-106	1	Steam Drum - Horizontal vessel. The vessel serves as common drum for E-101 and E-105, and is designed and fabricated in accordance with Section 1 of the ASME Code for Power Biolers.

Rotating Equipment

Item No.	Quantity	Description
C-101	1	Offgas Feed Compressor – Two stage reciprocating compressor with interstage water cooling.
P-101 A,B	1	BFW Pumps – Diaphragm type pumps with 316 SS Head.

Vessels

Vessel design will be in accordance with CB&I standards. All vessels are carbon steel unless otherwise noted.

Item No.	Quantity	Description
V-103	1	Hydrodesulfurizer – Vertical vessel complete with catalyst fill and dump nozzles, inlet distributor and outlet screen.
V-104	1	Shift Converter – Vertical vessel complete with catalyst fill nozzle, inlet distributor, and outlet screen. 1.25 Cr – 0.5 Mo construction with stainless steel internals.
V-105	1	Condensate Separator – Vertical vessel complete with full diameter demister pad, and inlet baffle; All stainless steel construction.
V-108	1	Deaerator – Horizontal storage vessel with vertical stripping section and stainless steel internals in the stripping section.
V-101 A-H	8	#1 PSA Adsorbers – Vertical vessels complete with adsorbent fill nozzle and gas inlet and outlet distributor screens.
V-102	1	#1 Waste Gas Drum – Vertical vessel complete with internal stand pipe.
V-109 A-H	8	#2 PSA Adsorbers – Vertical vessels complete with adsorbent fill nozzle and gas inlet and outlet distributor screens.
V-110	1	#2 Waste Gas Drum – Vertical vessel complete with internal stand pipe.

Heat Exchangers

The heat exchangers are constructed in accordance with CB&I standards as applicable. All exchangers are carbon steel construction unless otherwise.

Item No.	Quantity	Description
E-102	1	Feed Preheater – Double pipe exchanger with carbon steel shell and 1.25 Cr – 0.5 Mo tubes.
E-103	1	Process Gas Cooler – Multitube exchanger with stainless steel shell, tubes, and tubesheet: carbon steel tube closures.
E-104	1	Offgas Compressor Recycle Cooler – Double pipe exchanger with carbon steel shell and tubes.

Appendix D — IH^2 Wood Supply Study

Revised: March 28, 2011
Prepared By: Bill Gilbert and John Gephart, Johnson Timber Corporation

Introduction

The following report was prepared to estimate wood feedstock sources, costs, properties, and the fuel consumption in their collection and transportation based on a proprietary model developed by Johnson Timber to analyze the cost of wood feedstocks for the upper Midwest and determine the optimal biomass conversion plant size.

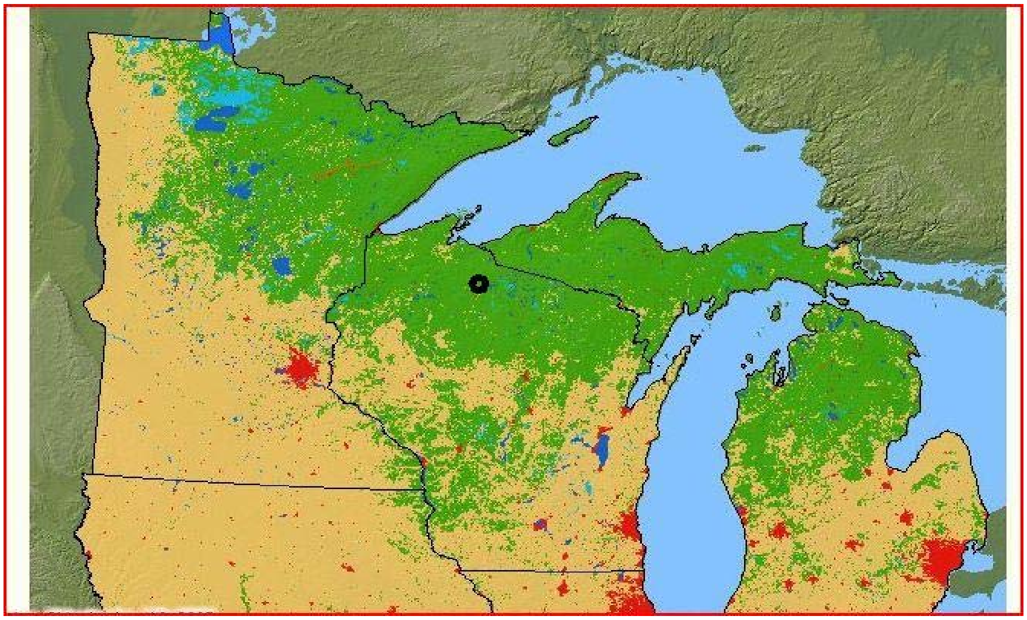
Input

Input values used in these tables are the expert opinions of the forestry and accounting staff at Johnson Timber Corporation and its affiliates. These companies consist of 15 forestry professionals, 5 accounting staff professionals, and a number of support staff. Operations include 6 major wood yards, three chip mills, a combined steam and power plant, and a pulp and paper manufacturing facility. Approximately 75 logging crews and over 200 independent truckers are harvesting and transporting of 1,500 bone dry tons per day of mill residues, forest residues, and growing stock from company controlled timber sales to mill locations in Minnesota, Wisconsin, and Michigan. An additional 1,000 bone dry tons per day of wood based feedstock are purchased from over 300 independent logging contractors.

Plant Size Modeling

Figure 1 shows the upper Midwest timber area where the wood feedstocks for the plant would originate.

Figure 1: Upper Midwest Timber



Tables 2 and 3 illustrate the changes in feedstock sources and costs. As the plant size increases the type of feedstock sources move from low cost mill residues to forest residues, and then towards both unmarketable and marketable roundwood sources. The preference is to use as much of the lowest cost feedstock as possible.

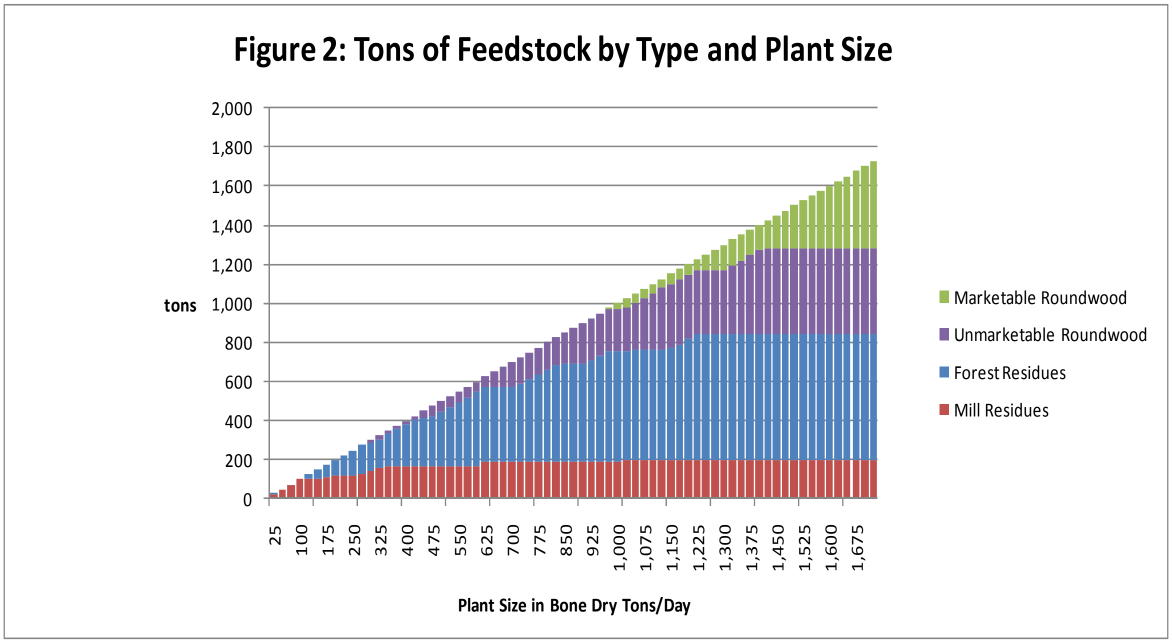


Figure 2: Tons of Feedstock by Type and Plant Size

Figure 3 shows both the weighted wood cost in red and the marginal wood costs in blue.

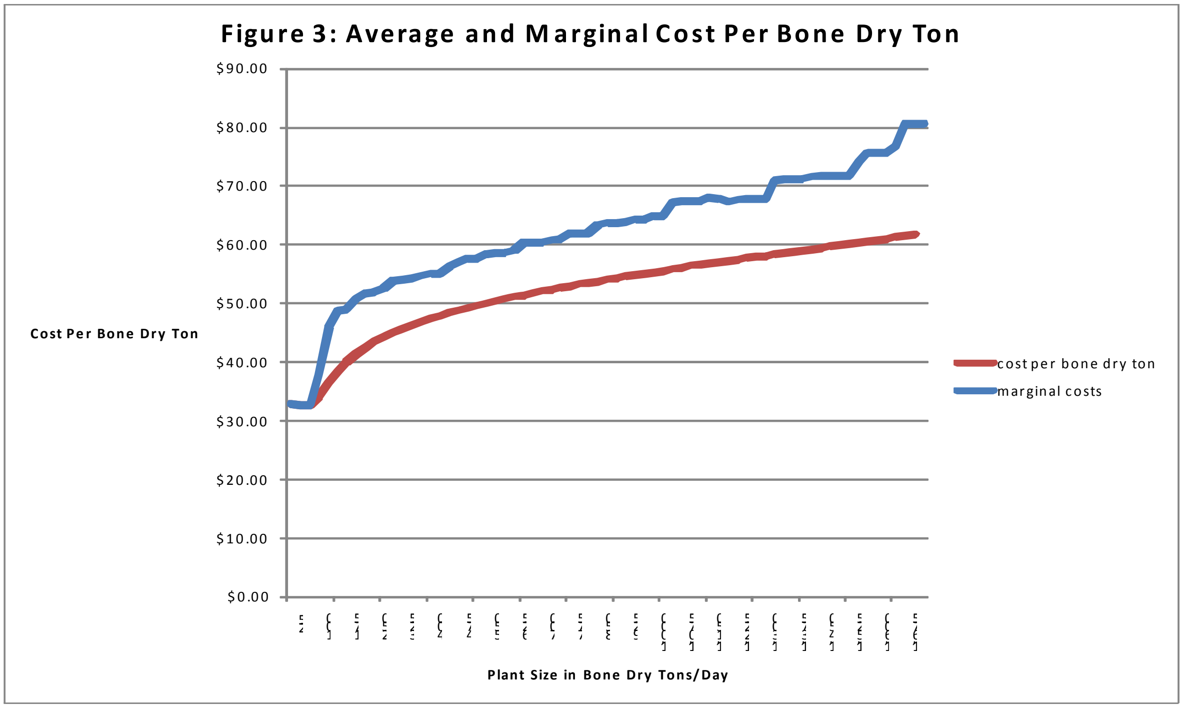


Figure 3: Average and Marginal Cost Per Bone Dry Ton

Figures 4 show the total amount of diesel fuel that would be required for collection and preparation to be required at each plant size. As would be expected, larger plant sizes require increasing amount of fuel utilized for transportation as materials are transported from longer distances.

Table 4- Total Gallons of Fuel consumed in collection and preparation vs Plant size

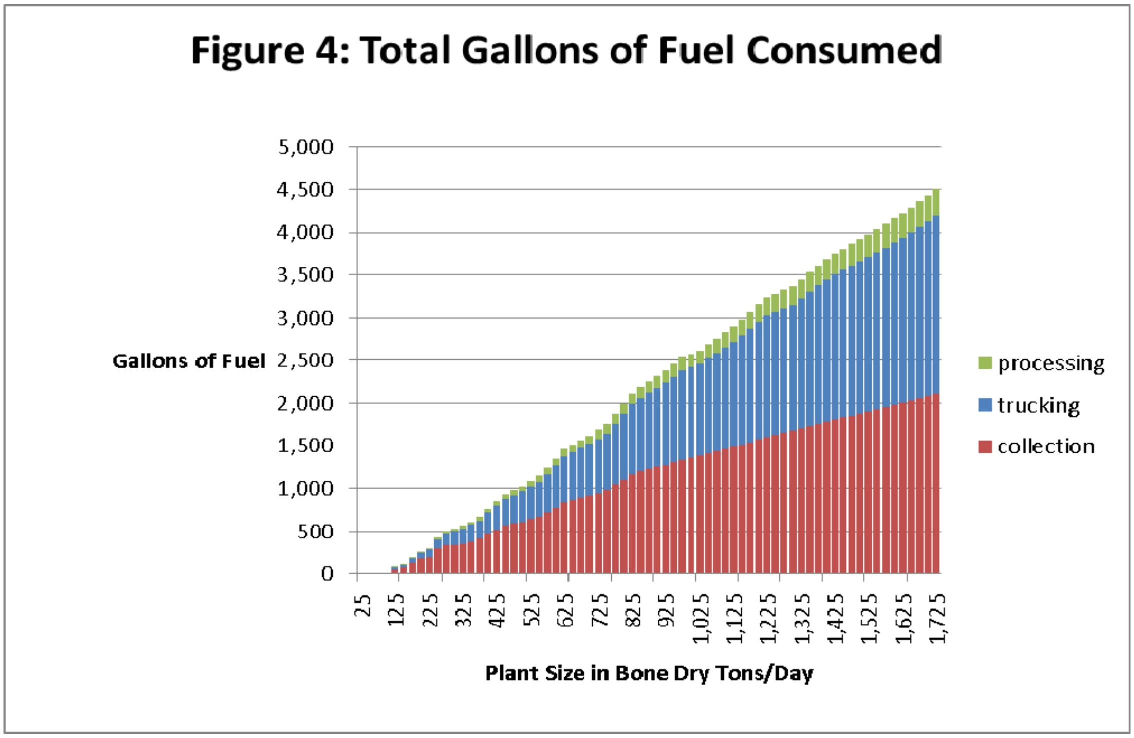
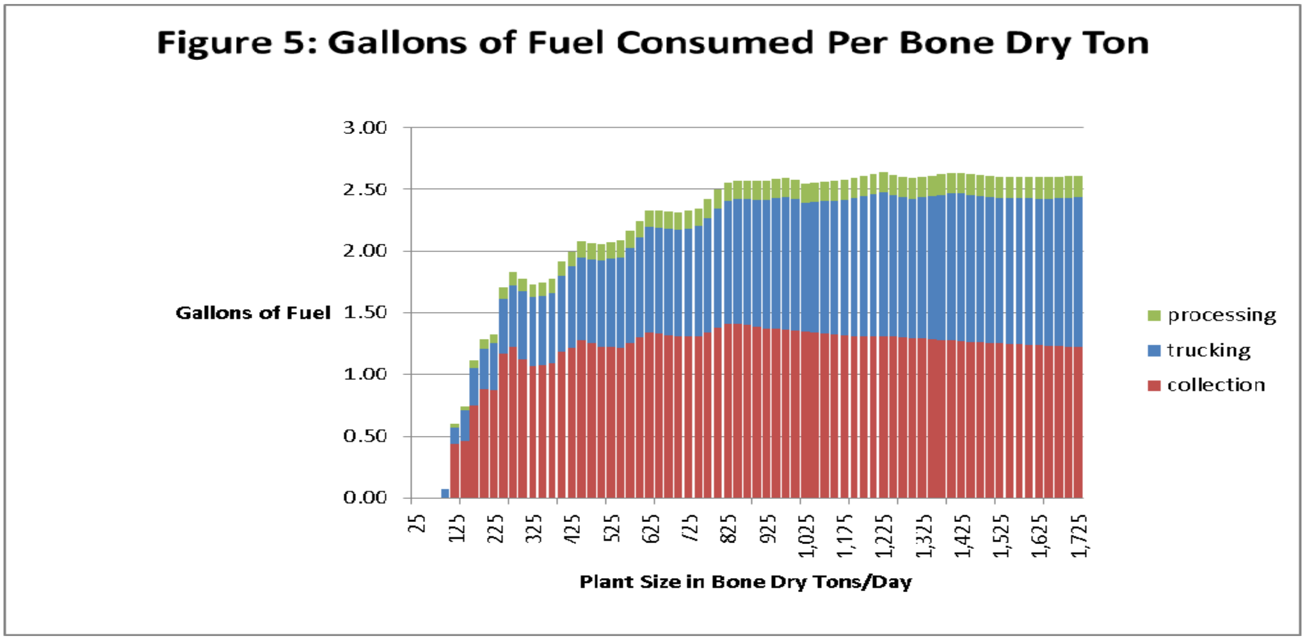


Figure 5 shows the amount of fuel for each bone dry ton as the plant sizes increase. As more material is needed there a decrease in the amount of fuel required for collection and an increase in transportation.



The weighted average properties of the feedstock undergo changes with changing plant size. Figure 6 shows how the ash content decreases with increasing plant size. This is due to a shift from the higher percentage ash content found in mill residues and biomass towards the lower ash content found in roundwood.

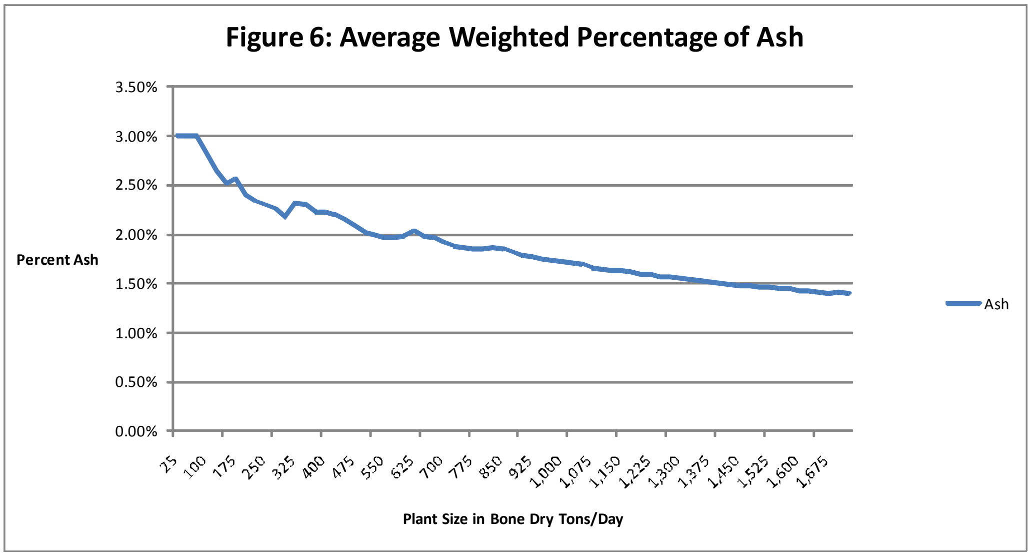


Figure 6: Average Weighted Percentage of Ash

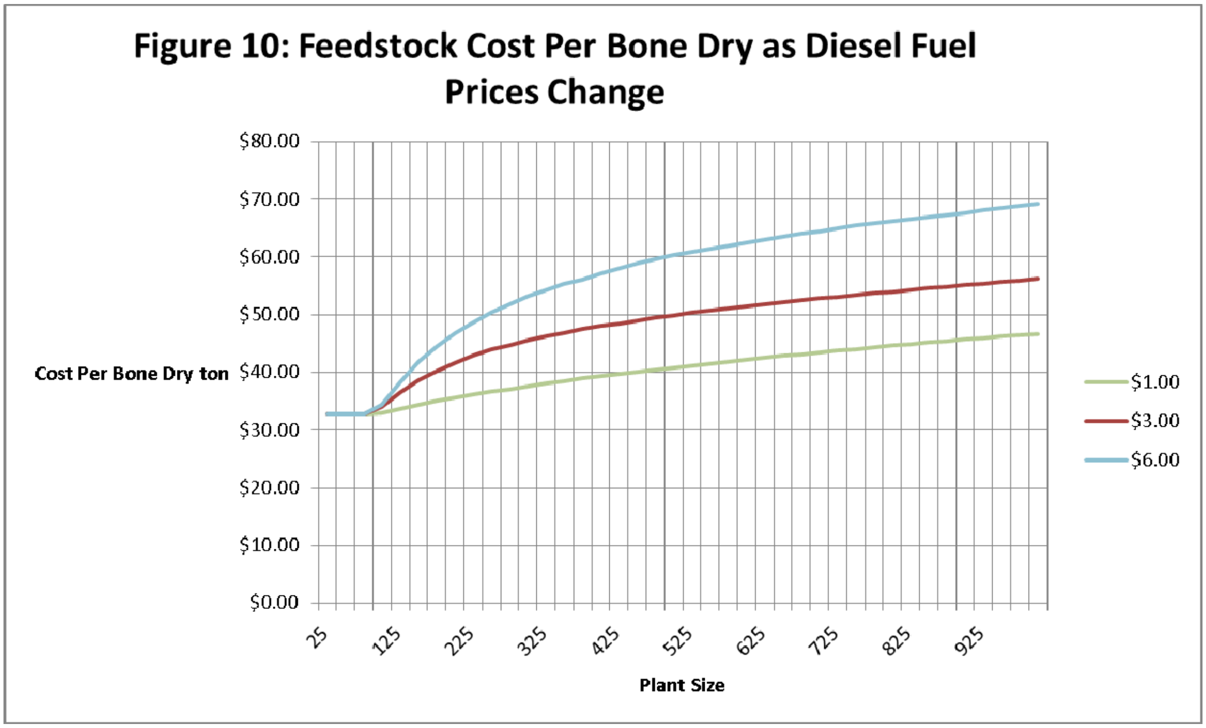
Table 1 is the summary data used for the LCA analysis of a 500 and 1000t/d IH2 plant

Table 1 - Summary Data Output for 500 and 1,000 Bone Dry Plant Sizes for LCA Analysis.

Summary Data for 500 and 1,000 Bone Dry Ton Plants			**totals** 500 bone dry ton per day	1000 bone dry ton per day
Raw material collection	**Lubricants/Fuel**	diesel gallons	611	1,361
		lubricating oil gallons	6.89	17.48
		hydraulic fluid gallons	7.18	18.21
		tubes of grease	18.94	48.07
		gasoline gallons	19.52	49.53
	Feedstock's			
	mill residues	bark	154	163
		sawdust	15	18
		slabs	15	18
		sub total	184	199
	forest materials	wood chips	184	336
		fuel rods	76	226
		underutilized roundwood	55	220
		merchantable roundwood	0	20
		sub total	316	801
		total	500	1,000
	volume by species group	hardwoods	373	707
		softwoods	127	293
		sub total	500	1,000
Transportation		total miles	42,400	127,130
		average haul distance	42	64
	Lubricants/fuel	diesel gallons	353	1,059
		lubricating oil gallons	**0**	**0**
		hydraulic fluid gallons	**0**	**0**
		tubes of grease	**0**	**0**
Yard and Processing	**Yard equipment**			
	Lubricants/fuel	diesel gallons	63	160
		lubricating oil gallons	**0.016**	**0.016**
		hydraulic fluid gallons	**0.016**	**0.016**
		tubes of grease	**0.043**	**0.043**
		gasoline gallons		
	electrical power to process feedstock	horse power	1000	2000
	totals		500 bone dry ton per day	1000 bone dry ton per day
Summary for Fuel and Lubricants				
	Lubricants/fuel	diesel (gallons)	1,028	2,581
		lubricating oil (gallons)	6.90	17.50
		hydraulic fluid (gallons)	7.19	18.23
		tubes of grease	18.99	48.12
		gasoline (gallons)	19.52	49.53
New output tables in Version 6.8				
Yard Equipment Volumes		type	500 bone dry ton per day	1000 bone dry ton per day
		chip dump	354	516
		log loaders	146	484
		processing (grinders)	146	484
		mixing loaders	500	1,000
Yard Equipment number of machines		type	500 bone dry ton per day	1000 bone dry ton per day
		# of chip dumps	2	2
		# of log loaders	1	2
		# of processors (grinders)	1	1
		# of mixing loaders	1	2

Figure 7 shows the effect of increased fuel costs on the average feedstock costs. As the fuel prices increase the cost for production and transportation per bone dry ton increases. The steady costs on the left hand side reflect the use of mill residues.

Figure 7 – Feedstock Cost per Bone Dry Tone as Diesel Prices Change



Appendix E — GTI Hydropyrolysis Process Energy Integration with Bioprocessing Industry

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Process Solutions Technology Development Center, Cargill Incorporated.

1.0 Introduction

GTI has developed a combined hydropyrolysis and hydroconversion process (Marker et al., 2009) to convert biomass into fuels such as gasoline and diesel (henceforth referred to as "GTI process"). **Figure 1** shows a basic block flow diagram of the GTI process. The overall mass balance for the process with a basis of 1000 MT/day corn stover on moisture and ash free (MAF) basis is shown in **Figure 2** (Marker, 2011). When 20% moisture and ash are considered, the actual corn stover consumption assumed is 1389 MT/day.

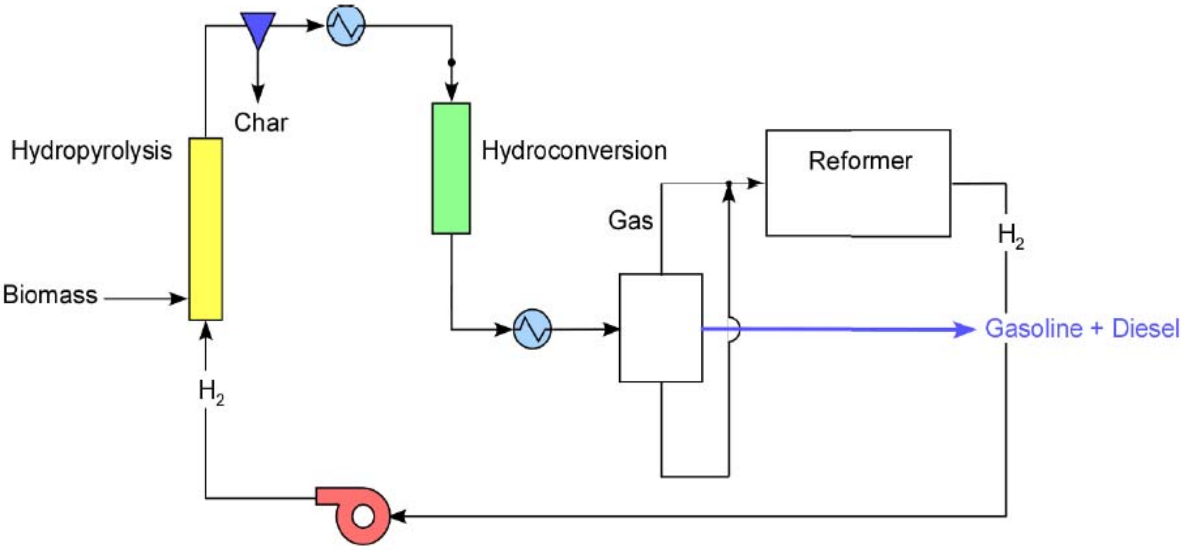

Figure 1. Basic process flow diagram for GTI hydropyrolysis/hydroconversion process for making gasoline and diesel from biomass (Marker et al., 2009).

As seen in **Figure 2**, there is a net heat generation in the GTI process which can be utilized to export high pressure steam. Some other co-products along with the gasoline and diesel products are water, ammonia and char. Hence there is an opportunity to co-locate the GTI process next to a bio-processing plant, such as a corn dry-milling ethanol facility, and integrate the two processes. Such integration is likely to substantially improve the greenhouse gas footprint of the bio-based products.

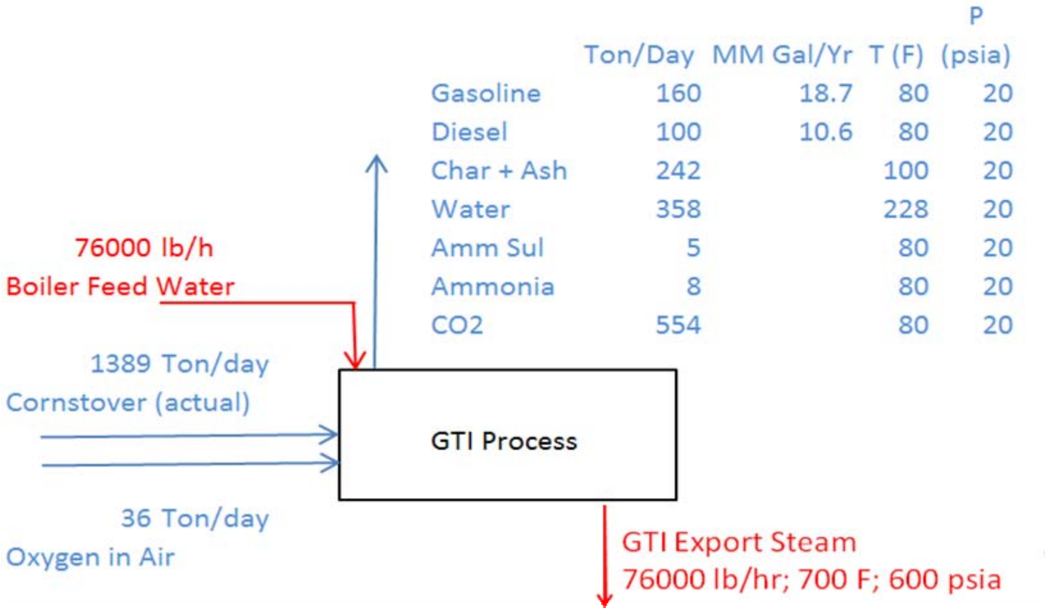

Figure 2. Overall mass balance for the GTI process (Marker, 2011).
Note : 1389 Ton/Day Corn Stover (20% moisture) = 1000 tons/day Moisture and Ash Free (MAF)

For the purpose of this report we based our analysis on the assumption that the GTI plant processes 2000 tons/day of corn stover or double the size provided by GTI.

3.0 Integration with a Corn Dry-Milling Ethanol Plant

A corn dry mill essentially takes corn and converts it to ethanol. A co-product of the process is dried distillers grains with solubles (DDGS), which is a nourishing animal feed. There is an installed capacity of about 13.5 billion gallons EtOH per year currently in the US, with most of the plants located in the mid-west agricultural belt. The typical size range of a dry mill ethanol plant is 50-150 MM gal/yr. About 56 plants in the US have a nominal capacity of 100 MM gal/yr or more (Renewable Fuels Association, 2011).

Figure 3 shows a simplified block flow diagram of a typical dry milling ethanol plant (Dale and Tyner, 2006). Corn is milled and slurry is formed with recycled water. It is then fed to a steam jet after enzyme addition to break down and open up the starch chains. Another enzyme dose is added and the starch is liquefied (hydrolyzed) and saccharified to convert starch into fermentable sugars. The saccharified material is then cooled, pitched with yeast, and converted to ethanol and CO_2 in an anaerobic fermentor. The beer from the fermentor contains about 12-15 wt% ethanol and is next fed to a series of distillation columns to enrich the alcohol content. The ethanol rich vapors (95 wt% ethanol) from the top of the distillation unit are further dried in a molecular sieve adsorption process to make >99 wt% ethanol, condensed and sold as a fuel.

The distillation bottoms (stillage) primarily contain water and unfermentable residue such as fiber, protein and yeast. This stream is centrifuged to recover solids as wet cake. The liquids are partially recycled as backset to form the corn slurry and provide dilution in the fermentors. The remaining stillage is concentrated in a multiple effect evaporator to form a syrup which is rich in nutrients. This syrup is mixed with the wet grain residue to enhance its nutritional value. This mixture is then fed to a dryer to obtain the dried distillers grains with solubles (DDGS) which serves as animal feed.

As seen in **Figure 3**, several unit operations in the ethanol process utilize low pressure steam (50-100 psig) as a heat source. The grain dryer could be either steam heated or direct fired using natural gas. Also the plant consumes electrical power to run the milling, pumps, centrifuges, agitators, compressors, etc. The dry mill is also located in the vicinity of the source of both corn and corn stover. Hence there is an excellent opportunity to co-locate a GTI hydropyrolysis plant next to a dry grind ethanol plant and integrate the two processes with the objective to reduce the environmental footprint of the ethanol process. The export steam from the GTI process can be used to generate electricity using a steam turbine, and the steam at the reduced pressure can be used to provide heat wherever needed in the ethanol plant.

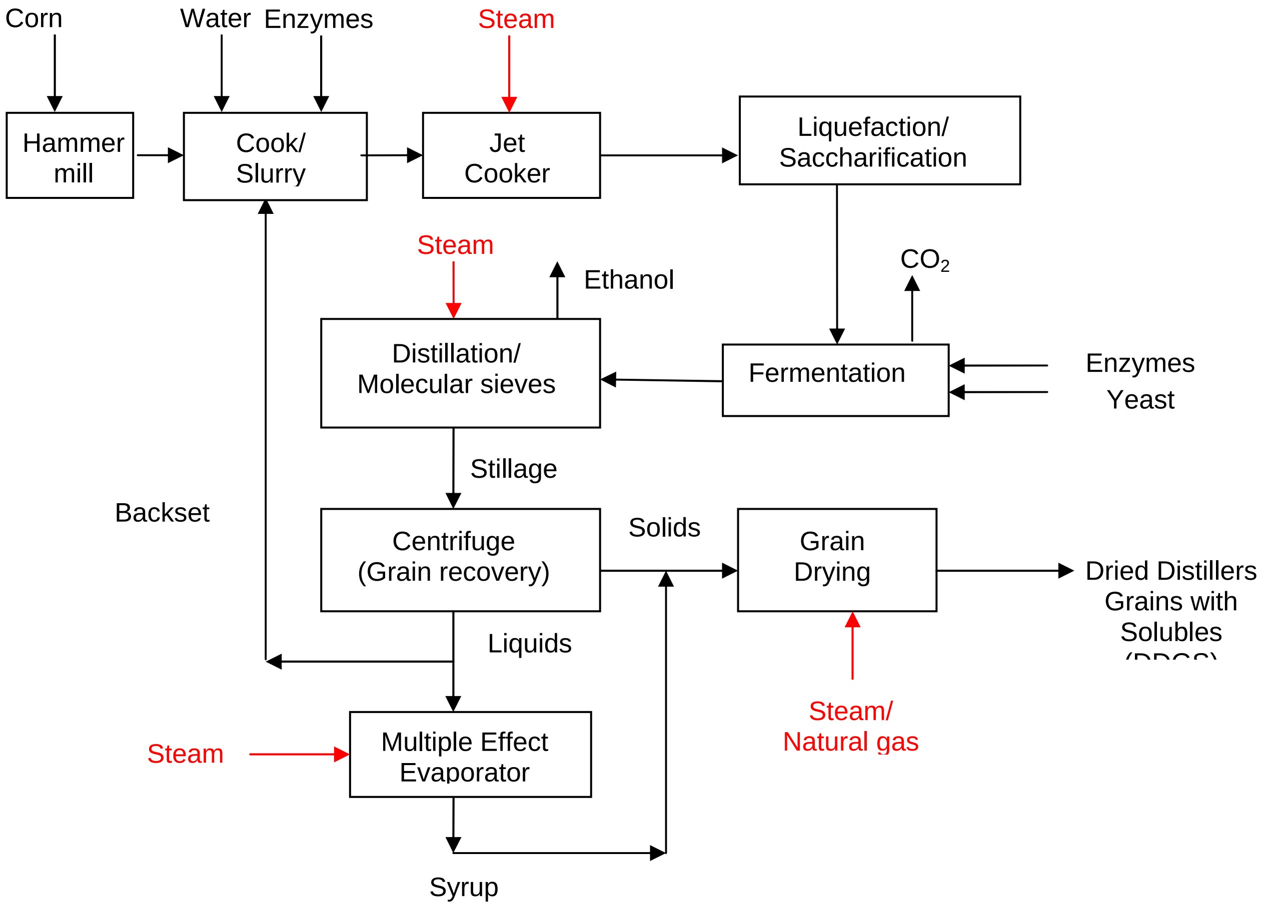

Figure 3. General block flow diagram of a dry milling ethanol plant.

4.0 Energy Requirement of a Corn Dry-Milling Ethanol Plant

Table 1 shows a literature review of the specific thermal energy and electrical power usage per gallon of ethanol produced. The energy efficiency of the plants has been improving over the years and hence the latest data needs to be used. The 2008 national dry mill survey (Mueller, 2010) was published based on responses of 90 dry grind plants (out of 150-plant sample size) and appears to be the most credible reference. The energy values are also in close agreement with other numbers quoted in literature. The present study will assume the dry mill energy usage quoted in the 2008 national survey to identify integration opportunities with the GTI process. Most of the thermal energy is used in form of steam (90% steam; 10% natural gas).

Table 1. Literature data for specific energy requirement per gallon of ethanol product of a corn dry milling ethanol plant.

Data vintage	Electrical Use kWh/Gallon	Thermal Use BTU/Gallon	Reference
2010	0.96	34,800	Rodriguez et al., 2010
2008	0.74	25,859	Mueller, 2010
2008	1.53	11,254	Franceschin et al., 2008
2006	0.68	11,711	Dale and Tyner, 2006
2005	2.75	39,076	Pimentel, 2005, 2007
2003	4.45	38,215	Tiffany and Eidman, 2003
2003	1.49	38,500	Pimentel, 2003
2002	1.19	34,800	Shapouri and Gallagher, 2005
2001	1.09	34,700	Shapouri et al., 2002
2000	1.14	31,879	McAloon et al., 2000

Table 2 lists the assumptions made within this study.

Based on the listed assumptions, the following is the estimated energy requirement for a 100 MM gallon/year ethanol dry grind plant:

- Electricity requirement: 8.80 MW
- Steam requirement: 23,400 Btu/gal ethanol
- Effective Energy Requirement (Steam + Electricity) = 25,924 Btu/gal ethanol

Table 2. List of assumptions made in modeling the GTI process-dry mill ethanol integration process.

Assumptions/Values Used		
Dry Mill Ethanol Plant Capacity	100	MM Gallon/Year
Working Days per year	350	days/year
Ethanol Yield	2.78	Gallon/Bushel of Corn
Corn: Corn Stover Ratio	1 ton stover at 15% moisture for 1 ton of corn	
1 bushel of corn	56	lb/bushel
Moisture content of GTI Feed	20	%
Electricity Requirement for Dry Mill Plant	0.74	kWh/Gallon
Thermal Energy Requirement	26,000	BTU/Gallon
Fraction of Thermal Energy in form of Natural Gas	10	%
Fraction of Thermal Energy in form of Steam	90	%
Export Steam Temperature from GTI Process	700	F
Export Steam pressure from GTI Process	600	psia
Export Steam Quantity from GTI Process	76	(lb/hr) steam for 1 (ton/day) of MAF Stover
Overall Turbine Efficiency	76	%

Evaluation of Energy Integration Options

The following integration options between the dry mill and the GTI process have been explored:

1. Use GTI export high pressure steam to produce electricity using a non-condensing steam turbine and provide low pressure steam to dry mill.
2. Use GTI export high pressure steam to produce electricity only using a condensing steam turbine.
3. Use a natural gas fired high pressure boiler to supplement GTI steam and provide entire electricity and steam requirement for the dry mill
4. Use char produced in GTI process as fuel to provide thermal energy in dry mill (in combination with using non-condensing steam turbine with GTI steam to provide electricity).

Each case was evaluated using the Aspen Custom Modeler (ACM v. 7.1) software from AspenTech, Inc. using a proprietary Cargill agri-food model library.

4.1 Case 1: Non-condensing steam turbine to generate electric power

Figure 4 shows the first option which consists of taking the high pressure export steam from GTI process at 600 psi and feeding it to a non-condensing steam turbine to generate electric power. The outlet steam is at 100 psig which has sufficient enthalpy to provide a substantial portion of the steam requirement in the dry mill.

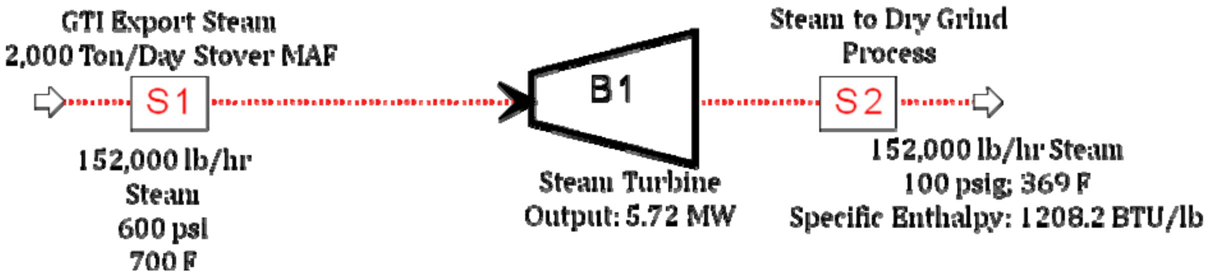

Figure 4. Case 1: Use GTI export steam in a non-condensible turbine to generate electrical power.

Modeling shows that the GTI steam generated from processing 2000 MT/day corn stover could meet about 2/3rds of the electric and steam usage of a 100 MM gal/yr ethanol plant. **Figure 5** shows the percent of 100 MM gal/yr dry mill ethanol plant electric power and thermal energy requirement which can be met by the GTI process based on varying amounts of harvestable corn stover (MAF basis, in tons/day).

Table 3. Electric and steam requirement for 100 MM gal/yr dry mill ethanol plant met by adding a non-condensing steam turbine to GTI export steam.

Unit	**% Requirement Compensated**		**External Energy Required**		**External Energy Used**
	Steam	**Electricity**	**Steam**	**Electricity**	**Nat Gas**
%	66	65	34	35	-
BTU/Gallon	15,444	1,641	7,956	884	-
Effective External Energy Required			8,840 BTU/Gallon		

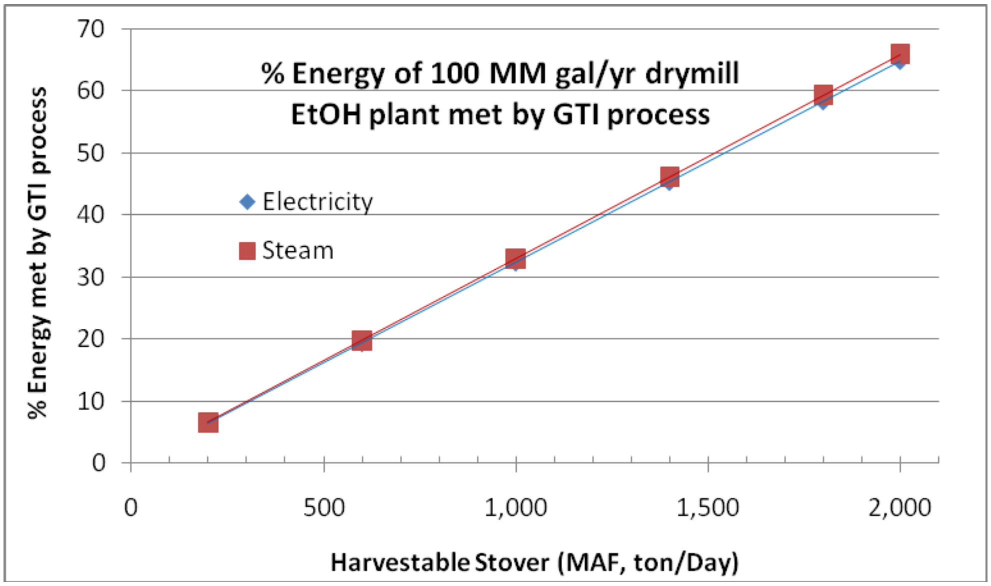

Figure 5. Percent of electrical power requirement of a 100 MM gal/yr dry mill ethanol plant met by different amounts of available harvestable stover (MAF: moisture and ash free basis).

4.2 Case 2: Condensing steam turbine to generate electric power

This case is essentially similar to Case 1, except that the steam emerging out of the steam turbine is condensed with a cooling water stream in a direct contact barometric condenser. Condensing the steam reduces the pressure at the turbine exhaust to just below atmospheric pressure, thus increasing the electric power output of the turbine.

As shown in **Table 4**, The electric output of the condensing turbine option would meet about 92% of the dry mill power requirement. However, a downside of this option is that a lot of hot water would be generated instead of steam. The amount of hot water generated is about 40 times the amount of water needed for the dry grind ethanol plant. Also the temperature and enthalpy of the hot water stream is greatly reduced compared to the exit steam in Case 1, which reduces the utility of this stream. Hence this is not an attractive option relative to
Case 1.

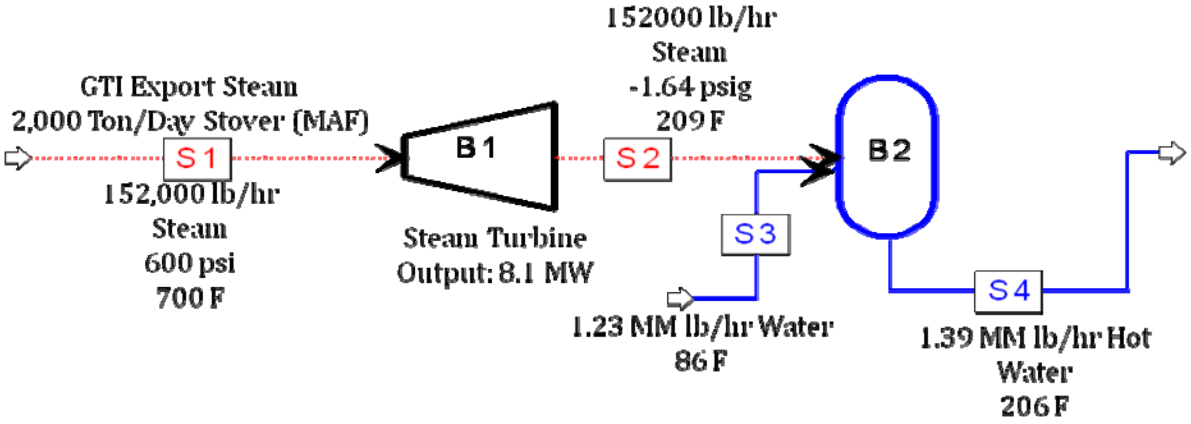

Figure 6. Scenario 2: Use GTI export steam in a condensable turbine to generate electrical power.

Table 4. Electric and steam requirement for 100 MM gal/yr dry mill ethanol plant met by adding a condensing steam turbine to GTI export steam.

Unit	**% Requirement Offset**		**External Energy Required**		**External Energy Used**
	Steam	**Electricity**	**Steam**	**Electricity**	**Nat Gas**
%	0	92	100	8	-
BTU/Gallon	0	2,323	23,400	202	-
Effective External Energy Required			23,602 BTU/Gallon		

4.3 Case 3: Supplementary boiler to meet entire electric power and steam requirement

Since Case 1 meets only 66% of the electric and steam requirement, an additional high pressure boiler could provide the balance (34%) steam at the same pressure as the GTI export steam (600 psi). The two high pressure steam streams can be combined and fed to the steam turbine. Doing so would generate the entire amount of the electric power as well as the steam required by the dry mill ethanol plant. Note that in this case, the electric power requirement of the fans and pumps driving the burner/boiler was not considered, but is assumed to be negligible.

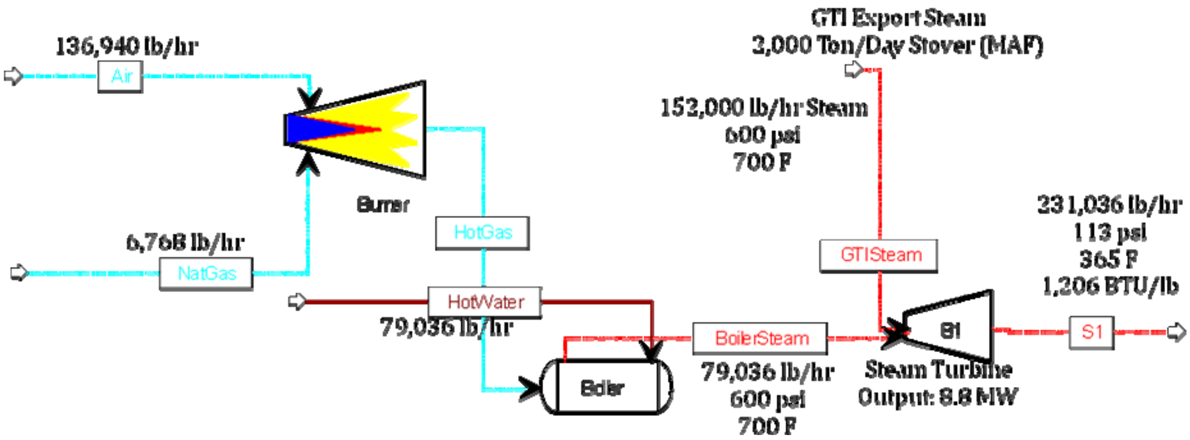

Figure 7. Case 3: Supplement GTI export steam with additional high pressure steam from a boiler to meet entire steam and electricity requirement of dry mill ethanol plant.

Table 4. Electric and steam requirement for 100 MM gal/yr dry mill ethanol plant met by adding a high pressure boiler to supplement GTI export steam.

Unit	**% Requirement Compensated**		**External Energy Required**		**External Energy Used**
	Steam	**Electricity**	**Steam**	**Electricity**	**Nat Gas**
%	100	100	0	0	6,768 lb/hr
BTU/Gallon	23,400	2,525	0	0	11,370*
Effective External Energy Required			11,370 BTU/Gallon		

* Natural gas heating value assumed to be 20,000 BTU/lb.

4.4 Case 4: Burn char to provide thermal energy in combination with steam turbine power generation

One of the co-products from the GTI process is char which is produced at 242 MT/day. On a moisture and ash free (MAF) basis, the char produced is 130 MT/day (MAF) for 1000 MT/day corn stover (MAF). Hence 260 MT/day char (MAF) is produced if the GTI process capacity is 2000 MT/day corn stover (MAF). The char has a heating value and can be burnt as a fuel in a boiler. Based on literature values for commercially available bio-chars made by pyrolysis (Dynamotive, Inc., 2011), the heating value is approximately 30 MM Btu/MT char (MAF).

Thus, for a 100 MM gal/yr ethanol plant, the char generated by a GTI hydropyrolysis plant processing 2000 MT/day corn stover can provide 27,402 Btu/gal EtOH heating value. From **Table 2**, we know that the dry mill ethanol plant requires about 26,000 Btu/gal EtOH in thermal energy. Hence burning char generated by the GTI process can provide 100% of the thermal energy required by the dry mill plant. Since the char is a renewable fuel, it is greenhouse gas neutral, which dramatically improves the environmental footprint of the ethanol process.

Based on **Table 3** for Case 1 (using a steam turbine to generate power from GTI export steam), the balance thermal power requirement was 7,956 Btu/Gallon. This energy requirement can be met with 29% of the char generated by the GTI process.

5.0 Emission Factor Comparison of Various Scenarios

The various options discussed in the previous section can now be compared on the basis of greenhouse gas (CO_2) emissions. Since most dry mills are located in and around the state of Iowa, the emission coefficients relevant to this state are assumed in this work:

State of Iowa CO_2 Emission Coefficients (US DOE, 2001)

- 0.9 kg of CO2 /kWh of Electricity
- 53.22 kg CO2/MMBTU of Natural Gas

These emission coefficients can be used in estimating the specific amount of CO_2 generated per gallon of ethanol, as shown in **Table 5**.

Table 5. Comparison of different integration options between the GTI process (2000 MT/day corn stover MAF) and a 100 MM gal/yr dry mill ethanol plant on basis of amount of CO2 generated per gallon of ethanol.

Case #	Description	Steam + Nat Gas (BTU/Gallon)	Electricity (kWh/Gallon)	Total (kg CO_2/Gallon)
Base Case	Conventional Process	23,400	0.74	1.92
1	Non condensing Turbine	7,956	0.26	0.65
2	Condensing Turbine	23,400	0.06	1.30
3	Boiler Addition	11,370	0	0.61
4	Non condensing Turbine + Biochar combustion	0	0.26	0.23

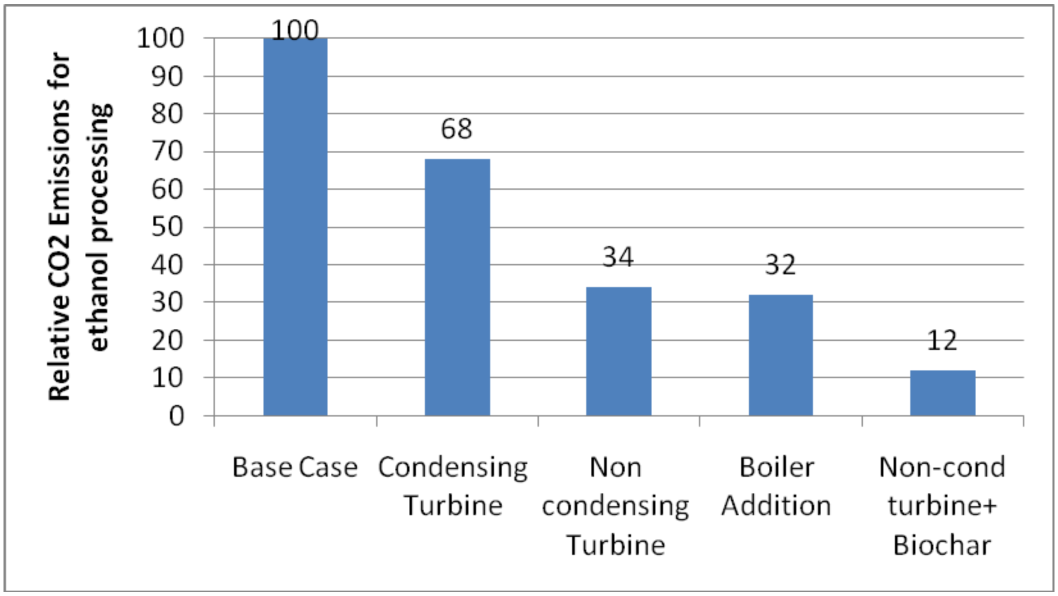

Figure 8. Relative CO_2 emissions (processing only) of a dry mill ethanol plant after integration with the GTI process.

The relative specific CO_2 generation of the different options (assuming the base case at 100 arbitrary units) is shown in **Figure 8**. It is evident that integration of the two processes can reduce greenhouse gas emissions for the ethanol plant by 66% using the export steam alone, and by a further 22% (for a total of 88% reduction) if the char generated in the GTI process is used as fuel for steam generation. This is a significant improvement in the environmental footprint of the ethanol dry grind process.

6.0 Further Integration Opportunities

Some additional integration opportunities have been identified to reduce the environmental footprint of the ethanol product, the evaluation of which was beyond the scope of the present study. These are as follows:

1. Hot water coming out of GTI process can be used in dry grind ethanol process. For this purpose, the water should meet city water quality.
2. The biochar, if not fully used as a fuel, can be used for soil amendment.
3. Based on quality, the ammonia solution from GTI process can be used in the ethanol fermentation process and as crop fertilizer.
4. Carbon dioxide from GTI process can be collected and used for enhanced oil recovery, especially if located close to oil wells.
5. The biochar addition to soil is a way of carbon dioxide sequestration.

7.0 Conclusions

- This study has identified several process integration options between the GTI process and a dry grind ethanol process which can substantially lower operating costs and the environmental footprint of the dry grind ethanol process.
- There is an opportunity to lower the carbon dioxide emissions from the ethanol production process by 66-88%. This may potentially open new markets for the domestic ethanol industry since there are new mandates in some states for biofuels to meet stringent environmental footprints.
- Besides energy, there are other opportunities to integrate the GTI process with the crop farms such as use of char and ammonia for fertilizer, or with an oil well to use CO_2 for enhanced oil recovery (EOR). These are attractive options and should be explored further.

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Appendix G — Key Reactions in the IH2 HYSIS Model

Table 1- Key Reactions in the HYSYS Model

Reaction	Heat of reaction BTU/lb-mole	Heat of reaction BTU/lb
$C_{12}H_{20}O_{10}\ +7H_2 \rightarrow 3CO\ +7H_20+\ C_9H_{20}$	$-3.2x10^5$	-987
$C_{24}H_{40}O_{20}\ +23H_2 \rightarrow CO\ +19H_20+C_4H_8+\ C_{19}H_{40}$	$-8.8x10^5$	-1358
$C_{12}H_{20}O_{10}\ +14H_2 \rightarrow CO_2\ +6H_20+2CO+\ 9CH_4$	$-5.3x10^5$	-1635
$C_2H_4+H2 \rightarrow C_2H_6$	$-5.9x10^4$	-2107
$C_{24}H_{40}O_{20}\ +13H_2 \rightarrow 2CO_2\ +12H_20+4CO+\ 3C_6H_{14}$	$-6.6x10^5$	-1019
$2C_9H_{10}O_3 \rightarrow 5H_2O+13C+C_2H_6+\ C_2H_4+CO$	$-1.1x10^5$	- 663
$2C_9H_{10}O_3\ +7H2 \rightarrow 5H_2O+CH_4+2C_7H_8+CH_4+CO+C2H4$	$-8.9x10^4$	-536
$C_{12}H_{20}O_{10}\ +9H_2 \rightarrow 2CO\ +8H_20+\ C_{10}H_{22}$	$-3.8x10^5$	-1172
$C_{12}H_{20}O_{10}\ +H_2 \rightarrow 4CO_2\ +2H_20+\ C_8H_{18}$	$-2.5x10^5$	-772
$C_{24}H_{40}O_{20}\ +11H_2 \rightarrow 5CO\ +15H_20+C_{12}H_{26}+C_7H_{16}$	$-6.7x10^5$	-1034
$C_{24}H_{40}O_{20}\ +14H_2 \rightarrow 3CO+2CO_2\ +13H_20+C_{16}H_{34}+C_3H_6$	$-7.1x10^5$	-1095
$C_{24}H_{40}O_{20}\ +14H_2 \rightarrow 3CO+2CO_2\ +13H_20+C_{14}H_{30}+C_5H_{12}$	$-7.1x10^5$	-1095
$C_{12}H_{20}O_{10}\ +8H_2 \rightarrow CO_2\ +2CO+6H_20+\ 3C_3H_8$	$-3.7x10^5$	-1142
$C_{12}H_{20}O_{10}\ +8H_2 \rightarrow 2CO_2\ +6H_20+\ 2C_5H_{12}$	$-4.2x10^5$	-1296
$C_{12}H_{20}O_{10}\ +15H_2 \rightarrow 10H_20+\ 3C_4H_{10}$	$-5.5x10^5$	-1698
$C_{24}H_{40}O_{20}\ +20H_2 \rightarrow 2CO+CO_2\ +16H_20+3C_7H_{16}$	$-8.4x10^5$	-1296
$C_6H_{14}S+H_2 \rightarrow H_2S+C_6H_{14}$	$-2.2x10^4$	-186
$2C_{12}H_{20}O_{10}\ +11H_2 \rightarrow 2CO_2\ +4CO+12H_20+\ C_9H_{18}+\ C_9H_{20}$	$-3.1x10^5$	-957
$C_9H_{18}+\ H_2 \rightarrow\ C_9H_{20}$	$-5.4x10^4$	-428
$C_{12}H_{20}O_{10}\ +5H_2 \rightarrow 2\ CO+1CO_2\ +6H_20+\ 3C_3H_6$	$-2.1x10^5$	-648
$C_3H_6\ +H2 \rightarrow C_3H_8$	$-5.3x10^4$	-1262
$CO+H_2O \rightarrow CO_2\ +H_2O$	$-1.8x10^4$	-642
$C_{24}H_{40}O_{20}\ +17H_2 \rightarrow 3CO+CO_2\ +15H_20+3C_4H_{8\,+}\ 2C_4H_{10}$	$-6.5x10^5$	-1003
$C_9H_{10}O_3\ +7H_2 \rightarrow 3H_2O+C_9H_{18}$	$-1.8x10^5$	-1084
$C_4H_8\ +H2 \rightarrow C_4H_{10}$	$-5.4x10^4$	-964
$C_{12}H_{20}O_{10}\ +4H_2 \rightarrow CO+1CO_2\ +7H_20+\ C_{10}H_{14}$	$-3.0x10^5$	-925
$C_{24}H_{40}O_{20}\ +3H_2 \rightarrow 4CO+2CO_2\ +12H_20+C_{18}H_{22}$	$-4.2x10^5$	-648
$C_2H_7N\ +H_2 \rightarrow C_2H_6+NH_3$	$-3.6x10^4$	-800