CARB Method 2 Fuel Pathway Report
UCO Biodiesel
Revised

Prepared For:

FutureFuel Chemical Company
2800 Gap Road
PO Box 2357
Batesville, Arkansas
72501

Prepared By

(S&T)^2 Consultants Inc.
11657 Summit Crescent
Delta, BC
Canada, V4E 2Z2

Date: January 7, 2014
Revised: May 26, 2014
Revised: June 10, 2014
Revised: August 5, 2014
Revised: August 29, 2014
Revised: October 15, 2014

EXECUTIVE SUMMARY

In 2009 the California Air Resources Board (ARB/Board) approved the California Low Carbon Fuel Standard (LCFS). The LCFS establishes a compliance schedule that requires fuel providers to reduce the carbon intensity of the fuels they provide each year between 2011 and 2020.

The LCFS requires fuel providers to determine the carbon intensity of the fuels they provide, and to report that information to ARB. ARB uses approved fuel carbon intensities to determine whether providers are in compliance with the regulation. Most transportation fuels sold in California are subject to the provisions of the LCFS.

Fuel providers may use one of two methods to determine the carbon intensities of the transportation fuels they provide to the California market. Under Method 1, fuel providers select carbon intensity values from the fuel carbon intensity lookup table found in the LCFS Regulation. Under Method 2, any entity, whether a regulated party or not, may seek Board or Executive Officer approval of additional fuel pathways or sub-pathways. If a proposed pathway or sub-pathway is approved, it is added to the lookup table, and becomes available to all fuel providers. The use of a new pathway or sub-pathway may begin as soon as it has been added to the lookup table.

Under Method 2, fuel providers may apply for a new fuel pathway that reflects their specific fuel production process. This would be required if some of the pathway activities occurred in a region outside of the regions specified in the approved CARB pathways.

The modified pathway that is covered by this application is for a very similar concept to the UCO biodiesel pathway developed by CARB in June 2011 except that the biodiesel production is located in Arkansas. The feedstock and biodiesel transportation distances have been altered and the carbon intensity of the electric power in Arkansas is different than it is in the other regions included in the CA GREET model. In addition, the proponent, FutureFuel, utilizes a slightly different biodiesel production process, which uses more energy than the typical biodiesel plant modelled by CARB. The differences in each stage of the production process are described in more detail in later sections of this report.

The GHG emissions for each stage of the lifecycle for the reference case and for the FutureFuel case are summarized in the following table.

Table ES- 1 Lifecycle GHG Emissions

Parameter	Base Case	FutureFuel
	g/MJ	
Rendering of UCO	5.69	5.54
UCO Transportation	0.30	1.90
Biodiesel Production	6.06	9.09
Biodiesel Transportation	2.19	2.80
Total Tank to Wheel	14.24	19.33
Vehicle Operation	4.48	4.48
Total	18.72	23.81

The CI for the FutureFuel UCO biodiesel is 5.09 g/MJ higher than the existing pathway due to the longer transportation distances for feedstock and biodiesel and the higher biodiesel production emissions resulting from higher energy use and a portion of that energy being from coal.

TABLE OF CONTENTS

List of Tables

List of Figures

1. Introduction

In 2009 the California Air Resources Board (ARB/Board) approved the California Low Carbon Fuel Standard (LCFS). The LCFS establishes a compliance schedule that requires fuel providers to reduce the carbon intensity of the fuels they provide each year between 2011 and 2020.

The 2020 carbon intensity level is ten percent below the baseline 2010 level. "Carbon intensity" is the total greenhouse gas emissions from the production, transport, storage, dispensing and use of a fuel. It is expressed as grams of carbon-dioxide-equivalent per megajoule of fuel energy (g CO_2e/MJ). In the context of the LCFS, the term "carbon intensity" refers to the full lifecycle greenhouse gas emissions associated with a specific fuel "pathway."

The LCFS requires fuel providers to determine the carbon intensity of the fuels they provide, and to report that information to ARB. ARB uses approved fuel carbon intensities to determine whether providers are in compliance with the regulation. Most transportation fuels sold in California are subject to the provisions of the LCFS.

Regulated parties must report the carbon intensities of the fuels they provide using a table of Board-approved carbon intensity values (a "lookup table"). Carbon intensities outside of the core set developed by staff are the responsibility of fuel providers.

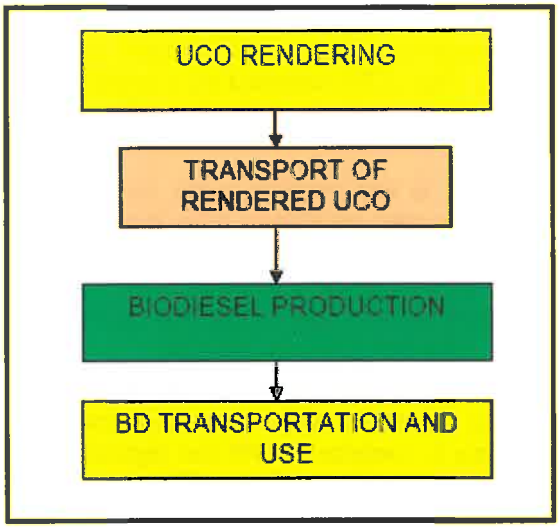
Fuel providers may use one of two methods to determine the carbon intensities of the transportation fuels they provide to the California market. Under Method 1, fuel providers select carbon intensity values from the fuel carbon intensity lookup table found in the LCFS Regulation. Under Method 2, any entity, whether a regulated party or not, may seek Board or Executive Officer approval of additional fuel pathways or sub-pathways. If a proposed pathway or sub-pathway is approved, it is added to the lookup table, and becomes available to all fuel providers. The use of a new pathway or sub-pathway may begin as soon as it has been added to the lookup table.

Under Method 2, fuel providers may apply for a new fuel pathway that reflects their specific fuel production process. This would be required if some of the pathway activities occurred in a region outside of the regions specified in the approved CARB pathways.

1.1 Reference Pathway

CARB published a Used Cooking Oil to biodiesel pathway in June 2011. That pathway was approved by the Board Feb 21, 2012. It is identified as BIOD004 in the CARB lookup table. The components of the pathway are shown in the following figure.

Figure 1-1 UCO Biodiesel Discrete Components



The biodiesel production scenario covered by this pathway was for the biodiesel production to be in the US Midwest. Two options were provided, one with and one without cooking in the rendering process. The calculated well to wheel emissions for the cooking process are shown in the following table.

Table 1-1 Lifecycle CI Results for UCO Biodiesel – US Production

Stage	Emissions, g CO_2eq/MJ
UCO Rendering	5.69
UCO Transport	0.30
Biodiesel Production	6.06
Biodiesel Transport	2.19
Total Tank to Wheel	14.24
Vehicle Operation	4.48
Total	18.72

These emissions have been verified with the base GREET model used for this work, ca_greet1.8b_dec09_CA_Corn_OilWDGS_01302012.xls.

1.2 Modified Pathway Description

The modified pathway that is covered by this application is for a very similar concept except that the biodiesel production is located in Arkansas. The feedstock and biodiesel transportation distances have been altered and the carbon intensity of the electric power in Arkansas is different than it is in the other regions included in the CA GREET model. In addition, the proponent, FutureFuel, uses more energy than the typical biodiesel plant modelled by CARB. The differences in each stage of the production process are described in more detail in later sections of this report.

Changes to the model inputs on the UCO BD sheet are highlighted with a light orange background. The results are summarized on rows 258 to 266, columns I to N.

1.2.1 Arkansas Power

The marginal power production in the Arkansas has been added to the base GREET model that was obtained from CARB. This model is identified as ca_greet1.8b_dec09_CA_Corn_OilWDGS_01302012.xls.

The average power production in Arkansas and the assumed marginal mix is summarized in the following table. The power mix is derived from EPA eGrid data for 2009 for the SERC Reliability Corporation, Mississippi Valley sub region. The marginal mix is derived by adding the coal, nuclear and biomass percentages to natural gas, as per CARB practice.

Table 1-2 Arkansas Power Mix

	Average	Marginal
Residual oil	2.3%	2.31%
Natural gas	45.1%	73.02%
Coal	22.7%	22.73%
Nuclear	26.0%	0.0%
Biomass	1.9%	1.93%
Other (renewables)	2.0%	0.0%

The look up table on the Regional LT tab has been modified to include an Arkansas average and Arkansas marginal option in columns M and N.

1.2.2 FutureFuel Chemical Company

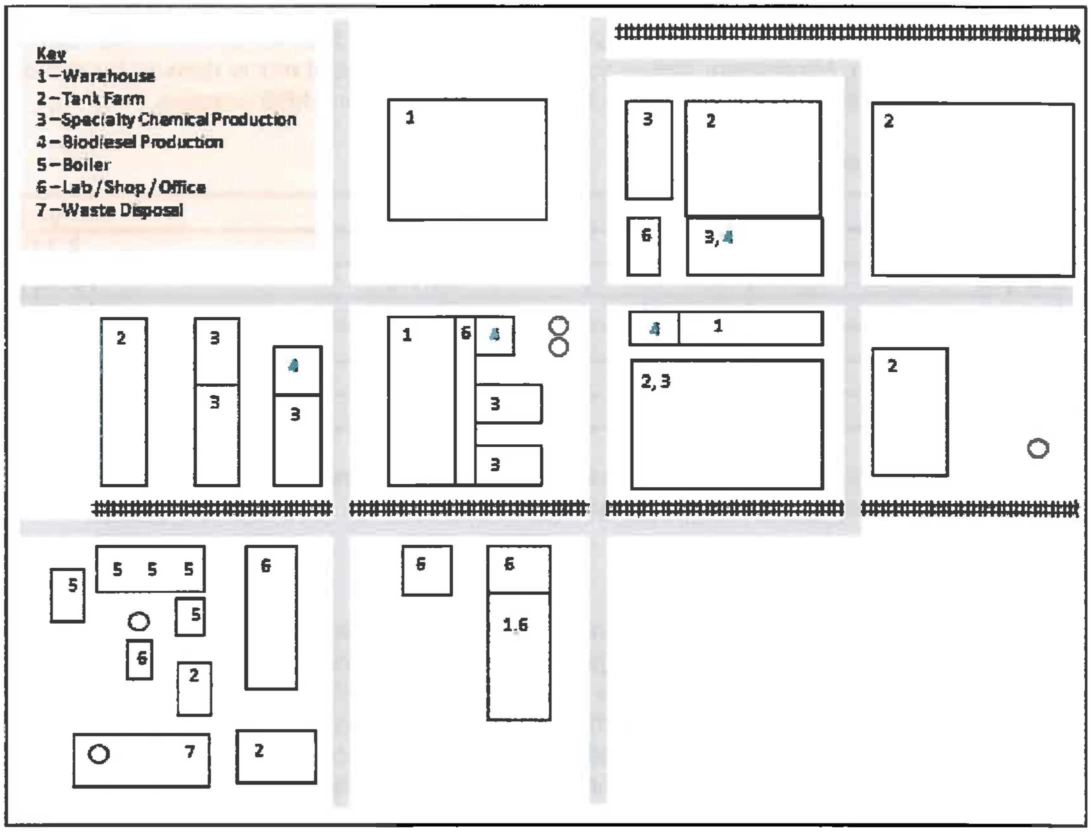
FutureFuel Chemical Company has numerous production facilities located on a single plant site in Batesville, Arkansas. FutureFuel produces biodiesel and is a supplier of specialty organic chemical intermediates used in the manufacture of paints and coatings, plastics and bottle polymers, medical supplies, prescription medicines, food supplements, household detergents, and agricultural products. Hundreds of different products could be made on-site. Typical reactions practiced at FutureFuel include but are not limited to the following:

Acetylations	Bromination	Friedel Craft Reactions
Acylations	Chlorinations	Methylations
Aldol Reactions	Condensations	Oxidations
Alkylations	Diazotizations	Polymerizations
Addition Reactions	Esterifications	Saponifications
Amidations	Etherifications	Sulfonations

The plant has a complete analytical testing facility staffed by FutureFuel employees who troubleshoot production and quality issues using a wide array of analytical instrumentation. For quality assurance the plant is a ISO 9001:2008 certified manufacturing facility. ISO 9001:2008 is an international certification that ensures both quality and environmental guidelines are adhered to. FutureFuel is a member of the American Chemistry Council and a Responsible Care member. All operations are computer controlled. The plant utilizes an in-house archiving system for data retrieval and utilizes a fully integrated SAP system. The plant has an environmental staff with over 150 years of combined experience that safeguards the environment and ensures regulatory compliance.

Biodiesel production equipment is integrated with other production facilities across the site. A common infrastructure supports the entire plant site. A simplified block diagram of the site is shown below.

Figure 1-2 FutureFuel Facility Layout

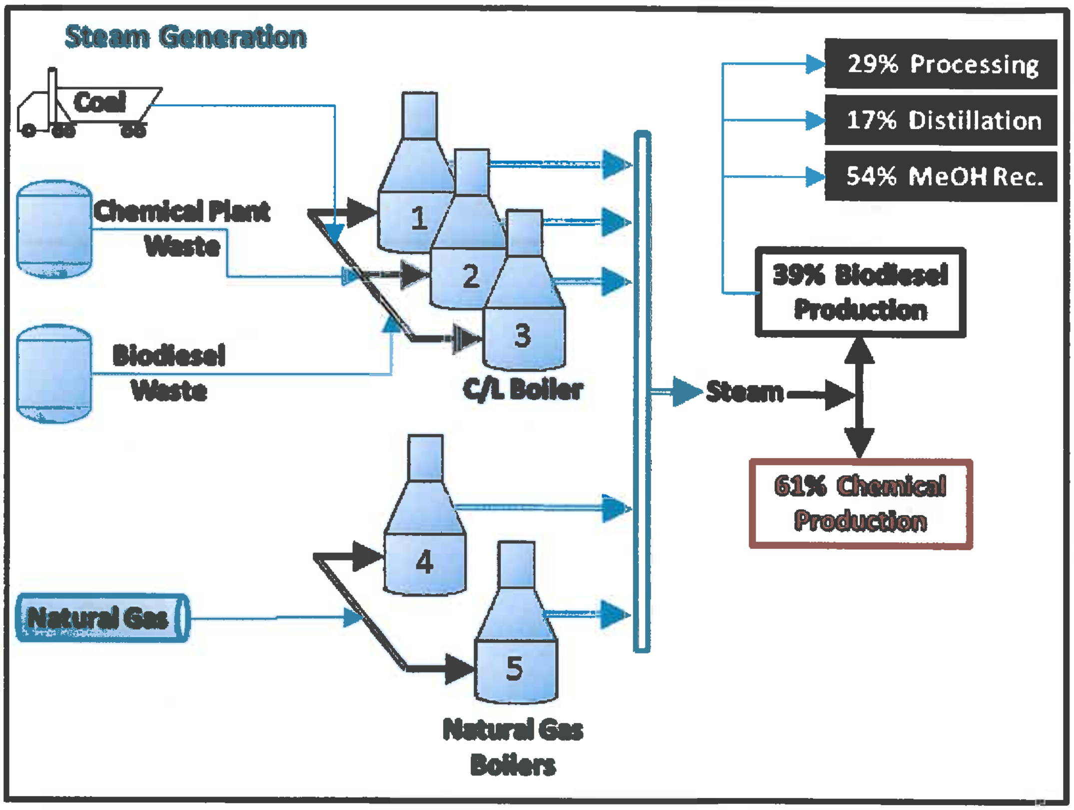


FutureFuel's biodiesel production facility has been BQ9000 certified since 2006 and their biodiesel fully meets or exceeds all ASTM D6751-12 specifications. FutureFuel is also registered with the EPA under the Renewable Fuel Standard (RFS) and have been since its inception. Annual attestation audits have been performed under this program on the facility and there have been no significant findings. In addition, FutureFuel became certified in 2013 and continues as an active participant in the voluntary RFS Quality Assurance Program.

1.2.2.1 Plant Services - Steam

Common or shared plant services include steam, grid electricity, cooling water, process water, sewer systems, waste disposal, plant air and nitrogen systems. FutureFuel has 5 boilers that supply the plant steam distribution system. Two natural gas boilers are rated to provide 59% of the steam capacity while the remaining 41% of the steam capacity comes from 3 coal/liquid (C/L) fired boilers. High fuel value waste from chemical and biodiesel production are combusted along with coal in the 3 C/L boilers. They are identical side-by-side units discharging into a common stack.

Figure 1-3 Steam Supply System



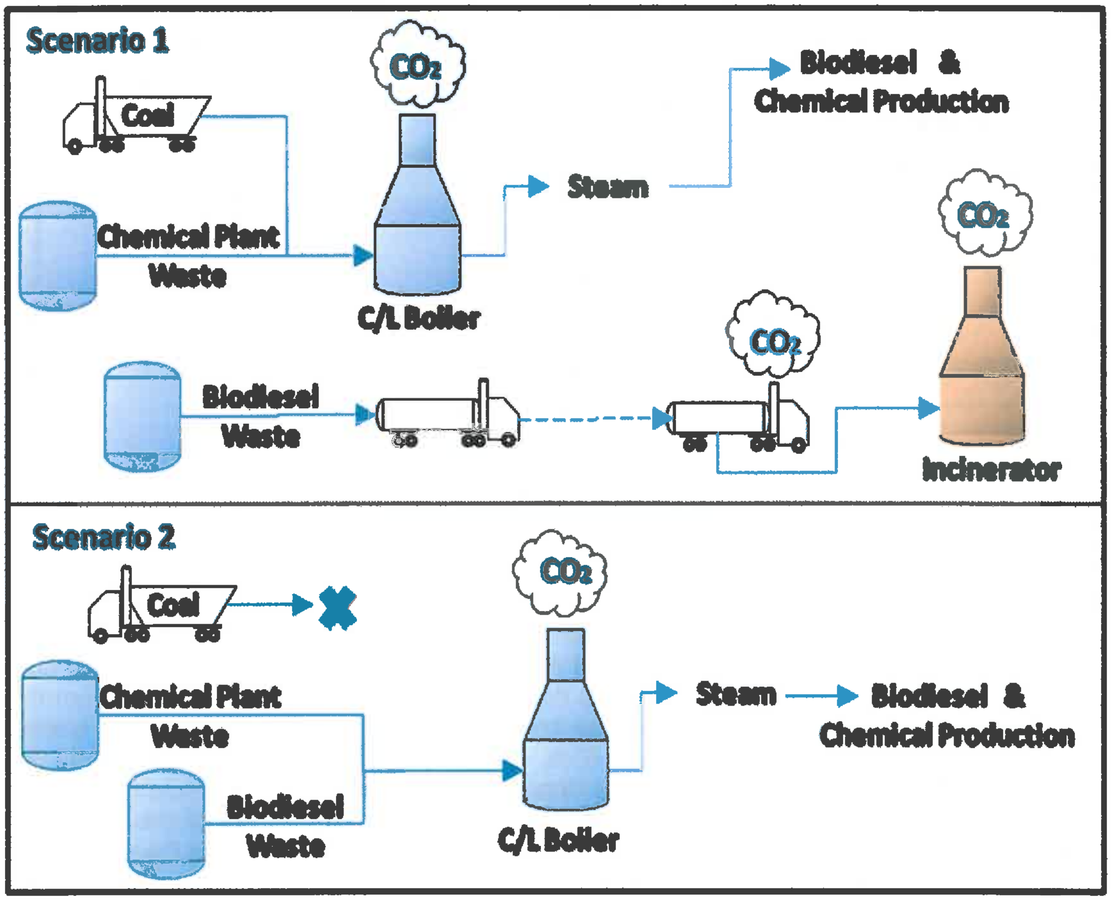
Burning liquid streams in the C/L boilers allows FutureFuel to reduce coal burning while continuing to meet the facility steam demand. A description of liquid waste burned at FutureFuel is shown in Appendix 4. Some of the liquid waste that is burned to displace coal and for energy recovery in the C/L boilers is designated as RCRA hazardous; therefore the C/L boilers are performance tested and operated to achieve maximum achievable control technology (MACT) standards per U.S. EPA 40 CFR 63 Subpart EEE, Standards for Hazardous Waste Pollutants for Hazardous Waste Combustors. The most recent C/L boiler compliance performance test was concluded June 4, 2010. The results of this test were submitted as the Notice of Compliance (NOC) to the EPA and the Arkansas Department of Environmental Quality (ADEQ). This document, on file with EPA Region 6, contains detailed information about emission rates, emission control efficiency, operating parameters, and feed stream composition.

1.2.2.2 CO_2e Generation

Liquid streams burned in the C/L boilers are of variable composition due to the large variety of specialty chemical products produced at FutureFuel. The combustion of these waste streams onsite instead of shipping them off site reduced not only the transportation emissions but since steam can be recovered when they are burned on site the CO_2 emissions generated by coal to produce the steam can be avoided.

At times, non-biodiesel constituent build up in process tanks and storage tanks. These non-biodiesel constituents must be purged from the system and they often carry valuable biodiesel, methanol, and glycerin with them. FutureFuel reclaims the fuel value of these waste streams by burning them in the C/L boilers to produce steam. Burning this material to produce steam displaces coal and reduces carbon emissions. The following scenarios are presented to help explain the CO_2e benefit of using biodiesel waste streams in the C/L boilers.

Figure 1-4 Biodiesel Waste Handling Scenarios



FutureFuel operates using Scenario 2. This option eliminates the cost and hazards associated with disposing of the chemical and biodiesel waste material off-site. It also reduces CO_2e emissions by over 4.5 million pounds. Burning the waste to produce steam in the C/L boilers emits the same amount of CO_2e as created when burning in an incinerator but recovering some steam from the on site combustion avoids the need to burn coal on site. Since the emissions from burning the chemical waste would occur with or without the biodiesel production, from a life cycle analysis perspective they don't need to be quantified since they exist in both the system under study and the reference system.

Both the C/L boilers and incinerators are required to meet Maximum Achievable Control Technology (MACT) standards for combustion efficiency. These standards apply to both solid fuel boilers {40 CFR 63.1216(b)(5)(ii)} and hazardous waste incinerators {40 CFR 63.1219(b)(5)(ii)}. Because incinerators and boilers operate with approximately the same destruction removal efficiency, CO_2 emissions should be nearly equivalent. Subpart EEE requires hydrocarbon emissions to be less than 10 ppm. FFCC demonstrated a hydrocarbon emission rate of 0.4 ppm in Comprehensive Performance Testing completed on June 4, 2010. EPA and Arkansas DEQ officials were on-site to oversee this test. Regulations require re-testing every 5 years. The Arkansas DEQ audits boiler compliance, operating limits and equipment condition annually. Additional regulatory information is shown in Appendix 3.

Table 1-3 Emissions Reduced by Using Biodiesel Waste to Produce Steam[1]

Scenario 1: Dispose of Biodiesel By-Products		**Scenario 2:** Reclaim Heat Value of Biodiesel By-Products	
Activity	**CO_2e pounds**	**Activity**	**CO_2e 4**
Incinerate stream		*Incinerate stream*	
Transport[1]:	0	Transport:	N/A
Combustion[2]:	3,667,839	Combustion:	N/A
Burn coal for process steam		*Burn By-Product for process steam*	
Transport:	0	Transport:	0
Combustion[3]:	4,592,440	Combustion[4]:	3,667,839
Total CO_2e:	8,260,279		3,667,839

[1] Assume transportation to incineration site is negligable.

[2] CO_2e conversion factors from Table C-1 to Subpart C of 40 CFR Part 98—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel.

[3] CO_2e conversion factors from Table C-1 to Subpart C of 40 CFR Part 98—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

[4] C/L boilers meet MACT standards per U.S. EPA 40 CFR 63 Subpart EEE, Standards for Hazardous Waste Pollutants for Hazardous Waste Combustors.

This analysis takes a very conservative approach and does not claim a credit for avoided coal GHG emissions. It only accounts for the fact that the waste emissions will happen with or without the biodiesel production and therefore these emissions do not need to be included in the LCA analysis in accordance with ISO LCA guidelines.

1.2.2.3 Biodiesel Production

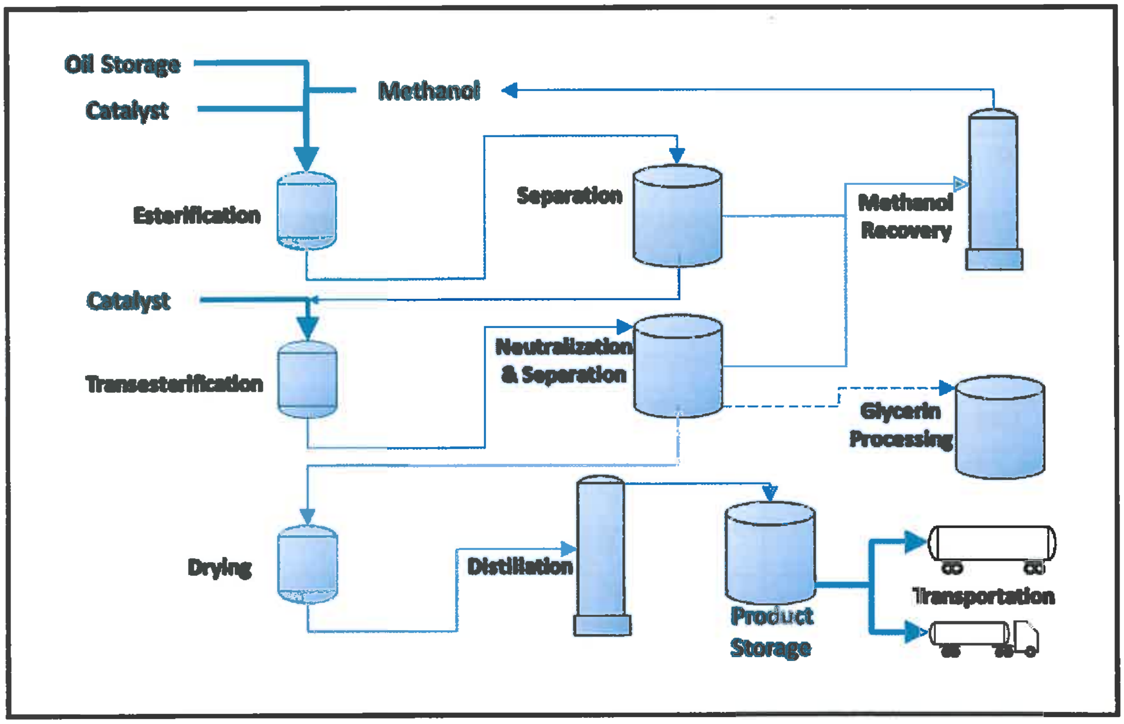
Biodiesel production can be broken down into the following functional areas; Esterification, Transesterification, Washing/Drying, Methanol Recovery, and Distillation. The biodiesel facility completed construction in May 2005 and started production in October 2005. FutureFuel's Chemical production facilities in Batesville, AR have been in operation since 1975.

The facility currently provides for continuous esterification and transesterification processes. The facility is designed for an annual production of 59 million US gallons per year of

[1] CO_2e calculations are shown in Appendix 2

biodiesel and produces glycerine as a co-product for non-fuel markets. The basic flow diagram is shown in the following figure.

Figure 1-5 FutureFuel Biodiesel Process



More information on the materials and energy use of the biodiesel process is provided in section 4 of this report.

2. UCO Rendering

No changes are made to the UCO rendering stage of the pathway. The rendering energy assumptions are based on the CARB UCO Biodiesel Pathway. The only allocation of energy and emissions in the biodiesel pathway involves an allocation for glycerine production. The glycerine production is 0.105 lb./lb. of biodiesel (cell C39 on the UCO BD sheet).

2.1 Energy

The rendering assumptions are for the "with cooking" rendering process. Most of the modelling assumptions are the same as used in the CARB pathway and are:

- Rendering uses 1,073 Btu/lb. UCO,
- 89.77% of the energy is supplied by natural gas,
- 10.23% of the energy is electric power, and

The UCO is collected from more than just the US Midwest so the US average power is used to calculate these emissions.

2.2 Emissions

The emissions for the rendering stage are shown in the following table. The only factor that has changed for the proposed pathway is the electric power mix is the US average.

Table 2-1 UCO Rendering Emissions

Parameter	Base Case	FutureFuel
	g/MJ Biodiesel	
VOC	0.0007	0.0006
CO	0.0035	0.0034
CH_4	0.0100	0.0096
N_2O	0.0000	0.0000
CO_2	5.42	5.28
GHG Emissions	5.69	5.54

3. Rendered UCO Transport

Generally, the renderer and the biodiesel plant are not co-located and there are transportation emissions associated with moving the feedstock from one site to the other. FutureFuel have a number of feedstock suppliers and receive product by truck and by rail.

3.1 Distances

The UCO BD pathway has been added to GREET 1.8d by CARB. While the additions are correct, the structure of the transportation and Distribution calculations are not the same for UCO as they are for the original pathways. The transportation distances are entered on the T&D sheet and not on the T&D Flowcharts sheet. The base model also did not have the capacity for rail freight but did have two truck freight options. One of the truck freight columns (IG on T&D) has been converted to rail for this project. This also required Cell DP 141 to have the fraction shipped by rail added and cells DP 144 to DP 165 to be changed so that they are the sum of the rail and road values.

In the CARB scenario, the UCO is assumed to be transported 50 miles by HHD truck to the biodiesel plant. The biodiesel is produced outside of California and then transported to California for blending and use there.

For this pathway we use the FutureFuel scenario where the UCO is shipped from multiple sources by truck or rail to the biodiesel plant in Arkansas. The fractions and average distances for each mode are shown in the following table.

Table 3-1 Used Cooking Oil Transportation

	Fraction Shipped	Average Distance, miles
Truck	0.44	500
Rail	0.56	824

3.2 Emissions

The emissions for the UCO production stage are shown in the following table. The longer transportation distances result in higher emissions.

Table 3-2 UCO Transport Emissions

Parameter	Base Case	FutureFuel
	g/MJ	
VOC	0.0002	0.0010
CO	0.0007	0.0031
CH_4	0.0005	0.0014
N_2O	0.0000	0.0006
CO_2	0.45	1.69
GHG Emissions	0.47	1.90

4. Biodiesel Production

The CARB pathway assumed that the biodiesel was produced in the Midwest. In this case, the biodiesel is produced in Arkansas and rather than using natural gas for the process energy, a combination of natural gas, coal, and process waste is combusted to produce the steam for the biodiesel plant.

4.1 Energy

The biodiesel energy consumption in the reference pathway is 2,116 BTU/lb. This includes the process energy and the energy embedded in the chemicals consumed in the process. The breakdown is shown in the following table.

Table 4-1 Biodiesel Energy Consumption – Reference Case

Component	Value	BTU/lb.
Total	2,116 BTU/lb.	2,116
Natural gas	42.0%	889
Electricity	2.2%	47
Methanol	40.9%	865
Sodium Hydroxide	2.0%	42
Sodium Methoxide	9.9%	209
Hydrochloric acid	3.0%	63

We have modelled the other chemicals in the same way as the CARB process.

The energy requirements at the FutureFuel plant are slightly higher than the values used by CARB. The plant uses 1,607 BTU/lb of fuel for thermal energy and 84 BTU/lb as electricity. One of the reasons for the higher energy is the fact that the plant distills the biodiesel to improve the quality. The biodiesel distillation increases the thermal energy use by 20% and the electricity requirements by 64%.

The thermal energy requirements are met by burning natural gas, coal, and waste materials. The waste material would otherwise be transported to a hazardous waste incinerator for disposal without any energy recovery. By using this material on site, not only are the transportation emissions avoided but some energy recovery is possible and the combustion of coal is avoided. Under ISO LCA guidelines, the emissions from the waste material should be included in both the reference system and the biodiesel production system. The reference system should also include the transportation emissions.

Since the reference system (diesel fuel production) is set by CARB, the appropriate way to deal with the emissions from the waste combustion for this modeling is to assume that the energy recovery from the waste is emission free, as these emissions would occur even if the energy wasn't used in the plant[2]. The transportation emissions are not included as a credit to be conservative. The difference in the emissions between burning this waste and the combustion of coal is not being claimed as a credit. In 2013, 4,463,720 gal of chemicals were burned along with 334,779 gal of biodiesel waste products. The chemical waste had an estimated BTU content of 66,000 BTU/gal (+29%) and the biodiesel waste is estimated at 66,275 BTU/gal (+3%).

The fuel used for the steam production is summarized in the following table.

[2] Reference Section 1.2.2.2 of this document for CO_2 emission information.

Table 4-2 Fuel for Steam Production

Fuel	Percent	BTU/lb biodiesel
Coal	36.3%	584
Waste	12.6%	202
Natural Gas	51.1%	821
Total	100.0%	1,607

Based on the discussion and the above table, the FutureFuel biodiesel production energy use for modelling is summarized in the following table.

Table 4-3 FutureFuel Energy Use

Component	Value	BTU/lb.
Total	2,666	2,666
Natural gas	30.8%	821
Coal	21.9%	584
Electricity	3.1%	82
Methanol	32.4%	865
Sodium Hydroxide	1.6%	42
Sodium Methoxide	7.8%	209
Hydrochloric acid	2.4%	63

The product yield is the same as the reference case, 1.11 lb. feedstock/lb. biodiesel produced.

4.2 Emissions

The emissions for this stage of the lifecycle are shown in the following table. They are derived from the energy use data shown above and the Arkansas marginal power. The higher energy use and the use of coal in the process result in higher GHG emissions.

Table 4-4 Biodiesel Production Emissions

Parameter	Base Case	FutureFuel
	g/MJ	
VOC	0.0018	0.0020
CO	0.0044	0.0065
CH_4	0.0179	0.0209
N_2O	0.0000	0.0001
CO_2	5.59	8.53
GHG Emissions	6.06	9.09

5. Biodiesel Transportation and Distribution

5.1 Distances

In the CARB reference case, biodiesel is transported 1,400 miles by rail to blending stations, then 90 miles by HDDT (100%) to refueling stations.

For this pathway the rail distance is increased to 2,000 miles, the distance from Arkansas to California. Then 80% of the biodiesel is transported by heavy duty truck 50 miles from the plant to bulk terminals; the remaining 20% is distributed directly from the plant. All BD is then transported 90 miles by heavy duty truck from the bulk terminal to refueling stations.

5.2 Emissions

The emissions for this stage are shown in the following table for the reference case and the FutureFuel case.

Table 5-1 Biodiesel Transportation Emissions

Parameter	Base Case	FutureFuel
	g/MJ	
VOC	0.0012	0.0018
CO	0.0045	0.0064
CH_4	0.0021	0.0030
N_2O	0.0000	0.0001
CO_2	1.88	2.69
GHG Emissions	1.95	2.80

6. Vehicle Operation

The final stage of the lifecycle is the use stage. In the CARB framework, the fossil carbon that was in the methanol is oxidized when the fuel is combusted and is accounted for when the biodiesel is burned.

6.1 Emissions

The vehicle operation emissions are the same for all biodiesels. These emissions are 4.48 g CO_2eq/MJ.

7. SUMMARY

The GHG emissions for each stage of the lifecycle for the reference case and for the FutureFuel case are summarized in the following table.

Table 7-1 Lifecycle GHG Emissions

Parameter	Base Case	FutureFuel
	g/MJ	
UCO Rendering	5.69	5.54
UCO Transport	0.30	1.90
Biodiesel Production	6.06	9.09
Biodiesel Transport	2.19	2.80
Total Tank to Wheel	14.24	19.33
Vehicle Operation	4.48	4.48
Total	18.72	23.81

The CI for the FutureFuel UCO biodiesel is 5.09 g/MJ higher than the existing pathway due to the longer transportation distances for feedstock and biodiesel and the higher biodiesel production emissions resulting from higher energy use and a portion of that energy being from coal.

8. References

CARB. 2011. Detailed California Modified GREET Pathway for Biodiesel Produced in the Midwest from Used Cooking Oil and Used in California. http://www.arb.ca.gov/fuels/lcfs/2a2b/internal/15day-mw-uco-bd-rpt-022112.pdf

US EPA. 2013. eGrid. http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html

9. APPENDIX 1 – GREET MODIFIED CELLS

9.1 UCO BIODIESEL – FUTURE FUELS

Sheet	Cell	Original Value	New value
Regional LT	N83 for C83	2.31%	2.31%
	N84 for C84	45.09%	73.02%
	N85 for C85	22.73%	22.73%
	N86 for C86	25.97%	0.00%
	N87 for C87	1.93%	1.93%
	N88 for C88	0.00%	0.00%
T&D[3]	IG91	Truck	Rail
	IG93	0	824
	IH93	50	500
	CL142	0	80%
	DP141	0	56%
	DP142	100%	44%
	DP144	DP142*IH111	DP142*IH111+DP$141*IG111
	DP145	DP142*IH112	DP142*IH112+DP$141*IG112
	DP146	DP142*IH113	DP142*IH113+DP$141*IG113
	DP147	DP142*IH114	DP142*IH114+DP$141*IG114
	DP148	DP142*IH115	DP142*IH115+DP$141*IG115
	DP150	DP142*IH117	DP142*IH117+DP$141*IG117
	DP151	DP142*IH118	DP142*IH118+DP$141*IG118
	DP152	DP142*IH119	DP142*IH119+DP$141*IG119
	DP153	DP142*IH120	DP142*IH120+DP$141*IG120
	DP154	DP142*IH121	DP142*IH121+DP$141*IG121
	DP155	DP142*IH122	DP142*IH122+DP$141*IG122
	DP156	DP142*IH123	DP142*IH123+DP$141*IG123
	DP157	DP142*IH124	DP142*IH124+DP$141*IG124
	DP158	DP142*IH125	DP142*IH125+DP$141*IG125
	DP160	DP142*IH127	DP142*IH127+DP$141*IG127
	DP161	DP142*IH128	DP142*IH128+DP$141*IG128
	DP162	DP142*IH129	DP142*IH129+DP$141*IG129
	DP163	DP142*IH130	DP142*IH130+DP$141*IG130
	DP164	DP142*IH131	DP142*IH131+DP$141*IG131
	DP165	DP142*IH132	DP142*IH132+DP$141*IG132
UCO BD	B13	2,116	2,666
	D160	0	100%
	F174	42.0%	30.8%
	F175	0.0%	21.9%
	F177	2.2%	3.1%
	F179	40.9%	32.4%
	F180	2.0%	1.6%
	F181	9.9%	7.8%
	F182	3.0%	2.4%

[3] For corn oil transport.

T&D Flowchart[4]	F1393	100%	100%
	F1394	1,400	2,000

[4] For biodiesel transport.

10. APPENDIX 2 CO_2E CALCULATIONS FOR TABLE 1-3

Energy value of biodiesel waste stream:	334,779 gal	x	0.066 mmBtu / gal	=	22,200 mmBtu
Btu value of coal:	21.0 mmBtu / ton				
Amount of coal required to replace biodiesel (Btu basis):	22,200 mmBtu	x	1 ton / 21 mmBtu	=	1,059 ton coal

Emissions from Disposal

CO2e from coal burned to replace biodiesel componenets burned in boilers in 2013:

1,059 tons	21.0 mmBtu / ton	93.28 kg CO2 / mmBtu	2.2 lb / 1 kg		4,555,722 lb CO2e
1,059 tons	21.0 mmBtu / ton	0.011 kg CH4 / mmBtu	2.2 lb / 1 kg	25 lb CO2e / lb CH4	13,431 lb CO2e
1,059 tons	21.0 mmBtu / ton	0.0016 kg N2O / mmBtu	2.2 lb / 1 kg	298 lb CO2e / lb N2O	23,287 lb CO2e
					4,592,440 lb CO2e

Emissions from Heat Recovery

CO2e from biodiesel chemicals burned in boilers in 2013:

334,779 gal	0.066 mmBtu / gal	75.04 kg CO2 / mmBtu	2.2 lb / 1 kg		3,664,895 lb CO2e
334,779 gal	0.066 mmBtu / gal	0.0011 kg CH4 / mmBtu	2.2 lb / 1 kg	25 lb CO2e / lb CH4	1,343 lb CO2e
334,779 gal	0.066 mmBtu / gal	0.00011 kg N2O / mmBtu	2.2 lb / 1 kg	298 lb CO2e / lb N2O	1,601 lb CO2e
					3,667,839 lb CO2e

CO_2e emission factors (93.28 kg CO_2/mmBtu for coal, 75.04 kg CO_2/mmBtu for biofuel waste) are from Table C-1 to Subpart C of 40 CFR Part 98—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel.

Emission factors for CH_4 (0.011kg CH_4/mmBtu coal, 0.0011kg CH_4/mmBtu biofuel waste) and N_2O (0.0016kg N_2O/mmBtu coal, 0.00011kg N_2O/mmBtu biofuel waste) are from Table C-2 of Part 98—Default CH_4 and N_2O Emission Factors for Various Types of Fuel.

Conversion factor for methane (25) and nitrous oxide (298) to CO_2e are from Table A-1 to Subpart A of Part 98—Global Warming Potentials.

11. Appendix 3 Additional Regulatory Information

40 CFR Part 98, Mandatory Greenhouse Gas Reporting, treats boiler and incineration combustion sources as equivalent. The emission factors contained in Subpart C are fuel specific and do not distinguish between boilers, incinerators, or other combustion sources. AP-42 does distinguish between combustion sources in Table 1.11-3, Emission Factors for Total Organic Compounds (TOC), Hydrogen Chloride (HCl), and Carbon Dioxide (CO_2) from Waste Oil Combustors, but the CO_2 emission factor for all source categories is the same. Therefore, it is reasonable to conclude that CO_2e emissions generated when a liquid stream is burned in a boiler is approximately equivalent to the CO_2e emissions generated when burning the same liquid stream in an incinerator. This conclusion is supported by the attached EPA regulations and the boiler compliance test results shown in Table ES-1 on page 30.

§63.1216 What are the standards for solid fuel boilers that burn hazardous waste?

(a) Emission limits for existing sources. You must not discharge or cause combustion gases to be emitted into the atmosphere that contain:

(1) For dioxins and furans, either carbon monoxide or hydrocarbon emissions in excess of the limits provided by paragraph (a)(5) of this section;

(2) Mercury in excess of 11 µgm/dscm corrected to 7 percent oxygen;

(3) For cadmium and lead combined, except for an area source as defined under §63.2, emissions in excess of 180 µgm/dscm, corrected to 7 percent oxygen;

(4) For arsenic, beryllium, and chromium combined, except for an area source as defined under §63.2, emissions in excess of 380 µgm/dscm, corrected to 7 percent oxygen;

(5) For carbon monoxide and hydrocarbons, either:

(i) Carbon monoxide in excess of 100 parts per million by volume, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis and corrected to 7 percent oxygen. If you elect to comply with this carbon monoxide standard rather than the hydrocarbon standard under paragraph (a)(5)(ii) of this section, you must also document that, during the destruction and removal efficiency (DRE) test runs or their equivalent as provided by §63.1206(b)(7), hydrocarbons do not exceed 10 parts per million by volume during those runs, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis, corrected to 7 percent oxygen, and reported as propane; or

(ii) Hydrocarbons in excess of 10 parts per million by volume, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis, corrected to 7 percent oxygen, and reported as propane;

(6) For hydrogen chloride and chlorine combined, except for an area source as defined under §63.2, emissions in excess of 440 parts per million by volume, expressed as a chloride (Cl(−)) equivalent, dry basis and corrected to 7 percent oxygen; and

(7) For particulate matter, except for an area source as defined under §63.2 or as provided by paragraph (e) of this section, emissions in excess of 68 mg/dscm corrected to 7 percent oxygen.

(b) Emission limits for new sources. You must not discharge or cause combustion gases to be emitted into the atmosphere that contain:

(1) For dioxins and furans, either carbon monoxide or hydrocarbon emissions in excess of the limits provided by paragraph (b)(5) of this section;

(2) Mercury in excess of 11 μgm/dscm corrected to 7 percent oxygen;

(3) For cadmium and lead combined, except for an area source as defined under §63.2, emissions in excess of 180 μgm/dscm, corrected to 7 percent oxygen;

(4) For arsenic, beryllium, and chromium combined, except for an area source as defined under §63.2, emissions in excess of 190 μgm/dscm, corrected to 7 percent oxygen;

(5) For carbon monoxide and hydrocarbons, either:

(i) Carbon monoxide in excess of 100 parts per million by volume, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis and corrected to 7 percent oxygen. If you elect to comply with this carbon monoxide standard rather than the hydrocarbon standard under paragraph (b)(5)(ii) of this section, you must also document that, during the destruction and removal efficiency (DRE) test runs or their equivalent as provided by §63.1206(b)(7), hydrocarbons do not exceed 10 parts per million by volume during those runs, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis, corrected to 7 percent oxygen, and reported as propane; or

(ii) Hydrocarbons in excess of 10 parts per million by volume, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis, corrected to 7 percent oxygen, and reported as propane;

(6) For hydrogen chloride and chlorine combined, except for an area source as defined under §63.2, emissions in excess of 73 parts per million by volume, expressed as a chloride ($Cl^{(-)}$) equivalent, dry basis and corrected to 7 percent oxygen; and

(7) For particulate matter, except for an area source as defined under §63.2 or as provided by paragraph (e) of this section, emissions in excess of 34 mg/dscm corrected to 7 percent oxygen.

(c) Destruction and removal efficiency (DRE) standard—(1) 99.99% DRE. Except as provided in paragraph (c)(2) of this section, you must achieve a DRE of 99.99% for each principle organic hazardous constituent (POHC) designated under paragraph (c)(3) of this section. You must calculate DRE for each POHC from the following equation:

$$DRE = [1 - (W_{out} \div W_{in})] \times 100\%$$

Where:

Win = mass feedrate of one POHC in a waste feedstream; and

Wout = mass emission rate of the same POHC present in exhaust emissions prior to release to the atmosphere.

(2) 99.9999% DRE. If you burn the dioxin-listed hazardous wastes F020, F021, F022, F023, F026, or F027 (see §261.31 of this chapter), you must achieve a DRE of 99.9999% for each POHC that you designate under paragraph (c)(3) of this section. You must demonstrate this DRE performance on POHCs that are more difficult to incinerate than tetra-, penta-, and hexachlorodibenzo-p-dioxins and dibenzofurans. You must use the equation in paragraph (c)(1) of this section to calculate DRE for each POHC. In addition, you must notify the Administrator of your intent to incinerate hazardous wastes F020, F021, F022, F023, F026, or F027.

(3) Principal organic hazardous constituents (POHCs).

(i) You must treat the POHCs in the waste feed that you specify under paragraph (c)(3)(ii) of this section to the extent required by paragraphs (c)(1) and (c)(2) of this section.

(ii) You must specify one or more POHCs that are representative of the most difficult to destroy organic compounds in your hazardous waste feedstream. You must base this specification on the degree of difficulty of incineration of the organic constituents in the hazardous waste and on their concentration or mass in the hazardous waste feed, considering the results of hazardous waste analyses or other data and information.

(d) Significant figures. The emission limits provided by paragraphs (a) and (b) of this section are presented with two significant figures. Although you must perform intermediate calculations using at least three significant figures, you may round the resultant emission levels to two significant figures to document compliance.

(e) Alternative to the particulate matter standard—

(1) General. In lieu of complying with the particulate matter standards of this section, you may elect to comply with the following alternative metal emission control requirement:

(2) Alternative metal emission control requirements for existing solid fuel boilers.

(i) You must not discharge or cause combustion gases to be emitted into the atmosphere that contain cadmium, lead, and selenium in excess of 180 µgm/dscm, combined emissions, corrected to 7 percent oxygen; and,

(ii) You must not discharge or cause combustion gases to be emitted into the atmosphere that contain antimony, arsenic, beryllium, chromium, cobalt, manganese, and nickel in excess of 380 µgm/dscm, combined emissions, corrected to 7 percent oxygen.

(3) Alternative metal emission control requirements for new solid fuel boilers.

(i) You must not discharge or cause combustion gases to be emitted into the atmosphere that contain cadmium, lead, and selenium in excess of 180 µgm/dscm, combined emissions, corrected to 7 percent oxygen; and,

(ii) You must not discharge or cause combustion gases to be emitted into the atmosphere that contain antimony, arsenic, beryllium, chromium, cobalt, manganese, and nickel in excess of 190 µgm/dscm, combined emissions, corrected to 7 percent oxygen.

(4) Operating limits. Semivolatile and low volatile metal operating parameter limits must be established to ensure compliance with the alternative emission limitations described in paragraphs (e)(2) and (e)(3) of this section pursuant to §63.1209(n), except that semivolatile metal feedrate limits apply to lead, cadmium, and selenium, combined, and low volatile metal feedrate limits apply to arsenic, beryllium, chromium, antimony, cobalt, manganese, and nickel, combined.

(f) Elective standards for area sources. Area sources as defined under §63.2 are subject to the standards for cadmium and lead, the standards for arsenic, beryllium, and chromium, the standards for hydrogen chloride and chlorine, and the standards for particulate matter under this section if they elect under §266.100(b)(3) of this chapter to comply with those standards in lieu of the standards under 40 CFR 266.105, 266.106, and 266.107 to control those pollutants.

[70 FR 59565, Oct. 12, 2005]

§63.1219 What are the replacement standards for hazardous waste incinerators?

(a) Emission limits for existing sources. You must not discharge or cause combustion gases to be emitted into the atmosphere that contain:

(1) For dioxins and furans:

(i) For incinerators equipped with either a waste heat boiler or dry air pollution control system, either:

(A) Emissions in excess of 0.20 ng TEQ/dscm, corrected to 7 percent oxygen; or

(B) Emissions in excess of 0.40 ng TEQ/dscm, corrected to 7 percent oxygen, provided that the combustion gas temperature at the inlet to the initial particulate matter control device is 400 °F or lower based on the average of the test run average temperatures. (For purposes of compliance, operation of a wet particulate matter control device is presumed to meet the 400 °F or lower requirement);

(ii) Emissions in excess of 0.40 ng TEQ/dscm, corrected to 7 percent oxygen, for incinerators not equipped with either a waste heat boiler or dry air pollution control system;

(iii) A source equipped with a wet air pollution control system followed by a dry air pollution control system is not considered to be a dry air pollution control system, and a source equipped with a dry air pollution control system followed by a wet air pollution control system is considered to be a dry air pollution control system for purposes of this standard;

(2) Mercury in excess of 130 µgm/dscm, corrected to 7 percent oxygen;

(3) Cadmium and lead in excess of 230 µgm/dscm, combined emissions, corrected to 7 percent oxygen;

(4) Arsenic, beryllium, and chromium in excess of 92 µgm/dscm, combined emissions, corrected to 7 percent oxygen;

(5) For carbon monoxide and hydrocarbons, either:

(i) Carbon monoxide in excess of 100 parts per million by volume, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis and corrected to 7 percent oxygen. If you elect to comply with this carbon monoxide standard rather than the hydrocarbon standard under paragraph (a)(5)(ii) of this section, you must also document that, during the destruction and removal efficiency (DRE) test runs or their equivalent as provided by §63.1206(b)(7), hydrocarbons do not exceed 10 parts per million by volume during those runs, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis, corrected to 7 percent oxygen, and reported as propane; or

(ii) Hydrocarbons in excess of 10 parts per million by volume, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis, corrected to 7 percent oxygen, and reported as propane;

(6) Hydrogen chloride and chlorine gas (total chlorine) in excess of 32 parts per million by volume, combined emissions, expressed as a chloride (Cl(−)) equivalent, dry basis and corrected to 7 percent oxygen; and

(7) Except as provided by paragraph (e) of this section, particulate matter in excess of 0.013 gr/dscf corrected to 7 percent oxygen.

(b) Emission limits for new sources. You must not discharge or cause combustion gases to be emitted into the atmosphere that contain:

(1)(i) Dioxins and furans in excess of 0.11 ng TEQ/dscm corrected to 7 percent oxygen for incinerators equipped with either a waste heat boiler or dry air pollution control system; or

(ii) Dioxins and furans in excess of 0.20 ng TEQ/dscm corrected to 7 percent oxygen for sources not equipped with either a waste heat boiler or dry air pollution control system;

(iii) A source equipped with a wet air pollution control system followed by a dry air pollution control system is not considered to be a dry air pollution control system, and a source equipped with a dry air pollution control system followed by a wet air pollution control system is considered to be a dry air pollution control system for purposes of this standard;

(2) Mercury in excess of 8.1 µgm/dscm, corrected to 7 percent oxygen;

(3) Cadmium and lead in excess of 10 µgm/dscm, combined emissions, corrected to 7 percent oxygen;

(4) Arsenic, beryllium, and chromium in excess of 23 µgm/dscm, combined emissions, corrected to 7 percent oxygen;

(5) For carbon monoxide and hydrocarbons, either:

(i) Carbon monoxide in excess of 100 parts per million by volume, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis and corrected to 7 percent oxygen. If you elect to comply with this carbon monoxide standard rather than the hydrocarbon standard under paragraph (b)(5)(ii) of this section, you must also document that, during the destruction and removal efficiency (DRE) test runs or their equivalent as provided by §63.1206(b)(7), hydrocarbons do not exceed 10 parts per million by volume during those runs, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis, corrected to 7 percent oxygen, and reported as propane; or

(ii) Hydrocarbons in excess of 10 parts per million by volume, over an hourly rolling average (monitored continuously with a continuous emissions monitoring system), dry basis, corrected to 7 percent oxygen, and reported as propane;

(6) Hydrogen chloride and chlorine gas in excess of 21 parts per million by volume, combined emissions, expressed as a chloride ($Cl^{(-)}$) equivalent, dry basis and corrected to 7 percent oxygen; and

(7) Except as provided by paragraph (e) of this section, particulate matter emissions in excess of 0.0016 gr/dscf corrected to 7 percent oxygen.

(c) Destruction and removal efficiency (DRE) standard—(1) 99.99% DRE. Except as provided in paragraph (c)(2) of this section, you must achieve a destruction and removal efficiency (DRE) of 99.99% for each principle organic hazardous constituent (POHC) designated under paragraph (c)(3) of this section. You must calculate DRE for each POHC from the following equation:

$$DRE = [1 - (W_{out} / W_{in})] \times 100\%$$

Where:

Win = mass feedrate of one POHC in a waste feedstream; and

Wout = mass emission rate of the same POHC present in exhaust emissions prior to release to the atmosphere.

(2) 99.9999% DRE. If you burn the dioxin-listed hazardous wastes F020, F021, F022, F023, F026, or F027 (see §261.31 of this chapter), you must achieve a DRE of 99.9999% for each POHC that you designate under paragraph (c)(3) of this section. You must demonstrate this DRE performance on POHCs that are more difficult to incinerate than tetra-, penta-, and hexachlorodibenzo-p-dioxins and dibenzofurans. You must use the equation in paragraph (c)(1) of this section to calculate DRE for each POHC. In addition, you must notify the Administrator of your intent to incinerate hazardous wastes F020, F021, F022, F023, F026, or F027.

(3) Principal organic hazardous constituent (POHC). (i) You must treat each POHC in the waste feed that you specify under paragraph (c)(3)(ii) of this section to the extent required by paragraphs (c)(1) and (c)(2) of this section.

(ii) You must specify one or more POHCs that are representative of the most difficult to destroy organic compounds in your hazardous waste feedstream. You must base this specification on the degree of difficulty of incineration of the organic constituents in the hazardous waste and on their concentration or mass in the hazardous waste feed, considering the results of hazardous waste analyses or other data and information.

(d) Significant figures. The emission limits provided by paragraphs (a) and (b) of this section are presented with two significant figures. Although you must perform intermediate calculations using at least three significant figures, you may round the resultant emission levels to two significant figures to document compliance.

(e) Alternative to the particulate matter standard—(1) General. In lieu of complying with the particulate matter standards of this section, you may elect to comply with the following alternative metal emission control requirement:

(2) Alternative metal emission control requirements for existing incinerators.

(i) You must not discharge or cause combustion gases to be emitted into the atmosphere that contain cadmium, lead, and selenium in excess of 230 µgm/dscm, combined emissions, corrected to 7 percent oxygen; and,

(ii) You must not discharge or cause combustion gases to be emitted into the atmosphere that contain antimony, arsenic, beryllium, chromium, cobalt, manganese, and nickel in excess of 92 µgm/dscm, combined emissions, corrected to 7 percent oxygen.

(3) Alternative metal emission control requirements for new incinerators.

(i) You must not discharge or cause combustion gases to be emitted into the atmosphere that contain cadmium, lead, and selenium in excess of 10 µgm/dscm, combined emissions, corrected to 7 percent oxygen; and,

(ii) You must not discharge or cause combustion gases to be emitted into the atmosphere that contain antimony, arsenic, beryllium, chromium, cobalt, manganese, and nickel in excess of 23 µgm/dscm, combined emissions, corrected to 7 percent oxygen.

(4) Operating limits. Semivolatile and low volatile metal operating parameter limits must be established to ensure compliance with the alternative emission limitations described in paragraphs (e)(2) and (e)(3) of this section pursuant to §63.1209(n), except that semivolatile metal feedrate limits apply to lead, cadmium, and selenium, combined, and low volatile metal feedrate limits apply to arsenic, beryllium, chromium, antimony, cobalt, manganese, and nickel, combined.

[70 FR 59570, Oct. 12, 2005, as amended at 73 FR 64097, Oct. 28, 2008]

A summary table of C/L boiler compliance test results are shown below.

Table ES-1

Specific Objective	CPT Result
Demonstrate 99.99 % DRE of the designated POHC Chlorobenzene	≥ 99.9991 %
Demonstrate control of hydrocarbon emissions to less than 10 parts per million dry volume (ppmv), corrected 7 percent oxygen, on a hourly rolling average.	≤ 0.4 ppmv @ 7% O_2
Conduct a one time emission test for Dioxin/Furan or submit adequate data in lieu of testing, and Demonstrate control of hydrocarbon emissions to less than 10 parts per million dry volume (ppmv), corrected 7 percent oxygen, on a hourly rolling average (as shown above)	Agency approved data in lieu of D/F test located in Appendix F of the CPT Plan. One time D/F test results were 0.092 ng TEQ/dscm @ 7% O_2
Demonstrate control of particulate emissions to less than 68 micrograms per dry standard cubic meter (ug/dscm) at to 7 percent oxygen.	26.2 ug/dscm @ 7% O_2
Demonstrate that control of HCl and free chlorine emissions are equal to or less than limit established using the health-based alternative compliance demonstration described in Appendix D of the CPT Plan (< 1,886.8 lb/hr chloride feed rate)	494 lb/hr
Demonstrate that control of mercury emissions are equal to or less than 11 micrograms per dry standard cubic meter (ug/dscm) corrected to 7 percent oxygen. During Test 2.	3.9 ug/dscm @ 7% O_2
Demonstrate that control of Semi-Volatile metals (SVM) emissions are equal to or less than 180 micrograms per dry standard cubic meter (ug/dscm) corrected to 7 percent oxygen during Test 2.	158.8 ug/dscm @ 7% O_2
Demonstrate that control of Low-Volatile metals (LVM) emissions are equal to or less than 380 micrograms per dry standard cubic meter (ug/dscm) corrected to 7 percent oxygen during Test 2.	117.3 ug/dscm @ 7% O_2
Gather data regarding waste feed characteristics and process operating conditions that will be used to develop operational permit limits that will ensure compliance with regulatory performance standards.	FFCC obtained all the necessary information to establish permit limits and demonstrate performance standards during the CPT.

12. Appendix 4 Waste Stream Characterization

FutureFuel operates a large batch specialty chemical facility with over 70 active chemical operating procedures. Product demand dictated the product mix at any given time; therefore the waste stream is highly variable. The table below shows typical constituents in waste burned for energy recovery at FutureFuel.

Specialty Chemical Energy Recovery Constituents	Typical Conc.	Conc. Variability
	%	+/- %
Acetic Acid	13.6	5
Acetone	1.8	11
Chlorobenzene	12.2	10
Fatty Acid	5.7	0.2
Heptane	1.4	9
[redacted]	1.6	1
Inorganic	0.1	1
Isopropanol	1.4	8
Methanol	13.6	13
[redacted]	5.5	3
Organic Microorganisms	0.4	1
Other Organics	14.8	8
Toluene	15.0	12
Triethylene Glycol	1.4	1
[redacted]	0.1	2.1
Water	10.0	7
Xylene	1.4	10

The waste stream from the biodiesel process is much less variable in composition. The normal constituents in the biodiesel waste stream include methanol, glycerin, biodiesel/MONG, water and salt.

As noted in section 1.2.2 on page 3 of this report, FutureFuel utilizes complex chemistry to produce a wide variety of products in the Specialty Chemical portion of the plant. The chemicals listed in the table above comprise the primary and typical constituents in the waste burn stream. The table below contains a list of chemicals that may exist in the burn stream in trace quantities.

Trace Components That May Exist In The Burn Stream From The Specialty Chemical Facility		
1,1-DIMETHOXYETHANE	DMAP HCL SALT	PELARGONIC ACID
[redacted]	[redacted]	PHENOL, USP GRADE
3-(ETHYLTHIO)BUTANAL	EPOLENE E-43 WAX	PHENYL ETHER
3-METHOXY-1-BUTANAL	EPOXIDIZED OCTYL TALLATE	[redacted]
3-SODIOSULFOBENZOIC ACID	ETHANOL	PM 11729-A0 TARS
[redacted]	[redacted]	[redacted]
4-6-DI(ETHYLTHIO)-2-HEPTANONE	ETHYL ALCOHOL 2-B, ANHY, DENATURED	PM 1584, SODIUM SALT
[redacted]	ETHYL ALCOHOL, MISC FORMULAS 95	PM 20127 LOW BOILERS
5-LITHIOSULFOISOPHTHALIC ACID	[redacted]	PM 20127 LOW BOILERS
5-SODIOSULFOISOPHTHALIC ACID	Ethylene Dichloride	[redacted]
6-(ETHYLTHIO)-4-HYDROXY-2-HEPTANONE	ETHYLENE GLYCOL, FIBER GRADE	PM 5723, NA SALT
6-ACETOXY-2,4-DIMETHYL-M-DIOXANE	EXP-118 ACRYLIC LATEX POLYMER	PROPIONALDEHYDE
6-ETHYLTHIO-3-METHOXY-2-HEPTANONE	EXP-125 ACRYLIC LATEX POLYMER	PROPIONIC ACID, NA SALT
6-ETHYLTHIOHEPT-3-ENE-2-ONE	FATTY ACID SALTS	REDUCED-VOLATILITY AROMATIC SOLVENT
6-ETHYLTHIOHEPTENE-2-ONE	GLUTARALDEHYDE	[redacted]
ACETALDEHYDE	HEPTA-3,5-DIENE-2-ONE	RESIDUE FROM TIPB COLUMN
ACETIC ACID, NA SALT	HEXANE	RESORCINOL DIBENZOATE
ACETIC ANHYDRIDE, SALES GRADE	[redacted]	RESORCINOL MONOBENZOATE
ALDOL	HYDROQUINONE, INHIBITOR GRADE	[redacted]
AMMONIUM ACETATE	HYDROQUINONE, PHOTOGRAPHIC GRADE	SODIUM BENZOATE
ANTIFOAM	ISODEHYDROACETIC ACID	SODIUM BICARBONATE
BIODIESEL FROM CONTINUOUS PROCESS	ISOPROPYL ALCOHOL [redacted]	SODIUM BISULFATE
[redacted]	KEROSENE	SODIUM BISULFITE
BMBN	LARD	SODIUM LAURYL SULFATE
C13H22O4S WET WITH 50% TOLUENE	MALONATE ADDUCT OF PM 14643	SODIUM METHYLATE
[redacted]	MeODMOX	SODIUM PHENOLSULFONATE
[redacted]	METHACROLEIN	[redacted]
[redacted]	METHOXYDIBUTOXYMETHANE	SOY OIL
CP-730-1	METHOXYETHOXYMETHANE	[redacted]
CROSSLINKABLE CHLORINATED POLYOLEFN	METHYL ACETATE (100 PERCENT)	[redacted]
[redacted]	METHYL ACETOACETATE	TARS/UNKNOWNS
[redacted]	METHYL ISODEHYDROACETATE	TARS-MONO-CHLORINATED
CYANAMIDE	[redacted]	TETRAHYDROFURAN
DHEP	METHYLPIPERIDINE	THP
DHMP	[redacted]	TMA-H2SO4 SALT
DIBROMO	MPDC-DME	TRANS-1,3-DICHLOROPROPENE
DIBUTOXYMETHANE	N,N-DAH, NA SALT	TRIBROMO
DIETHOXYMETHANE	N,N'-DHPU	TRIETHYLAMINE
DIETHYL OXALATE	NA FORMATE SALT	TRIETHYLAMINE HYDROCHLORIDE
DIMETHOXYDIBUTOXYMETHANE	N-DHPU	TRIGLYCERIDE
DIMETHYL MALONATE	NONIONIC TERGITOL 15-S-7	[redacted]
DIMETHYL OXALATE	O,P-SULFONE	[redacted]
DI-N-PROPYL AMMONIUM SULFATE	OLIGOMERS	TRIOXANE
DI-N-PROPYLMETHYL AMMONIUM SULFATE	O-METHYL DIONE	[redacted]
DISULFONATED SPS	O-METHYL PM 14643	VINYL ACETATE +15PPM HYDROQUINONE
DMAP	OXALIC ACID, DIHYDRAZIDE	

13. APPENDIX 5 INCINERATOR / BOILER COMPARISON

Combustion Chemistry, Assuming 100% Destruction Removal Efficiency (DRE)[5]

Methanol: $CH_3OH + \frac{3}{2}O_2 \rightarrow CO_2 + 2H_2O$

Glycerin: $C_3H_5(OH)_3 + \frac{7}{2}O_2 \rightarrow 3CO_2 + 4H_2O$

Biodiesel[6]: $CH_3(CH_2)_{14}COOCH_3 + \frac{49}{2}02 \rightarrow 17CO2 + 17H2O$

The C/L boiler demonstrated 99.9991% DRE when compliance performance tested[7]. Commercial incinerators vary in efficiency, but are only required to meet a DRE of 99.99%[8]. However, if we consider commercial incinerators to be 100% efficient, the difference in demonstrated and required efficiency is only 0.0009%. The following calculation shows a possible change in CO_2 emissions due to this difference in combustion efficiency.

Commercial Incinerator Efficiency (DRE)	100.0000%
FutureFuel Efficiency (DRE)	99.9991%
Difference in Efficiency	0.0009%

Annual Biodiesel Burn Volume 334,779 gal

334,779 gal x 0.0009% (1/100%) = 3.01 gallons of biodiesel waste not efficiently destroyed.

Based on the above assumptions, sending biodiesel waste to a commercial incinerator that is 100% efficient could improve destruction efficiency by 3.01 gallons annually. The most carbon-intense molecule in the waste stream is biodiesel (75.5% C).

$$3.01\ gal \times \frac{9.23\ lb}{gal} \times \frac{76\%\ C}{100\%} \times \frac{44\ CO_2}{12\ C} = 68.61\ lb\ CO_2 \text{ per year}$$

CO_2 produced from burning biodiesel waste in FutureFuel's C/L boiler is 3,667,839 pounds annually[9]. The possible percent change in CO_2 emissions due to the increased efficiency of a commercial incinerator over the C/L boiler is calculated below:

$$\frac{68.61\ lb\ CO_2}{(3{,}667{,}839 + 68.61)\ lb\ CO_2} \times 100\% = 0.00002\%\ reduction$$

[5] Incomplete combustion results in the emission of carbon monoxide (CO) rather than carbon dioxide (CO_2). CO is not listed on Table A-1 to Subpart A of Part 98 – Global Warming Potentials.
[6] Fatty acid chain length is variable, normally containing from 12 to 20 carbons.
[7] Compliance Performance Test DRE, Notification of Compliance Report, NESHAP: Standards for Hazardous Air Pollutants for Hazardous Waste Combustors (40 CFR 63 Subpart EEE, Phase II) Submitted to US EPA September 01, 2010.
[8] 40 CFR 63.1219(c), See Appendix 3, Additional Regulatory Information.
[9] Table 1-3, Scenario 2 and Appendix 2, CO_2e Calculations for Table 1-3.

In an effort to be conservative, FutureFuel is not claiming any CO_2 emission reductions associated with the transfer of biodiesel waste to a commercial incinerator.