FINAL Coal/Biomass-to-Liquids Demonstration Testing for DLA Energy

Report on Project Tests, Evaluations, and Recommendations

Contract No. SP4701-10-C-0001

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14. ABSTRACT

This project conducted testing to assess whether liquid fuel can be produced commercially from coal and biomass mixtures while meeting the requirements of Section 526, which requires that GHG emissions from alternative fuels purchased by federal agencies be less than or equal to emissions from conventional petroleum fuel. This report describes the wide variety of gasification equipment, coals, and biomass used, and reports and analyzes the test results. Additionally, the team worked with DOE NETL to conduct life cycle and economic analyses of the demonstration scale test results applied to commercial scale production, with the goal of demonstrating the capability of CBTL to meet Section 526.

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Table of Contents

Tables

Figures

Appendices

Acronyms and Abbreviations

%	percent
%mol	molar percent
%vol	percent by volume
$/dbbl	cost per daily barrel
Accelergy	Accelergy Corporation
Alter NRG	Alter NRG Corp.
ARCADIS	ARCADIS U.S., Inc.
ARR	annual revenue requirement
ASTM	ASTM International
bbl	barrels
bpd	barrels per day
BTEX	benzene, toluene, ethylbenzene, and xylenes
BTL	biomass to liquids
Btu	British thermal unit
Btu/dscf	British thermal units per dry standard cubic feet
Btu/lb	British thermal unit per pound
Btu/lb-mol	British thermal units per pound-mole
Btu/scf	British thermal units per standard cubic foot
°F	degrees Fahrenheit
CBTL	coal/biomass to liquids
CCAT	Connecticut Center for Advanced Technology, Inc.
CCS	carbon capture and sequestration
CEM	continuous emission monitoring
CEMS	continuous emission monitoring system
ClearFuels®	ClearFuels® Technology, Inc.
$CO:CO_2$	carbon monoxide to carbon dioxide molar ratio
CO_2e	carbon dioxide equivalent
COD	chemical oxygen demand
Contract	Contract No. SP4701-10-C-0001
CPM	condensable particulate matter
CR	carbon reuse
CTC	carbon trim cell
CTL	coal to liquids
dbbl	daily barrel
DLA Energy	Defense Logistics Agency Energy
DoD	U.S. Department of Defense

DOE	U.S. Department of Energy
dscf	dry standard cubic feet
dscm	dry standard cubic meter
dtpd	dry tons per day
EERC	Energy and Environmental Research Center
EFG	entrained-flow gasifier
EIA	U.S. Energy Information Administration
Emery	Emery Energy Company
EOR	enhanced oil recovery
FID	flame ionization detector
FPM	filterable particulate matter
FT	Fischer-Tropsch
g/mol	grams per mole
GC	gas chromatography
GC/FID	gas chromatography-flame ionization detector
GC/MS	gas chromatography-mass spectrometry
GC/SCD	gas chromatograph with sulfur chemiluminescence detector
GHG	greenhouse gas
GREET model	Greenhouse Gases, Regulated Emissions, and Energy in Transportation model
H_2:CO	hydrogen to carbon monoxide molar ratio
HHV	higher heating value
HMB	heat and material balance
hr(s)	hour(s)
IAWG	Inter-Agency Working Group
ICCI	Illinois Clean Coal Institute
IL No. 6	Illinois Number 6 coal
KBR	KBR, Inc.
kg	kilogram
lb/hr	pounds per hour
lb/lb	pounds per pound
lb/lb-mol	pounds per pound-mole
lb-mol/hr	pound-mole per hour
LCA	life-cycle assessment; analysis
LGA	laser gas analyzer
LHV	lower heating value
LOI	loss on ignition
LPG	liquefied petroleum gas
MCL	maximum contaminant level

MDEA	methydiethanolamine
mg/L	milligrams per liter
MJ	megajoule
MMBtu/hr	million British thermal units per hour
MS	mass spectrometry
MSW	municipal solid waste
MW	molecular weight
MWe	megawatt electrical
MWh	megawatt hour
NA	not available
NC	not calculated
NCCC	National Carbon Capture Center
ND	not detected above the laboratory detection limit
NE	not established
NETL	National Energy Technology Laboratory
Ni-DFB	nickel-based catalyst dual fluidized bed
PCD	particulate control device
PDU	process demonstration unit
PGVR	plasma gasification vitrification reactor
ppbm	parts per billion by mole
ppbv	parts per billion by volume
ppm	parts per million
ppmv	parts per million by volume
ppmw	parts per million by weight
PRB	Powder River Basin
Project Team	CCAT, ARCADIS, Avetec, technical advisors, and subject matter experts
psia	pounds per square inch absolute
psig	pounds per square inch gauge
RCRA	Resource Conservation and Recovery Act
RDF	refuse-derived fuel
Rentech	Rentech, Inc.
RIN	renewable identification numbers
ROE	return on equity
RSP	required selling price
SCD	sulfur chemiluminescence detector
scfh	standard cubic feet per hour
scfm	standard cubic feet per minute
SME	subject matter expert

STP	standard temperature and pressure
SVOC	semivolatile organic compound
syngas	synthesis gas
TCLP	Toxicity Characteristic Leachate Procedure
TestAmerica	TestAmerica Laboratories, Inc.
TIC	total inorganic carbon
TOC	total organic carbon
TPC	total plant cost
tpd	tons per day
TRDU	transport reactor development unit
TRI	ThermoChem Recovery International, Inc.
TRIG™	transport reactor integrated gasifier™
TRL	technology readiness level
USEPA	U.S. Environmental Protection Agency
WBS	Work Breakdown Structure
WPC	Westinghouse Plasma Corporation
WGS	water gas shift
WTI	West Texas Intermediate
WTL	waste-to-liquids
wscf	wet standard cubic feet
wt%	percent by weight

Chemicals – Symbols and Names

Al_2O_3	aluminum oxide
C	carbon
C_2H_6	ethane
C_3H_8	propane
C_4H_{10}	butane
C_5H_{12}	pentane
C_6H_6	benzene
C_6H_{14}	hexane
C_7H_8	toluene
$C_{10}H_8$	naphthalene
$C_{12}H_8$	acenaphthylene
$C_{12}H_{10}$	acenaphthene
$C_{13}H_{10}$	fluorene
$C_{14}H_{10}$	Phenanthrene
$C_{16}H_{10}$	pyrene
$C_{16}H_{10}$	fluroanthene (same as pyrene)
CaO	calcium oxide
CH_4	methane
Cl	chlorine
CO	carbon monoxide
CO_2	carbon dioxide
Fe_2O_3	iron oxide
H	hydrogen
H_2	hydrogen gas
H_2O	water
H_2S	hydrogen sulfide
HCl	hydrochloric acid
HCN	hydrogen cyanide
K_2O	potassium oxide
MgO	magnesium oxide
N	nitrogen
N_2	nitrogen gas
Na_2O	sodium oxide
NH_3	ammonia
NH_4	ammonium
NiO_2	nickel oxide

NOx	nitrogen oxides
O	oxygen
O_2	oxygen gas
O_3	ozone
OH	hydroxide
P_2O_5	phosphorus pentoxide
S	sulfur
SiO_2	silicon dioxide (silica)
SO_2	sulfur dioxide
SO3	sulfur trioxide
TiO_2	titanium dioxide
ZnO	zinc oxide

Metals – Symbols and Names

Ag	Silver
As	Arsenic
Ba	Barium
B	Boron
Cd	Cadmium
Cr	Chromium
Hg	Mercury
Ni	Nickel
Pb	Lead
Se	Selenium
V	Vanadium
Zn	Zinc

Executive Summary

This report summarizes work completed by the Connecticut Center for Advanced Technology, Inc. (CCAT) and partners ARCADIS U.S., Inc. (ARCADIS; formerly Malcolm Pirnie, Inc.) and Avetec under Contract No. SP4701-10-C-0001 (the Contract), awarded by the Defense Logistics Agency Energy (DLA Energy) to CCAT on January 28, 2010.

The objective of this work was to investigate, through analyses and testing, the use of domestic coal and biomass to make liquid fuel and electricity for the U.S. military. Technical feasibility and commercial viability for meeting U.S. military alternative fuel use goals in the near- and mid-term timeframes and complying with greenhouse gas (GHG) emissions requirements of Title V Section 526 of the Energy Independence and Security Act of 2007 (Section 526) were examined. Section 526 requires that GHG emissions from alternative fuels purchased by federal agencies be less than or equal to emissions from conventional petroleum-based fuel. As per the Department of Defense (DoD) Alternative Fuels Policy for Operational Platforms (DoD, 2012), all commercial procurements of alternative fuels must be cost competitive with conventional fuels.

CCAT, ARCADIS U.S., Inc., Avetec, technical advisors, and subject matter experts (the Project Team) worked collaboratively with DLA Energy and a Military Advisory Panel to execute this project. The Project Team also engaged in a Cooperative Research and Development Agreement with the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) and leveraged significantly the existing public and private test facilities and expertise that were already in place in the United States.

The investigation began with an assessment of state-of-the-art technologies pertaining to liquid fuel production and electricity/heat generation from coal, including carbon capture and sequestration (CCS), carbon utilization/reuse, and the potential for conducting demonstration tests at U.S. military installations.

The initial assessment revealed a low number of coal-burning facilities (12), and relatively small amounts of coal were used for those facilities. In addition, opportunities for CCS demonstration testing at existing U.S military installations were limited, and CCS work sponsored by the U.S. government and industry was already in progress at non-military sites. The Project Team determined that minimal benefits would result from testing and analyses for coal-to-electricity/heat plants at DoD installations and that additional examination of CCS would not contribute significantly to the DoD’s future energy goals.

These initial assessment results led the Project Team to focus on coal/biomass-to-liquid (CBTL) fuel production, consistent with DoD’s alternative fuels goals and the 2013 U.S. Air Force Strategic Energy Plan, which calls for the increased use of cost-competitive, drop-in alternative aviation fuel blends for non-contingency operations to 50 percent (%) of total consumption by 2025.

CBTL fuel processes offer significant potential benefits to the DoD in producing Section 526-compliant clean liquid fuel and in the gasification of a variety of secure domestic coal/biomass feedstock mixtures.

The Project Team determined that gasification of coal and biomass using indirect liquefaction technologies, with the potential for commercial operation by 2020, presented the best chance to meet DLA Energy’s requirements. Gasification processes convert solid feedstocks, such as coal and biomass, into product gases. These product gases are then cleaned and conditioned, including the partial capture of carbon dioxide, resulting in synthesis gas that can be converted to jet fuel by the well-established Fischer-Tropsch (FT) process. Blends of conventional petroleum-based fuels and FT-based fuels have already been qualified for use in many military aircraft. The integrated system is referred to as a CBTL plant (Figure ES-1).

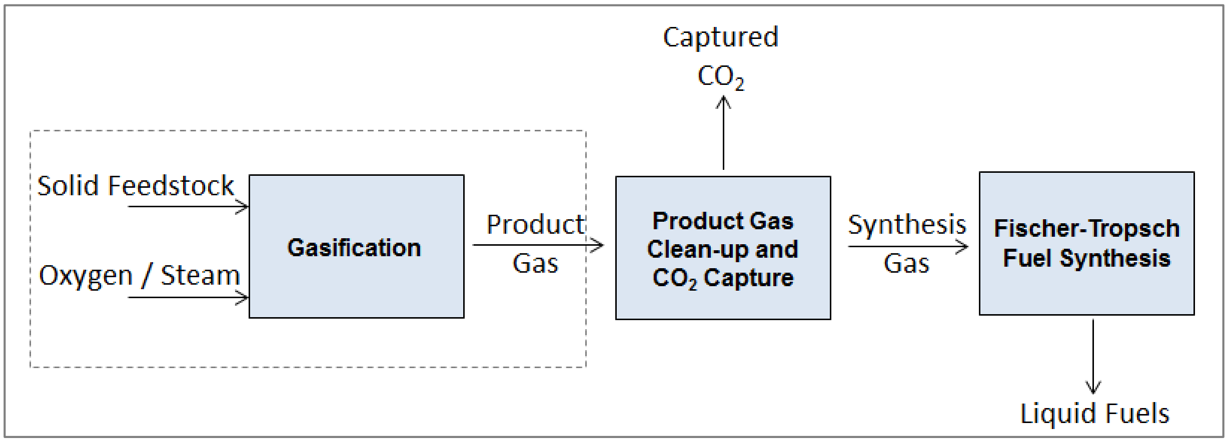

Figure ES-1: Over-Simplified Coal/Biomass-to-Liquid Plant Block Diagram
(Project Team performed extensive tests on gasification processes)

Why Coal and Biomass?

Coal is mined in more than 50 countries, with the United States controlling the largest coal reserves in the world. Primary technologies for converting coal into liquids are mature today, as evidenced in South Africa where coal has been used to make liquid fuels for the last 60 years. Using domestic feedstocks, such as coal and biomass, offers a degree of energy security and can decrease United States dependency on petroleum imports. Because coal-consuming processes emit relatively large amounts of carbon dioxide, the Project Team tested and analyzed the impact of processing biomass mixed with coal to achieve Section 526 requirements for carbon dioxide. Raw biomass, torrefied biomass, and municipal solid waste are all domestic feedstocks that can reduce carbon dioxide emissions from CBTL processes.

The Project Team executed 150 gasification tests and analyzed results for 104 coal/biomass feedstock combinations. Testing was performed with partners and facilities at the Energy and Environmental Research Center, DOE National Carbon Capture Center, AlterNRG/Westinghouse Plasma Corporation, ThermoChem Recovery International, Inc., and Emery Energy Company. Testing was performed at scales up to 50 tons per day using gasifiers that are potentially suitable for large scale (30,000 to 50,000 barrel per day capacity) and smaller distributed scale (1,000 to 3,000 barrels per day) CBTL systems. Analyses for technical feasibility and commercial viability were performed by the Project Team and subject matter experts.

Table ES-1: Summary of 150 Gasification Tests Performed

Biomass Type	Coal Type				Gasifier Technology Type				
	PRB	Lignite	IL No. 6	Biomass Only	Entrained Flow	Transport Reactor	Fixed Bed	Steam Reformer	Plasma
Coal Only	17	3	4		10	13	1		
Raw Wood	27	1	2		12	16	1	1	
Torrefied Wood	25		2	1	12	16			
Switchgrass	3				0	3			
Shale Gas	6	8			6	8			
Natural Gas		9			0	9			
Methane	5				5				
Railroad Ties	7				0	7			
Raw Corn Stover	5		2		4	3			
Torrefied Corn Stover			3		3				
Filamentous Algae	6				4	2			
Water Hyacinth	3				1	2			
Water Lettuce	4				1	3			
Water Lettuce/Hyacinth Blend	3				3				
MSW	2	1		1	0			1	3
Total	**113**	**22**	**13**	**2**	**61**	**82**	**2**	**2**	**3**
Total Number of Tests	**150**				**150**				

Key Findings

The testing program met the project objective of demonstrating the viability of gasifying coal/biomass mixtures. All gasifiers tested were able to successfully feed coal/biomass mixtures and attain stable operations for most of the tests conducted. Composition of the product gas produced in the different gasifier technologies tested was influenced by a wide range of factors, but generally showed that product gas compositions could potentially produce liquid fuels using a variety of feedstocks, after necessary "shifting" of the product gas to yield a hydrogen to carbon monoxide molar ratio typically needed for the FT process. The desired ratio is dependent on FT reactor design, particularly, the type of catalyst used.

Using test data, the Project Team and NETL performed life cycle analyses (LCAs) and techno-economic modeling for a commercial scale 50,000 barrel per day CBTL plant to address Section 526 carbon dioxide emission requirements and commercial viability. This scale CBTL plant will satisfy the stated alternative jet fuel needs of the U.S. Air Force for non-contingency operations.

Results predicted that average carbon dioxide emissions satisfied Section 526 requirements, providing that a significant portion of the carbon dioxide generated by the CBTL plant was captured and utilized or sequestered. When coal was the sole feedstock, the carbon dioxide footprint was the largest and required the most carbon dioxide capture and utilization or sequestration, on the order of 90%.

Increasing percentages of biomass in the solid feed resulted in lower carbon dioxide footprints and smaller amounts of required carbon dioxide capture. In the case of 30% woody biomass feedstock, on the order of 40% of the carbon dioxide, would require capture and utilization or sequestration and still satisfy Section 526 requirements. Results for carbon dioxide emissions are shown on Figure ES-2. Average carbon dioxide footprints of alternative jet fuel made from the solid feedstocks that were tested were projected to be below the petroleum baseline for blended jet fuel (50% alternative fuel + 50% petroleum-based fuel).

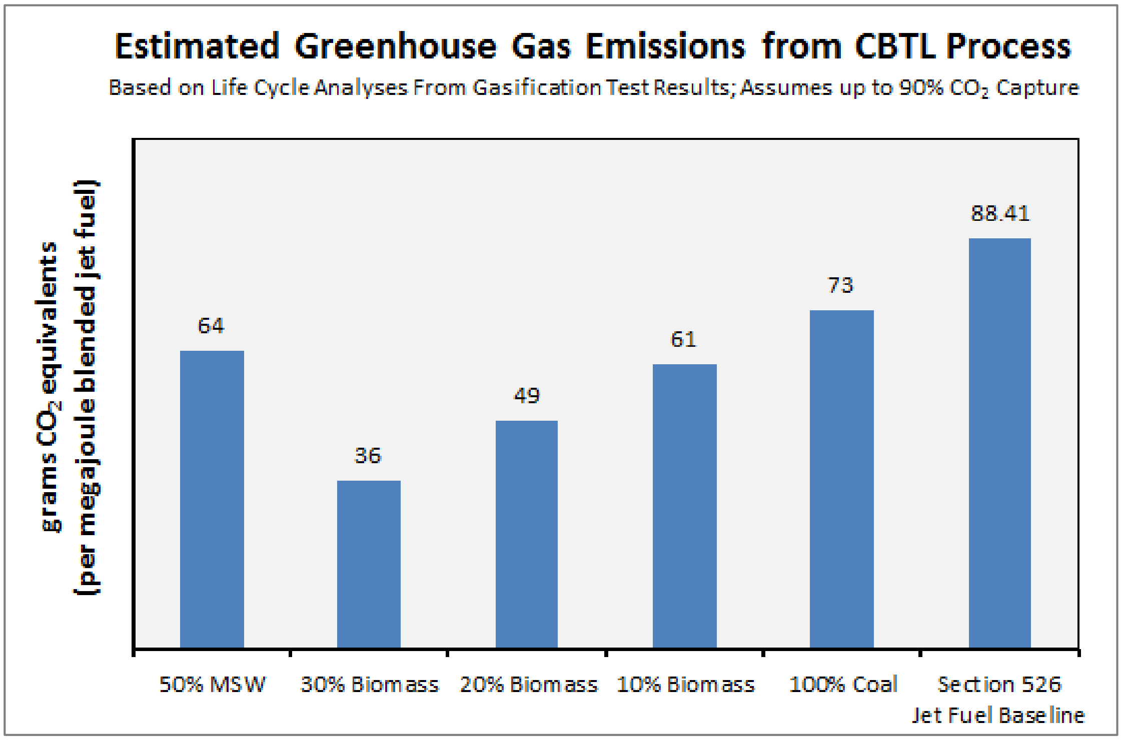

Figure ES-2: Carbon Dioxide Life Cycle Analysis Results

Rough order of magnitude cost estimates using the techno-economic model for a 50,000 barrel per day CBTL plant with an entrained flow gasifier or transport gasifier showed that the average required selling price of jet fuel (on a crude oil equivalent basis) ranged from approximately $134 per barrel to $170 per barrel. Cases where coal was the sole feedstock resulted in the lowest price; increasing percentages of raw biomass in the solid feed generally resulted in a higher price.

Improving Commercial Viability

Several factors can improve the commercial viability of CBTL plants. Utilization of municipal solid waste as a positive revenue feedstock, for example, can alleviate some financial burden of buying feedstock, and instead provide plant revenue. Optimization of the CBTL plant for a particular feedstock blend may allow for less than 90% carbon dioxide capture requirement and still meet Section 526 requirements, thereby improving capital and operating costs and lowering the required selling price. Alternative financing, based on a government DOE loan guarantee scenario (40% equity, 4.56% interest), rather than private financing (50% equity, 8.00% interest), can result in an approximately 23% per barrel reduction in the required selling price.

Additional detailed process development/engineering and cost analyses are required to determine more accurate costs and required selling prices for CBTL plant development. Based on the projected required selling prices and LCAs, future techno-economic evaluations should address alternative CBTL process configurations that minimize project capital costs by optimizing coal/biomass feedstock blends and capturing/sequestering only enough carbon to satisfy Section 526 requirements.

Recommendations for Future Action

The need for secure, clean, affordable alternative jet fuel is of increasing importance. Technology to convert diverse types of domestic solid feedstocks (coal, biomass, municipal solid waste) into alternative jet fuel suitable for the U.S. military exists today. To help ensure that Section 526 air emissions requirements are met and price points for the alternative fuel are competitive, the following actions are recommended:

1. Improve gasification technology efficiency for utilizing mixed coal/biomass feedstocks.

2. Increase efficiency for preparing domestic feedstock mixtures (drying, torrefying, grinding).

3. Pursue improvement of CBTL designs to optimize biomass content, CCS, and plant capital costs so that Section 526 compliant fuels are more cost competitive to produce. Develop solutions to decrease cost, minimize the water footprint, and increase efficiency of key CBTL plant sub-processes, such as tar reforming and replacing conventional oxygen supply via air separation with newer technology.

4. Reduce component costs for small-scale (1,000 to 3,000 barrels per day) distributed CBTL plants, as a smaller scale requires smaller amounts of feedstocks, allowing for a more practical and affordable harvesting radius for biomass and waste as feedstocks.

5. Because CBTL plants generate fuel and electricity, integration of CBTL plants with microgrids and waste management should be considered as part of a resilient strategy for installation of energy security that includes an assured fuel supply.

Contract Background and Compliance Summary

In response to the Defense Logistics Agency Energy (DLA Energy) solicitation BAA 0004-08, the Connecticut Center or Advanced Technology, Inc. (CCAT) submitted the proposal "Environmental and Engineering Assessments, Feasibility Analyses, and Tests for Carbon Capture and Sequestration and Carbon Reuse Technologies for DoD", dated August 7, 2009 (CCAT, 2009). This proposal was incorporated by reference in Section B-1 "Supplies/Services" and Section C "Work Statement" of DLA Contract SP4701-10-C-0001 (the Contract), executed January 28, 2010.

The executive summary of the proposal focused on the core issue of reducing carbon dioxide emissions from the production of liquid fuel from coal:

> "The U.S. Department of Defense (DoD) seeks to increase its utilization of secure, domestic coal to produce liquid fuel to support its operations and to produce electricity for its facilities. This is a major initiative of the Department's stated goal of achieving significant domestic energy source sustainability by 2015. One major issue in utilizing coal is that large amounts of carbon dioxide are emitted when it is processed. The Connecticut Center for Advanced Technology, Inc. (CCAT), with primary subcontractor Malcolm Pirnie, Inc.[1] (hereafter collectively called the Team), in conjunction with a Working Group of independent Carbon Capture and Sequestration (CCS) experts, propose to conduct research and demonstration efforts to mitigate the carbon dioxide emission problems, which will help enable the DoD to utilize domestic coal for liquid fuels and electricity." (CCAT, 2009)

Reducing carbon dioxide emissions will aid the DoD in meeting the requirements of Title V Section 526 of the Energy Independence and Security Act (EISA) of 2007 (Section 526), which requires that greenhouse gas emissions from alternative fuels purchased by federal agencies are less than or equal to emissions from conventional petroleum fuel. The Team's) proposed plan for evaluating technologies to mitigate carbon dioxide emissions from coal to liquid fuel production included three "Work Breakdown Structure" (WBS) tasks, which were completed in two phases (Phase 1 and Phase 2).

- **WBS Task 1.0 – Program Management:** This involved the overall management of each task associated with the plan through both Phases 1 and 2.

- **WBS Task 2.0 – Evaluation of CCS and carbon reuse (CR) for DoD Applications:** This task constituted Phase 1 of the plan. The objective was to identify, and recommend for subsequent testing, CCS and related technologies that may be beneficial to DoD's efforts to support producing liquid fuels and electricity from coal. Based on the evaluation of identified technologies, the Team recommended technologies suitable for subsequent testing to DLA Energy.

- **WBS Task 3.0 – Pilot Feasibility Assessments (Testing of Recommended Technologies):** This task constituted Phase 2 of the plan. The objective was to complete focused testing of technologies identified during the WBS Task 2.0 evaluation and to document the tests, results, evaluations, and subsequent recommendations.

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[1] In 2009, Malcolm Pirnie merged with ARCADIS U.S., Inc. (ARCADIS); therefore, the Team refers collectively to CCAT, Malcolm Pirnie, and ARCADIS.

WBS Task 1.0 – Program Management

This task encompassed both phases of the plan and involved managing all aspects of WBS Tasks 2.0 and 3.0. WBS Task 1.0 involved the three subtasks described below; these are also shown in Table C-1, below.

- **WBS Task 1.1 – Detailed Work Plan:** The work plan explained how the work described in the informational report (see WBS Task 1.2) would be accomplished.
- **WBS Task 1.2 – Informational Report:** Submitted to DLA Energy immediately after the project began, this report provided an overview of the expected scope of work for the project.
- **WBS Task 1.3 – Program Execution and Progress Reports:** This task required quarterly reporting, beginning from the end of the month after the start of the Contract. At the Contract kickoff meeting on February 11, 2010 in Fort Belvoir, Virginia, DLA Energy instructed CCAT to report activity through January 31, 2010 by the end of February 2010, and to continue every 3 months to report on the quarter completed 1 month prior to the report date.

WBS Task 2.0 – Evaluation of CCS and CR for DoD Applications

As part of WBS Task 2.0, the Team identified and proposed five areas of interest (subtasks) for which they would analyze and review technologies considered to have the potential to mitigate carbon dioxide that is released when coal is used for fuel or electricity production. The five subtasks are listed below:

- **WBS Task 2.1 – Carbon Capture and Sequestration Technology Analyses and Review:** Summarize the CCS technology development and demonstration projects in the United States and elsewhere. Identify a short list of CCS technologies for consideration by DLA Energy for pilot/feasibility testing.
- **WBS Task 2.2 – Carbon Reuse Technology Analyses and Review:** Summarize the CR technology development and demonstration projects in the United States and elsewhere. Identify a short list of CR technologies for consideration by DLA for pilot/feasibility testing.
- **WBS Task 2.3 – DoD Evaluation of CCS and Related CR Needs and Opportunities:** Determine DoD carbon dioxide management needs and whether the technologies identified in WBS Tasks 2.1 and 2.2 can fulfill those needs.
- **WBS Task 2.4 – DoD Review of Liquid Fuels Derived from Coal:** Understand DoD activity regarding liquid fuels derived from coal or other resources. Summarize the needs and priorities with regard to synthesis and implementation of these fuels within the timelines set by the DoD.
- **WBS Task 2.5 – DoD Energy Efficiency Review:** Evaluate the DoD’s current energy efficiency programs and approach for addressing future energy efficiency goals

Consistent with the WBS Task 2.0 statement of work, CCAT assembled a team of subject matter experts (SMEs) in each area of interest, as well as related areas of interest. The SMEs, identified in Table 2-1 of this report, were tasked with investigating the most promising technologies in their assigned fields. Each SME submitted a written report, which CCAT provided to DLA Energy under the WBS Task 2.0 contract deliverables (Table C-1, below).

On December 2, 2010, the SMEs, guided by a professional moderator, met with CCAT to present and review the technologies evaluated under WBS Task 2.0, and to select technologies with the best potential for WBS Task 3.0 testing. The results of this meeting were presented to DLA and the Military Advisory Panel on December 13, 2010 at the DLA Energy/Defense Energy Support Center (DESC) in Fort Belvoir, Virginia. Meeting minutes of the Fort Belvoir presentation were compiled by CCAT and submitted to DLA Energy on December 23, 2010 as contract Transmittal No. 0013. The selection process and criteria used to identify the technologies proposed for WBS Task 3.0 testing are excerpted below from the meeting minutes:

> "During the December 2 subject matter expert meeting, the team evaluated all options brought forth and reviewed thus far in the program. Using a set of evaluation criteria weighted towards:
>
> - EISA, Title V, Section 526 compliance,
> - Doing something "new or novel" that has not already been done, and
> - Commercialization on or around 2016,
>   the Team created a short list of possible next step project possibilities."

The Team compared the technologies reviewed at the December 2010 meeting to the above criteria, and recommended, with concurrence from DLA Energy/DESC and Military Advisory Panel, that WBS Task 3.0 testing focus on coal/biomass-to-liquids (CBTL) technologies rather than on CCS or coal-to-liquids processes alone. It was agreed that testing CBTL technologies would be the most advantageous use of project resources and would aid the DoD in meeting the requirements of Section 526. Additionally, in light of the current, pre-commercial state of CBTL technology, it was decided that a longer development timeframe would be appropriate (i.e., commercialization by 2020 rather than the initial target date of 2016). CCAT submitted Detailed Work Plans For Proposed Testing (Transmittal 0010) and "Report on Projects Recommended for Start in GFY 2010 and Beyond" (Transmittal 0019) to inform DLA Energy of the projects to be pursued.

<u>WBS Task 3.0 – Pilot Feasibility Assessments (Testing of Recommended Technologies)</u>

- **WBS Task 3.1 – Project/Test Site Selection and Work Plan Activities:** Select gasification technologies and sites for demonstration testing. Prepare project work plans for each test.

- **WBS Task 3.2 – Environmental Assessment and Permitting:** Facilitate obtaining the necessary permits to implement testing.

- **WBS Task 3.3 – Project/Test Implementation:** Provide project management and oversight, report the test results, and evaluate the findings for each demonstration test conducted.

- **WBS Task 3.4 – Develop Implementation Strategy and Cost Estimates for Follow-on Years:** Prepare annual summary reports. Recommend future investments in CCS and CBTL technologies and new pilot/feasibility tests.

Based on the decision described above to focus WBS Task 3.0 testing on CBTL technologies, some of the initial test recommendations were implemented, such as coal/biomass gasification, testing using algae as the biomass source, and tar reforming, while others were not, such as work with the Rentech Inc. gas-to-liquids process. Based on the initial test work and ongoing evaluation of gasification technologies CCAT submitted Transmittal 0026 to DLA Energy on June 21, 2012, proposing additional test opportunities. CCAT and DLA Energy met at Fort Belvoir on July 16, 2012 to select the most promising of these proposed tests, and the minutes of the selection meeting were recorded by CCAT and submitted to DLA Energy as Transmittal 0028, dated July 19, 2012. Further testing opportunities recommended and supported by DLA Energy included testing diverse biomass feedstocks to demonstrate the potential for feedstock flexibility and gasification technologies suitable for smaller scale production.

Contract Modifications and Details

- Contract Modification P00003, dated July 19, 2012, added 24 months to the initial 36-month contract period.

- Contract Modification P00006, dated March 6, 2014, further extended the Contract through August 31, 2015. As part of this contract modification, the WBS Task 3.0 final contract deliverable (this report) due date, and the recurring contract deliverables (WBS Task 1.3 quarterly progress reports and WBS Task 3.4 annual reports) shifted to the new contract end date.

- Section B-2 of the contract, with Contract Modification P00002 dated August 5, 2010, provides the contract value and funding for the work, and specifies that it is a cost plus fixed fee contract.

- Section B-3 provides the Contract Data Requirements List, which specifies the format for the quarterly status reports, and for the cover page and submission of this report.

Project Deliverables

The table below summarizes the project deliverables, including the date changes from Contract Modification P00003, and provides the dates and transmittal numbers of CCAT's deliverables to DLA Energy.

Table C-1: Project Deliverables and Submittal Dates

WBS Task	Deliverable	Due	Delivery Transmittal No.	Delivery Date
1.1	Detailed Work Plan	3/15/2010	0004	3/15/2010
1.2	Informational Report	3/15/2010	None	1/29/2011
1.3	Program Execution and Progress Reports	1 month after end of each calendar quarter	0002	2/28/2010
			0006	5/31/2010
			0007	8/31/2010
			0010	11/30/2010
			0011	2/28/2011
			0015	5/31/2011
			0017	8/31/2011
			0020	11/30/2011
			0022	2/29/2012
			0025	5/31/2012
			0029	8/31/2012
			0031	11/30/2012
			0032	2/28/2013
			0033	5/31/2013
			0034	8/31/2013
			0035	11/30/2013
			0036	2/28/2014
			0037	5/31/2014
			0038	8/31/2014
			0039	11/30/2014
			0040	2/28/2015
			0041	5/31/2015
2.1	Report on CCS Technology Analysis and Review	4/30/2011	0014	4/30/2011
2.2	Report on CR Technology Analysis and Review	4/30/2011	0014	4/30/2011
2.3	Report on DoD Evaluation of CCS & related CR Needs and Opportunities	4/30/2011	0014	4/30/2011
2.4	Report on DoD Review of Liquid Fuels Derived from Coal	1/31/2011	0012	1/31/2012
2.5	Report on DoD Energy Efficiency	8/31/2011	0018	8/31/2011
3.1	Report on Project Site Evaluations/Selected Site Project Plan	5/31/2011	0016	5/31/2012
3.2	Permits to Implement Selected Project(s)	1/31/2012	NA	NA

WBS Task	Deliverable	Due	Delivery Transmittal No.	Delivery Date
3.3	Report on Project Test, Evaluation, and Recommendations	8/31/2015	0042 (Draft) 0043 (Final Draft) 0044 (Final)	6/3/2015 7/7/2015 8/20/2015
3.4	Report on Projects Recommended for Start in Government Fiscal Year 2010 and Beyond	3 months after contract start, and updated annually thereafter	0019 0030	11/15/2011 11/29/2012 11/29/2013 11/30/2014

Notes:
NA = not applicable
TBD = to be determined

1. Introduction

In response to rising oil prices, uncertainties in the foreign oil market, and energy security concerns, the U.S. Department of Defense (DoD) set a goal to meet 50 percent (%) of the U.S. Air Force's domestic aviation fuel requirements with domestically produced fuel (DoD, 2008; U.S. Air Force, 2013). Coal is the most abundant fossil fuel resource in the United States and can be gasified to create liquid fuels, including diesel and jet fuel, using coal-to-liquids (CTL) processes. However, the process of creating liquid fuel from coal produces large amounts of carbon dioxide and other greenhouse gases (GHGs). Title V Section 526 of the Energy Independence and Security Act of 2007 (Section 526) requires that GHG emissions from alternative fuels purchased by federal agencies are less than or equal to emissions from conventional petroleum fuel. Although technically feasible, commercial production of Section 526-compliant fuels from coal would require carbon dioxide to be captured and sequestered or reused. Recent conceptual studies indicate that GHG emissions from fuels generated from the gasification of a mixture of coal and biomass can be significantly less than emissions from gasification using only coal to produce liquid fuels (U.S. Department of Energy [DOE] National Energy Technology Laboratory [NETL; 2011]).

In an effort to advance scientific research in these areas, the Defense Logistics Agency Energy (DLA Energy) awarded Contract No. SP4701-10-C-0001, "Environmental and Engineering Assessments, Feasibility Analyses and Tests for Carbon Capture and Sequestration and Carbon Reuse Technologies for DoD" (the Contract) to the Connecticut Center for Advanced Technology, Inc. (CCAT) on January 28, 2010. Work under the Contract was performed by CCAT and partners ARCADIS U.S., Inc. (ARCADIS; formerly Malcolm Pirnie, Inc.) and Avetec. The original goals of this project were to explore methods of lowering the carbon dioxide footprint of fuel and electricity produced from coal in the United States for the DoD, research methods for managing carbon dioxide emissions from the production of coal-based fuels, and perform tests to assess whether liquid fuel can be produced commercially from coal while meeting the requirements of Section 526. Work for this project was completed in two phases:

- Phase 1 – Evaluate DoD needs and carbon capture and sequestration (CCS) and carbon reuse (CR) technologies for use in coal/biomass-to-liquids (CBTL) production.
- Phase 2 – Perform CBTL demonstration testing of technologies selected from the Phase 1 evaluation.

Phase 1 was completed in April 2011. The results were reported in the Phase 1 Final Report (CCAT, 2011) and are summarized in Section 2 of this report. Phase 2 testing was conducted from October 2011 through December 2014, with the final test results delivered in May 2015. This report contains the information available as of May 31, 2015; the remainder will be included in the final report, which will be submitted by August 31, 2015. This report summarizes the testing conducted at five facilities across the United States, including facility-reported results and Project Team observations, as well as life cycle and economic modeling analyses. In addition, this report provides overall project findings and recommendations.

The remainder of this report is organized as follows:

Table 1-1: Report Organization

Section Number	Section Title	Description
2	Phase 1 Summary	Summarizes the technology evaluation completed in Phase 1 and the technologies identified for testing in Phase 2.
3	Phase 2 Scope and Objectives	Presents the overall scope and objectives for Phase 2, as well as the objectives for each facility selected for testing.
4	Technologies Tested	Describes the technologies tested during Phase 2, including gasification, steam reforming, and tar reforming technologies.
5	Feedstocks Considered for Testing	Discusses the feedstocks tested, such as coal types, energy crops, residues, municipal solid waste (MSW), and gaseous feed.
6	Facility Testing and Reported Results	Summarizes the information provided in the test report for each facility, including test descriptions, results, analyses, and data interpretation. This section also includes additional analyses performed by CCAT, such as carbon conversion, and solid sample analyses.
7	Test Results Discussion	Discusses the Project Team's observations regarding the test results provided in Section 6 and any potential concerns upon reviewing these results.
8	Life-cycle Analyses	Describes the environmental modeling developed and used to perform life-cycle analyses based on the results presented in Section 6 and to predict future outcomes.
9	Economic Analyses	Describes modeling developed and used to perform economic analyses based on the results presented in Section 6 and to predict future outcomes.
10	Overall Project Findings and Recommendations	Presents the Project Team's overall findings and recommendations based on facility testing and results
11	Works Cited	Lists the documents referenced throughout this report.

2. Phase 1 Summary

Phase 1, the evaluation phase of the project, was completed between January 2010 and April 2011. During this phase, a number of technologies were evaluated based on their potential ability to meet the DoD's alternative fuel and carbon dioxide emission-reduction objectives. A group of technical advisors and subject matter experts was convened to assist with these evaluations. Table 2-1 lists these team members. To meet the needs of the DoD, as set forth in the Contract, CCAT, ARCADIS, Avetec, technical advisors, and subject matter experts (Project Team) conducted research to:

1. Examine state-of-the-art CCS and CR technologies that may prove beneficial to the DoD.
2. Assess the possibility of conducting tests at a U.S. military institution.
3. Research possible improvements to CTL processes that will allow compliance with Section 526 mandates and be ready for near-term commercialization (i.e., 2020).
4. Recommend technologies to be tested and possible test site locations.

Results of this research are summarized below and are presented in the Phase 1 Final Report (CCAT, 2011), which was submitted to DLA Energy and the Military Advisory Panel for their consideration.

Table 2-1: Project Team Technical Advisors and Subject Matter Experts

Technical Advisors			
Name	**Sector**	**Affiliation**	
Howard Herzog	Academia	Massachusetts Institute of Technology	
Daniel Schrag, PhD	Academia	Harvard University	
George Richards, PhD	Government	Department of Energy, National Energy Technology Laboratory	
Sam Venneri	Government	National Aeronautics and Space Administration	
Subject Matter Experts			
Name	**Sector**	**Affiliation**	**Subject Matter**
Arie Geertsema, PhD	Industry	GeertTech LLC	CTL
Tom Filburn, PhD	Academia	University of Hartford	Carbon capture
Vella Kuuskraa	Industry	Advanced Resources International	Carbon sequestration
Joe Genovese	Industry	Sustainable Living, LLC	Carbon reuse
Jordan Peccia, PhD	Academia	Yale University	Algae to fuel
Ray Necci	Public Utility	Connecticut Light & Power	Electric utilities

2.1 Carbon Capture, Sequestration, and Reuse Technologies

This section describes existing, near-term, and next-generation carbon capture, sequestration, and reuse technologies evaluated by the Project Team and presents the results of these evaluations. Complete details are provided in the Phase 1 Final Report (CCAT, 2011).

2.1.1 Carbon Capture

The Project Team evaluated existing and near-term pre- and post-combustion carbon capture technologies including the use of chemical and physical absorbents, membrane technology, and chemical looping. Chemical-absorbent/adsorbent technologies have been proven to work effectively at the commercial scale; however, in order to capture carbon dioxide these technologies consume a large amount of energy (20 to 30% of the power plant's output). The Project Team also evaluated carbon capture associated with oxy-combustion technology. Oxy-combustion is a method for combusting coal with pure oxygen in a nitrogen-free environment or using oxygen enriched air. Because the flue gas consists primarily of carbon dioxide and water, improved carbon dioxide capture can be realized after condensation of water and removal of contaminants (e.g., nitrogen oxides and sulfur dioxide) from the flue gas without large, capture-related energy penalties. The principle disadvantages of an oxy-combustion system are operational complexities and the high cost and energy requirement of generating pure oxygen in an air separation unit. After evaluating these incumbent carbon capture technologies, the Project Team advised the DLA and Military Advisory Panel that these technologies are already established or extensive ongoing research is currently being supported by other organizations like the DOE. As a result, carbon capture demonstration tests performed within the project budget would not substantially add to the knowledge base on this topic and further testing in this area under the DLA Energy program is not warranted. The Project Team also investigated membrane separation and chemical looping, a process similar to oxy-combustion but with no air separation unit required. Although promising, these next-generation technologies (i.e., 15+ years to commercial development) were determined to have low technology readiness levels (TRLs). Because one of the primary objectives of this project was to examine technologies that can be commercially feasible by 2020, these technologies were not tested in Phase 2.

2.1.2 Carbon Sequestration

The Project Team also evaluated existing and near-term carbon sequestration technologies including enhanced oil recovery (EOR), oceanic storage, and carbon sequestration in appropriate geologic formations. Other, less developed methods of carbon sequestration considered were algal and terrestrial storage. EOR is a proven technology that has been in use for more than 70 years, but has the disadvantage of not permanently sequestering all of the carbon dioxide injected due to the emission of carbon dioxide during the oil recovery process, and is better categorized as a reuse opportunity. Geologic storage, or injecting carbon dioxide into porous rock thousands of feet below the Earth's surface, has great potential for providing long-term carbon storage. Use of deep saline aquifers has been widely studied. Other geologic formations that may be suitable include basalt, gas shales, unmineable coal seams, and depleted oil and gas reservoirs. Because large-scale geologic storage of carbon dioxide has occurred for less than 50 years, there are uncertainties about the storage capacity of each formation and how to accurately determine that storage is "permanent". Because carbon sequestration technologies are already in use or the subject of much research by others, the Project Team determined that demonstration tests performed within the project budget would not substantially add to the knowledge base on this topic.

2.1.3 Carbon Reuse

As a result of the challenges associated with long-term carbon sequestration and in an effort to increase the efficiency of fuel production processes, the Project Team evaluated the following technologies for reusing carbon dioxide to make fuel:

- Methanol synthesis from synthesis gas (syngas)
- Reverse water gas shift (WGS) with Fischer-Tropsch (FT)
- Solar thermochemical ferrite cycle
- Solar thermochemical zinc oxide/zinc cycle
- Electrochemical processes to produce syngas

Based on evaluation results, the Project Team concluded and reported to DLA Energy and Military Advisory Panel that the energy requirements for these CR technologies are too high and their TRL levels are too low to justify their use for the production of alternative fuels for military applications. Therefore, CR technologies were not considered for further study or demonstration testing.

2.2 U.S. Military Base Coal-Fired Plant Review

The Project Team visited three of 12 coal-fired plants currently operating on DoD bases (Wright-Patterson Air Force Base, Rock Island Arsenal, and Marine Corps Air Station Cherry Point) to assess the possibility of conducting tests at a U.S. military institution. Site visit evaluations are provided in the Phase 1 Final Report (CCAT, 2011). The primary purpose of these coal-fired plants is heat and/or process steam generation. After conducting the site visits and reviewing information on the plants provided by DLA Energy, the Project Team determined that due to the age and configuration of these plants, only post-combustion carbon capture could be tested, and this has already been demonstrated at several commercial power plants. Further, the plants would need to install carbon capture equipment to perform these tests. This would result in a significant loss of plant output (heat or steam) due to power necessary to operate the carbon capture equipment. Finally, because of the small size and number of coal-fired plants in operation, it would not be economically beneficial to pursue capturing carbon at DoD installations for the relatively small potential reduction in carbon dioxide emissions that could be obtained. Considering these limitations, the Project Team reported to DLA Energy and Military Advisory Panel that performing demonstration testing on a military base would not be practical for this project.

2.3 Liquid Fuel Production

The Project Team studied two CTL synthetic fuel processes: direct liquefaction and indirect liquefaction.

Direct Liquefaction: The Project Team evaluated Accelergy Corporation’s (Accelergy’s) direct liquefaction process, which is based on a technology originally developed by ExxonMobil (cleantech® Group LLC, 2009). The Accelergy process incorporates the addition of algal biomass gasification and terrestrial sequestration to reduce the life-cycle carbon footprint of the fuel production process. However, the Accelergy process and direct liquefaction processes have a low TRL, as discussed in the Phase 1 Final Report. Because near-term commercialization is unlikely, the Project Team recommended to DLA Energy and Military Advisory Panel not to pursue testing of this technology (CCAT, 2011).

Indirect Liquefaction: The Project Team evaluated the well-established indirect liquefaction and FT process, which was invented in the 1920s and has been implemented commercially. The gasification of coal (and other suitable fuel sources) produces syngas, primarily a carbon monoxide and hydrogen mixture. The FT technology converts syngas into a wide range of higher carbon number hydrocarbons, up to waxes, which can be further treated or upgraded to obtain a desired product (in this case jet fuel). Upon evaluation of the FT liquefaction technology, the Project Team concluded that with the addition of biomass to the CTL process (CBTL) and CCS, a CBTL plant using the FT process could be designed to produce jet fuel meeting Section 526 requirements, as can a CTL plant, if CCS is at a sufficiently high level. This conclusion was founded on work supported by DOE (Section 3). Therefore, the Project Team determined and recommended that an FT liquefaction technology would be the most beneficial to the DoD in accordance with project objectives and should serve as the basis for Phase 2 demonstration testing.

2.4 Testing Phase Recommendations

Based on research, site visits, and evaluations conducted during Phase 1 of the project, the Project Team recommended that the testing phase of the project focus on demonstration testing of the gasification component of CBTL processes for the production of alternative fuels. Unique technical and economic challenges are associated with the gasification of biomass and coal/biomass mixtures. Technical challenges include feedstock reactivity, ash quantity and chemistry, and tar production. Additionally, most gasification systems are designed for uniformly sized coal particles, difficulties arise when introducing biomass as a feedstock due to differences in preparation, size, density, moisture, and morphology. Major logistical and economic challenges for a commercial-scale CBTL plant include sourcing enough biomass feedstock from a centralized location and the cost associated with preparing biomass for gasification. In addition, an expressed objective of DLA Energy for a CBTL plant is fuel flexibility. The ability to use multiple types of feedstock mitigates potential supply risks that could disrupt production if a plant was dependent on only one feedstock. Therefore, demonstration testing for converting a wide range of feedstock types in several different gasification systems is a critical step in furthering the commercial development of CBTL technologies and achieving feedstock flexibility.

The Project Team recommended to DLA Energy and Military Advisory Panel the following as the primary focus for Phase 2 testing:

- Test different types of biomass as feedstock, including waste products and nuisance plants.
- Gasify coal/biomass mixtures in a single, co-feeding gasifier (e.g., entrained-flow gasifier [EFG], transport gasifier, plasma gasifier).
- Gasify coal and biomass in separate dedicated gasifiers prior to combining the syngas for liquid fuel production.
- Reform tar/char from coal/biomass mixtures or from biomass and/or coal gasification to obtain higher syngas product yield.

The scope and objectives for Phase 2 are described in Section 3.

3. Phase 2 Scope and Objectives

The second phase of the program focused on gasification in a CBTL process using coal mixed with biomass as the feedstock. Previous life-cycle models published by NETL and the Inter-Agency Working Group (IAWG) show that adding biomass to coal feedstock reduces the amount of carbon dioxide required to be captured and sequestered or reused from CBTL plants compared to CTL plants; therefore, improving the plant's ability to achieve compliance with Section 526 (NETL, 2009; IAWG, 2011). Extensive testing has been performed demonstrating the gasification of coal. Similarly, much testing has been performed demonstrating the gasification of biomass. However, the Project Team found very little data to demonstrate co-gasification of coal mixed with biomass and fed at the same time.

Based on Phase 1 evaluations, NETL and IAWG's previous modeling results, and DLA Energy's desire to demonstrate feedstock flexibility in a CBTL process, the Project Team decided to conduct demonstration testing of gasification and reforming technologies using coal and biomass mixtures. To begin this course, The Project Team extended the subcontract of Subject Matter Expert, Arie Geertsema, of Geerttech LLC, an internationally recognized expert on the CBTL process. Dr. Geertsema had written an introduction to CBTL for the Phase 1 deliverable, and for Phase 2, provided additional and more detailed writings on CBTL, which helped to guide the Project Team in developing the CBTL test objectives. Dr. Geertsema's writings on CBTL are provided as Appendix A.

Specific Phase 2 objectives were:

- Conduct tests using gasification technologies with the potential to help advance the commercialization of CBTL facilities by 2020.
- Identify and test gasification technologies suitable for use with domestic coal and various biomass resources that enhance the DoD's energy security goal of procuring a reliable source of fuel using domestic feedstock.
- Demonstrate the ability to introduce a variety of coal-biomass mixtures into a high-temperature, high-pressure gasifier design.
- Assess gasifier operating conditions and the ability to attain stable gasifier operations with a variety of biomass types and coal/biomass feed ratios.
- Characterize effluent gas products resulting from the gasification of various coal/biomass combinations.
- Determine the amount of trace contaminants expected from gasification of different coal/biomass mixtures. Evaluate the impact of these contaminants on downstream gasification processes.
- Assess the impact of prepared feedstocks, such as torrefied wood, on the gasification process.
- Assess the potential of tar reforming technologies on product gas composition.

- Generate enough test data to update models that will determine Section 526 compliance for CBTL processes.

- Contribute to the scientific literature and understanding of coal and biomass synthetic fuel production options through targeted demonstration testing and disseminating project results to key stakeholders and the public.

3.1 Test Selection Process

Upon completing the evaluation phase of the project, the Project Team provided a recommendation to DLA Energy to conduct demonstration testing of gasification technologies suitable for large-scale operations (e.g., production of 30,000 to 50,000 barrels per day [bpd] of liquid fuels), with a focus on the following:

- Test different types of biomass with coal.

- Gasify coal and biomass mixtures in a single co-feeding gasifier (e.g., entrained-flow gasifier and transport gasifier).

- Gasify coal and biomass in separate gasifiers prior to combining the syngas for liquid fuel production.

- Reform tar/char produced from gasification of coal/biomass mixtures to increase product gas yield.

Initially, only technologies capable of being commercially developed at a large scale (30,000 to 50,000 bpd) were considered for demonstration testing. The Project Team researched numerous facilities throughout the United States that could potentially test available gasification technologies to determine the tests that would be feasible to best fulfill the project objectives. The test selection process included identifying and screening test facilities, evaluating the cost for testing, and determining a facility’s ability to develop valid test plans.

After completing several demonstration tests in 2012, the Project Team expanded the criteria for additional tests to include gasification technologies more suited for producing smaller, distributed-generation-scale quantities (700 to 3,000 bpd) of liquid fuels. Consistent with DLA Energy and Military Advisory Panel’s desire to address feedstock flexibility, gasification technologies with the ability to process a wider range of feedstock were also considered. Twenty-two new tests were considered that included different gasification technologies, various feedstocks, catalytic processes for tar reforming and liquid fuel production, carbon capture, and carbon sequestration. The tests were then ranked according to their likelihood of producing useful data and recommendations were made to DLA Energy. Following approval by DLA Energy and the Military Advisory Panel, additional demonstration tests were planned and conducted.

3.2 Test Facility Selection

Although numerous commercial-scale coal gasifiers are in operation worldwide, gasification facilities in the United States with the capability for conducting demonstration tests suitable for this project were limited. This limited the number and scale of gasification technologies available for testing within the project budget. For example, although entrained-flow slagging gasifiers are well developed on a commercial scale, the only available comparable United States test unit was the small-scale entrained-flow slagging gasifier at the Energy and Environmental Research Center (the EERC) in North Dakota.

Based on a review of available literature, including input from DOE, technical advisors, and subject matter experts, the Project Team assembled a list of suitable test facilities and potential tests for each large-scale facility. The merits of each test were discussed and ranked by the Project Team. Members of the Project Team visited the facilities that appeared to have the most potential to meet project needs and to confirm the facilities' capabilities and interest in conducting demonstration testing for the project. Test facilities visited included the EERC; Rentech, Inc. (Rentech); National Carbon Capture Center (NCCC); University of Dayton Research Institute; Multipollutant Control Research Facility at the U.S. Environmental Protection Agency's (USEPA's) Environmental Research Center in Research Triangle Park, North Carolina; and Emery Energy Company (Emery).

After the facility visits, the Project Team established facility selection criteria, identified and evaluated candidate facilities, and submitted recommendations for demonstration testing to DLA Energy. The Project Team recommended testing the gasification of various coal/biomass mixtures at the EERC and NCCC and testing the reforming of tar from biomass gasification at Rentech; DLA Energy approved these recommendations. Testing at Rentech was contingent upon Rentech's ability to commission their new ClearFuels® Technology, Inc. (ClearFuels®) gasifier unit and secure funding to install a reforming plant at their Product Demonstration Unit in Commerce City, Colorado. This testing was not conducted because the Rentech facility closed in February 2013 before the tar reforming plant was built.

Before demonstration testing began, the Project Team conducted an environmental review under the National Environmental Policy Act on behalf of DLA Energy and reviewed permit requirements with the proposed test facilities. It was determined that each facility maintains all of the necessary permits; therefore, no additional permitting was required to conduct demonstration testing. On February 9, 2012, DLA Energy submitted DLA Form 1664, Record of Determination Environmental Evaluation, which determined that the proposed tests at these facilities are a categorically excluded action and that further environmental review was not necessary.

In May 2013, additional test facilities were identified for testing technologies appropriate for smaller scale production. The Project Team met with technical staff from Westinghouse Plasma Corporation (WPC), ThermoChem Recovery International, Inc. (TRI), and Enerkem. Discussions were also had with PyroGenesis, Synterra Energy, General Atomics, and the Gas Technology Institute. Based on the results of these meetings, the Project Team recommended to DLA Energy testing at Emery (specifically for testing of the Ceramatec cold plasma tar reforming technology), WPC, TRI, Enerkem, and additional testing on the entrained-flow and transport gasifiers at the EERC.

The Project Team, with concurrence from DLA Energy, proceeded to investigate demonstration testing at the following test facilities:

- The EERC, located in Grand Forks, North Dakota
- Emery, located in Laramie, Wyoming
- NCCC, located in Wilsonville, Alabama
- TRI, located in Durham, North Carolina

- Enerkem, located in Westbury, Quebec
- WPC, located in Madison, Pennsylvania

In September 2014, Enerkem decided they could not support the proposed testing; therefore, the remainder of this report focuses on the five facilities where testing was conducted. The rationale for conducting testing at each facility is provided below.

The EERC – The Project Team's technical advisor from DOE indicated that DOE had successfully worked with the EERC in the past. This facility operates several gasifiers, including an EFG and a transport reactor integrated gasifier™ (TRIG™). Testing at this facility allowed the Project Team to leverage significant investments made by DOE and others for testing and for post-test data analyses. The EERC has significant expertise in coal and biomass gasification and the capability to perform multiple demonstration tests. In addition, the EERC has a small-scale FT reactor capable of generating liquids from syngas, and the ability to test tar reforming catalysts using the transport reactor development unit (TRDU) product gas.

Emery – The Project Team reached an agreement with DLA Energy to investigate tar reforming, a process that may improve the efficiency of coal/biomass gasification by deriving additional fuel or energy from a biomass gasification byproduct. Emery operated a modified moving-bed gasifier in Wyoming, which included an electric plasma tar reforming technology developed and patented by Ceramatec. While the Emery facility did not have a long operational history or experience with research and development testing, it offered the opportunity for testing an innovative tar reforming technology. Emery had previously run a test program with DOE, indicating potential capability to perform a test that would meet our project objectives.

NCCC – Operated by the Southern Company, NCCC is funded by DOE and functions to further the Southern Company's investment in the KBR, Inc. (KBR) TRIG™ technology. The NCCC creates significant quantities of product gas that can be used for testing new gas cleanup technologies. The TRIG™ at NCCC is a scaled up version of the TRIG™ tested at the EERC.

TRI – TRI offers a proprietary steam reforming technology, which was developed to gasify biomass and waste feedstocks. TRI had extensive experience gasifying biomass (under several DOE programs); however, it had limited experience with coal. As a result, TRI determined that its technology would be most suitable for low-rank coal such as lignite.

WPC – The purpose of the test at WPC was to perform plasma gasification of coal with MSW. WPC had extensive experience gasifying MSW, but not coal. Plasma provides the extremely high temperatures needed to gasify heterogeneous MSW feedstock.

The Project Team prepared a draft scope of work for each test facility, which provided test objectives and general concepts for a demonstration test (e.g., gasification of three biomass types mixed with two types of coal at two mixture ratios each). Each test facility prepared a cost estimate based on the draft scope of work, and the Project Team then worked with each test facility to develop a test plan that would achieve the test objectives within a given budget. The test plans included operating conditions, feedstock types, percentage mixtures of feedstocks, sampling/data collection, reporting, and schedule. The number of samples to be collected and the sampling methods were detailed in the sampling protocols.

Several facilities selected for testing were built and are operated with significant financial support from DOE. Conducting demonstration tests at these facilities enabled the DoD to benefit from prior and ongoing DOE investment. In addition, this collaboration is consistent with a Memorandum of Understanding issued in July 2010 between the DoD and DOE, which was designed to strengthen the two agencies' coordination of efforts to enhance national energy security. Further, at DLA Energy's recommendation and to leverage the DOE's previous gasification research, CCAT entered into a Cooperative Research and Development Agreement with DOE/NETL for Phase 2 of the program. The DOE/NETL work included development of techno-economic and life-cycle analysis (LCA) models for the EFG and TRIG™ gasification technologies. The DOE/NETL effort included validating their models using actual gasification test data from the Project Team's gasification tests. DOE/NETL also analyzed a small quantity of FT liquids produced during demonstration testing at the EERC to verify chemical composition of the end product.

3.3 Selection of Feedstock for Testing

The Project Team recommended testing various types of coal, biomass, and mixture ratios. Test objectives with respect to the feedstock were:

1. Determine suitability for mixing various biomass and coal types.

2. Evaluate the ability to feed the various feedstocks into different gasifier designs.

3. Evaluate product gas composition and its suitability for producing liquid fuels. Testing various feedstocks/feedstock combinations supported DLA Energy's goal of achieving feedstock flexibility.

Prior to finalizing the test plan for each facility, samples of each target feedstock were acquired and analyzed for physical properties important to gasification (Section 6), including proximate analysis, ultimate analysis, and heating value analysis. Upon finalization of the test plans, CCAT purchased the necessary quantities of each feedstock for the test facilities.

Based on the Project Team's research and review of DOE/NETL's database (Annual Energy Review 2011; U.S. Energy Information Administration [EIA], 2012), three types of coal were selected for demonstration testing: bituminous Illinois No. 6 (IL No. 6), sub-bituminous Powder River Basin (PRB), and lignite. These coal types and the rationale for testing each type is provided in Section 5.

To achieve the objective of evaluating feedstock flexibility, the Project Team selected a wide range of biomass feedstocks for testing, including both hard and soft wood, agricultural residue, energy crops, waste, and algae. These feedstocks, along with the Project's Team rationale for selecting each feedstock, are described in Section 5.

3.4 Selection of Feedstock Blend Ratios

The biomass percent of the feedstocks tested at each facility was determined by considering the logistics and economics of a potential commercial plant, as well as the physical capabilities of the test facility. In the case of coal/biomass and coal/shale gas blends at the EERC and at NCCC, the potential commercial application would be a large-scale CBTL plant in the range of 30,000 to 50,000 bpd of liquid fuels. The logistics of harvesting and delivering biomass within a certain geographic vicinity limits the percent of biomass that can be considered. With this consideration, the Project Team decided to test various feedstock blends up to 30% biomass at those facilities. In addition, a 100% biomass test was conducted at EERC to obtain gasification data under that condition.

In the case of the coal/MSW blends gasified at WPC and TRI, feedstock blends up to 100% MSW- were used. This was because a CBTL plant based on MSW is potentially feasible at a much smaller scale due to the revenue available from the MSW. For example, conventional waste-to-energy power plants are based on securing a waste stream of typically 500 to 3000 tons per day (tpd) MSW. The benefits of using MSW in a CBTL plant include the GHG benefit from the biogenic portion of the waste (see Section 8), and the financial benefit from the tipping fee revenue (see Section 9). By using a higher percentage of MSW in the feedstock, a CBTL plant can maximize these benefits.

4. Technologies Tested

The reports presented in Appendix A summarize publicly available information on developments on CTL and CBTL technology that are pertinent to this project. While both technical and economic aspects were discussed, this section focuses on technologies only, not economic viability. As discussed in Section 2.3, only technologies using indirect coal liquefaction were considered suitable for this project. Although a commercial plant has been commissioned in China using direct coal liquefaction technology, this technology is not currently developed for commercial use in the United States. Gasification technologies that are or potentially could be implemented in the United States include entrained, slagging gasifiers such as E-Gas™ (ConocoPhillips/CB&I), GE, Siemens, Shell, Prenflo™ (Uhde), Lurgi, and U-Gas (SES), as well as TRIG™. Steam reforming, bubbling fluidized-bed, and plasma technologies have been commercialized for small-scale conversion of waste or biomass to liquid fuels, chemicals, or power. Although gas-to-liquids plants could potentially achieve the technical LCA emissions criteria of Section 526 and may be more economically feasible than CTL plants under current conditions (Appendix A), gas to liquids was beyond the scope of this project and not considered under this technology review.

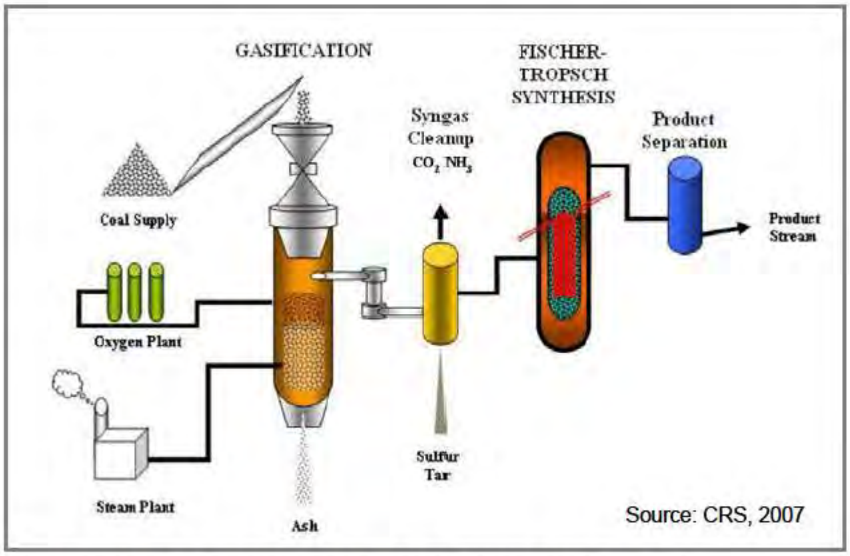
Economic viability of a CBTL plant will be influenced by several factors, including scale, year-round availability of suitable biomass feedstock, and markets/off-take agreements for the products. To meet the U.S. Air Force goal of using alternative aviation fuel blends for non-contingency operations equivalent to 50% of total U.S. Air Force fuel needs (up to approximately 40,000 bpd) by 2025 (U.S. Air Force, 2013), total FT liquid production of 80,000 bpd is required (assuming 50% of total FT products yield jet fuel). Clearly, a firm quantity of alternative fuel that DoD is committed to acquire is necessary to determine the scale of production projects. This need could be met by one large plant or more than one plant with smaller capacities. Commercial viability of small-scale FT liquid production has not yet been established. Additionally, upgrading raw FT products to meet jet fuel specifications becomes very expensive at a small scale unless existing refinery infrastructure can be used. As noted earlier, large-scale production is considered greater than 30,000 bpd. Therefore, if economy of scale favors the construction of a 50,000 to 100,000 bpd plant over a 20,000 bpd plant, additional markets for the excess product would be necessary to make the plant economically viable. For example, commercial aviation companies would purchase competitively priced fuel in excess of that produced to meet DoD alternative fuel needs.

Detailed reports on the technologies that were reviewed and considered for this project, including details of gasification technology at a commercial scale, are provided in Appendix A. This section summarizes key features of the technologies that were tested in Phase 2 of the project. When selecting facilities for demonstration testing, the Project Team was significantly constrained by the limited availability of plants/facilities in the United States for such testing. Thus, the technologies tested were based on availability and suitability to meet the project objectives described in Section 3, without constraint by the current commercial status or viability of each technology.

Tests were conducted on four gasification and two tar reforming technologies at five facilities. The test units at EERC and Emery are considered experimental/ research and development-scale units, while those at NCCC, TRI, and WPC are considered demonstration-scale units. The tests were conducted at these facilities to characterize the suitability of particular approaches to produce syngas capable of being converted to fuels and chemicals using a variety of feedstocks. Although much of the work was conducted at a research and development-scale level, the variations in feedstock and operating parameters provided valid insights into the ability of the tested technologies to produce syngas. Each of the technologies tested are described in detail in the individual facility test reports (Appendices C through I). The rationale for selecting these technologies and these test facilities is explained in Section 3.2, above.

4.1 Gasification

Gasification has been practiced for more than a century to supply gas for domestic and industrial use before natural gas became widely available (Higman and van der Burgt, 2008). While modern gasifiers are very different from earlier versions, the basic process chemistry is similar. Gasification refers to the reaction between carbonaceous material (e.g., coal, biomass, MSW) and steam at elevated temperatures with sub-stoichiometric oxygen to produce primarily hydrogen and carbon monoxide (called syngas). Syngas can be used for the synthesis of chemicals and fuels or for power generation. Steam plays an important role in gasification, whether it is derived from the inherent moisture in the feedstock or injected into the gasifier. Carbon dioxide is produced from the oxidation of organic carbon (exothermic process) and the reaction of carbon monoxide with steam (WGS reaction). A generic schematic of the FT CTL process is shown on Figure 4-1.



Source: CRS, 2007

Figure 4-1: Simplified Generic FT CTL Process Configuration

4.1.1 EERC – Entrained-flow Gasifier

Various EFG configurations exist, as described in Appendix A. This section briefly describes the configuration of EFG used at the EERC. A simplified schematic of the EERC's EFG is shown on Figure 4-2. The EERC's EFG is a vertical, cylindrical vessel with a typical feed rate of 8 to 12 pounds per hour (lb/hr). Dry feedstock enters the top of the gasifier and flows downward concurrently with nitrogen, pure oxygen, and steam. The EFG operates at very high temperatures (nominal 2,700 degrees Fahrenheit [°F]), which is above the typical melting point of the ash contained in feedstocks tested at the EERC. The molten ash forms a liquid slag, which flows to and collects in the bottom of the gasifier vessel where it is removed after cooling. At such high temperatures, the reactions are rapid and should lead to the destruction of most of the "heavier" de-volatized and product gas components, which may otherwise form tars and cause fouling of interior gasifier surfaces and downstream equipment (e.g. sulfur scrubbing, carbon capture, or FT synthesis) at lower temperatures. After a short residence time, the product gas exits out of the bottom of the gasifier.

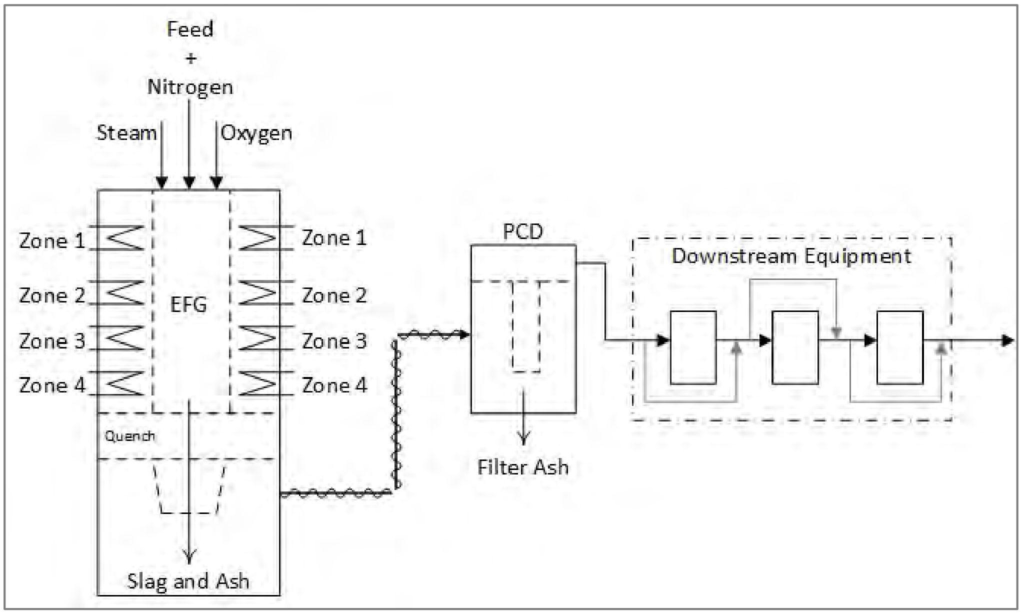
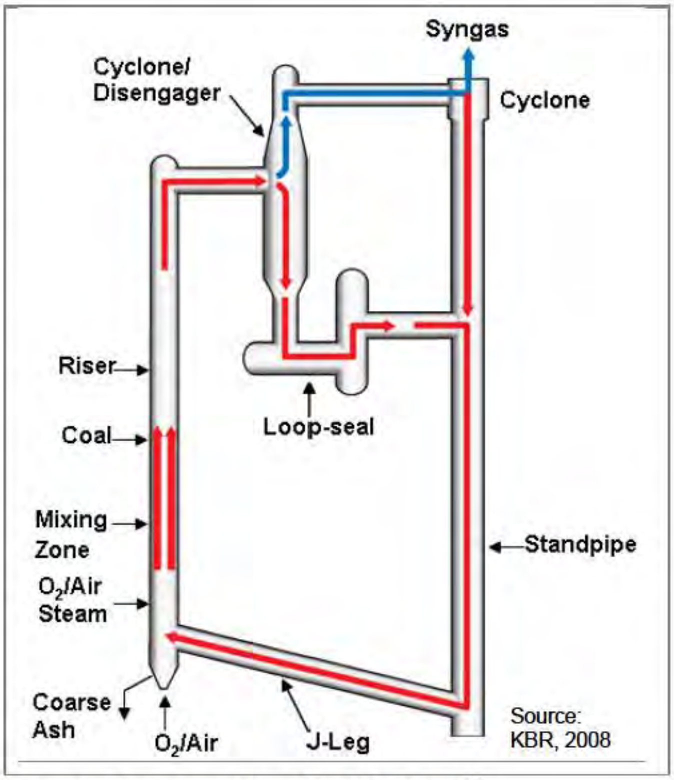


Figure 4-2: Simplified Schematic of the EERC's EFG

Thermal management is a key design consideration for an EFG. The EERC unit is not large enough to self-maintain the gasification process. As such, electric heaters provide the majority of heat inside the gasifier, and downstream heat-tranced lines prevent excessive cooling. As shown on Figure 4-2, the system consists of four heating zones; each zone is independently controlled to maintain a time-temperature profile closer to commercial EFGs. Similar to a commercial gasifier, the EERC's EFG includes a quench zone in which a gas can be injected to cool the product gas. However, because of the scale of the EERC's EFG, it is not typically necessary to inject gas into the quench zone.

Appendix C, Appendix D, and Appendix E provide additional information about the EFG used for project testing at EERC.

4.1.2 EERC and NCCC – Transport Reactors (TRDU and TRIG™)



Source: KBR, 2008

Figure 4-3: Schematic of the KBR TRIG™

Transport reactors were tested at the EERC and NCCC. The transport reactor at EERC, the TRDU, was used by the Southern Company and KBR to gather data to develop reactor technology for the reactor installed at NCCC in 1996. The TRDU has a dual lock-hopper feed system that can supply 300 to 600 lb/hr to the gasifier. As described in Section 6, the TRDU was used for testing mixtures of coal and biomass and coal and shale gas. The transport reactor at NCCC, the TRIG™, is a demonstration unit 10 times larger than the TRDU. Although both units were designed by KBR, there are differences between the two in addition to size. For instance, while, coal and biomass were blended and fed together at EERC, the feed system at NCCC consists of separate feeders for coal and biomass (total feed rate 3,000 to 4,000 lb/hr). Differences also exist in the configuration of the standpipe, loop-seal, and seal leg. Another significant difference between the two gasifiers is in the use of nitrogen. The EERC uses nitrogen to fluidize the bed material in the standpipe and as a transport gas. At NCCC, recycled product gas is used, which offsets a large portion of the total nitrogen used in the whole TRIG™ system.

The TRIG™ is a fast flowing, circulating fluidized bed system with solids recirculation to maintain the desired temperature profiles. It operates in the 1,500 to 1,950°F temperature range, which is below the softening point of most ashes from coal. The TRIG™ can handle a wide range of coal types, including high-moisture, low-rank coal such as lignite.

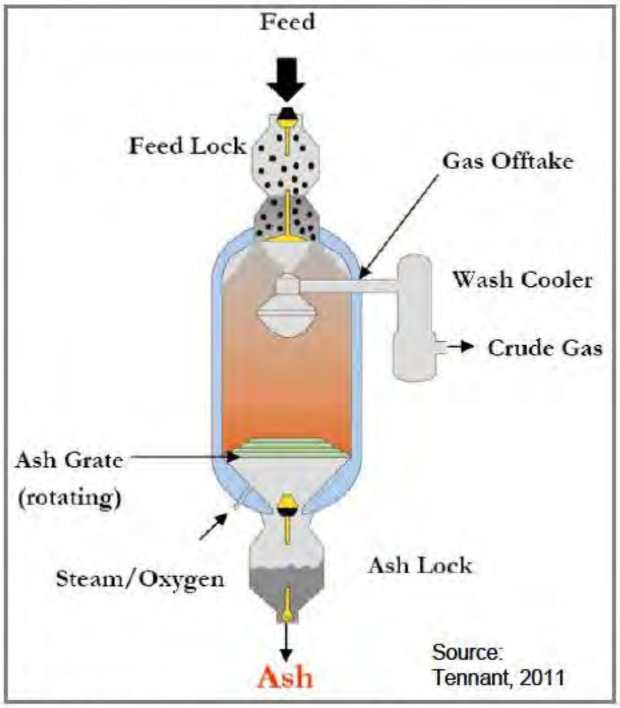
A schematic of the KBR TRIG™ is shown on Figure 4-3. It consists of a mixing zone, riser, cyclones, loop-seal, standpipe, and a J-leg. Coal or other carbonaceous feedstock is fed slightly above the mixing zone in the riser in a reducing atmosphere to avoid premature combustion with the oxidant. Steam and oxidant (oxygen/air) are injected separately and mixed together in the mixing zone, along with the circulating solids returning from the J-Leg. The mixing zone of the gasifier can also be referred to as a 'combustion zone,' where oxidation reactions occur between the unreacted carbon (char) in the solids returning from the J-leg and the injected oxidant (oxygen/air). The coal gasification reactions take place primarily in the riser above the coal feed injection point (gasification zone) by utilizing the heat generated from char combustion in the mixing zone. The circulating solids in the system act as heat carriers that transfer heat generated from the bottom (combustion) zone to the gasification zone. This staging effect is another feature of the gasifier in that fresh coal is primarily utilized for gasification, while the unreacted carbon in the returning solids is sourced for heat generation (KBR, 2008). Another advantage of continuous solids recirculation is to increase the conversion to product gas of carbonaceous material (carbon conversion) that was unreacted after a single pass through the gasification zone.

Appendix C and Appendix D provide specific information on the transport gasifier used at the EERC's TRDU, and Appendix F provides specific information on NCCC's TRIG™.

4.1.3 Emery – Fixed-bed Gasifier

A fixed-bed gasifier was used by Emery to produce product gas to test the proprietary plasma tar reforming technology of Ceramatec, which is described in Section 4.2.1. This gasifier technology was not the focus of project testing. Appendix G provides specific information on the fixed-bed gasifier used for project testing at Emery.

The Emery gasifier uses a gravity feed through lock hopper on top of the gasifier. The fuel moves downwards and oxygen and steam are injected upwards at the bottom through a grate. This gasifier operates in a counter-current configuration with the product gas exhausting above the bed. The fuel begins to devolatilize in the middle of the bed as soon as higher temperatures in the gasifier are reached. These volatile components are entrained in the outlet gas stream and fed to the installed reformer at Emery. The ash is discarded through a lock hopper. An overview schematic of a Lurgi fixed-bed gasifier is shown on Figure 4-4, which is similar to the gasifier used at Emery. The wash cooler shown on the figure is not included in Emery's gasifier.



Source: Tennant, 2011

Figure 4-4: Fixed-Bed Dry-bottom Gasifier

4.1.4 TRI – Steam Reformer Fluidized Bed Gasifier

The TRI steam reformer gasifier is a unique proprietary process that uses indirectly heated fluidized beds with superheated steam as a fluidizing medium to achieve the conversion of carbonaceous feedstocks into product gas. This is a two-step process: the first step is steam reforming, which is similar to pyrolysis, and the second step is partial oxidation in which residual carbon is converted to additional product gas. Partial oxidation is used to the degree necessary to adjust the hydrogen to carbon monoxide molar ratio (H_2:CO molar ratio) required for the downstream FT synthesis process. According to TRI, the system is capable of generating product gas with an H_2:CO molar ratio ranging from 1.5 to 3.5 (using woody biomass, for example). An overview schematic of TRI's steam reformer gasifier is shown on Figure 4-5.

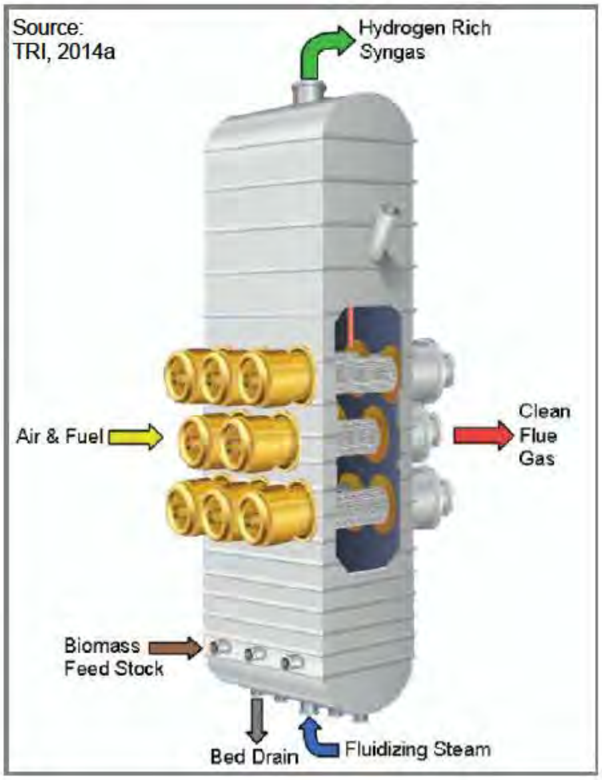

Source:
TRI, 2014a

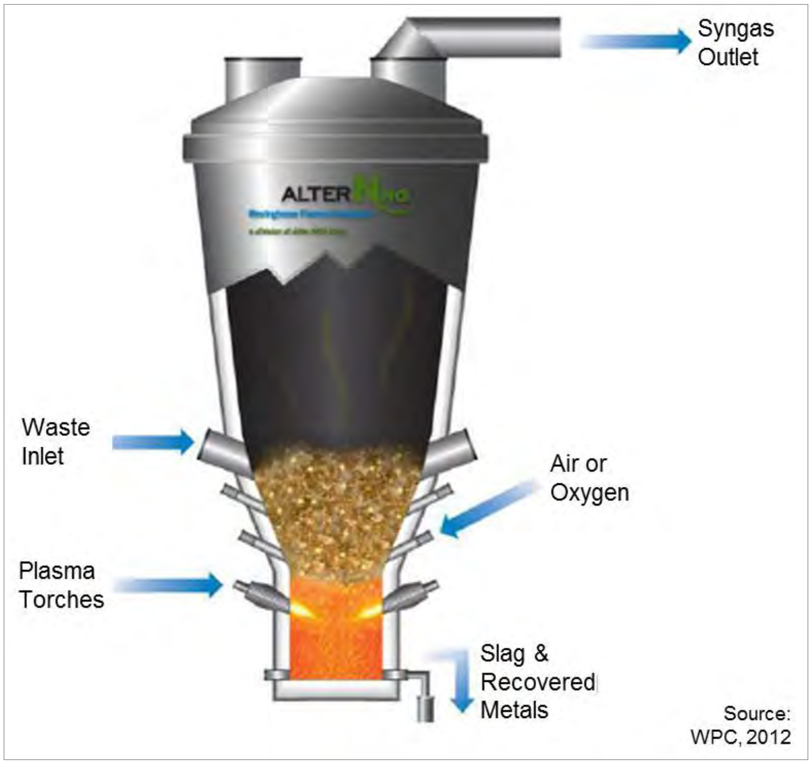
Figure 4-5: TRI Steam Reformer Gasifier

A TRI steam reforming system has been in operation since 2003 for the gasification of black liquor from pulp and paper mills. TRI licensed its gasification system to Fulcrum Bioenergy, which is constructing a commercial biorefinery in Nevada designed to produce approximately 240,000 barrels of FT syncrude a year from 200,000 tons of MSW feedstock. Commercial operation is scheduled to begin in 2017. Appendix I provides specific information on the steam reforming gasification technology tested at TRI.

4.1.5 WPC – Plasma Gasifier

A more recent type of gasifier is the WPC's high-temperature unit, which is in the process of being commercialized. The WPC unit is a fixed-bed, plasma-assisted gasifier that operates at atmospheric pressure and above ash melting temperature (3,000 to 5,000°F combined plasma and gas flow). It is based on the production of high-temperature plasma from an electrically powered plasma torch, and the introduction of sub-stoichiometric air (or oxygen) with the carbonaceous feedstock material. Solid ash present in the feed is withdrawn from the bottom of the vessel as a molten slag.

The plasma torch is used to supply super-heated air and some of the heat required for gasification. The torch is immersed in a bed of lump sized metallurgical coke (met coke). The met coke serves to dissipate heat from the plasma torch and creates a porous support bed for the feedstock allowing slag to flow easily to the bottom. The met coke is gradually consumed in the gasification reactions and must be topped up throughout the operation.



Source: WPC, 2012

Figure 4-6: Alter NRG's 1,000 Tons per Day G65 Design Plasma Gasifier

Flux materials ensure a reasonably low slag melting point, reducing both coke utilization and the plasma torch power requirement. Typically, calcium carbonate is used as the flux material to lower the melting temperature at the met coke bed. Fuel is mixed with flux material, which is fed to the gasifier from the top of the bed and the product gas exits from the top of the gasifier. Oxygen is fed into the bed for gasification reaction with the fuel. Figure 4-6 shows a schematic of the largest commercial WPC plasma gasifier, which can operate on 1,000 tpd of sorted and processed MSW feedstocks. WPC has several commercial gasifiers in operation, under construction, or in commissioning for converting waste to power or liquid fuels. These gasifiers are all located outside the United States.

Appendix H provides additional information on the plasma gasifier used for demonstration testing at WPC.

4.2 Tar Reforming

The term "reforming" has various applications in the field of chemical process technology. In the context of this report, tar reforming is the conversion of tars into product gas in a unit operation separate from the gasifier.

When coal and biomass are heated, volatile components and tars are liberated. If the temperature is high enough (as in high-temperature slagging gasifiers), these components are cracked and thermally converted to product gas, especially in the presence of steam and oxygen. For gasification at lower temperatures, these components leave the gasifier and can foul the colder surfaces of downstream equipment. Depending on the plant configuration, tars can be condensed and separated from the gas stream prior to down-stream processing. It is beneficial if tars are processed to convert the carbon in these components to carbon monoxide and hydrogen and in that way, increase the production of syngas. Issues encountered with tar reforming catalyst technologies include fouling by char and particulates, operating temperatures, and catalyst deactivation. There is extensive literature on tar reforming and the composition of tars from various sources (Tchapda and Pisupati, 2014). Two recent technologies that target tar reforming were tested for this project and are discussed below.

4.2.1 Non-Thermal Plasma Tar Reforming

Non-thermal plasma is an ionized gas consisting of a mixture of charged particles (electrons, ions), active chemical radicals (e.g., oxygen, hydroxide), and highly excited species that are known to accelerate reforming reactions similar to traditional metal-based catalysts. Plasmas have several advantages over traditional catalytic systems in that they do not suffer from catalyst poisoning problems and their performance does not decline over time. The specific energy requirement to incorporate non-thermal plasmas into reforming systems is typically low, with less than 5% of the reformate energy consumed to generate the plasma (NETL, 2014a).

Appendix G provides specific information on Ceramatec's non-thermal plasma reforming technology tested at Emery. This technology is shown on Figure 4-7. Ceramatec uses GlidArc electrodes to generate low-temperature plasma in three stages. An oxygen buffer is installed between plasma stages. Emery's fixed-bed gasifier was used to generate the tars for testing Ceramatec's technology.

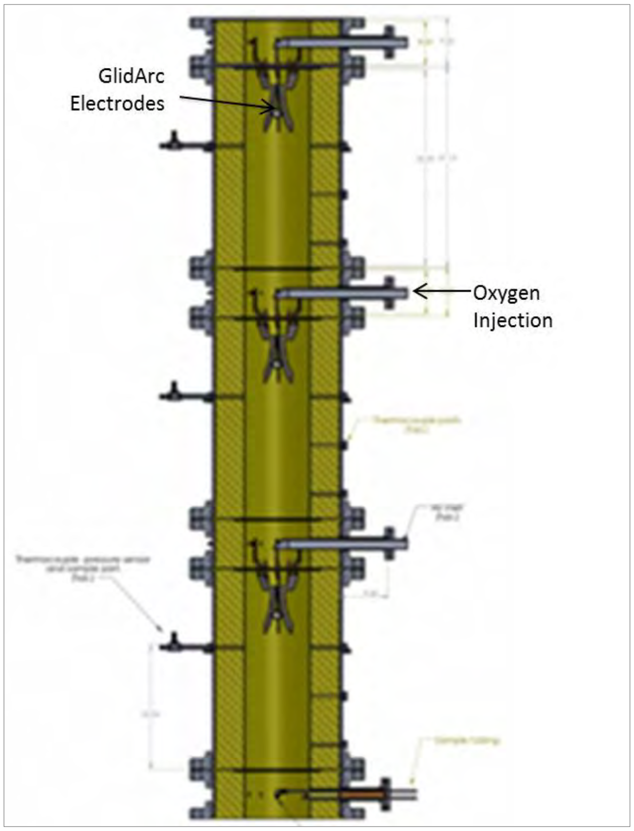


Figure 4-7: Ceramatec Technology

4.2.2 Catalytic Tar Reforming

Typical catalytic tar reforming systems operate most efficiently at high temperatures (about 1,560°F). The goal is to operate the system at temperatures that minimize carbon deposition on the catalyst, which causes deactivation. In addition, it is necessary to remove particulates from the product gas stream to prevent fouling of the tar reforming catalyst bed.

Typical catalysts necessitate the use of a high-temperature filtration medium or the cooling and subsequent reheating of the product gas. To address this problem, low-temperature catalysts developed by the Lummus Refining and Gasification Division of the Chicago Bridge & Iron Company were tested at the EERC to determine if catalytic tar reforming could be achieved at lower temperatures (approximately 700 to 800 degrees Celsius). These specific catalysts had not been tested previously. Appendix D provides information on the catalytic tar reforming technology tested at the EERC.

5. Feedstocks Considered for Testing

Demonstrating feedstock flexibility is critical to address the potential logistical and economic challenges of a commercial-scale CBTL plant. The ability to use multiple types of biomass feedstock can provide flexibility in plant siting and mitigate against potential supply issues that could disrupt production if a plant was dependent on only one feedstock. Therefore, in support of DLA Energy's objective to achieve feedstock flexibility, the Project Team recommended co-feeding different types of coal and biomass to gather data on a wide array of feedstocks and feedstock combinations. This section describes feedstocks considered for testing in Phase 2 of the project and the Project Team's rationale for the feedstocks selected. Appendix B provides data tables with the properties of the feedstocks considered for testing, and proximate and ultimate analyses, as appropriate.

Most gasification systems have been designed for a single feedstock (typically coal) with defined properties. Physical differences between coal and biomass present potential challenges in handling and feeding the material, especially across the pressure boundary of a typical gasifier. Even heavily pre-treated biomass feedstocks can have a broad range of densities and shapes, often resulting in a fibrous morphology. Fibrous biomass particles can be problematic to handle because they are difficult to pulverize and remaining fibers can plug feed systems. Some materials tend to cake more than others, which can cause feed and flow problems.

In addition to physical variability, the chemical variability of biomass can also create challenges in gasifiers typically used for coal. Chemical variability includes ash composition, moisture, volatile matter, fixed carbon, and heating value. The heating value of a feedstock is the energy available in the fuel per unit mass. The difference in available energy is due to each feedstock's different chemical composition, including moisture and ash content. If the biomass is torrefied, the solid fuel is converted to a product with a lower mass and higher heating value than the raw product. Torrefaction is the slow heating of raw biomass at temperatures ranging from 480 to 660°F in an oxygen-free environment to drive off volatile compounds and moisture. This results in a substantial increase in the heating value per unit mass and a decrease in the fibrous nature of biomass. Torrefied biomass can be ground to a consistency that is similar to coal powder, making for easier handling, blending with coal, and feeding compared to raw biomass.

As the scope of the project was modified to include small-scale gasifiers (300 to 1,500 bpd), the variety of feedstocks was expanded. Smaller gasifiers can use resources that may not be economical to collect and transport to a large centralized facility. Many of the smaller gasification systems have also been specifically designed to use non-coal alternative feedstocks. These feedstocks include biomasses such as agricultural crop residues, energy crops, used biomass, railroad ties, MSW, and shale gas. Table 5-1 lists the feedstocks tested for this project and the source of these feedstocks.

Table 5-1: Analyzed Feedstocks and Source

Feedstock	Source
IL No. 6 Bituminous Coal	Nighthawk and Gateway Mines, southwestern IL
Rosebud PRB Sub-Bituminous Coal	Rosebud Mine, near Colstrip, MT
Antelope PRB Sub-Bituminous Coal	Antelope Mine, near Gillette, WY

Feedstock	Source
Black Thunder PRB Sub-Bituminous Coal	Black Thunder Mine, Wright, WY
Eagle Butte PRB Sub-Bituminous Coal	Eagle Butte Mine, WY
Fort Union Lignite Coal	Fort Union Mine, North Dakota
Falkirk Lignite Coal	Falkirk Mine, North Dakota
Raw Southern Pine Wood Pellets	Green Circle Bio Energy, Inc., Cottondale, FL New Biomass Energy, Quitman, MS
Torrefied Southern Pine Wood Pellets	Earth Care Products, Inc., Independence, KS New Biomass Energy, Quitman, MS
Sub-Alpine Fir Wood Chips	Laramie, WY
Mixed hardwood chips	Mesa Reduction Engineering & Processing, Auburn, NY
Raw Corn Stover	Tom Meyeraan Farms, Fulda, MN
Torrefied Corn Stover	Earth Care Products, Inc., Independence, KS
Switchgrass	Genera Energy Corporation, Knoxville, TN
Railroad Ties	Freundlich Transport, Enderlin, NDTerra Firma Organics, Jackson, WY
Filamentous Algae Powder	VEN Consulting, Indian River County Stormwater Engineering Division's Egret Marsh Algal Turf Scrubber, Vero Beach, FL
Water Hyacinth	VEN Consulting, St. Johns River Water Improvement District agricultural canals, Vero Beach, FL
Water Lettuce	VEN Consulting, St. Johns River Water Improvement District agricultural canals, Vero Beach, FL
MSW (simulated)	Greenwood Energy, Green Bay, WI
Post-Sorted MSW	TRI, Durham, NC
Rich Shale Gas	Simulated by EERC, Grand Forks, ND
Lean Shale Gas	Bottled Methane and Natural Gas, Grand Forks, ND

5.1 Coal

DLA Energy identified coal as a feedstock requirement at the inception of the project. Coal mined in the United States is typically categorized into four ranks, as listed in Table 5-2. Increased heat and pressure over millions of years produces a progression of coals, expelling moisture and carbon dioxide over a period of time. The four ranks of coal, in order of geologic age from youngest to most mature, are lignite, sub-bituminous, bituminous, and anthracite. Lignite is the lowest rank coal. It is a soft coal and has the lowest energy value and highest moisture content of the coal types. Sub-bituminous is a darker, harder coal that has a higher heating value than lignite. Bituminous coals are harder, have greater energy value, and generally lower moisture than sub-bituminous and lignite coals. Anthracite, the highest rank coal, is a hard black coal with a high carbon content.

Table 5-2: Coal Ranks

Coal Rank	Estimated Calorific Value Limits (Btu/lb as HHV)	Estimated Carbon Content (%)	Moisture content (%)
Lignite	5,500 – 8,300	25 – 35	40 – 50
Sub-bituminous	8,300 – 13,000	35 – 45	20 – 40
Bituminous	11,000 – 15,000	45 – 86	8 – 20
Anthracite	13,500 – 15,600	86 – 97	Repels moisture

Source: http://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/coal
Notes:
Btu/lb = British thermal unit per pound
HHV = higher heating value

The Project Team reviewed a DOE/NETL database (EIA, 2012) as a guide to select the coal types for demonstration testing. Three coal types were selected: lignite (Falkirk), sub-bituminous PRB, and bituminous IL No. 6. Within each rank, testing was completed on one lignite, four sub-bituminous, and two bituminous coals. In general, sub-bituminous PRBs were tested more frequently because the existing knowledge base for gasification of this coal rank is much less extensive than for the other tested coal ranks. Details on procuring, transporting, storing, drying, and preparing the coals at each test facility are provided in Appendices C through I.

5.2 Energy Crops

Energy crops are plants specifically grown to be used as a biomass source for fuel production. These include perennial grasses such as switchgrass, sugarcane, and Miscanthus; woody crops such as poplar, willow, southern pine, and alpine fir; and annual plants, such as sorghum (DOE, 2011). Currently, energy crops are not widely grown, but it is estimated that more than 100 million dry tons could be produced annually by 2017. Growing energy crops with the intention of harvesting to make biofuels or other various energy end uses requires little cost and little maintenance (DOE, 2011). Some of these crops may be grown on land that would not be suitable for food crops or could be used for erosion control. Energy crops generally grow quickly with minimal inputs, provide a homogeneous product, and offer carbon sequestration potential. Current strategies for the use of energy crops are limited, but research on growing strategies for switchgrass dates to 1936 when the U.S. Department of Agriculture began breeding native grasses to protect damaged land.

The following types of energy crops were tested for this project: switchgrass, southern pine, alpine fir, and mixed hardwoods. These are described below:

Switchgrass (*Panicum virgatum*) – This has been identified as a potential biomass source of energy in the United States since 1936. It is a broadly adaptive native grass and is non-invasive. Switchgrass was selected as an energy crop feedstock because it is hardy, can be grown on land considered unsuitable for crop production, grows throughout North America, and has been found to store significant amounts of carbon in soil.

Southern Pine, Alpine Fir, and Mixed Hardwoods – These were used for testing raw woody biomass. Raw wood is one of the most widely used and available biomass sources, and the associated growth, harvest, transportation, and processing industries are well established in the United States. Generally, the wood is processed into chips or pellets. Typically, only pulpwood is used, but bark and other components can be used, depending on the application.

Torrefied Southern Pine – This was used for testing torrefied woody biomass. Torrefaction reduces the moisture and volatile content from the raw wood, resulting in a more energy-dense product with handling characteristics similar to coal and which is better suited for transporting significant distances. Commercial torrefaction enterprises are more developed in Europe than in the United States. However, several commercial torrefaction systems are operating or under development in the United States.

Table 5-3 summarizes baseline and high-yield energy crop availability predicted at different prices per dry ton for the years 2017 and 2022 (DOE, 2011).

Table 5-3: Summary of Baseline and High-Yield Scenario Availability of Energy Crops

	<$40 per dry ton		<$50 per dry ton		<$60 per dry ton	
Feedstock	**2017**	**2022**	**2017**	**2022**	**2017**	**2022**
Baseline Scenario	Million Dry Tons					
Perennial Grasses	3.0	12.0	41.0	77.0	90.0	188.0
Woody Crops	0.0	0.0	0.9	40.0	5.7	84.0
Annual Energy Crops	0.7	1.8	3.8	7.3	5.0	10.0
Total*	**4**	**14**	**46**	**124**	**101**	**282**
High-Yield (2% annual growth)						
Perennial Grasses	11.0	43.0	67.0	152.0	122.0	253.0
Woody Crops	0.0	0.1	1.9	78.0	10.0	145.0
Annual Energy Crops	1.6	4.1	5.5	8.7	6.9	11.0
Total	**13**	**47**	**75**	**239**	**139**	**409**
High-Yield (3% annual growth)						
Perennial Grasses	24.0	71.0	85.0	213.0	138.0	296.0
Woody Crops	0.0	1.5	9.3	101.0	14.0	168.0
Annual Energy Crops	2.4	6.6	6.2	10.0	8.0	12.0
Total	**26**	**79**	**101**	**324**	**160**	**476**

	<$40 per dry ton		<$50 per dry ton		<$60 per dry ton	
Feedstock	**2017**	**2022**	**2017**	**2022**	**2017**	**2022**
High-Yield (4% annual growth)						
Perennial Grasses	35.0	100.0	106.0	270.0	154.0	338.0
Woody Crops	0.1	5.3	12.0	118.0	16.0	212.0
Annual Energy Crops	3.4	9.0	6.8	11.0	9.4.0	14.0
Total	**39**	**114**	**124**	**399**	**180**	**564**

Note: *Totals are rounded.
Source: DOE, 2011

Table 5-4 provides the estimated higher heating values of various energy crops.

Table 5-4: Higher Heating Values of Select Energy Crops

Energy Crops	Higher Heating Values (Btu/lb)
Switchgrass	7,754 – 8,233
Black locust	8,409 – 8,582
Eucalyptus	8,174 – 8,432
Hybrid poplar	8,183 – 8,491
Willow	7,983 – 8,497

Source: DOE, 2011.

5.3 Residues

Agricultural crop residues are widely available and produced as a byproduct of the harvesting of beans, peas, peanuts, cotton, canola, rice, potatoes, sunflowers, barley, corn, oats, rye, sorghum, soybeans, wheat, flaxseed, and sugarcane. The total crop residue biomass is predicted to be 77 to 221 million dry tons annually nationwide by 2020, and it is estimated that approximately 35% of the total residue from harvesting is underutilized (DOE, 2011). Currently, 30% of crop residue is used for soil protection, 20 to 25% for grazing, and 10 to 15% for miscellaneous uses, which results in 30 to 40% unused (DOE, 2011). The range of available biomass depends on the value of the biomass, ranging from $40/dry ton to $60/dry ton. With approximately 35% of crop residue unused, a potential of 27 to 77 million dry tons could be available annually, depending on total growth scenarios (DOE, 2011).

Crop residues are available in multiple regions of the United States including the Northwest, Midwest, Hawaii, certain sections of the Atlantic coast, Texas, Oklahoma, Missouri, Louisiana, Colorado, and California. This wide distribution helps offset the low energy per volume of the residue, which contributes to relatively high cost of collecting and transporting the biomass long distances. Additionally, crop residues can be delivered for gasification in a relatively homogeneous type and size, reducing the processing required prior to gasification. The type of crop residue tested for this project was corn stover, which is a byproduct of harvesting corn. Corn stover includes the stalk, leaf, and husk, and for corn harvested for cereal grains, also the cob. Both raw and torrefied corn stover were tested for this project. Torrefied corn stover was tested as a means for mitigating the low energy density of crop residues, to provide a comparison to raw corn stover, and to extend the Project Team's experience with a different torrefied biomass feedstock.

Forest residue includes the unharvested remains from logging, thinning, or weeding operations, as well as from land clearings and other forest uses. These sources are concentrated in east and west coast areas, the south, northern Minnesota, and Michigan. Approximately 80 to 100 million dry tons are expected to be available annually by 2020. The benefit of this source is that a large mass is available. Some of the difficulties associated with this source pertain to the labor and equipment costs attributed to collecting the residue, especially from logging operations in remote terrain.

Primary milling residue is produced from round wood products that are processed into primary wood products like slabs, edging, trimmings, sawdust, veneer chippings and cores, as well as pulp screenings. These residues total approximately 32 million dry tons per year and are heavily concentrated in the Northwest, South, northern Midwest, and New England. This source is consolidated at specific locations and it is collected at the sites, easing transportation concerns. Primary and secondary milling residues are currently often used for making high-value products, to meet onsite energy needs, and for various other purposes (DOE, 2011). Woodworking shops, furniture factories, wood container and pallet mills, and wholesale lumber yards produce secondary mill residue. The sources are typically located near city centers and areas of industry; however, total availability is difficult to calculate.

Table 5-5 provides the estimated higher heating values of various residues.

Table 5-5: Higher Heating Values of Select Residues

Biomass Type	Higher Heating Values (Btu/lb)
Agricultural Residues	
Corn stalks/stover	7,587 – 7,967
Sugarcane bagasse	7,450 – 8,349
Wheat straw	6,964 – 8,148
Hulls, shells, prunings	6,811 – 8,838
Fruit pits	8,950 – 10,000
Forest Residues	
Hardwood wood	8,017 – 8,920
Softwood wood	8,000 – 9,120

Source: Biomass Energy Data Book, Oak Ridge National Laboratory

5.4 Municipal Solid Waste

MSW is defined in the Energy Security Act (P.L. 96-294; 1980) as "any organic matter, including sewage, sewage sludge, and industrial or commercial waste, and mixtures of such matter and inorganic refuse from any publicly or privately operated municipal waste collection or similar disposal system, or from similar waste flows (other than such flows which constitute agricultural wastes or residues, or wood wastes or residues from wood harvesting activities or production of forest products)." The total United States MSW generation in 2011 was 250 million tons; organic materials are the largest component, with paper, yard waste, and food waste comprising the majority of the components (USEPA, 2013).

The total mass potentially available for use as a biomass feedstock depends on the amount of organic material recycled and composted. Gasification technology typically requires the MSW to be processed into a refuse-derived fuel (RDF). RDF is defined as “the product of a mixed waste processing system in which certain recyclable and non-combustible materials are removed with the remaining combustible material converted for use as a fuel to create energy” (USEPA, 2013). To improve material composition and handling for gasification, RDF is sorted, screened, and sometimes dried and pelletized. There are increased costs associated with the additional processing of RDF from MSW, though the potential trade-off is a more efficient gasifier operation when utilizing RDF versus MSW. If MSW is to be used in a gasification system, the system must be robust enough to accommodate variability in the composition of waste streams.

MSW has a higher heating value of approximately 5,100 Btu/lb on as-received basis (Pacific Northwest National Laboratory, 2008), which is somewhat lower than conventional biomass feedstocks. However, MSW has the benefit of existing transportation and collection infrastructure, which currently does not exist for other biomass sources. Additional potential benefits of using MSW as a feedstock for CBTL include its wide availability and its potential as a net zero or positive revenue feedstock. The challenges of using MSW include its seasonal variability, relatively low heating value, and the regulatory requirements that dictate collection and storage logistics. However, diversion of MSW from landfills has become a priority for many municipalities, mainly because of limited available land. Gasification of MSW can utilize its energy value and avoid potential fugitive methane emissions in the form of landfill gas.

5.5 Gaseous Feed

Shale gas occurs naturally in shale and oil formations. Shale gas consists mostly of methane, which has a global warming potential 30 times greater than carbon dioxide. Recent advances in horizontal drilling and hydraulic fracturing have allowed access to shale gas that was previously inaccessible or not economical to produce. Currently, shale gas is being produced in large quantities in the United States, largely as a result of fracking to increase production of oil, and much of the gas is wasted (flared). In July 2014, the North Dakota Industrial Commission approved a regulation to significantly reduce the amount of gas that is flared by requiring oil drillers to capture 74% of their gas by October 1, 2014 and 90 to 95% by the end of 2020 (King, 2014). On the national level, the Obama administration set a target to cut methane emissions from oil and gas drilling in the United States by 40 to 45% by 2025, compared with 2012 levels (Hartford Courant, 2015).

Shale gas as a feedstock has unique challenges compared to more traditional biomass feedstocks. Therefore, the Project Team established objectives specifically for testing shale gas as a feedstock, including:

- Determine the optimal mixture by thermal content (heating value) of coal and gas for liquid fuel production that meets Section 526 requirements for both natural gas and shale gas.

- Assess how the inlet feed location of natural gas or shale gas to the gasifier affects process performance and efficiency in one or more types of gasifiers.

- Assess the effect of gasifying natural gas or shale gas with coal on GHG emissions and the likelihood of meeting Section 526 requirements.

- Determine optimal gasifier operation temperatures for improving carbon conversion efficiency with the addition of natural and shale gas.

At the time of this report, the Project Team was not aware of any previous tests performed that attempted to determine an optimal mixture of coal and shale gas specifically for synthetic jet fuel production. However, work has been underway for several years by companies like SRI International (under Defense Advanced Research Projects Agency funding) for converting coal/natural gas to methanol, which is then converted to other liquid fuels. It was assumed that because gas-to-liquids processes produce lower GHG levels than CTL, less carbon dioxide would need to be captured to satisfy Section 526 requirements. The Project Team generated simulated shale gas mixtures representing a lean Marcellus-like gas and a rich Bakken-like gas for natural gas liquid extraction. Simulated gas mixtures were based on phase (liquid/gas) predictions for raw gas composition compressed to 500 pounds per square inch gauge (psig) even though testing took place at lower pressures.

5.6 Other

In addition to the types of biomass included in the Billion Ton Study (DOE, 2011), the Project Team included railroad ties, algae, and nuisance aquatic plants in Phase 2 of the project. These are described below:

Used Railroad Ties – Used railroad ties were included as a feedstock because they are currently in large supply, as used wood ties are routinely replaced by railroad companies. In addition, the Military Advisory Panel suggested gasification of used railroad ties as part of Phase 2 testing. The energy content of creosote-treated railroad ties is higher than most other biomass feedstocks, with a British thermal unit (Btu) value similar to coal, which makes it a potentially attractive feedstock.

Algae – In recent years, algae have been recognized by the DoD/DLA Energy as a promising biofuel feedstock, particularly through the conversion of lipids into liquid fuels. The Project Team considered the energy value of gasifying whole algae or the dried residue after lipid extraction. The algae used for gasification testing was lipid-extracted filamentous algae harvested from the Egret Marsh Algal Turf Scrubber in Indian River County, Florida. The Algal Turf Scrubber was specifically designed for the purpose of removing nitrogen and phosphorous from urban and agricultural runoff in south Florida. As such, this algae could also be considered a waste product or residue.

Nuisance Aquatic Plants – Nuisance aquatic plants, such as water hyacinth and water lettuce, have very fast growth rates, high yields based on area, high photosynthetic efficiency, and grow in many different climatic environments. These plants are a nuisance in waterways, adversely affecting flood control, navigation, and recreation. According to the Cooperative Aquatic Plant Control Program (Annual Report of Activities Conducted in Florida Public Waters for Fiscal Year 2011-2012) administered by the Florida Fish and Wildlife Conservation Commission, invasive plants infest 94% of Florida’s public waters (1.26 million acres). Millions of dollars are spent annually to kill with herbicides or remove and discard nuisance invasive aquatic species from Florida waterways. This represents an enormous potential source of renewable biomass in Florida alone. CCAT secured a source of water hyacinth and water lettuce harvested from Florida, dried and ground to project specifications, for testing as a gasification feedstock with coal.

6. Facility Testing and Reported Results

This section summarizes the test reports for each facility that conducted demonstration testing for this project. This section provides only the results for each facility, while Section 7 discusses CCAT's interpretation of the results and Section 10 compares the results from the various facilities. Complete test reports from the test facilities are provided in Appendices C through I. Although the test reports provide information slightly differently and may use varying terms to discuss the same topics, for the purposes of this report, the summaries are standardized with regard to organization, definitions of terms, calculations of key parameters, and the basis upon which information is presented. This standardization does not change the results of the testing, rather it facilitates discussion and comparison of the testing results for the various facilities in this and subsequent sections. In addition to summarizing facility test results, this section provides results from additional analyses conducted for each facility to further the understanding of the overall results and capabilities of the various technologies and feedstocks tested. In some instances, the analyses were conducted by the facility, and in other instances, by the Project Team. The calculations for the data presented in this section are provided in Appendix J.

Definitions for terms used throughout this section that are essential for understanding the results are provided in Table 6-1. These terms and concepts represent key measures of gasification at a potential CBTL plant. Because the facilities provided information in varying ways, calculations may have been performed differently than described in this table. In these instances, deviations from the standards provided below are clearly stated.

Table 6-1: Terms and Concepts

Term/Concept	Definition
Ash Analysis	An analysis of the elemental content of feedstocks or any/all solid gasification residues, generally presented as oxides; only the key components that affect the ash/slag handling properties are presented. Presented oxides may vary with gasification technology and may not total 100%. When not provided, the ash content was estimated as100% minus loss on ignition (LOI; percent by weight [wt%]); however, this will not provide an elemental breakdown of the ash.
Carbon Conversion	The relative measure of carbon in the feedstock converted to carbon in the product gas during the gasification process. For this report carbon conversion is calculated using the carbon content of solid residues (course ash, fine ash, bottom ash, or slag). In instances when carbon content of solid residues was not available, LOI was used as an approximation of carbon content. Carbon Conversion = {1 – (carbon in solid residue ÷ carbon in feedstock)} x 100%.
Cold Gas Efficiency	Relates the chemical energy of the product gas to the chemical energy in the feedstock. Several methods can be used to calculate the cold gas efficiency of a gasifier. For this report, heating value of the product gas is expressed as a percentage of the heating value of the feedstock. Cold Gas Efficiency = {HHV of product gas ÷ HHV of feedstock} x 100%.

Term/Concept	Definition
Condensate	Liquids and solidified liquids at or below atmospheric temperatures that remain in the product gas streams (e.g., water and hydrocarbons).
Energy Balance	Relates the total energy outputs from the system to the total energy inputs. Inputs are predominantly chemical (in the form of HHV of a feedstock), while outputs may be thermal (in the form of high temperature products, heat loss from equipment) or chemical (HHV of the product gas). For CBTL design, an important use of the energy balance is the comparison of chemical energy of the product gas to the chemical energy in the feedstock, known as cold gas efficiency.
Feedstock Analysis	This includes proximate, ultimate, heating value, ash, mineral and elemental analyses, which help determine gasifier operational set points and gasifier chemistry.
Gasification Solid Residues	A gasification solid residue is any solid material removed from the gasifier or product gas stream such as coarse ash, fine ash or slag. The materials in the residue differ based on the type of gasifier and downstream particulate collection equipment Analysis of solid residues includes calculation of the mass rate and the composition, which may include LOI, heating value and elemental analysis. Analyses of these solid residues are used to determine carbon conversion.
Heating Value	The energy content of substance; amount of heat produced by combustion of a unit quantity of a substance given on an HHV basis. • Heating value (gas) – calculated based on gas composition and individual gas species heating values given by Engineering ToolBox (standard temperatures and pressure of dry gas - 60°F and 14.7 pounds per square inch absolute [psia]) (http://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html). • Heating value (feedstock) – experimentally measured by bomb calorimeter or equivalent.
Loss on Ignition	The loss in sample mass after ignition/complete combustion occurs. LOI is expressed as a percent of its mass prior to ignition. If experimental LOI was not provided by the test facility, it was approximated by the sum of moisture, fixed carbon, and volatile matter from the proximate analysis of gasification residue.
Mass Balance	Mass balance, which includes carbon conversion, relates the total mass outputs from the system to the total mass inputs, and is normally expressed as a percentage.
Product Gas	Gas produced from gasification or reforming process, which may include hydrogen, carbon monoxide, carbon dioxide, oxygen, methane, ethane, nitrogen, argon, hydrogen sulfide, carbonyl sulfide, etc.
Product Gas Composition	The composition of the product gas, presented on a dry and nitrogen-free basis, normalized to 100% with only hydrogen, carbon monoxide, carbon dioxide, and methane.
Proximate Analysis	An analysis of the composition of solid material (feedstock or gasification residue), presented as a mass percent of moisture, volatile matter, fixed carbon, and ash.

Term/Concept	Definition
Standard Temperature and Pressure (STP)	60°F and 14.7 psia
Synthesis Gas (syngas)	The portion of product gas consisting of hydrogen and carbon monoxide.
Tars	Tars in the context of this report are all organic contaminants with a molecular weight greater than benzene (78 grams per mole [g/mol]) (Devi et al., 2003).
Toxicity Characteristic Leachate Procedure (TCLP)	Specific sampling method for determining if hazardous compounds will leach from a material if it is landfilled.
Ultimate Analysis	An analysis of the composition of solid material (feedstock or gasification residue); this is presented as a mass percent of elemental carbon, hydrogen, nitrogen, oxygen, sulfur, moisture, and ash. The hydrogen and oxygen excludes the contribution from the moisture present in the sample.

These terms and concepts represent key measures of the gasification plant at a potential CBTL plant. Specific concepts are explained in more detail below as they pertain to this report; these are presented in the order in which they are discussed throughout this section.

Product Gas – Product gas is the main output of the gasification plant at a CBTL plant and will ultimately become the working material (syngas) for the creation of liquid fuels in the FT portion of a CBTL plant. For this reason, it is essential to determine the product gas composition and product gas flow rate. In this report, product gas compositions are presented on a dry and nitrogen-free basis to help account for the differences in the various gasifier designs used for testing, as well as operational differences at the various facilities.

Gasification Solid Residues – For solid samples, especially slag, TCLP analyses may be performed to determine the suitability of solid material as a useful by-product (e.g., for sand blasting grit, road base, or construction material). Usefulness is determined by comparing sample results to the hazardous characteristic criteria for the eight heavy metals regulated under the Resource Conservation and Recovery Act (RCRA).

Condensates – In addition to product gas, a CBTL gasification plant will produce liquid and solidified liquid (condensates). Hydrocarbons remaining in the product gas streams do not contribute to useful carbon monoxide and hydrogen in the FT portion of the facility without additional processing (e.g., tar reforming). Analysis of condensates helps determine tar content, carbon conversion and cold gas efficiency.

Carbon Conversion – Calculations of carbon conversion can be accomplished by quantifying carbon content in the product gas or in the gasifier residue stream(s) coming from the gasifier. The calculations for this report used carbon in the gasifier residue streams (e.g., course ash, fine ash, bottom ash, or slag) as described in Table 6-1, above. However, for some of the technologies tested, this methodology may be misleading, either positively or negatively. For instance, if a gasification technology (on a particular feedstock) tends to generate longer chain hydrocarbons (i.e., tars) that condense out of the gas-phase between the gasifier and the downstream FT systems, quantifying carbon content in the gasifier solids waste streams (without accounting for these condensed hydrocarbons) could imply that the gas-phase carbon conversion was higher (better) than the usable (gas-phase) carbon that enters the FT unit.

Cold Gas Efficiency – Similar to carbon conversion, several methods can be used to calculate the cold gas efficiency of a gasifier. For this report, HHVs of both the product gas and the feedstock were used, with the assumption that the gas and feedstock are both at STP. HHV of product gas is calculated from hydrogen, carbon monoxide, and methane only. For facilities that did not provide this calculation, CCAT performed the calculations, which were then validated by the facilities. In the subsections below, cold gas efficiency calculations are provided with carbon conversion calculations.

Mass Balance – Mass balance helps determine if the majority of all flows (e.g., fuel, oxidant, conveying/carrier gas[es], product gas, product gas condensate[s]) are represented by the measurements performed and assumptions about non-measured values. Failure to close the mass balance (i.e., a large departure from unity or 100%) indicates an error in one or more measurement systems (e.g., an online gas analyzer), errors introduced by inaccurate assumptions, or that an important input or output stream had been omitted from the calculation. In this capacity the mass balance serves as a quality assurance measure for the results provided by the facilities.

In addition to the standardization of information identified for the concepts above, CCAT verified facility-supplied mass balance calculations on the systems tested or performed these calculations if the facility did not provide them. When performing calculations, the Project Team worked with the facility to verify the methodology used.

Throughout this report, the Project Team distinguishes between measured flows and concentrations and flows and concentrations that were assumed or back-calculated from other values. As a system's scale increases, the uncertainty introduced by assumptions and back-calculations decreases. This is partly because as the magnitude of the system increases, more system control/instrumentation is typically available. Additionally, as the scale increases, the impact of the assumed values decreases with regard to the overall mass balance. The significance of this is discussed in Section 7.

Energy Balance – Although in-depth energy balances were performed, due to facility instrumentation and data acquisition limitations, cold gas efficiency was calculated for each facility as described above. For facilities that did not provide this calculation, CCAT performed the calculations, which were then validated by the facilities. In the subsections below, cold gas efficiency calculations are provided with carbon conversion calculations.

6.1 EERC

Testing at the EERC was conducted in two phases: 2012 to 2013 and 2013 to 2014, and was conducted using the EERC's EFG and TRDU. The EFG was used to test solid carbonaceous fuels at a temperature hot enough to melt the ash portion of the feedstock. The TRDU was developed in conjunction with KBR. EERC tested different feedstocks during the 2 years of testing, and in some instances, feedstocks were tested multiple times.

The following sections summarize the tests conducted at the EERC, the test results, and the facility's reported conclusions.

- Section 6.1.1summarizes results for testing completed using the EERC's EFG pilot unit.
- Section 6.1.2 summarizes results for testing conducted using the EFG in partnership with the Illinois Clean Coal Institute (ICCI) and the DOE.
- Section 6.1.3 summarizes results for testing conducted using the EERC's TRDU.
- Section 6.1.4 summarizes testing results of tar reforming conducted in tandem with the EERC's TRDU.

For summary purposes, only a portion of test results is presented in this report. Additionally, when comparing the results summarized in this section, it is important to recognize that the listed test runs may have differing operational parameters (such as temperatures, oxygen-to-steam ratios, operating conditions), which are not provided in the tables throughout this section, but that may significantly influence the presented results/interpretation. Operational parameters that significantly influenced results are discussed in Section 7.The EERC's Phase I and Phase II test reports are provided as Appendix C and Appendix D, respectively, and the ICCI test report is provided as Appendix E.

6.1.1 EFG

The EERC's EFG is a lab-scale unit that operates under slagging conditions at short residence times. This EFG is a vertically housed, down-fired reaction chamber that simulates many characteristics of a commercial EFG (Figure 4-2). The reaction tube is housed inside a water-cooled, refractory-lined pressure vessel that is 7 feet long and has an outer diameter of approximately 24 inches. The pressure vessel is rated for 300 psig. The reaction tube has an inner diameter of approximately 2 inches. Between the refractory and the outside of the reaction tube, four independently controlled heating zones, consisting of six radial spaced heaters per zone, provide a vast majority of the endothermic heat necessary for the gasification reactions. The gasifier is capable of operating in oxygen mode or air-blown mode, while firing approximately 4 to 16 lb/hr of fuel and producing upwards of 16 to 20 standard cubic feet per minute (scfm) of product gas (in oxygen-blown mode). The gasifier and its ancillary equipment can be configured for various testing needs. The ancillary equipment includes up to four fixed-bed reactors, a Selexol™-like acid gas removal unit, a thermal oxidizer, and a fixed-bed FT liquid production skid with two parallel reactors. The fixed beds can be used to test product gas cleanup sorbents such as sulfur or heavy metal sorbents, or WGS catalysis. The thermal oxidizer is used to combust all gases generated during gasification. The FT reactor was designed by the EERC and has a maximum production capacity of approximately 4 liters per day.

A list of tests that were planned for the EFG is provided in Table 6-2. A total of 60 tests were specified in the five test plans prepared over the course of the testing program. These include multiple tests of the same blend at different gasifier operating conditions. Sixty-four tests were actually run on the EFG. With 2 years of testing, a large volume of data/results were generated. To facilitate a summary discussion in this report, only the 70% coal/30% non-coal feedstock tests (referred to as coal/biomass blends and coal/shale gas blends) are presented. It was anticipated these tests would show clear differences in product gas composition compared to coal-only baseline tests. When selecting tests to present in this summary, preference was given to longer duration test runs and test runs with a mass closure value closer to 100% from a mass balance calculation. A summary of this testing and test results are provided in Sections 6.1.1.1 through

6.1.1.4. Complete testing details are provided in Appendix C and Appendix D. While results from only the non-duplicated 70% coal/30% non-coal feedstock tests are presented here, the reported conclusions in Section 6.1.1.4 and discussions in Sections 7 and 10 are based on the entire series of tests.

Table 6-2: Planned Tests for the EERC's EFG

Coal Feedstock	Biomass/Alternative Feedstock	Blend Ratio
Rosebud PRB	None	100/0*
Rosebud PRB	Earth Care Torrefied Pine	95/5*, 90/10*, 85/15, 80/20
Rosebud PRB	Green Circle Raw Pine	95/5*, 90/10*, 85/15*, 80/20*
Antelope PRB	None	100/0*
Antelope PRB	Earth Care Torrefied Pine	90/10, 80/20, 70/30, 0/100
Antelope PRB	Green Circle Raw Pine	90/10, 80/20
Antelope PRB	Green Circle Raw Pine	70/30
Antelope PRB	Tom Meyeraan Farms Corn Stover	90/10
Antelope PRB	Tom Meyeraan Farms Corn Stover	70/30
Antelope PRB	VEN Consulting Water Lettuce/Water Hyacinth	90/5/5, 80/10/10, 70/15/15
Antelope PRB	VEN Consulting Water Hyacinth	80/20
Antelope PRB	VEN Consulting Water Lettuce	80/20
Antelope PRB	VEN Consulting Filamentous Algae	90/10, 80/20*, 70/30
Antelope PRB	Lean Shale Gas (Nozzle)	90/10, 80/20, 70/30
Antelope PRB	Rich Shale Gas (Nozzle)	90/10, 80/20*, 70/30
Antelope PRB	Lean Shale Gas (Quench)	90/10, 70/30
Antelope PRB	Rich Shale Gas (Quench)	90/10*, 70/30*
Gateway IL No. 6	None	100/0*
Gateway IL No. 6	Torrefied Corn Stover	80/20*
Nighthawk IL No. 6	Earth Care Torrefied Pine	90/10, 70/30

Note: * = multiple test runs planned for this coal/feedstock blend

6.1.1.1 *Test Description*

Gasifier Operations – Several flow configurations were tested on the EERC's EFG; however, Figure 6-1 shows the simplified schematic for all tests. In this figure, "Fuel" is any combination of tested coal and non-coal feedstock blends. Not shown on the figure is the slipstream of product gas that, for some tests, was sent to the EERC's gas cleanup unit and FT liquid production skid. When the gas cleanup and FT units were operational, the "Product Gas" stream on the figure (and in Section 6.1.1.2.4) is the sum of gas sent to the cleanup/FT units and the product gas sent to the thermal oxidizer. For all non-gas cleanup and non-FT test runs the entire product gas stream was sent to the thermal oxidizer. Limited test results for the FT liquid production are provided in Section 6.1.1.3 and Appendix C. Figure 6-1 includes a "Recycled Product Gas" stream and "Fixed Beds" block, which were not always included in the tests. Despite the difference in the flow configurations tested or ancillary equipment employed, for each test, the gasifier was operated in oxygen-blown mode at approximately 250 to 300 psig, with a target flame zone temperature of 2,700°F. The targeted run duration for each test was 8 hours. Although testing was conducted in oxygen-blown mode, the gasifier uses a large quantity of nitrogen as a conveying gas in the feed system and for instrumentation purging purposes. Table 6-3 summarizes the planned testing conditions for non-duplicated 70% coal/30% non-coal feedstock tests, including feed rate ratios for oxygen to fuel and steam to fuel, and planned run durations. During testing these values were used as guidelines for the system operators; however, variations from these planned conditions were driven by operator observation and system behavior.

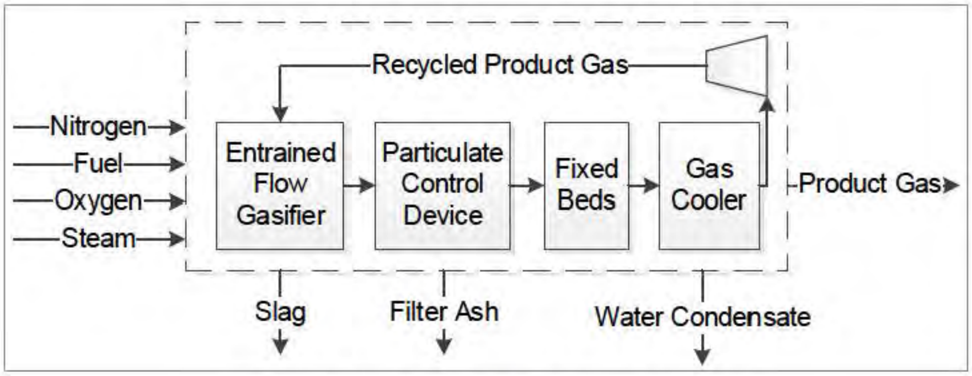


Figure 6-1: Simplified EERC EFG Schematic

Table 6-3: EFG Test Plan for Selected Tests

EERC EFG Test Identifier	Coal	Non-coal (Biomass/Gas)	O:C (Molar Ratio)	Steam to Carbon (Mass Ratio)
20131028A	Antelope PRB	None	1.41	1.61
20130319A	Antelope PRB	Torrefied Pine	1.41	1.61
20130319C	Antelope PRB	Raw Pine	1.41	1.61
20130321A	Antelope PRB	Corn Stover	1.41	1.61
20131101A	Antelope PRB	Filamentous Algae	1.41	1.61
20130604D	Antelope PRB	Water Lettuce/Water	1.41	1.61
20130322B	Nighthawk IL No. 6	Torrefied Pine	1.41	1.61
20130807A	Antelope PRB	28.2% Lean Nozzle	1.6	1.9
20131029A	Antelope PRB	27.1% Rich Nozzle	1.62	1.92
20131031B	Antelope PRB	16.7% Lean Quench	1.41	1.61
20131030B	Antelope PRB	23.7% Rich Quench	1.41	1.61

Feedstocks – All solid feeds tested at the EERC were premixed and processed through the same equipment onsite at the EERC. The details of this preparation are presented in the EFG sections of the facility reports provided in Appendix C and Appendix D.

Sampling and Analysis – During all testing, gas composition was measured using online (real-time) laser gas analyzers and gas chromatography (GC), trace species were measured using Draeger tubes, and condensate/quench water samples were collected with municipal water supply cooled quench pots. In addition, as-fed samples of each pure feedstock were collected for proximate, ultimate, heating value, and ash analyses.

6.1.1.2 *Test Results – Gasification*

For this summary, all time-dependent values were averaged over a steady-state period. During testing, when only point values were available (e.g., Draeger tube samples), the values were assumed to be representative of the entire steady-state period. For this section, only the test results for the non-duplicated 70% coal/30% non-coal feedstock tests are presented.

6.1.1.2.1 Feedstock Analysis

In most test cases these feedstock analysis parameters were calculated based on the as-fed analysis of the individual feedstocks. However, in some test cases, the blends were analyzed directly. In this report, a distinction is not necessary and therefore, not provided. Note that these are blended as-fed feedstock analyses, not the individual as-received feedstock analyses presented in Section 5 of this report and in Appendix B. Table 6-4 provides selected proximate, ultimate, heating value, and feedstock ash analyses for the as-fed selected 70% coal/30% coal/biomass blends. In Table 6-4, the feedstock ash analyses are presented as oxides. Only those constituents that are important to how the ash behaves within the gasifier (e.g., slagging flow) are presented, with additional oxides grouped as “other” (Higman and van der Burgt, 2008). The complete feedstock ash analyses are provided in Appendix C and Appendix D.

Table 6-4: EERC EFG Feedstock Analysis of Coal Only and Coal and Biomass Blends

Proximate, Ultimate, Heating Value and Ash Analyses of Various Coal and Biomass Blended Feedstocks
Facility: EERC, Technology: EFG

Test Cases							
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Nighthawk IL No. 6
Biomass Type	None	Torrefied Pine	Raw Pine	Corn Stover	Filamentous Algae	Water Lettuce/ Water Hyacinth	Torrefied Pine
Biomass (wt%)	Coal Only	30	30	30	30	15/15	30
Analyses							
Proximate Analysis (wt%)							
Moisture	5.36	4.90	5.04	8.68	5.75	5.77	4.86
Volatile Matter	35.81	45.33	48.92	42.39	44.51	46.42	43.71
Fixed Carbon	53.79	45.96	42.30	41.09	38.54	40.61	42.97
Ash	5.04	3.81	3.74	7.84	11.20	7.19	8.46
Ultimate Analysis (wt%)							
C	65.69	63.18	60.70	55.95	56.83	58.50	62.92
H	4.52	4.78	4.93	4.42	4.44	4.43	4.64
N	0.72	0.53	0.54	0.69	1.57	0.91	1.00
O	18.29	22.53	24.78	22.14	19.54	22.89	16.57
S	0.37	0.26	0.26	0.27	0.67	0.29	1.55
Moisture	5.36	4.90	5.04	8.68	5.75	5.77	4.86
Ash	5.04	3.81	3.74	7.84	11.20	7.19	8.46
Heating Value, HHV (Btu/lb)	11,289	10,869	10,424	9,579	9,441	9,685	10,920
Ash Analysis as Oxides (wt%)							
CaO	30.83	31.17	30.88	20.53	30.57	40.11	2.61
MgO	6.07	6.36	6.24	7.10	5.06	7.61	1.44
Fe_2O_3	9.22	8.70	8.77	5.77	4.00	4.34	14.70
Na_2O	0.94	0.98	0.96	0.75	0.98	1.28	0.33
K_2O	0.64	2.64	2.33	7.31	9.56	4.70	3.58
SiO_2	23.30	22.23	22.56	40.26	26.02	19.81	51.19
Al_2O_3	11.98	11.27	11.44	8.42	8.14	10.60	23.61
TiO_2	1.30	1.22	1.23	0.77	0.66	0.90	1.10
Other	15.72	15.44	15.58	9.08	15.02	10.64	1.45

The as-fed molar composition, calculated molecular weight (MW), calculated molar heating value and calculated molar flow rates of the gaseous hydrocarbons used during simulated shale gas testing are provided in Table 6-5. This table provides data for the attempted coal/shale gas feedstock blends. The blend percentages provided in the table are based on heating value, not weight. The discrepancies between the targeted 30% and actual feed percentages are discussed in Section 7 of this report. Values in Table 6-5 were calculated based on the molar composition and volumetric flow rates of the individual gas components provided by EERC. Rich shale gas was simulated by combining lean gas (containing methane and ethane) and a liquid stream containing propane, butane, pentane, and hexane. The heating values of the gas mixtures were then calculated based on the calculated composition. The coal used during shale gas testing was similar to the coal-only case provided in Table 6-4. The rationale for the specific composition is provided in Appendix D.

Table 6-5: EERC EFG Feedstock Analysis of Simulated Shale Gas Feedstocks

Flow Rates, Compositions and Heating Value (HHV) of Various Methane/Coal and Shale Gas/Coal Mixtures
Facility: EERC, Technology: EFG

	Test Cases			
Blend HHV (%)	**28.2 Lean Nozzle**	**27.1 Rich Nozzle**	**16.7 Lean Quench**	**23.7 Rich Quench**
Hydrocarbon Flow (lb-mol/hr)	0.086	0.053	0.057	0.053
Hydrocarbon MW (lb/lb-mol or g/mol)	16.04	28.36	16.04	28.34
Hydrocarbon Heating Value, HHV (Btu/lb-mol)	381,990	633,468	381,990	633,234
	Hydrocarbon Analysis (%mol)			
CH_4	100	58.86	100	58.87
C_2H_6	0	11.34	0	11.34
C_3H_8	0	16.84	0	16.83
C_4H_{10}	0	9.83	0	9.83
C_5H_{12}	0	2.38	0	2.38
C_6H_{14}	0	0.75	0	0.74

Notes:
Btu/lb-mol = British thermal units per pound-mole
lb-mole/hr = pound-mole per hour
lb/lb-mol = pounds per pound-mole
%mol = molar percent

6.1.1.2.2 Gasifier Operation and Product Gas Composition

During testing at EERC for this project, more than 230 hours of steady-state data were logged for the EFG. Gas composition data were provided by GC/laser gas analysis sampling downstream of the gas cooler and the particulate control device (PCD) (Figure 6-1) for all test cases. The product gas samples were collected at temperatures ranging from 65 to 118°F and pressures ranging from 248 to 250 psig. Table 6-6 and Table 6-7 provide the averaged steady-state product gas compositions for the selected 70%/30% coal/biomass and coal/shale gas blends, respectively. Each table includes a coal-only baseline for reference. The compositions are provided on a nitrogen and dry (moisture-free) basis, and correspond to averaged product gas flow rates of 33.2 to 39.5 lb/hr for the solid fuel feedstock blends and 33.3 to 41.5 lb/hr for shale gas blends measured via a dry gas meter downstream of the sampling location. The tables also provide the H_2:CO molar ratios and product gas energy flow rates. Complete details for product gas composition and system flow rates are provided in the EFG sections of Appendix C and Appendix D. For this report, the volumetric-based results from Appendix C and Appendix D were converted to mass basis. This conversion is described in Section 6.1.1.2.4.

Table 6-6: EERC EFG Dry and N_2-Free Product Gas Composition for Various Biomass and Coal Blends

Dry and N_2-Free Product Gas Composition for Various Coal and Biomass Blends Facility: EERC, Technology: EFG, Temperature: 2,560°F, Pressure: 249 psig							
Test Cases							
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Nighthawk IL No. 6
Biomass Type	None	Torrefied Pine	Raw Pine	Corn Stover	Filamentous Algae	Water Lettuce/Water Hyacinth	Torrefied Wood
Biomass (wt%)	Coal	30	30	30	30	15/15	30
Steady-state Duration (hrs)	6.22	4.75	4.78	5.75	3.87	1.03	2.20
Product Gas Composition and Energy Flow							
Dry and N_2-Free Product Gas Composition	%mol						
H_2	35.21	40.94	41.87	39.98	32.61	40.01	32.55
CO	27.51	36.91	37.92	38.86	25.43	32.15	29.78
CO_2	37.28	22.15	20.21	21.16	41.96	27.84	37.16
CH_4	0.00	0.00	0.00	0.00	0.00	0.00	0.51
H_2:CO Molar Ratio	1.28	1.11	1.10	1.03	1.28	1.24	1.09
Product Gas Heating Value, HHV dry basis (Btu/scf)	113	155	162	159	90	128	112
Product Gas Energy Flow, HHV dry basis (MMBtu/hr)	0.065	0.098	0.104	0.096	0.042	0.076	0.060

Notes:
hrs = hours
MMBtu/hr = million British thermal units per hour

Table 6-7: EERC EFG Dry and N_2-Free Product Gas Composition for Lean/Rich Gas and Coal Blends

Dry and N_2-Free Product Gas Composition for Various Coal and Gas Blends Facility: EERC, Technology: EFG, Temperature: 2,640°F, Pressure: 250 psig					
Test Cases					
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB
Gas (Btu%)/Location	Coal Only	28.2 Lean Nozzle	27.1 Rich Nozzle	16.7 Lean Quench	23.7 Rich Quench
Steady-state Duration (hrs)	6.22	4.77	4.50	2.13	3.12
Product Gas Composition and Energy Flow					
Dry and N_2-Free Product Gas Composition	%mol				
H_2	35.21	40.71	41.92	30.88	28.21
CO	27.51	25.36	27.92	26.08	22.10
CO_2	37.28	33.94	30.16	36.98	40.50
CH_4	0.00	0.00	0.00	6.06	9.19
H_2:CO Molar Ratio	1.28	1.61	1.5	1.18	1.28
Product Gas Heating Value, HHV dry basis (Btu/scf)	113	128	135	132	129
Product Gas Energy Flow, HHV dry basis (MMBtu/hr)	0.065	0.064	0.077	0.071	0.074

Real-time GC was also used to measure trace levels of key hydrocarbons such as methane, ethylene, ethane, and propene. Draeger tubes were selectively used to measure trace amounts of ammonia, hydrogen sulfide, hydrochloric acid, and hydrogen cyanide. In addition, select product gas condensate samples were collected and selectively analyzed for chemical oxygen demand (COD), total organic carbon (TOC), total inorganic carbon (TIC), chloride, and ammonia. Results of these samples/analyses are provided in Table 6-8 and Table 6-9 for the selected coal/biomass and coal/shale gas blends, respectively. A coal-only case is provided in each table as a baseline for reference.

Table 6-8: EERC EFG Trace Species Analysis for Various Coal and Biomass Blends

Analysis of Condensate Samples from Gasification of Various Coal and Biomass Feedstock Blends Facility: EERC, Technology: EFG, Temperature: 2,560°F, Pressure: 249 psig							
Test Cases							
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Nighthawk IL No. 6
Biomass Type	None	Torrefied Pine	Raw Pine	Corn Stover	Filamentous Algae	Water Lettuce/ Water Hyacinth	Torrefied Pine
Biomass (wt%)	Coal Only	30	30	30	30%	15/15	30
Steady-state Duration (hrs)	6.2	4.8	4.8	5.8	3.9	1.0	2.2
Analyses							
Draeger Tube Samples (ppmv)							
NH_3	0.0	100.0	0.0	0.0	0.0	150.0	100.0
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HCN	5.0	45.0	30.0	8.0	30.0	167.0	>50
H_2S	600.0	NA	NA	NA	950.0	500.0	NA
Quench Water Samples (mg/L)							
NH_3	185.0	4,530.0	4,950.0	2,640.0	NA	6,150.0	2100.0
COD	NA	260.0	300.0	220.0	NA	250.0	290.0
Cl	20.7	NA	NA	NA	12.0	161.0	NA
TOC	13.0	440.0	460.0	270.0	11.0	12.8	160.0

Notes:

mg/L = milligrams per liter
NA = not available
ppmv = parts per million by volume

Table 6-9: EERC EFG Trace Species Analysis for Lean/Rich Gas and Coal Blends

Analysis of Condensate Samples from Gasification of Various Coal and Gas Feedstock Blends Facility: EERC, Technology: EFG, Temperature: 2,640°F, Pressure: 250 psig					
Test Cases					
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB
Gas (Btu%)/Location	Coal Only	28.2 Lean Nozzle	27.1 Rich Nozzle	16.7 Lean Quench	23.7 Rich Quench
Steady-state Duration (hrs)	6.22	4.77	4.50	2.13	3.12
Analyses					
Draeger Tube Samples (ppm)					
NH_3	0	6	0	0	5
HCl	0	0	0	0	0
HCN	5	15	4	3	13
H_2S	600	NA	600	800	3000
Particulate Quench Water Samples (mg/L)					
NH_3	185	328	1,370	197	183
COD	NA	40	NA	NA	NA
Cl	20.7	15	9.3	23.1	27.7
TOC	13	8	20	33	38

Note: ppm = parts per million

6.1.1.2.3 Gasifier Residue Sample Analysis

During gasification, fine ash entrained in the product gas exiting the EFG was captured with a PCD, as shown on Figure 6-1. This ash (labeled Filter Ash in Figure 6-1) was removed from the system via a lock-hopper style pressure let-down system, as needed, during each test case. Ash removed from the PCD was analyized for LOI. Results are provided in Table 6-10 and Table 6-11 for the selected coal/biomass and coal/shale gas blends, respectively. Complete details on the ash sampling procedures and specific anaylses are provided in the EFG sections of the facility reports (Appendix C and Appendix D).

Table 6-10: EERC EFG Analysis of Gasifier Residue (from PCD) for Various Biomass Blends

Analysis of Gasifier Filter Ash Samples for Various Coal and Biomass Feedstock Blends Facility: EERC, Technology: EFG, Temperature: 2,560°F, Pressure: 249 psig							
Test Cases							
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Nighthawk IL No. 6
Biomass Type	None	Torrefied Pine	Raw Pine	Corn Stover	Filamentous Algae	Water Lettuce/ Water Hyacinth	Torrefied Pine
Biomass (wt%)	Coal Only	30	30	30	30	15/15	30
Steady-state Duration (hrs)	6.22	4.75	4.78	5.75	3.87	1.03	2.20
Analysis							
Filter Ash LOI	11.60	19.10	25.90	14.20	6.20	11.90	52.10

Table 6-11: EERC EFG Analysis of Gasifier Residue (from PCD) Ash for Lean/Rich Gas and Coal Blends

Analysis of Gasifier Filter Ash Samples for Various Coal and Gas Feedstock Blends Facility: EERC, Technology: EFG, Temperature: 2,640°F, Pressure: 250 psig					
Test Cases					
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB
Gas (Btu%)/Location	--	28.2 Lean Nozzle	27.1 Rich Nozzle	16.7 Lean Quench	23.7 Rich Quench
Steady-state Duration (hrs)	6.22	4.77	4.50	2.13	3.12
Analysis					
Filter Ash LOI (wt%)	11.60	9.20	7.20	4.20	3.30

Note: -- = no sample collected

In addition to LOI, representative filter ash samples were submitted for third-party TCLP analysis at TestAmerica Laboratories, Inc. (TestAmerica).

A significant portion of solids were also collected in the EFG's slag pot and in the horizontal leg of the gasifier exit. As documented in the facility test reports, the slag pot was emptied only after the EFG was shut down, and therefore, individual slag samples could not be collected from each test case. Despite this limitation, slag samples from the slag pot were collected during EFG shutdown and submitted for TCLP analysis. Selected results of the TCLP analyses for both filter ash and slag are provided in Table 6-12 and compared to the hazardous characteristic criteria for the eight heavy metals regulated under RCRA to determine if the material would be considered hazardous for disposal purposes. As shown, all results are below the applicable regulatory levels. All solid residue sample results are provided in Appendix C, Appendix D, and Appendix K.

Table 6-12: EERC Ash Samples - TCLP Results

TCLP Analysis of Filter Ash and Slag Samples from Various Coal and Biomass Feedstock Blends
Facility: EERC, Technology: EFG, Temperature: 2,560°F, Pressure: 249 psig

Metal	100% Antelope PRB Coal (filter ash)	30% Raw Pine, 70% PRB Coal (filter ash)	30% Corn Stover, 70% PRB Coal (filter ash)	10-30% Pine Corn Stover Aggregate, 70-90% PRB Coal (composite slag)	RCRA MCLs
As	<0.600	<0.600	<0.600	<0.300	5
Ba	<1.00	<1.00	<1.00	2.21	100
B	7.96	7.85	14.8	1.0	NE
Cd	<0.0400	<0.0400	0.0998	<0.0200	1
Cr	<0.0400	<0.0400	<0.0400	<0.0200	5
Pb	<0.200	<0.200	<0.200	<0.100	5
Hg	<0.002000	<0.00200	<0.00200	<0.00200	0.2
Ni	NA	NA	NA	NA	NE
Se	<0.300	<0.300	<0.300	<0.150	1
Ag	<0.0400	<0.0400	<0.0400	<0.0200	5
V	<0.100	<0.100	<0.100	<0.0500	NE
Zn	0.340	<0.200	2.04	<0.100	NE

Notes:
All concentrations are in mg/L.
MCL = maximum contaminant level
NA = not analyzed
NE = MCL not established

6.1.1.2.4 Mass and Energy Balance

Based on physical system limitations (e.g., measured continuous removal of slag and ash), an extensive mass and energy balance based solely on measured values was not possible. For this reason, the EERC does not typically provide or perform a detailed mass or energy balance. Instead, balances can be assumed and non-measured flows and compositions are calculated or assumed. For the purpose of this project and for comparison to testing at other project facilities, CCAT conducted many of these calculations with concurrence from the EERC. The significance of these mass and energy balances is discussed in Section 7.1.1.

The system boundaries used for the mass balance are shown as a dashed line on Figure 6-1. The measured process input and output data that were used to perform the calculations are provided in Appendix C and Appendix D. Calculated process streams included the slag and water condensate flow rates. The slag flow rate out of the gasifier was calculated based on the measured ash content of the fuel (carbonaceous feedstock), the reported measured average fuel feed rate, ash content of the filter ash (PCD ash) and averaged filter ash rate (the rate of build-up of PCD ash). The EERC did not provide a complete proximate and ultimate analysis (which contains carbon content) on the PCD ash. However, the LOI (wt%) data provided by the EERC were used as proxies to calculate the carbon content of the PCD ash. Likewise, the EERC did not provide a complete proximate and ultimate analysis of the slag. However, it was assumed the slag contained only ash/minerals. Additionally, gaseous inputs, including lean/rich shale gas, and gaseous outputs measured on a volumetric flow-rate basis (standard cubic feet per hour [scfh] or milliliters per hour) were converted to a mass flow-rate basis (lb/hr). Volumetric flow rates were converted to mass flow rates using the volumetric flow rates provided in Appendix C and Appendix D and the corresponding MW of the gas. For the product gas, volumetric to mass conversion was conducted using the normalized product gas composition. Water condensate flow rate was then calculated by hydrogen balance.

Table 6-13 and Table 6-14 provide process stream data for the coal/biomass feedstock blends and the coal/shale gas feedstock blends, respectively. For the test cases presented in these tables, any gas that was sent to the gas cleanup/FT liquid production skid was accounted for in the total mass output.

Table 6-13: EERC EFG Process Stream Data for Mass Balance Summary of Various Biomass Blends

Process Stream Data for Various Coal and Biomass Blends Facility: EERC, Technology: EFG							
Test Cases							
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Nighthawk IL No. 6
Biomass Type	None	Torrefied Pine	Raw Pine	Corn Stover	Filamentous Algae	Water Lettuce/Water Hyacinth	Torrefied Pine
Biomass (wt%)	Coal Only	30	30	30	30	15/15	30
Steady-state Duration (hrs)	6.22	4.75	4.78	5.75	3.87	1.03	2.20
Mass Balance							
Inputs (lb/hr)							
Fuel	10.10	11.30	12.10	11.90	10.20	11.30	10.70
O_2	11.13	8.94	8.69	9.02	9.70	8.18	12.14
Steam	11.10	10.10	9.60	8.80	8.90	9.00	9.80
N_2	13.95	11.66	11.96	10.48	17.79	17.35	9.45
Total Mass Input	**46.28**	**42.00**	**42.34**	**40.20**	**46.59**	**45.83**	**42.09**
Outputs (lb/hr)							
Product Gas	39.21	39.54	39.03	37.66	33.25	38.56	37.48
Filter Ash	0.67	0.32	0.34	0.79	0.52	0.07	0.90
Slag (calculated)	NC	0.17	0.20	0.26	0.66	0.75	0.47
Water Condensate	12.94	11.67	11.52	10.94	11.75	11.01	12.33
Total Mass Output	**52.82**	**51.70**	**51.09**	**49.65**	**46.17**	**50.38**	**51.19**
Mass Closure, Mass Output to Mass Input Ratio (%)	114.13	123.09	120.66	123.50	99.11	109.95	121.62

Note: NC = not calculated

Table 6-14: EERC EFG Process Stream Data for Mass Balance Summary of Shale/Natural Gas Blends

Process Stream Data for Various Coal and Gas Blends Facility: EERC, Technology: EFG					
Test Cases					
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB
Gas (Btu%)/Location	Coal Only	28.2 Lean Nozzle	27.1 Rich Nozzle	16.7 Lean Quench	23.7 Rich Quench
Steady-state Duration (hrs)	6.22	4.77	4.50	2.13	3.12
Mass Balance					
Inputs (lb/hr)					
Fuel	10.10	8.78	9.51	10.62	11.11
O_2	11.13	11.13	11.13	11.13	11.13
Steam	11.10	11.00	11.10	11.00	11.00
N_2	13.95	13.51	16.02	16.24	17.20
Total Mass Input	**46.28**	**44.42**	**47.75**	**48.99**	**50.44**
Outputs (lb/hr)					
Product Gas	39.21	33.27	36.28	37.63	41.50
Filter Ash	0.67	0.42	0.52	0.64	0.63
Slag (calculated)	NC	NC	NC	NC	NC
Water Condensate (calculated)	12.94	14.70	14.08	11.47	11.48
Total Mass Output	**52.82**	**48.39**	**50.88**	**49.74**	**53.61**
Mass Closure, Mass Output to Mass Input Ratio (%)	114.13	108.94	106.54	101.53	106.28

Note: Experimental Filter Ash rate data were not provided during the test runs above; however, the approximate sum of the filter ash mass flow rate and slag mass flow rate was provided by the EERC and is presented as Filter Ash.

As described in the introduction to Section 6, carbon conversion and cold gas efficiency were calculated with the measured LOI values assumed as the carbon content of the filter ash. Table 6-15 and Table 6-16 provide the calculated values for the carbon conversion and cold gas efficiency for the selected coal/biomass and coal/shale gas blends, respectively.

Table 6-15: EERC EFG Carbon Conversion and Cold Gas Efficiency of Various Biomass Blends

Carbon Conversion and Cold Gas Efficiency for Various Coal and Biomass Blends
Facility: EERC/Technology: EFG, Temperature: 2,560°F, Pressure: 249 psig

	Test Cases						
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Nighthawk IL No. 6
Biomass Type	None	Torrefied Pine	Raw Pine	Corn Stover	Filamentous Algae	Water Lettuce/ Water Hyacinth	Torrefied Pine
Biomass (wt%)	Coal Only	30	30	30	30	15/15	30
Steady-state Duration (hrs)	6.22	4.75	4.78	5.75	3.87	1.03	2.20
	Carbon Conversion and Cold Gas Efficiency (%)						
Carbon Conversion	98.83	99.15	98.80	98.32	99.44	99.87	93.04
Cold Gas Efficiency	56.57	80.08	82.27	84.31	43.28	69.21	51.27

Table 6-16: EERC EFG Carbon Conversion and Cold Gas Efficiency of Shale/Natural Gas Blends

Carbon Conversion and Cold Gas Efficiency for Various Coal and Gas Blends
Facility: EERC, Technology: EFG, Temperature: 2,640°F, Pressure: 250 psig

	Test Cases				
Coal Type	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB	Antelope PRB
Gas (Btu%)/Location	Coal Only	28.2 Lean Nozzle	27.1 Rich Nozzle	16.7 Lean Quench	23.7 Rich Quench
Steady-state Duration (hrs)	6.22	4.77	4.50	2.13	3.12
	Carbon Conversion and Cold Gas Efficiency (%)				
Carbon Conversion	98.83	99.34	99.42	99.62	99.72
Cold Gas Efficiency	56.57	55.40	62.05	53.69	52.15

6.1.1.3 *Test Results – FT Liquid Production*

Early in the 2012 to 2013 testing phase, the EERC conducted pilot-scale gas cleanup and FT catalysis work. The results of this work are provided in Appendix C. While the initial intentions of the Project Team were to demonstrate the CBTL process from gasification through FT syntheses, the results of this early work with FT syntheses were not suitable for performing quantitative assessments of FT product yield, composition, or quality. As such, the Project Team did not reproduce the results in this section. The decision to exclude this work was based on the short steady-state durations reported by the facility for both the gasifier and FT unit, changes in system hardware between test runs and campaigns, and procedural inconsistencies. Although these factors may limit the quality of the data, the completed work shows that a raw FT product can be produced from the gasification of coal and various biomass mixtures.

6.1.1.4 *Reported Conclusions*

EFG testing at the EERC was conducted in two phases: 2012 to 2013 and 2013 to 2014. The EERC reported the 2012 to 2013 testing in its Phase I Final Report (Appendix C) and the 2013 to 2014 testing in its Phase 2 Final Report (Appendix D). This section summarizes the EERC's main conclusions for EFG testing from these two reports. Analyses of solid residue samples for pH, total metals, and TCLP were performed by a third-party laboratory (TestAmerica) and are reported in Appendix K.

Feedstock

In general, EFG testing demonstrated the ability to feed a range of biomass feedstocks with coal at blend ratios up to 30%. However, steady feeding was problematic at times due to the design of the feed system and the handling characteristics for certain feedstocks/feedstock blends. In certain instances, the inability to feed consistently was thought to be the root cause of system shutdowns (e.g., slag freezing causing plugging of the furnace tube). Frequent free flow of the 90% Antelope PRB coal –10% switchgrass blend through the feeder screws precluded obtaining any useful data for Test 6A. Because of the feeding problems with the first switchgrass blend, testing of the 70% Antelope PRB coal –30% switchgrass blend (Test 7A) was not attempted, and these tests were canceled from the test program. (Appendix D, page 168)

Throughout both phases of testing, the feeder required significant modifications and repairs; these are discussed in Appendix C and Appendix D. The impacts of these modifications and repairs on the test results are discussed in Section 7.

During 2012 to 2013 testing on woody biomass, the EERC reported that all coal/torrefied biomass blends fed well into the EFG, concluding: "While the torrefaction process reduces some of the available energy contained in the biomass, it improves the energy density of the material and helps with the feed characteristics." (Appendix C, page 82). Coal/raw biomass feedstocks up to 10% biomass also fed well into the EFG. However, the EERC noted inconsistencies in the feed at higher raw biomass content. These blends could be fed, but the feed line needed occasional purging to prevent plugging.

Similarly, the coal/aquatic biomass blends were successfully fed to the gasifier. The water hyacinth/water lettuce blends caused some plugging in the ½-inch exit line inside the horizontal section of the gasifier exit. The EERC speculates that the potassium content of these species may have contributed to this failure. The filamentous algae showed some signs of "free-flowing" and nozzle plugging but this was most likely due to operational upsets. (Appendix D, page 189)

Product Gas Composition

For coal/biomass blends, the EERC reported that during steady-state operation, product gas compositions were within reasonable agreement with expected values for an EFG, given fluctuation in other inputs such as steam, oxygen, and the system's external heater. During 2012 to 2013 testing, the EERC reported that syngas quality contained average bulk gas compositions at approximately 19.7% hydrogen, 23.1% carbon monoxide, 24.7% carbon dioxide, and 34.1% nitrogen by molar content. The average H_2:CO molar ratio was 0.92, and the average carbon monoxide to carbon dioxide (CO:CO_2) ratio was 1.0. The average HHV was 141 British thermal units per standard cubic feet (Btu/scf), with the N_2-free HHV at 206 Btu/scf. The EERC also noted that the process parameter that was shown to have the most influence on each of the responses was the oxygen to fuel ratio, which significantly influenced the compositions and the HHV of the syngas. (Appendix C page 82) For the coal/aquatic biomass tests, the average syngas composition was typical for an EFG, as the H_2:CO molar ratio was close to 1.0 and the CO:CO_2 ratio was around 1.4. These ratios varied to some extent with the biomass ratio in the fuel, but more noticeably with the oxygen to carbon feed ratio. (Appendix D, page 190)

Similarly, the shale gas testing during 2013 to 2014 resulted in product gas compositions within the expected range. The hydrogen concentration and heating value of the product gas trended upward with increasing shale gas feed content. For the nozzle zone injection tests, methane and higher hydrocarbons were not detected in the product gas, indicating complete reforming of the injected shale gas to syngas. However, the gas analysis data for the quench zone injection cases indicates that the shale gas was only partially reformed. (Appendix D, page 166)

Product Gas Condensate Analysis

Liquid condensation samples were collected during most test runs and analyzed for a mixture of COD, total carbon, TIC, TOC, ammonia, and ammonium. The EERC did not draw conclusion on overall trends for these analyses; however, it reported observations for groups of tests (e.g., a specific week of testing). The following quote is an example of an observation the EERC documented during a specific test week: “The quench waters produced showed very low levels of organic components produced. As expected, the high-temperature EFG process produces very low amounts of organics or tars.” (Appendix D, page 60).

Additional observations on quench water analysis are provided in the quench water analysis sections of Appendix D (pages 155, 171, and 189).

Gasifier Operations and Solid Residue

Throughout testing, various operational and functional issues were encountered. These are summarized below from the facility test reports and complete details are provided in Appendix C and Appendix D.

During several coal/woody biomass test runs using Rosebud PRB coal, slag freezing was observed at the bottom of the reactor tube, thereby blocking flow from the bottom of the gasifier. The EERC attributed some of the slag freezing issues to slag chemistry, which impacted the oxygen to fuel ratios that could be tested going forward. During 2012 to 2013 testing, the EERC reported that low calcium in the ash species and relatively high alumina and silica led to the formation of a crystalline compound, called anorthite, under the high temperature, reducing conditions of the gasifier. Anorthite has a very high melting point, approximately 2,800°F. This high melting temperature prevented slag flow from the very bottom of the furnace tube where temperatures are typically just below 2,700°F. (Appendix C, page 82)

Based on 2013 to 2014 testing with the Antelope PRB coal/aquatic biomass blends, the EERC reported that the ash-forming constituents in the coals and blends did not seem to produce problematic slag flow under normal operation. Slag freezing and plugging episodes could have been largely attributed to periodic blasts of cold nitrogen to maintain flow of fine ash through the ½-inch line in the horizontal pass. (Appendix D, page 190)

Mass and Energy Balance

The EERC reported that carbon conversion was within reasonable agreement with what is typical for EFG gasifier operations and the EERC's operational history, stating that during 2012 to 2013 testing, the carbon conversion averaged near 99.9% for all tests. (Appendix C, page 75) During 2013 to 2014 testing, most of the carbon conversions (reported in operational data tables) were above 98%.

Cold gas efficiency numbers were not provided by the EERC for EFG testing, and therefore, conclusive statements regarding cold gas efficiency were not provided. The Project Team calculated cold gas efficiency, and observations are provided in Section 7.1.

Additional Reported Conclusions

During 2012 to 2013 testing, the EERC performed a statistical regression analysis of the EFG data to assess the connection between key system input and output parameters. The analysis aimed to connect four input factors (biomass blend ratio, oxygen to fuel ratio, steam to fuel ratio, and biomass preprocessing – raw versus torrefied) to five output parameters (hydrogen concentration, carbon monoxide concentration, carbon dioxide concentration, H_2:CO, and product gas HHV). Based on this analysis, the EERC concluded the following:

> "The results of the analysis indicated that none of the factors had a significant influence on syngas hydrogen concentration; however, O_2/fuel ratio and steam/fuel ratio are expected to have an impact on hydrogen levels." (Appendix C, page 64)

and

> "Also, the analysis indicated a possible impact of raw versus torrefied biomass on the CO_2 concentration. However, since raw versus torrefied was not able to be fully randomized in the test matrix, it is possible that this result is confounded with the higher levels of O_2 that were introduced for some of the final torrefied runs." (Appendix C, page 66)

The statistical regression analysis was not repeated during 2013 to 2014 testing or the TRDU testing.

6.1.2 Illinois Clean Coal Institute Testing at EERC

In addition to the EFG testing summarized above, the Project Team leveraged investments by ICCI and the DOE to perform additional testing on the EFG. This testing was conducted from February to April 2014. The partnership with the EERC, DOE, and ICCI facilitated testing of an additional biomass type and additional biomass percentages with parametric gas cleanup and iron-based FT liquids. Under the ICCI testing agreement the Project Team agreed to fund additional testing, with the understanding that the funds would be used predominantly for gasification operations since gas cleanup and FT catalysis work is not the primary focus of this project.

Sections 6.1.2.1 through 6.1.2.4 summarize this additional testing, the associated test results, and reported conclusions, with complete testing details provided in Appendix E. These sections summarize only a select portion of test runs, specifically, those runs with longer run durations and better (closer to unity or 100%)

mass closure. This section does not include results or conclusions for test runs that were duplicated due to problems during the initial runs. Details for the duplicate test runs are provided in Appendix E.

6.1.2.1 *Test Description*

Testing under the ICCI contract was conducted using EERC's EFG.

Gasifier Operations – Figure 6-2 shows a simplified schematic for the EFG testing conducted under the ICCI work. Not shown on the figure is the slipstream of product gas sent to the gas cleanup and FT liquid production skid. Two fixed-bed reactors ("Fixed Beds" on the figure) were used for sulfur capture. For the DOE and ICCI, this testing focused on the parametric study of the effect of gas cleanliness on the production of FT liquids. FT production is of interest to the Project Team; however, the team's main focus was the opportunity to gasify additional coal-biomass mixtures and an additional biomass type. The Project Team decided to test mixtures of corn stover and torrefied corn stover with a bituminous coal. While raw corn stover was tested under the second phase (2013-2014) of the EERC's EFG work, it was conducted with PRB coal. As required under the ICCI funding, an Illinois basin coal was used. For each test, the gasifier was operated in oxygen-blown gasification mode at approximately 250 to 275 psig, with a target flame zone temperature of 2,800°F. Table 6-17 lists the planned tests and testing conditions (e.g., feed rate ratios for oxygen to fuel and steam to fuel, and planned run durations). During testing these values were used as guidelines for the system operators; however, variations from these planned conditions were driven by operator observation and system behavior. Although testing was conducted in oxygen-blown mode, the gasifier uses a large quantity of nitrogen as a conveying gas in the feed system and for instrumentation purging purposes.

Table 6-17 also provides the secondary gas cleanup and FT operation plan driven by DOE and ICCI. Terms used in the table to describe the FT Feed Condition are as follows:

- **Warm** – Product gas from the gasifier was scrubbed of sulfur using the fixed beds and sent directly to the FT reactor.
- **Quench** – Product gas from the gasifier was scrubbed of sulfur using the fixed beds, passed through an indirect heat exchanger to cool the gas, and then sent to the FT reactor.
- **Sweet** – Similar to quench, with the addition of a Selexol™-like acid gas (carbon dioxide) removal system between the indirect heat exchanger/gas cooling and the FT reactor.

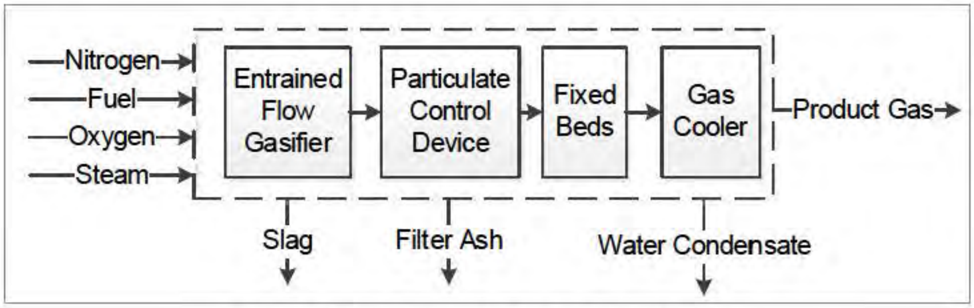


Figure 6-2: Simplified EERC EFG Schematic

Table 6-17: ICCI EFG Test Plan

Coal Type	Biomass Type	Blend Ratio	Feed Rate (lb/hr)	FT Feed Condition
Gateway IL No. 6	None	100/0	10	Sweet
Gateway IL No. 6	Torrefied Corn Stover	80/20	10	Sweet
Gateway IL No. 6	Torrefied Corn Stover	90/10	10	Sweet
Gateway IL No. 6	Torrefied Corn Stover	90/10	10	Quench
Gateway IL No. 6	Torrefied Corn Stover	90/10	10	Warm
Gateway IL No. 6	Raw Corn Stover	90/10	10	Sweet
Gateway IL No. 6	Raw Corn Stover	80/20	10	Sweet
Gateway Il No. 6	None	100/0	8	Warm
Gateway IL No. 6	None	100/0	8	Sweet
Gateway IL No. 6	Raw Corn Stover	90/10	8	Sweet
Gateway IL No. 6	Raw Corn Stover	80/20	8	Sweet

Feedstocks – All feeds tested at the EERC were premixed and processed through the same equipment. The details of this preparation are provided in the facility test report (Appendix E). Additionally, general information on corn stover and torrefied corn stover is described in Section 5 of this report and in Appendix B.

Sampling and Analysis – During testing, gas composition was measured using online (real-time) gas laser gas analyzers and GC, trace species were measured using Draeger tubes, and condensate/quench water samples were collected with municipal water supply cold quench pots. In addition, samples of each feedstock mixture were collected for proximate, ultimate, heating value, and ash analyses. Results are summarized below and detailed in Appendix E.

6.1.2.2 *Test Results – Gasification*

For this summary, all time dependent values were averaged over a steady-state period. When only point values were available (e.g., Draeger tube samples), the values were assumed to be representative of the entire steady-state period.

6.1.2.2.1 Feedstock Analysis

Table 6-18 provides the proximate, ultimate, and heating value for the as-fed coal/corn stover feedstock blends for the selected test runs. For these test cases, the feedstock blend compositions were calculated based on the as-fed analysis of the individual feedstocks. Note that these are blended as-fed feedstock analyses, not the individual as-received analyses presented in Section 5 of this report and in Appendix B. During this testing, a complete elemental ash analysis, presented as oxides, was not performed.

Table 6-18: ICCI Feedstock Analysis

Proximate, Ultimate, Heating Value and Ash Analyses of Various Coal and Biomass Blended Feedstocks Facility: EERC, Technology: EFG					
Test Cases					
Coal Type	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous
Biomass Type	Torrefied Corn Stover	Torrefied Corn Stover	None	Raw Corn Stover	Raw Corn Stover
Biomass (wt%)	20	10	Coal Only	10	20
Analyses					
Proximate Analysis (wt%)					
Moisture	6.23	6.05	5.87	6.93	7.98
Volatile Matter	35.72	36.40	37.07	39.14	41.21
Fixed Carbon	43.87	44.78	45.69	42.27	38.84
Ash	14.18	12.77	11.37	11.67	11.97
Ultimate Analysis (wt%)					
C	61.25	63.01	64.77	61.61	58.46
H	4.16	4.30	4.44	4.42	4.40
N	1.23	1.27	1.30	1.23	1.16
O	10.02	9.31	8.60	10.85	13.10
S	2.94	3.30	3.66	3.30	2.94
Moisture	6.23	6.05	5.87	6.93	7.98
Ash	14.18	12.77	11.37	11.67	11.97
Heating Value, HHV (Btu/lb)	10,611	10,986	11,361	10,784	10,207

6.1.2.2.2 Gasifier Operation and Product Gas Composition

The averaged steady-state product gas compositions for the selected ICCI tests of feedstock blends is provided in Table 6-19. The table also provides a coal-only baseline for reference. This gas composition data were provided by GC/laser gas analysis sampling downstream of gas cooler and the PCD (shown on Figure 6-2) for all test cases. Due to the nature of this testing, gas compositions at additional locations were measured. However, for this report, gas composition only for the above-described location is of interest. In Table 6-19, the compositions are provided on a nitrogen and dry (moisture-free) basis. The product gas samples were collected at temperatures ranging from 67 to 118°F and pressures ranging from 238 to 245 psig. The compositions correspond to averaged product gas flow rates of 37.2 lb/hr measured via a dry gas meter downstream of the sampling location. Table 6-19 also presents the H_2:CO molar ratio and the product gas energy flow rate. Complete details on the flow rates and composition of product gas are provided in the facility test report (Appendix E). For this report, the volumetric-based results provided in Appendix E were converted to mass basis. This conversion is described in Section 6.1.2.2.4, below.

Table 6-19: EERC EFG Dry and N_2-Free Product Gas Composition for ICCI Coal and Biomass Blends

Dry and N_2-Free Product Gas Composition for Various Coal and Biomass Blends
Facility: EERC, Technology: EFG, Temperature; 2,468°F, Pressure: 275 psig

Test Cases					
Coal Type	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous
Biomass Type	Torrefied Corn Stover	Torrefied Corn Stover	None	Raw Corn Stover	Raw Corn Stover
Biomass (wt%)	20	10	Coal Only	10	20
Steady-state Duration (hrs)	7.75	7.82	6.83	5.00	4.00
Product Gas Composition and Energy Flow					
Dry and N_2-Free Product Gas Composition (%mol)					
H_2	33.67	36.34	37.25	34.35	33.33
CO	26.04	24.54	32.94	28.85	27.02
CO_2	40.29	39.12	29.80	36.80	39.65
CH_4	0.00	0.00	0.00	0.00	0.00
H_2:CO Molar Ratio	1.29	1.48	1.13	1.19	1.23
Product Gas Heating Value, HHV dry basis (Btu/scf)	67	96	116	100	90
Product Gas Energy Flow, HHV dry Basis (MMBtu/hr)	0.047	0.045	0.062	0.055	0.046

Real-time GC was used to measure key hydrocarbons such as methane, ethylene, ethane, and propene. In addition, select product gas condensate samples were collected and analyzed for COD, TOC, chloride, and ammonia. Results of these samples/analyses are provided in Table 6-20. A coal-only case is provided as a baseline for reference.

Table 6-20: EERC EFG Trace Species Analysis for ICCI Coal and Biomass Blends

Analysis of Trace Species and Condensate Samples from Gasification of Various Coal and Biomass Feedstock Blends Facility: EERC, Technology: EFG, Temperature: 2,468°F, Pressure: 275 psig					
Test Cases					
Coal Type	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous
Biomass Type	Torrefied Corn Stover	Torrefied Corn Stover	None	Raw Corn Stover	Raw Corn Stover
Biomass (wt%)	20	10	Coal Only	10	20
Steady-state Duration (hrs)	7.75	7.82	6.83	5.00	4.00
Quench Water Samples	mg/L				
NH_3	2,100.0	166.5	1,304.0	Not provided	250.0
COD	80.0	40.0	50.0	Not provided	60.0
Cl	1.0	191.5	575.5	Not provided	64.9
TOC	934.0	45.2	65.0	Not provided	59.0

6.1.2.2.3 Gasifier Residue Sample Analysis

During gasification, fine ash entrained in the product gas exiting the EFG was captured with a PCD, as shown on Figure 6-2. This ash (labeled Filter Ash in Figure 6-2) was removed from the system via a lock-hopper style pressure let-down system, as needed, during each test run and was analyzed for LOI. Results are provided in Table 6-21 for the selected test runs. Complete details on the ash sampling procedures and specific anaylses (e.g., x-ray fluorescence, nuclear magnetic resonance analysis) are provided in Appendix E. Two representative fine/filter ash samples were additionally submitted to TestAmerica for analysis.

A significant portion of solids was also collected in the EFG's slag pot. As documented in the facility test report, the slag pot was emptied only after the EFG was shut down. As such, individual slag samples could not be collected from each test case. A slag sample was separated from the bulk solids residue removed from the slag pot and submitted to TestAmerica for analysis. All samples submitted to TestAmerica were analyzed for leachable metals using TCLP. The results of the TCLP analyses were compared to the hazardous characteristic criteria for the eight heavy metals regulated under RCRA to determine if the material would be considered hazardous for disposal purposes. The results are below the applicable regulatory levels. All solid sample results are provided in Appendix E and Appendix K.

Table 6-21: EERC EFG Analysis of Gasifier Residue (from PCD) for Various ICCI Biomass Blends

Analysis of Gasifier Ash Samples for Various Coal and Biomass Feedstock Blends
Facility: EERC, Technology: EFG, Temperature: 2,468°F, Pressure: 275 psig

Feedstock Type and Analysis	Test Cases				
Coal Type	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous
Biomass Type	Torrefied Corn Stover	Torrefied Corn Stover	None	Raw Corn Stover	Raw Corn Stover
Biomass (wt%)	20	10	Coal Only	10	20
Steady-state Duration (hrs)	7.75	7.82	6.83	5.00	4.00
Fine Ash LOI (wt%)	1.00	3.00	2.40	1.30	0.70

6.1.2.2.4 Mass and Energy Balance

Similar to the EFG, CCAT (with concurrence from the EERC) conducted many of the calculations needed to perform the mass and energy balances. The significance of these mass and energy balances is discussed in Section 7.1.1.

The system boundaries used for the mass balance are shown on Figure 6-2. The measured process input and output data that were used to perform the calculations are provided in Appendix E. Calculated process streams included the slag and water condensate flow rates. The slag flow rate out of the gasifier was calculated based on the measured ash content of the fuel (carbonaceous feedstock), the fuel feed rate, ash content of the filter ash (PCD ash) and filter ash rate (the rate of the build-up of PCD ash). The EERC did not provide a complete proximate and ultimate analysis (which contains carbon content) on the PCD ash. However, the LOI (wt%) data provided by the EERC were used as proxies to calculate the carbon content of the PCD ash. Likewise, the EERC did not provide a complete proximate and ultimate analysis of the slag. However, it was assumed the slag contained only ash/minerals. Additionally, gaseous inputs and outputs measured on a volumetric flow-rate basis (scfh) were converted into a mass flow-rate basis (lb/hr). Volumetric flow rates were converted to mass flow rates using the volumetric flow rates provided in Appendix E, and the corresponding MW of the gas. For the product gas volumetric conversion the normalized product gas composition was used. Water condensate flow rate was then calculated by hydrogen balance.

The following tables summarize the process flows (both measured and calculated). Specifically, Table 6-22 provides the process stream data for mass in and mass out for the ICCI coal and biomass blends. Table 6-23 provides the calculated values for carbon conversion and cold gas efficiency for the test cases. Carbon conversion and cold gas efficiency were calculated as described in the introduction to Section 6, with the measured LOI values assumed as the carbon content of the filter ash. For the test cases presented in these tables, any gas that was sent to the gas cleanup/FT liquid production skid was accounted for in the total mass output.

Table 6-22: EERC EFG Process Stream Data for Mass Balance Summary of ICCI Coal and Biomass Blends

Process Stream Data for Various Coal and Biomass Blends
Facility: EERC, Technology: EFG

Feedstock Types and Mass Balance	**Test Cases**				
Coal Type	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous
Biomass Type	Torrefied Corn Stover	Torrefied Corn Stover	None	Raw Corn Stover	Raw Corn Stover
Biomass (wt%)	20	10	Coal Only	10	20
Steady-state Duration (hrs)	7.75	7.82	6.83	5.00	4.00
Inputs	lb/hr				
Fuel	9.60	7.20	8.20	7.80	7.40
O_2	10.88	9.02	8.85	9.87	9.28
Steam	10.30	8.70	8.60	8.30	7.90
N_2	13.21	11.22	16.90	17.20	17.13
Total Mass Input	**43.99**	**36.14**	**42.56**	**43.17**	**41.70**
Outputs	lb/hr				
Product Gas	42.48	32.65	35.98	38.47	36.62
Filter Ash	0.09	0.08	0.09	0.05	0.04
Slag (calculated)	1.28	0.87	0.86	0.87	0.85
Water Condensate (calculated)	12.48	9.90	9.97	9.76	9.56
Total Mass Output	**56.33**	**43.50**	**46.90**	**49.16**	**47.08**
Mass Closure, Mass Output to Mass Input Ratio (%)	128.05	120.36	110.21	113.88	112.89

Table 6-23: EERC EFG Carbon Conversion and Cold Gas Efficiency of ICCI Coal and Biomass Blends

Carbon Conversion and Cold Gas Efficiency for Various Coal and Biomass Blends
Facility: EERC, Technology: EFG, Temperature: 2,468°F, Pressure: 275 psig

Feedstock Type, Conversion and Efficiency	Test Cases				
Coal Type	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous	Gateway IL No. 6 Bituminous
Biomass Type	Torrefied Corn Stover	Torrefied Corn Stover	None	Raw Corn Stover	Raw Corn Stover
Biomass (wt%)	20	10	Coal Only	10	20
Steady-state Duration (hrs)	7.75	7.82	6.83	5.00	4.00
Carbon Conversion (%)	99.77	99.37	99.57	99.75	99.86
Cold Gas Efficiency (%)	39.35	56.97	66.56	65.69	61.26

6.1.2.3 *Test Results – FT Liquid Production and Process Modeling*

EERC conducted pilot-scale gas cleanup and FT catalysis work during ICCI testing. EERC also intended to use testing conducted under the ICCI contract to further develop internal modeling capabilities to predict the integrated gasification and FT product production distribution and rate. The results of this work are provided in Appendix E. As discussed in Section 6.1.1.3, because gas cleanup and FT catalysis work is not the focus of this project and earlier testing with FT synthesis was not conclusive, this information is not included in this report. The decision to exclude this work was based on the short steady-state durations reported by the facility for both the gasifier and FT unit and operational problems that arose during the testing. Although the short durations may limit the usefulness of the gas cleanup and FT data, the completed work shows that a raw FT product can be produced from the gasification of coal and various corn stover-based mixtures.

6.1.2.4 *Reported Conclusions*

The EERC successfully completed EFG testing of raw and torrefied corn stover at different ratios with an Illinois No. 6 coal under steady-state gasifier conditions. The main conclusions reported from the ICCI tests are provided below, with detailed comments and conclusions for individual test cases, blends, and various parametric tests provided in Appendix E. The Project Team's main focus was the gasification of coal/biomass blends, and therefore, this section does not include EERC's conclusions regarding the gas cleanup and FT tests conducted concurrently.

Feedstock

Given the current design of the feed system and the handling characteristics of the Illinois No. 6 coal and corn stover (both raw and torrefied), steady feeding was problematic, and in certain instances, the inability to feed consistently was thought to be the root cause of major system failure (slag freezing causing plugging of the furnace tube). The EERC reported that operational challenges were encountered for each of the testing conditions, with the biggest challenge being fuel feed consistency. There seemed to be more challenges operating with the coal/biomass blends than with the raw coal. The EERC suggested that more testing would be needed to verify this conclusion. (Appendix E, page 46)

The EERC also reported that some of these issues were overcome, or at least minimized, by reducing the heating in the feed line (Appendix E, page 24), thus reducing the driving force for the known swelling property of IL No. 6 coal.

Additionally, as was seen during the previous EFG testing, the feed system was affected by downstream equipment/operational issues such as frequent pulsing of the filter vessel.

Product Gas Composition

As reported by the EERC, the product gas compositions did not seem to show significant differences or trends as biomass concentration increased. The EERC noted an H_2:CO molar ratio ranging from 1.08 to 1.14 for the optimization tests, further indicating consistency of syngas composition with the addition of up to 20% raw corn stover. (Appendix E, page 27). This ratio range was only for the optimized test, which due to operational issues, only entailed raw corn stover and coal tests. Refer to Appendix E for additional details.

Product Gas Condensate Analysis

Only limited condensate analyses were completed during the ICCI work. The EERC reported that after the first set of parametric tests, the condensate TOC data were consistent with what would be expected from the small-scale EFG and consistent with what would be expected in a commercial system. (Appendix E, page 31)

Gasifier Operations and Solid Residue

While continuous removal of slag is not possible with the EERC EFG, fine ash can be removed as it accumulates in the PCD. Removal of this finer filter vessel ash was sometimes problematic. During the ICCI work the EERC reported that frequent pulsing of the filter vessel was required during some of the testing and these issues were observed with both the raw coal and the coal/biomass blends. (Appendix E, page 24 and 46). The EERC also reported ash buildup in the baffle section of the gasifier, but no evidence to suggest that this buildup was worse when running biomass blends (Appendix E, page 46).

A slag sample was analyzed by scanning electron microscopy, and the image showed that the slag did not reach a temperature high enough to completely melt the ash particles. (Appendix E, page 34)

Mass and Energy Balance

Though not specifically stated in the text of the ICCI report (Appendix E), all but one of the reported ICCI carbon conversions were above 99%.The facility did not comment on trends in carbon conversion and did not explain the one sample that was below 99%.

The cold gas efficiency numbers provided in this section were not provided by the facility and thus the EERC did not make conclusive statements regarding agreement with commercial or historical EFG data.

6.1.3 TRDU

The EERC's TRDU was created in conjunction with KBR as a small-scale unit for future developmental work. The scale of the design was increased and was further advanced at the Power System Development Facility/NCCC in conjunction with the Southern Company. At the time of this report, commercial-scale commissioning of the TRIG™ was under way at the Southern Company's Mississippi Power - Kemper County power facility. The unit at the EERC is a refractory-lined circulating fluidized/transport-bed reactor large enough to sustain gasification without additional heating requirements (from electrical or other fossil sources). The reactor is designed for an operating pressure of 120 psig, firing approximately 200 to 500 lb/hr of fuel, to a maximum internal temperature of 2,000°F. The reactor can produce upwards of 250 scfm of product gas in oxygen blown mode. The development unit consists of the TRIG™, an in-house designed feed system, an indirect quench/product gas cooler, a PCD, and a thermal oxidizer. A slipstream of product gas can be taken from between the PCD and the thermal oxidizer to facilitate the testing of downstream product gas cleaning and conditioning systems (e.g., tar reformers).

A total of 67 tests were specified in four test plans prepared over the course of the testing program and are presented in Table 6-24. TRDU testing at the EERC started in February 2012 and was conducted in two phases (2012 to 2013 and 2013 to 2014). During this time, different feedstocks were tested and, in some cases, were tested multiple times resulting in a total of 68 tests actually run on the TRDU. The EERC documented the results in two separate reports, which are provided in Appendix C and Appendix D.

A large volume of data/results was generated during the 2 years of the EERC's TRDU testing. To facilitate a summary discussion in this report, only the 80%/20% feedstock blend ratio tests are presented. This blend ratio provided the widest range of non-coal feedstocks tested. Additionally, while the 70%/30% blend tests were most likely to show clear differences in product gas composition compared to coal only baseline tests, the 80%/20% blends also showed clear differences compared to baseline. When selecting tests to present in this summary, preference was given to mass closures closer to unity. While most test cases resulted in steady-state durations of 3 or more hours, a few did not. If these shorter test runs were of the selected 80%/20% blend ratio and were unique feedstocks (i.e., only one 20% switchgrass case was run), they are presented here. However, with the shorter duration, the test results are more uncertain.

Although results from only the 80% coal/20% non-coal feedstock tests are presented here, the reported conclusions in Section 6.1.3.3 and discussions in Sections 7 and 10 are based on the entire series of tests.

Table 6-24: Complete Listing of Planned Tests under Phase 1 and 2 TRDU Work

Coal Feedstock	Biomass/Alternative Feedstock	Blend Ratio
Rosebud PRB	None	100/0*
Rosebud PRB	Green Circle Raw Pine	95/5*, 90/10*, 85/15*, 80/20*
Rosebud PRB	Earth Care Torrefied Pine	80/20*, 85/25*, 90/10*, 95/5*
Rosebud PRB	Earth Care Torrefied Pine	70/30
Rosebud PRB	Green Circle Raw Pine	70/30
Rosebud PRB	Genera Energy Switchgrass	90/10, 80/20, 70/30
Rosebud PRB	Tom Meyeraan Farms Corn Stover	90/10, 80/20, 70/30

Coal Feedstock	Biomass/Alternative Feedstock	Blend Ratio
Rosebud PRB	Terra Firma Organics Railroad Ties	90/10*, 80/20*, 70/30*
Rosebud PRB	VEN Consulting Filamentous Algae	80/20*
Knight Hawk IL No. 6	Green Circle Raw Pine	80/20*
Falkirk Lignite	None	100/0*
Falkirk Lignite	Natural Gas (Location 1)	90/10, 80/20, 70/30
Falkirk Lignite	Shale Gas (Location 1)	90/10, 80/20, 70/30
Falkirk Lignite	Natural Gas (Location 2)	90/10, 80/20, 70/30*
Falkirk Lignite	Shale Gas (Location 2)	90/10, 80/20, 70/30
Falkirk Lignite	Natural Gas (Location 3)	80/20, 70/30
Falkirk Lignite	Shale Gas (Location 3)	80/20, 70/30
Rosebud PRB	VEN Consulting Water Hyacinth	80/20*
Rosebud PRB	VEN Consulting Water Lettuce	80/20*

Note:
* = multiple test runs planned for this coal/feedstock blend

For the coal/shale gas tests, three gas injection locations were used:

- Location 1 – The startup burner at the bottom of the mixing zone
- Location 2 – The coal feed nozzle at the top of the mixing zone
- Location 3 – The standpipe location being used as fluidized gas instead of nitrogen

6.1.3.1 *Test Description*

Testing was conducted using the EERC's TRDU over the course of 2 years. Gasifier operations, feedstocks, and the sampling and analyses that were performed are described below.

Gasifier Operations – Figure 6-3 shows the simplified schematic for all TRDU tests. Not shown on the figure is the slipstream of product gas that, for some tests, was sent to two fixed-bed catalytic tar reformer beds. Tar reforming tests are summarized in Section 6.1.4, below, and detailed in Appendix D. For all tests on the TRDU, the gasifier was operated in oxygen-blown mode. In this mode, both air and nitrogen (in addition to pure oxygen) are still used within the TRDU for conveying gas and purge gas. The gas generated in the gasifier passes through an indirect heat exchanger to cool the product gas prior to passing through the PCD. For each TRDU test, the gasifier was operated at approximately 120 psig, with average mixing zone temperatures (hottest part in the gasifier) of 1,700°F. Table 6-25 lists the selected 80% coal/20% non-coal (coal/biomass) feedstock blend tests and planned testing conditions, including feed rate, ratios for oxygen to fuel and steam to fuel, and planned run durations. During testing, these values were used as guidelines for the system operators; however, variations from these planned conditions were driven by operator observation and system behavior.

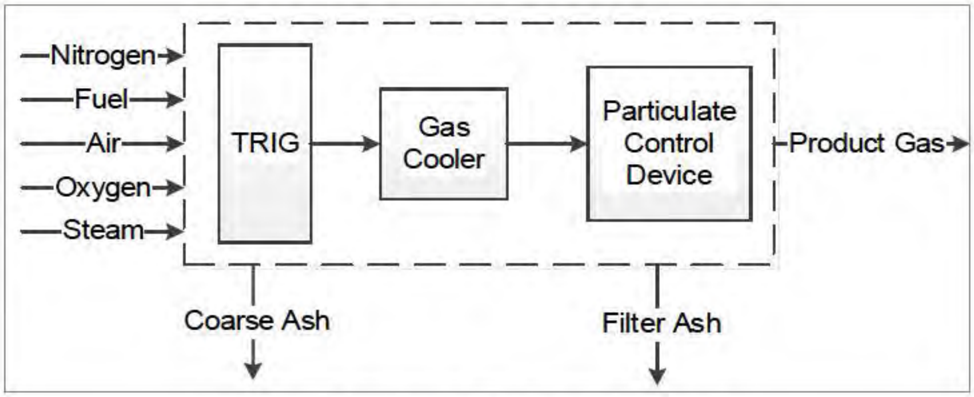


Figure 6-3: Simplified EERC TRDU Schematic

Table 6-25: TRDU Test Plan for Selected Tests

EERC's TRDU Test Identifier	Coal	Non-coal (Biomass/Gas)	Duration (hrs)	Fuel Feed Rate (lb/hr)	Temperature (°F)	O_2:Coal (lb/lb)
20120213A	Rosebud PRB	None	8	375	1,750	0.563
20130915A	Falkirk Lignite	None	8	450	1,750	0.528
20120218A	Rosebud PRB	Torrefied Wood	12	375	1,850	0.678
20120218A	Rosebud PRB	Raw Pine	8	325	1,750	0.658
20130625B	Rosebud PRB	Railroad Ties	12	400	1,750	0.528
20130301A	Rosebud PRB	Corn Stover	12	425	1,750	0.549
20130227B	Rosebud PRB	Switchgrass	12	425	1,750	0.549
20130629A	Rosebud PRB	Filamentous Algae	12	400	1,750	0.528
20130915B	Rosebud PRB	Water Hyacinth	12	450	1,750	0.518
20130917A	Rosebud PRB	Water Lettuce	12	450	1,750	0.518
20120322B	Nighthawk IL No. 6	Raw Pine	8	275	1,900	0.956
20130910B	Falkirk Lignite	Lean Location 1	8	400	1,750	0.594
20130910A	Falkirk Lignite	Rich Location 1	8	400	1,750	0.594
20130912D	Falkirk Lignite	Lean Location 2	8	400	1,750	0.594
20130912C	Falkirk Lignite	Rich Location 2	8	400	1,750	0.594
20130914C	Falkirk Lignite	Lean Location 3	8	400	1,750	0.594
20130914B	Falkirk Lignite	Rich Location 3	8	400	1,750	0.594

Note: lb/lb = pounds per pound

Feedstocks – All solid feeds tested at the EERC were premixed and processed through the same equipment. The details of this preparation are provided in the TRDU sections of the facility test reports (Appendix C and Appendix D).

Sampling and Analysis – During all testing, gas composition was measured using online (real-time) gas analyzers, trace species were measured using Draeger tubes, and condensate/quench water samples were collected using ice bathed quench pots. In addition, samples of each feedstock mixture were collected for proximate, ultimate, heating value, and feedstock ash analyses.

6.1.3.2 *Test Results – Gasification*

For this summary, all time-dependent values were averaged over a steady-state period. When only point values were available (e.g., Draeger tube samples), the values were assumed to be representative of the entire steady-state period.

6.1.3.2.1 Feedstock Analysis

In most cases, the blends were analyzed directly; however, in some cases the feedstock analysis parameters were calculated based on the as-fed analysis of the individual feedstocks. In this report, a distinction between the two is not necessary and therefore, not provided. Note that these are blended as-fed feedstock analyses, not the individual as-received analyses presented in Section 5 of this report and in Appendix B. Table 6-26 provides selected proximate, ultimate, heating value, and feedstock ash analyses for the as-fed selected 80% coal/20% biomass feedstock blends. In Table 6-26, the feedstock ash analyses are presented as oxides. Only those constituents identified by the EERC as important to how the ash behaves in the gasifier (e.g., ash agglomeration temperature) are presented with additional oxides grouped as “other.” This is described in the feedstock acquisition and characterization section of Appendix D, and the complete feedstock ash analyses are provided in Appendix C and Appendix D.

Table 6-26: EERC TRDU Feedstock Analysis of Various Biomass and Coal Feedstock Blends

Proximate, Ultimate, Heating Value and Ash Analyses of Various Biomass and Coal Feedstock Blends
Facility: EERC, Technology: TRIG™

Feedstock Type and Analyses	**Test Cases**										
Coal Type	Rosebud PRB	Falkirk Lignite	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Nighthawk IL No. 6
Biomass Type	None	None	Torrefied Pine	Raw Pine	Railroad Ties	Corn Stover	Switchgrass	Filamentous Algae	Water Hyacinth	Water Lettuce	Raw Pine
Biomass (wt%)	Coal Only	Coal Only	20	20	20	20	21	20	20	20	20
Proximate Analysis	wt%										
Moisture	25.77	27.91	20.82	21.65	20.28	20.79	23.35	22.04	20.79	22.29	7.09
Volatile Matter	27.72	27.16	35.92	38.37	32.6	31.58	32.59	29.73	30.4	32.17	40.62
Fixed Carbon	41.49	32.95	39.06	35.87	39.36	38.81	36.68	38.79	33.47	35.45	43.07
Ash	5.01	11.99	4.194	4.104	7.76	8.82	7.38	9.44	15.33	10.09	9.22
Ultimate Analysis	wt%										
C	50.52	40.97	52.71	50.17	51.09	50.07	51.19	48.88	44.92	46.59	59.97
H	3.32	2.84	3.70	3.76	3.69	3.51	3.61	3.40	3.32	3.48	4.38
N	0.76	0.7	0.62	0.62	0.66	0.78	0.81	0.91	0.82	1.05	0.99
O	13.84	14.6	17.33	19.07	15.75	15.19	12.97	14.47	13.88	15.64	16.29
S	0.78	0.99	0.63	0.63	0.76	0.85	0.69	0.86	0.93	0.86	2.07
Moisture	25.77	27.91	20.82	21.65	20.28	20.79	23.35	22.04	20.79	22.29	7.09
Ash	5.01	11.99	4.19	4.10	7.76	8.82	7.38	9.44	15.33	10.09	9.22
Heating Value, HHV (Btu/lb)	8,422	6,771	8,845	8,397	8,801	8,649	8,675	8,337	7,478	7,906	10,285

Table 6-26: EERC TRDU Feedstock Analysis of Various Biomass and Coal Feedstock Blends (Continued)

Proximate, Ultimate, Heating Value and Ash Analyses of Various Biomass and Coal Feedstock Blends
Facility: EERC, Technology: TRIG™

Feedstock Type and Analyses	Test Cases									
Coal Type	Rosebud PRB	Falkirk Lignite	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Nighthawk IL No. 6
Biomass Type	None	None	Torrefied Pine	Raw Pine	Railroad Ties	Corn Stover	Switchgrass	Filamentous Algae	Water Hyacinth	Water Lettuce	Raw Pine
Biomass (wt%)	Coal Only	Coal Only	20	20	20	20	21	20	20	20	20
Ash Analysis as Oxides	wt%										
CaO	12.01	10.98	12.93	12.47	13.13	11.90	14.60	18.36	10.08	16.81	2.58
MgO	7.53	4.77	7.65	7.61	4.78	4.23	4.77	4.86	3.51	4.41	1.51
Fe_2O_3	6.25	9.32	6.11	6.13	7.75	6.95	4.08	5.17	7.11	8.51	19.45
Na_2O	0.51	1.11	0.71	0.62	1.03	0.97	1.39	0.59	0.31	0.69	0.30
K_2O	0.33	2.15	1.34	0.91	0.76	1.77	0.84	3.13	1.13	2.24	2.88
SiO_2	39.92	46.71	38.53	39.16	41.77	42.80	42.00	40.09	55.93	40.56	47.20
P_2O_5	0.31	0.21	0.60	0.49	0.38	0.43	0.60	0.84	0.68	1.22	0.20
Other	33.14	24.75	32.12	32.61	30.40	30.95	31.72	26.96	21.25	25.56	25.88

The as-fed molar composition, calculated MW, calculated molar heating value, and calculated molar flow rates of the gaseous hydrocarbons used during the simulated shale gas testing are provided in Table 6-27. This table provides data for the 80% coal/20% gaseous fuel (coal/shale gas) feedstock blend. The blend percentages provided in the table are based on heating value, not weight. Discrepancies between the targeted 20% and actual feed percentages are discussed in Section 7 of this report. The calculated values are based on the molar composition and volumetric flow rates provided by EERC. Rich shale gas was simulated by combining the pipeline natural gas, gaseous ethane and propane, and liquid butane, pentane, and hexane. The compositions of shale gas provided in Table 6-27 were calculated by metered flow rate of the individual gas component. The heating values of the simulated shale gas were calculated based on the calculated composition. The heating value for the pipeline natural gas was provided by Excel Energy. During testing, select rich shale gas blends were verified using bag sampling and mass chromatography. The coal used during the shale gas testing was similar to the coal-only case provided in Table 6-26. The rationale for the specific compositions tested is provided in Appendix D.

Table 6-27: EERC TRDU Feedstock Analysis of Shale Gas and Coal Feedstocks

Flow Rates, Compositions and Heating Value (HHV) of Various Shale Gas and Coal Mixtures
Facility: EERC, Technology: EFG

Composition and Heating Value	**Test Cases**					
Blend (%)/Location	18 Lean Location 1	19 Rich Location 1	19.5 Lean Location 2	18.9 Rich Location 2	19.4 Lean Location 3	19.4 Rich Location 3
Total Hydrocarbon Flow (lb-mol/hr)	1.57	1.24	1.72	1.24	1.73	1.29
Composition, Gas + Liquid	(%mol)					
CH_4	96.87	72.26	96.87	72.58	96.87	71.04
C_2H_6	1.4	13.29	1.4	13.3	1.4	14.83
C_3H_8	0.06	7.22	0.06	7.25	0.06	7.1
C_4H_{10}	0	4.45	0	4.35	0	4.37
C_5H_{12}	0	0.82	0	0.59	0	1.02
C_6H_{14}	0	0.31	0	0.3	0	0.03
N_2	1.05	0.78	1.05	0.79	1.05	0.77
CO_2	0.61	0.46	0.61	0.46	0.61	0.45
Total Hydrocarbon MW (lb/lb-mol or g/mol)	16.5	22.5	16.5	22.3	16.5	22.5
Total Hydrocarbon Heating Value, HHV	379,987	509,299	379,987	505,803	379,987	510,739

6.1.3.2.2 Gasifier Operation and Product Gas Composition

During testing at the EERC for this project, more than 340 hours of steady-state data were logged for the TRDU. Gas composition data were provided by GC sampling after the gas cooler and the PCD (shown on Figure 6-3) for all test cases. Table 6-28 and Table 6-29 provide the averaged steady-state product gas compositions for the selected 80%/20% coal/biomass blends and coal/shale gas blends, respectively. Each table provides two coal-only baselines (for different coals) for reference. The compositions are provided on a nitrogen and dry (moisture free) basis, and correspond to averaged product gas flow rates of 1,540 lb/hr for the solid fuel feedstock blends and 1,360 lb/hr for the simulated shale gas cases measured via a dry gas meter downstream of the sampling location. Complete details for the product gas composition and system flow rates are provided in the TRDU sections of the facility test reports (Appendix C and Appendix D). For this report, volumetric-based results provided in Appendix C and Appendix D were converted to a mass flow basis. This conversion is described in Section 6.1.3.2.4, below.

Table 6-28: EERC TRDU Dry and N_2-Free Product Gas Composition for Various Biomass and Coal Blends

Dry and N_2-Free Product Gas Composition for Various Biomass and Coal Blends
Facility: EERC, Technology: TRIG™, Temperature: 1,707°F, Pressure: 120 psig

Feedstock Type and Product Gas Composition	Test Cases										
Coal Type	Rosebud PRB	Falkirk Lignite	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	IL No. 6
Biomass Type	None	None	Torrefied Pine	Raw Pine	Railroad Ties	Corn Stover	Switchgrass	Filamentous Algae	Water Hyacinth	Water Lettuce	Raw Pine
Biomass (wt%)	Coal Only	Coal Only	20	20	20	20	21	20	20	20	20
Steady-state Duration (hrs)	6.00	7.95	3.33	5.33	6.00	5.00	2.13	6.50	8.00	4.50	3.70
Dry and N_2-Free Product Gas Composition	(%mol)										
H_2	28.15	30.91	28.76	27.04	28.48	27.73	23.09	28.32	30.43	30.68	26.70
CO	19.31	16.35	23.00	22.55	20.49	17.25	15.46	17.77	17.06	17.79	20.21
CO_2	46.80	48.39	42.60	42.57	44.04	50.34	55.65	47.29	45.45	44.63	47.47
CH_4	5.73	4.35	5.65	7.84	6.99	4.68	5.80	6.63	7.06	6.91	5.62
H_2:CO Molar Ratio	1.46	1.89	1.25	1.20	1.39	1.61	1.49	1.59	1.78	1.72	1.32
Product Gas Heating Value, HHV dry basis (Btu/scf)	86	93	100	108	96	77	62	83	111	106	79
Product Gas Energy Flow, HHV dry basis (MMBtu/hr)	1.44	1.44	1.70	1.94	1.43	1.39	1.17	1.34	1.82	2.08	1.44

Table 6-29: EERC TRDU Dry and N_2-Free Product Gas Composition for Shale Gas and Coal Blends

Dry and N_2-Free Product Gas Composition for Shale Gas and Coal Blends Facility: EERC, Technology: TRIG™, Temperature: 1,700°F, Pressure: 120 psig							
Feedstock Types and Product Gas Composition	**Test Cases**						
Coal Type	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite
Gas (Btu%)/Location	Coal Only (Lignite)	18 Lean Location 1	19 Rich Location 1	19.5 Lean Location 2	18.9 Rich Location 2	19.4 Lean Location 3	19.4 Rich Location 3
Steady-state Duration (hrs)	7.95	5.00	5.00	5.00	3.00	5.50	7.00
Dry and N_2-Free Product Gas Composition	(%mol)						
H_2	30.91	36.22	35.86	28.97	29.92	34.84	35.07
CO	16.35	16.22	16.31	14.48	15.09	16.58	16.80
CO_2	48.39	41.92	42.18	44.24	44.43	41.30	41.41
CH_4	4.35	5.64	5.65	12.31	10.55	7.28	6.72
H_2:CO Molar Ratio	1.89	2.23	2.20	2.00	1.98	2.10	2.09
Product Gas Heating Value, HHV dry basis(Btu/scf)	93	124	122	136	139	123	119
Product Gas Energy Flow, HHV (MMBtu/hr)	1.44	1.97	1.95	2.02	2.09	1.96	1.90

Real-time GC and continuous emission monitors were used to measure key hydrocarbons such as methane, ethylene, ethane, and propene. Draeger tubes were used to measure trace amounts of ammonia, hydrogen sulfide, hydrochloric acid, hydrogen cyanide, toluene, and benzene. In addition, select product gas condensate samples were collected and selectively analyzed for COD, TOC, and ammonia. Results of these samples/analyses are provided in Table 6-30 and Table 6-31 for the selected coal/biomass feedstock blends and the coal/shale gas feedstock blends, respectively. Two coal-only cases are provided in Table 6-30 for reference – only lignite coal was used during simulated shale gas testing.

Table 6-30: EERC TRDU Trace Species Analysis for Various Biomass Blends

Analysis of Condensate Samples from Gasification of Various Biomass and Coal Feedstock Blends
Facility: EERC, Technology: TRIG™, Temperature: 1,707°F, Pressure: 120 psig

Feedstock Types and Analyses	Test Cases										
Coal Type	Rosebud PRB	Falkirk Lignite	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Nighthawk IL No. 6
Biomass Type	None	None	Torrefied Pine	Raw Pine	Railroad Ties	Corn Stover	Switchgrass	Filamentous Algae	Water Hyacinth	Water Lettuce	Raw Pine
Biomass (wt%)	Coal Only	Coal Only	20	20	20	20	21	20	20	20	20
Steady-state Duration	6.00	7.95	3.33	5.33	6.00	5.00	2.13	6.50	8.00	4.50	3.70
Draeger Tube Samples	ppmv										
NH_3	2,000	4,000	800	400	1,050	2,800	1,750	2,130	1,300	1400	600
HCN	3	>50	120	120	50	>100	>100	130	>100	>150	150
HCl	2	>10	1.8	1	13	5	8.5	8	5	>15	9
H_2S	1,574	2,000	1,600	1,200	992	2,800	3,700	4,000	1,250	2,200	>2,000
C_7H_8	3,600	9,000	3,600	3,600	3,250	4,000	5,000	3,680	6,300	6,000	3,000
C_6H_6	NA	>840	NA	NA	840	420	>840	530	>420	>420	NA

Note: NA = not analyzed

Table 6-30: EERC TRDU Trace Species Analysis for Various Biomass Blends (Continued)

Analysis of Condensate Samples from Gasification of Various Biomass and Coal Feedstock Blends
Facility: EERC, Technology: TRIG™, Temperature: 1,707°F, Pressure: 120 psig

Feedstock Types and Analyses	**Test Cases**										
Coal Type	Rosebud PRB	Falkirk Lignite	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	IL No. 6
Biomass Type	None	None	Torrefied Pine	Raw Pine	Railroad Ties	Corn Stover	Switchgrass	Filamentous Algae	Water Hyacinth	Water Lettuce	Raw Pine
Biomass (wt%)	Coal Only	Coal Only	20	20	20	20	21	20	20	20	20
Particulate Quench Water Samples	mg/L										
COD	380	NA	150	140	720	580	400	580	1,200	0	2,500
TOC	160	NA	99	82	289	126	198	413	696	0	320
NH_3	5,510	NA	5,850	4,260	4,370	3,620	915	6,660	7,990	0	5,900
Quench Water Analysis, Gas-phase Concentration	ppmw, (wet basis)										
COD	NA	NA	30	30	139	159	126	170	159	663	457
TOC	NA	NA	20	17	56	35	62	104	114	298	58
NH_3	NA	NA	1,168	909	1,239	1,422	408	1,284	1,830	3,289	1,077

Notes:
NA = not analyzed
ppmw = parts per million by weight;

Table 6-31: EERC TRDU Trace Species Analysis for Shale Gas Blends

Analysis of Condensate Samples from Gasification of Shale Gas and Coal Feedstock Blends Facility: EERC, Technology: TRIG™, Temperature: 1,700°F, Pressure: 120 psig							
Feedstock Type and Analysis	**Test Cases**						
Coal Type	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite
Gas (Btu%)/Location	Coal Only	18 Lean Location 1	19 Rich Location 1	19.5 Lean Location 2	18.9 Rich Location 2	19.4 Lean Location 3	19.4 Rich Location 3
Steady-state Duration	7.95	5.00	5.00	5.00	3.00	5.50	7.00
Draeger Tube Samples	ppm						
NH_3	4,000	2,100	3,000	2,750	2,500	1,000	1,000
HCN	>50	80	80	50	50	60	>100
HCl	>10	2	10	10	7	>10	>10
H_2S	2,000	1,500	1,750	2,000	2,500	2,000	2,250
C_7H_8	9,000	4,800	4,400	5,500	6,500	ND	4,820
C_6H_6	>840	530	520	>840	>840	>840	>420
Particulate Quench Water Samples	mg/L						
COD	NA	1,700	1,650	780	900	620	620
TOC	NA	980	1,220	478	491	573	592
NH_3	NA	6,610	7210	5,890	5,730	6,670	7,280
Quench Water Analysis, Gas-Phase Concentration	ppmw, wet basis						
COD	NA	468	450	224	253	176	184
TOC	NA	270	332	137	138	162	176
NH_3	NA	2,500	2,712	2,349	2,249	2,588	2,945

Notes:
NA = not analyzed
ND = not detected

6.1.3.2.3 Gasifier Residue Sample Analysis

During gasification fine ash entrained in the product gas exiting the TRDU was captured with a PCD, as shown in Figure 6-3. This ash was removed from the system via a lock-hopper style pressure let-down system, as needed, during each test case. Ash removed from the system was analyized for LOI. Results are provided in Table 6-32 and Table 6-33 for the selected coal/biomass feedstock blends and the coal/shale gas feedstock blends, respectively. Complete details on the ash sampling procedures and specific analyses (e.g., x-ray fluorescence, nuclear magnetic resonance analysis) are provided in the TRDU sections of the facility reports (Appendix C and Appendix D).

Table 6-32: EERC TRDU Analysis of Gasifier Filter Vessel (PCD) Ash for Various Biomass Blends

Analysis of Ash Samples from Gasified for Various Biomass and Coal Feedstock Blends
Facility: EERC, Technology: TRIG™, Temperature: 1,707°F, Pressure: 120 psig

Feedstock Type and Analysis	**Test Cases**										
Coal Type	Rosebud PRB	Falkirk Lignite	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	IL No. 6
Biomass Type	None	None	Torrefied Pine	Raw Pine	Railroad Ties	Corn Stover	Switchgrass	Filamentous Algae	Water Hyacinth	Water Lettuce	Raw Pine
Biomass (wt%)	Coal Only	Coal Only	20	20	20	20	21	20	20	20	20
Steady-state Duration (hrs)	6.00	7.95	3.33	5.33	6.00	5.00	2.13	6.50	8.00	4.50	3.70
Fine Ash LOI (wt%)	25.4	23.8	28.5	27.7	22.7	12.2	24.1	25.8	27.7	23.8	56.4

Table 6-33: EERC TRDU Analysis of Gasifier Filter Vessel (PCD) Ash for Shale/Natural Gas Blends

Analysis of Ash Samples from Gasified Shale Gas and Coal Feedstock Blends Facility: EERC, Technology: TRIG™, Temperature: 1,700°F, Pressure: 120 psig							
Feedstock Type and Analysis	**Test Cases**						
Coal Type	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite
Gas (Btu%)/Location	Coal Only	18 Lean Location 1	19 Rich Location 1	19.5 Lean Location 2	18.9 Rich Location 2	19.4 Lean Location 3	19.4 Rich Location 3
Steady-state Duration (hrs)	7.95	5.00	5.00	5.00	3.00	5.50	7.00
Fine Ash LOI (wt%)	23.8	26.1	26.6	13.3	13.8	23.1	19.0

Coarse solid samples were collected directly from the gasifier standpipe. These samples consist of coarse ash, sand from the startup bed material, and recirculated feed material. Solid samples of both coarse and fine ash from 20 different test cases, representing the array of coals and biomass types tested in the TRDU, were submitted to TestAmerica for analysis using the TCLP. Results of the TCLP analyses are provided in Table 6-34 and Table 6-35 and compared to the hazardous characteristic criteria for the eight heavy metals regulated under RCRA to determine if the material would be considered hazardous for disposal purposes. As shown, all results are below the applicable regulatory levels. All solid sample results are provided in Appendix C, Appendix D, and Appendix K.

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Table 6-34: EERC Coarse Ash Samples – TCLP Results (concentrations in mg/L)

Metal	Coarse Ash 100% Falkirk Lignite	Coarse Ash 1 100% PRB	Coarse Ash 2 100% PRB	Coarse Ash 20% Raw, 80% PRB	Coarse Ash 20% Torrefied, 80% PRB	Coarse Ash 20% Torrefied, 80% IL No. 6	Coarse Ash 20% Corn Stover, 80% PRB	Coarse Ash 21% Switchgrass, 80% PRB	Coarse Ash 20% Filamentous Algae, 80% PRB	Coarse Ash 20% Water Hyacinth, 80% PRB	Coarse Ash 20% Water Lettuce, 80% PRB	RCRA MCLs, mg/L
Ag	<0.0200	<0.25	<0.0200	<0.25	<0.25	<0.25	<0.0200	<0.0200	<0.0200	<0.0200	<0.0200	5
As	<0.300	<0.25	<0.300	<0.25	<0.25	<0.25	<0.300	<0.300	<0.300	<0.300	<0.300	5
Ba	26.1	11	9.93	15	23	6	15.0	12.5	6.81	12.0	5.07	100
B	2.20	<7.5	0.836	<7.5	<7.5	<7.5	1.18	0.620	1.85	1.11	1.57	NE
Cd	<0.0200	<0.20	<0.0200	<0.20	<0.20	<0.20	<0.0200	<0.0200	0.0234	<0.0200	<0.0200	1
Cr	<0.0200	<0.25	<0.0200	<0.25	<0.25	<0.25	<0.0200	<0.0200	<0.0200	<0.0200	<0.0200	5
Hg	<0.002	<0.020	<0.002	<0.020	<0.020	<0.020	<0.002	<0.002	<0.002	<0.002	<0.002	0.2
Ni	NA	<2.5	NA	<2.5	<2.5	<2.5	NA	NA	NA	NA	NA	NE
Pb	<0.100	<0.20	<0.100	<0.20	<0.20	<0.20	<0.100	<0.100	<0.100	<0.100	<0.100	5
Se	<0.150	<0.25	<0.150	<0.25	<0.25	<0.25	<0.150	<0.150	<0.150	<0.150	<0.150	1
V	<0.0500	<0.25	<0.0500	<0.25	<0.25	<0.25	<0.0500	<0.0500	<0.0500	<0.0500	<0.0500	NE
Zn	0.175	0.2	<0.100	0.2	0.22	0.26	<0.100	<0.100	0.154	0.274	0.570	NE

Notes:
All PRB referenced in the table is from Rosebud mine in Montana.
NA = not analyzed
NE = MCL not established

Table 6-35: EERC Fine Ash Samples – TCLP Results (concentrations in mg/L)

Analyte	Fine Ash 100% Falkirk Lignite	Fine Ash 1 100% PRB	Fine Ash 2 100% PRB	Fine Ash 20% Raw, 80% PRB	Fine Ash 20% Torrefied, 80% PRB	Fine Ash-20% Torrefied, 80% IL No. 6	Fine Ash 20% Corn Stover, 80% PRB	Fine Ash 21% Switchgrass, 80% PRB	Fine Ash-20% Filamentous Algae, 80% PRB	Fine Ash 20% Water Hyacinth, 80% PRB	Fine Ash 20% Water Lettuce, 80% PRB	RCRA MCLs, mg/L
Ag	<0.0400	<0.25	<0.0200	<0.25	<0.25	<0.25	<0.0200	<0.0200	<0.0600	<0.0600	<0.0600	5
As	<0.600	<0.25	<0.300	<0.25	<0.25	<0.25	<0.300	<0.300	<0.900	<0.900	<0.900	5
Ba	23.6	4.3	4.29	6.3	5.8	1.5	5.42	1.22	3.92	9.11	7.54	100
B	26.5	13	9.26	14	12	<7.5	8.95	11.8	11.8	19.0	18.2	NE
Cd	<0.0400	<0.20	<0.0200	<0.20	<0.20	0.11	<0.0200	<0.0200	<0.0600	<0.0600	<0.0600	1
Cr	<0.0400	<0.25	<0.0200	<0.25	<0.25	<0.25	<0.0200	<0.0200	<0.0600	<0.0600	<0.0600	5
Hg	<0.002	<0.020	<0.002	<0.020	<0.020	<0.020	<0.002	<0.002	<0.002	<0.002	<0.002	0.2
Ni	NA	<2.5	NA	<2.5	<2.5	0.19	NA	NA	NA	NA	NA	NE
Pb	<0.200	<0.20	<0.100	<0.20	<0.20	0.13	<0.100	<0.100	<0.300	<0.300	<0.300	5
Se	<0.300	<0.25	<0.150	<0.25	<0.25	<0.25	<0.150	<0.150	<0.450	<0.450	<0.450	1
V	0.210	0.24	0.244	0.25	0.24	<0.25	0.214	0.159	<0.150	0.153	<0.150	NE
Zn	<0.200	<2.5	0.126	<2.5	<2.5	1.9	0.106	<0.100	<0.300	<0.300	<0.300	NE

Notes: All PRB referenced in the table is from Rosebud mine in Montana.
NA = not analyzed
NE = MCL not established

6.1.3.2.4 Mass and Energy Balance

Similar to the EFG, CCAT (with concurrence from the EERC) conducted many of the calculations needed to perform the mass and energy balances. The significance of these balances is discussed further in Section 7.1.2.

The system boundaries used for the mass balance are shown on Figure 6-3. The process inputs included fuel (carbonaceous feedstocks), oxygen, air, nitrogen and steam, while process outputs included product gas (wet), coarse ash and filter ash. The measured process input and output data that were used to perform the calculations are provided in Appendix C and Appendix D. The coarse ash mass flow rate was not measured; rather, it was approximated as 50 lb/day (2.08 lb/hr) based on the EERC's historical experience with the TRDU. A full proximate and ultimate analysis on the PCD ash was not provided by the EERC. However, the LOI (wt%) data provided by the EERC were used as proxies to calculate the carbon content of the PCD ash samples. Likewise, the EERC did not provide a complete proximate and ultimate analysis of the coarse ash. However, it was assumed that the coarse ash contained only ash/minerals and therefore, would have the same ash analysis of the blended feedstocks provided in Table 6-26. Additionally, gaseous inputs, including lean/rich shale gas, and gaseous outputs measured on a volumetric flow-rate basis (e.g., scfh) were converted to a mass flow-rate basis (lb/hr). Volumetric flow rates were converted to mass flow rates using the volumetric flow rates provided in Appendix C and Appendix D, and the corresponding MW of the gas. For the product gas volumetric flow rate conversion the normalized product gas composition was used.

The following tables summarize of the process flows (both measured and calculated). Specifically Table 6-36 and Table 6-37 provide process stream data for mass in and mass out for the selected coal/biomass feedstock blends and the coal/shale gas feedstock blends, respectively.

Table 6-36: EERC TRDU Process Stream Data for Mass Balance Summary of Various Biomass Blends

Process Stream Data for Various Biomass and Coal Blends
Facility: EERC, Technology: TRIG™

Feedstock Type and Process Stream Data	Test Cases										
Coal Type	Rosebud PRB	Falkirk Lignite	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	IL No. 6
Biomass Type	None	None	Torrefied Pine	Raw Pine	Railroad Ties	Corn Stover	Switchgrass	Filamentous Algae	Water Hyacinth	Water Lettuce	Raw Pine
Biomass (wt%)	Coal Only	Coal Only	20	20	20	20	21	20	20	20	20
Steady-state Duration (hrs)	6.00	7.95	3.33	5.33	6.00	5.00	2.13	6.50	8.00	4.50	3.70
Inputs	lb/hr										
Fuel	359	404	374	446	410	400	413	496	484	508	301
Air	198	153	161	161	162	138	138	208	154	152	267
N_2	486	470	513	519	519	569	587	566	490	570	479
O_2	205	229	230	227	211	226	231	207	224	236	187
Steam	219	268	177	174	200	280	281	208	277	262	241
Total Mass Input	**1,467**	**1,523**	**1,455**	**1,527**	**1,501**	**1,613**	**1,650**	**1,695**	**1,628**	**1,728**	**1,475**
Outputs	lb/hr										
Product Gas	1,449	1,383	1,458	1,543	1,313	1,863	1,953	1,422	1,405	1,624	1,575
Filter Ash	36.4	33.4	35.6	41.3	24.8	85.2	25.6	40.2	43.1	57.1	51.8
Coarse Ash	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08
Total Mass Output	**1,487**	**1,418**	**1,496**	**1,586**	**1,340**	**1,950**	**1,981**	**1,464**	**1,450**	**1,683**	**1,629**
Mass Balance Closure, Output to Input Ratio (%)	101.38	93.13	102.78	103.86	89.22	120.88	120.04	86.91	89.06	97.44	110.42

Table 6-37: EERC TRDU Process Stream Data for Mass Balance Summary of Shale Gas Blends

Process Stream Data for Shale Gas and Coal Blends
Facility: EERC, Technology: TRIG™

Feedstock Type and Process Stream Data	**Test Cases**						
Coal Type	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite
Gas (Btu%)/Location	Coal Only	18 Lean Location 1	19 Rich Location 1	19.5 Lean Location 2	18.9 Rich Location 2	19.4 Lean Location 3	19.4 Rich Location 3
Steady-state Duration (hrs)	7.95	5.00	5.00	5.00	3.00	5.50	7.00
Inputs	lb/hr						
Fuel	404	426	421	426	418	433	425
Air	153	186	154	153	153	153	153
N_2	470	466	494	451	448	436	432
O_2	229	232	232	228	228	228	228
Steam	268	266	269	261	270	270	271
Total Mass Input	**1,523**	**1,576**	**1,570**	**1,520**	**1,517**	**1,519**	**1,508**
Outputs	lb/hr						
Product Gas	1,383	1,402	1,418	1,311	1,325	1,343	1,354
Filter Ash	33.4	44.7	43.4	35.7	41.2	43.9	37.0
Coarse Ash	2.08	2.08	2.08	2.08	2.08	2.08	2.08
Total Mass Output	**1,418**	**1,449**	**1,463**	**1,349**	**1,369**	**1,389**	**1,394**
Mass Balance Closure, Output to Input Ratio (%)	93.13	91.94	92.78	88.76	89.77	91.45	91.91

Carbon conversion and cold gas efficiency were calculated as described in the introduction to Section 6, but with the measured LOI values assumed as the carbon content of (used as a proxy for) the filter ash. Table 6-38 and Table 6-39 provide the calculated values for carbon conversion and cold gas efficiency for the selected coal/biomass feedstock blends and the coal/shale gas feedstock blends, respectively.

Table 6-38: EERC TRDU Carbon Conversion and Cold Gas Efficiency of Various Biomass Blends

Carbon Conversion and Cold Gas Efficiency for Various Biomass and Coal Blends
Facility: EERC, Technology: TRIG™, Temperature: 1,707°F, Pressure: 120 psig

Feedstock Type, Conversion, and Efficiency	**Test Cases**										
Coal Type	Rosebud PRB	Falkirk Lignite	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	Rosebud PRB	IL No. 6
Biomass Type	None	None	Torrefied Pine	Raw Pine	Railroad Ties	Corn Stover	Switchgrass	Filamentous Algae	Water Hyacinth	Water Lettuce	Raw Pine
Biomass (wt%)	Coal Only	Coal Only	20	20	20%	20	21%	20	20	20	20
Steady-state Duration (hrs)	6.00	7.95	3.33	5.33	6.00	5.00	2.13	6.50	8.00	4.50	3.70
Carbon Conversion (%)	94.9	95.2	94.9	94.9	97.3	94.8	97.1	95.7	94.5	94.3	83.8
Cold Gas Efficiency (%)	47.8	52.8	51.5	51.8	39.7	40.1	32.7	32.5	50.2	51.8	46.5

Table 6-39: EERC TRDU Carbon Conversion and Cold Gas Efficiency of Shale Gas Blends

Carbon Conversion and Cold Gas Efficiency for Shale Gas and Coal Blends Facility: EERC, Technology: TRIG™, Temperature: 1,700°F, Pressure: 120 psig							
Feedstock Type, Conversion, and Efficiency	**Test Cases**						
Coal Type	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite	Falkirk Lignite
Gas (Btu%)/Location	Coal Only	18 Lean Location 1	19 Rich Location 1	19.5 Lean Location 2	18.9 Rich Location 2	19.4 Lean Location 3	19.4 Rich Location 3
Steady-state Duration (hrs)	7.95	5.00	5.00	5.00	3.00	5.50	7.00
Carbon Conversion (%)	95.2	92.9	93.0	97.1	96.5	93.9	95.8
Cold Gas Efficiency (%)	52.8	59.5	58.5	60.4	62.8	57.7	56.1

6.1.3.3 *Reported Conclusions*

TRDU testing at the EERC was conducted in two phases: 2012 to 2013 and 2013 to 2014. The EERC reported the 2012 to 2013 testing in its Phase I Final Report (Appendix C) and the 2013 to 2014 testing in its Phase 2 Final Report (Appendix D). This section summarizes the EERC's main conclusions for TRDU testing from these two reports. Because the EERC did not provide pH, total metals, or TCLP analysis, it did not provide conclusive statements about these analyses in its reports. Analyses of solid residue samples for pH, total metals, and TCLP were performed by a third-party laboratory, TestAmerica, and are reported in Appendix K for completeness.

The EERC successfully completed TRDU gasification testing on a variety of biomass types, coal types, and at different ratios under steady-state gasifier conditions. The EERC also successfully fed two blends of simulated shale gas with North Dakota lignite coal at different blend ratios under steady-state gasifier conditions.

Feedstock

Feeding of the gasifier was generally trouble-free, with only a few exceptions noted by the EERC. During the 2012 to 2013 testing, more than 230 hours of operation on the TRDU were completed with no fuel feed issues. (Appendix C, page 29). During the 2013 to 2014 testing, several minor issues and one major feed plugging event were reported. It was noted that all feed issues were associated either with switchgrass or corn stover testing, but not with the raw wood or torrefied wood. (Appendix D, page 100). There was also one fuel feed plugging issue reported during the transition to railroad ties (30 wt%).

Product Gas Composition

The EERC concluded that the addition of the woody biomass to the feed did not appear to affect the TRDU gasifier performance. The EERC also conclude that in general, the use of any of the PRB coal/biomass blends did not result in major differences in TRDU performance. (Appendix D, page 101)

For the wide range of feedstocks tested and the different parameters under which tests were conducted, no conclusive statements on product gas composition were reported. From the 2012 to 2013 testing, the EERC notes that the quality of all the syngas [composition] created is acceptable and comparable with previous testing results seen on the TRDU. (Appendix C, page 20). These tests included both raw and torrefied biomass blended with PRB and IL No. 6 coals.

From the coal/shale gas testing, the EERC observed some differences in product composition depending on injection locations. Injection of the gas blends at Location 1 increased product gas hydrogen, carbon monoxide and heating value, while not significantly increasing the hydrocarbon concentration in the syngas. Injection at Location 2 also resulted in increased product gas heating value; however, most of this increase was due to the gaseous hydrocarbons passing through the gasifier without conversion. Injection at Location 3 resulted in much less hydrocarbon breakthrough. (Appendix D, page 101)

From the 2013 to 2014 tests of PRB coals blended with woody biomass, switchgrass and corn stover, the EERC noted that herbaceous biomasses like switchgrass and corn stover generated product gas heating values somewhat lower than those generated using woody biomass. The EERC speculated this could be the result of woody biomass containing more lignin and less cellulose and hemicellulose than the herbaceous plant material. (Appendix D, page 101)

Product Gas Condensate Analysis

Although broad conclusive statements about trace species and organic loading in condensate/quench water were not practical for this set of tests, the EERC reported the following:

From the 2012 to 2013 testing, the EERC concluded that tars, chlorine, and sulfur components were present in the product gas and would need to be controlled before sending the gas to an FT reactor. (Appendix C, page 20). These tests included both raw and torrefied biomass blended with PRB and IL No. 6 coals. The EERC added that “more and heavier organics such as aromatic compounds or tars” were produced with the bituminous (IL No. 6) coal.

From the 2013 to 2014 tests, the EERC concluded that the organic loading in the quench water was relatively low, although an order of magnitude higher than the levels seen in the quench water from the high-temperature EFG samples. (Appendix D, page 68). This statement was based on tests conducted with PRB coal blended with woody biomass, corn stover, and switchgrass.

Also from the 2013 to 2014 testing, the EERC noted that organic loading in the quench water was relatively low for the PRB coal/railroad tie blends, even lower than the coal-only tests. The EERC speculated that the “high hydrocarbon” railroad ties generated a non-water soluble organic fraction that would not have been detected in the testing. (Appendix D, page 88)

Gasifier Operations and Solid Residue

While difficulties with ash handling on specific tests were reported in one of the EERC's quarterly reports, the EERC reported the following conclusions in its final reports (Appendix C and Appendix D).

From the 2012 to 2013 testing, gasifier temperatures varied from 1,740 to 1,950°F without encountering ash deposition problems associated with the high potassium levels in the biomass ash. (Appendix C, page 29). These tests included both raw and torrefied biomass blended with PRB and Illinois No. 6 coals. The EERC noted the same observation for the PRB coal/railroad tie blends and PRB coal/aquatic algae blends from its 2013 to 2014 testing. (Appendix D, page 101)

From the 2013 to 2014 testing on PRB coal blended with corn stover and switch grass the EERC reported that biomass ash was mostly leaving the system with the PCD ash. The EERC stated that this is a positive outcome because it avoids the likelihood of lower-melting-point potassium silicates from reaching concentrations in the bed that would result in bed deposition and agglomeration problems. (Appendix D, page 68)

Mass and Energy Balance

Both carbon conversion and cold gas efficiencies were reported by the EERC for the TRDU tests. The EERC reported the following general conclusions:

From the 2012 to 2013 testing of coal/woody biomass blends, results showed high levels of carbon conversion for the Rosebud PRB blends. Reduced conversion was observed with the less reactive bituminous IL No. 6 blends. The EERC stated this is consistent with past coal-only testing. (Appendix C, page 31)

For the 2013 to 2014 testing of lignite blended with simulated shale gas, the EERC noted that carbon conversions were all above 90%. (Appendix D, page 101). The EERC also noted that "solid carbon conversions" appeared slightly lower with injection of blend gas at Location 1.

The product gas heating values from tests with coal and herbaceous biomasses, like switchgrass and corn stover, were somewhat lower than the product gas heating values generated from coal and woody biomass. The product gas heating value and CGE decrease as the oxygen/fuel ratio is increased (i.e., moves closer to stoichiometric combustion). The CGE for the coal-only tests overlay the CGE from the coal–biomass blends, indicating that the presence of biomass in the feedstock did not have a noticeable impact on the transport reactor performance. (Appendix D, page 103)

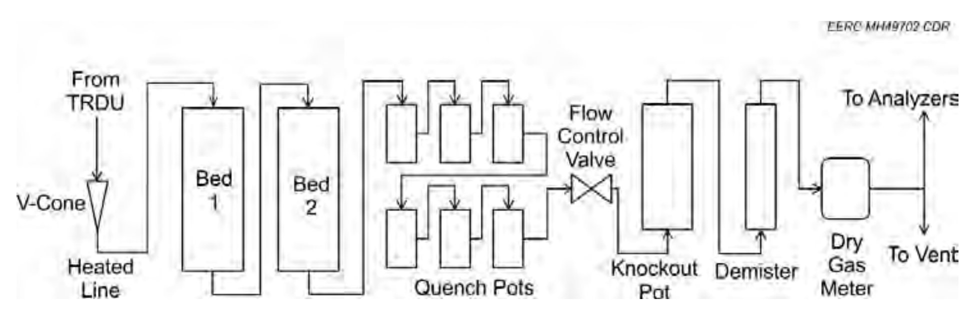
6.1.4 Tar Reforming

As described in Section 4 the production of tars is common with the gasification of biomass and coal, particularly at lower temperatures. Further, tars may be reformed by a variety of methods to create additional hydrogen and carbon monoxide. The objective of tar reforming tests at EERC was to demonstrate a novel catalyst designed to operate at relatively low temperatures, 670 to 840°F compared to conventional catalysts operated at nominally 1,560°F. Tests were performed using a slipstream of the product gas from the TRDU. Tar reforming tests took place during gasification tests under the second phase of work with the EERC (2013 to 2014). Testing and results are summarized below and detailed in Appendix D.

6.1.4.1 *Test Description*

Process gas reforming was tested during two separate campaigns: Week 1 comprising June 24 through June 30, 2013 and Week 2 comprising September 9 through 15, 2013. These tests were intended to align with TRDU tests using PRB coal with railroad ties or algae for Week 1 and lignite coal with simulated lean and rich shale gas for Week 2. Throughout the series of tests, both the flow rate and bed temperatures were varied to study the effects on tar reforming. The test matrix was developed by the catalyst manufacturer and modified by the EERC and the catalyst manufacturer as testing was conducted.

During tar reforming tests, a slipstream of TRDU product gas from a location between the PCD and thermal oxidizer was sent to two catalyst fixed -beds in series. Figure 6-4 shows a schematic of the tar reforming system. A baseline test bypassing the catalyst bed (bypass not shown) was planned for each week of reforming tests. The slipstream from the TRDU to the catalyst beds was heated to prevent condensation in the line. The two fixed beds were equipped with electric heaters to facilitate testing at various temperatures. The pressure in the beds was maintained as high as possible based on the flow rate and system pressure in the TRDU. A series of six indirectly cooled quench pots were used to capture condensables (e.g., water, alcohols, heavier hydrocarbons) downstream of the catalyst beds.



(Source: EERC Phase II Report; Appendix D)

Figure 6-4: Simplified EERC TRDU Tar Reforming Slipstream Schematic

Inlet gas composition was measured on a dry basis with an on-line GC system associated with TRDU operations. Outlet gas composition, downstream of the quench pots, was analyzed by two independent laser gas analyzers (LGAs) for hydrogen, carbon monoxide, carbon dioxide, nitrogen, water, hydrogen sulfide, oxygen, and methane. The LGA also determined hydrocarbons larger than methane as a pseudo-species. Additionally, Draeger tubes were used to measure ammonia, hydrogen cyanide, and benzene, toluene, and xylene at the outlet of the second fixed bed.

Condensate was collected periodically from quench pots at both the inlet and outlet locations. Inlet condensate samples were collected in association with TRDU tests and not in close association with the reformer tests as run; samples were reported pulled prior to each reforming test. Outlet condensate samples were reported pulled every 1 to 2 hours during the reformer test. Select samples were analyzed for TOC, COD, and organics composition by GC/mass spectrometry (MS).

Tars were found to condense and remain in the quench pots as a residue. These were classified as heavier “solid” tars. Outlet heavier “solid” tar samples were collected from the quench pots on a daily basis during both Week 1 and Week 2 test campaigns. “Solid” tar sample protocols differed between Week 1 and Week 2 tests. During Week1 testing, inlet “solid” tar samples were collected from the TRDU quench pots. During Week 2 testing, an independent series of ice-cooled quench pots was sampled intermittently at the inlet location separate from the TRDU quench pots; these pots were cleaned out prior to each test. Select samples from Week 1 tests were analyzed by GC/MS. Recovered solids from Week 2 tests were weighed as recovered, without drying or volatilization. The volume of product gas passing through the quench pots was used to normalize the mass collected.

In addition to the condensate and heavier “solid” tar samples above, Week 2 tests included whole gas samples to evaluate tars. Paired bomb cylinder grab samples were taken of the inlet and outlet slipstream to provide definitive data on the performance of the catalyst during two tests.

6.1.4.2 *Test Results*

For this summary, all time-dependent data were averaged over the test period. When only point values were available (e.g., condensate samples), the values are assumed to be representative of the entire period of operation.

6.1.4.2.1 Feedstock Analysis

The feed to the tar reforming system stand was wet product gas diverted from the exhaust of the TRDU downstream of the PCD and upstream of the thermal oxidizer. Having passed through the PCD, product gas was nearly particulate-free. The dry product gas composition of the slipstream from the TRDU is provided in Section 6.1.4.2.2. The composition varied throughout the reforming tests depending on the concurrent TRDU test cases. During Week 1 of tar reforming, the TRDU was primarily fed blends of Rosebud PRB coal and used railroad ties During Week 2 of tar reforming, the TRDU was fed North Dakota lignite coal and simulated shale gas. Additional details of TRDU operations can be found in Section 6.1.3 and Appendix D.

6.1.4.2.2 Operation and Product Gas Composition

Reforming tests were performed in two campaigns: Week 1 reforming PRB/biomass TRDU product gas and Week 2 reforming lignite/gaseous fuel TRDU product gas. After beginning the Week 1 test campaign, and in consultation with the catalyst manufacturer, the Week 1 test plan was modified dropping the total number of tests from 16 to eight. Actual run conditions for Week 1 are summarized in Table 6-40. The modification provided longer continuous periods of catalyst exposure to product gas. Similarly, after beginning the Week 2 test campaign, and in consultation with the catalyst manufacturer, the Week 2 test plan was modified. The actual test conditions for Week 2 tests are summarized in Table 6-41.

During operations prior to Week 2, the EERC reported a significant excursion of oxygen in product gas from the TRDU resulting in oxygen intrusion to the tar reforming system. A substantial temperature spike was observed in the first catalyst fixed-bed with this event. The subsequent quench pot water samples from Tests 8A and 8B were colored florescent red. Similarly, solid tars recovered from the quench pots after Test 10B were intensely colored. The oxygen intrusion may have affected catalyst activity.

Permanent gases and hydrocarbons were measured at the inlet and outlet of the tar reforming system. Results are summarized in Table 6-42 and Table 6-43 for Week 1 and Week 2 testing, respectively. Gas compositions were reported by the EERC as measured but were normalized for product gas composition consistent with standards for this report. Inlet product gas composition was measured by both continuous emission monitors (CEMs) and an on-line GC; the EERC expressed greater confidence in the GC readings, and these are reported in the tables. Tar reforming system outlet concentrations were measured by two LGAs, only one LGA represents a complete data set and is presented in these tables.

Select condensate samples from the inlet TRDU quench pots and outlet tar reforming system quench pots were analyzed for TOC; these results are presented in Table 6-44 and Table 6-45 for Week 1 and Week 2 tests, respectively. Samples are not coincident and further reflect different accumulation periods. Sample times are included to provide information on the time separation of the samples. A more complete presentation of the speciated organics from condensate samples can be found in Appendix D.

Finally, whole gas samples were collected for two tests in sample bombs at both the tar reforming system inlet and outlet during Week 2 testing. Tars and other organics were extracted and analyzed by GC/MS; these results are presented in Table 6-46.

Table 6-40: EERC Week 1 Tar Reforming Test Conditions

EERC Test Designation	Nominal Fuel Feed to TRDU Gasifier	Duration (hrs)	Dry Product Gas Flow (scfh)	Avg. Bed 1 Temp. (°F)	Avg. Bed 2 Temp. (°F)
2-1/ 3A-1[a]	10% railroad ties/PRB	5.7	234	594	558
3A-2/ 4B-1	20% railroad ties/PRB	21.1	290	608	660
5A-4	30% railroad ties/PRB	6.2	173	756	779
5A-5	30% railroad ties/PRB	9.0	368	709	801
5C-6	30% railroad ties/PRB	7.9	88	840	795
5C-7	30% railroad ties/PRB	8.3	189	736	786
6A-3	20% Algae/PRB	6.5	104	788	777
6A-4	20% Algae/PRB	2.8	205	738	766

Note: [a] Baseline test bypassing reformer.

Table 6-41: EERC Week 2 Tar Reforming Test Conditions

EERC Test Designation	Nominal Fuel Feed to TRDU Gasifier	Duration (hrs)	Dry Product Gas Flow (scfh)	Avg. Bed 1 Temp. (°F)	Avg. Bed 2 Temp. (°F)
Test 2A[a]	Lignite + 10% Lean Shale Gas	4.5	208	768	772
Test 2B[a]	Lignite + 10% Rich Shale Gas	4	232	847	829
Test 3A	Lignite + 20% Rich Shale Gas	5	234	552	806
Test 3B	Lignite + 20% Lean Shale Gas	5	134	712	921
Test 4A	Lignite + 30% Lean Shale Gas	5	127	711	820
Test 4B	Lignite + 30% Rich Shale Gas	6.4	103	757	880
Test 5A	Lignite	6	122	734	858

EERC Test Designation	Nominal Fuel Feed to TRDU Gasifier	Duration (hrs)	Dry Product Gas Flow (scfh)	Avg. Bed 1 Temp. (°F)	Avg. Bed 2 Temp. (°F)
Test 5B	Lignite	7	111	752	874
Test 6A	Lignite + 10% Lean Shale Gas	6	206	662	810
Test 6B	Lignite + 10% Rich Shale Gas	5	209	700	804
Test 7A	Lignite + 20% Rich Shale Gas	3	244	680	795
Test 7B	Lignite + 20% Lean Shale Gas	5	314	682	820
Test 8A	Lignite + 30% Lean Shale Gas	3.17	385	705	828
Test 8B	Lignite + 30% Rich Shale Gas	4.25	449	703	826
Test 10B	Lignite + 30% Rich Shale Gas	4.67	351	707	813

Note: [a] Baseline test bypassing reformer.

Table 6-42: Week 1 Tar Reforming Test Dry N_2-Free Product Gas Composition

EERC Test Designation	Sample Location	H_2, %mol	CO, %mol	CO_2, %mol	CH_4, %mol
2-1/ 3A-1[a]	Inlet	31.03	21.36	40.43	7.18
	Outlet	29.87	21.05	42.94	6.14
3A-2/ 4B-1	Inlet	29.00	21.12	42.44	7.44
	Outlet	37.44	3.95	53.47	5.14
5A-4	Inlet	26.19	19.19	47.86	6.76
	Outlet	34.48	5.57	54.57	5.38
5A-5	Inlet	27.29	19.35	46.64	6.72
	Outlet	34.51	6.57	53.72	5.20
5C-6	Inlet	29.18	21.54	43.75	5.53
	Outlet	37.33	5.44	53.09	4.14
5C-7	Inlet	29.35	22.06	42.72	5.87
	Outlet	38.39	5.85	51.26	4.50
6A-3	Inlet	28.51	17.81	46.92	6.76
	Outlet	34.45	6.32	53.72	5.51
6A-4	Inlet	28.04	17.59	48.57	5.81
	Outlet	32.16	8.21	55.24	4.40

Note: [a] Baseline test bypassing reformer.

Table 6-43: Week 2 Tar Reforming Test Dry N_2-Free Product Gas Composition

EERC Test Designation	Sample Location	H_2, %mol	CO, %mol	CO_2, %mol	CH_4, %mol
Test 2A[a]	Inlet	34.03	16.19	44.57	5.21
	Outlet	33.77	15.61	45.93	4.69
Test 2B[a]	Inlet	34.32	16.52	43.90	5.26
	Outlet	34.75	13.56	47.04	4.65
Test 3A	Inlet	35.87	16.34	42.14	5.65
	Outlet	41.63	5.31	48.48	4.58
Test 3B	Inlet	36.20	16.22	41.94	5.64
	Outlet	41.62	5.96	47.64	4.78
Test 4A	Inlet	37.09	15.99	40.01	6.91
	Outlet	44.05	3.31	47.60	5.03
Test 4B	Inlet	36.87	17.26	40.03	5.85
	Outlet	43.40	5.25	46.57	4.78
Test 5A	Inlet	31.81	17.30	46.51	4.38
	Outlet	38.96	4.51	52.92	3.61
Test 5B	Inlet	32.33	17.44	45.04	5.19
	Outlet	38.93	5.27	51.46	4.35
Test 6A	Inlet	30.38	16.35	44.61	8.66
	Outlet	36.96	6.50	49.48	7.06
Test 6B	Inlet	30.82	16.57	44.50	8.11
	Outlet	38.64	3.81	51.19	6.36
Test 7A	Inlet	29.91	15.10	44.44	10.55
	Outlet	36.91	3.79	50.89	8.42
Test 7B	Inlet	29.00	14.49	44.22	12.30
	Outlet	35.55	4.49	50.12	9.83
Test 8A	Inlet	27.45	14.38	43.16	15.01
	Outlet	33.69	5.87	48.62	11.83
Test 8B	Inlet	28.93	15.34	42.30	13.43
	Outlet	34.57	6.48	47.99	10.96
Test 10B	Inlet	33.77	16.52	40.98	8.73
	Outlet	39.71	7.09	46.27	6.92

Note: [a] Baseline test bypassing reformer.

Table 6-44: EERC Week 1 Reformer Condensate Sample Organics

EERC Test Designation	Inlet			Outlet		
	Sample Date	Sample Time	TOC (mg/L)	Sample Date	Sample Time	TOC (mg/L)
2-1/3A-1[a]	6/24	16:25	508	6/24	20:30	1540
3A-2/4B-1	6/25	22:11	217	6/25	23:10	290
5C-6	6/27	22:15	100	6/27	21:05	100
6A-3	6/29	7:40	78.2	6/29	0:54	610

Note: [a] Baseline test bypassing reformer.

Table 6-45: EERC Week 2 Reformer Condensate Sample Organics

EERC Test Designation	Inlet			Outlet		
	Sample Date	Sample Time	TOC (mg/L)	Sample Date	Sample Time	TOC (mg/L)
Test 2A[a]	9/9	18:40	1370			
Test 2B[a]	9/10	1:21	1030	9/10[b]	22:25	860
Test 3A	9/10	9:33	1220	9/10	7:34	60
Test 3B	9/10	13:10	980			
Test 4A	9/10	19:48	538	9/10	21:30	70
Test 4B	9/11	2:38	647	9/11	1:30	70
Test 5A	9/11	11:13	499	9/11	11:30	30
Test 5B	9/11	19:58	1010			
Test 6A	9/12	4:41	540			
Test 6B	9/12	10:09	624			
Test 7A	9/12	18:45	491	9/12	18:35	30
Test 7B	9/13	0:11	457	9/13	1:30	90
Test 8A	9/13	10:04	391			
Test 8B	9/13	14:50	593	9/13	17:35	310
Test 10B	9/13	0:00	573			

Notes:
[a] Baseline test bypassing reformer.
[b] Date is inconsistent with data. 9/9 is assumed the correct date.

Table 6-46: EERC Week 2 Tar Reforming Bomb Sample Results

	Test 4A: Low Flow – Average Temp		Test 8A: High Flow – Average Temp	
	Inlet	Outlet	Inlet	Outlet
Byproduct Species	Grains[a]	Grains[a]	Grains[a]	Grains[a]
Methanol	7.738	1.779	0.997	1.004
Benzene	0.378	0.256	0.276	0.242
Toluene	Trace	0.008	0.000	0.000
Naphthalene	0.139	0.074	0.090	0.120
2-Me-Naphthalene	0.000	0.000	0.000	0.000
1-Me-Naphthalene	0.000	0.000	0.000	0.000
Biphenyl	Trace	Trace	Trace	0.000
Acenaphthylene	0.019	Trace	0.009	0.009
Acenaphthene	0.000	0.000	Trace	Trace
Fluorene	Trace	Trace	Trace	0.000
Phenanthrene	0.022	0.000	0.025	0.012
Anthracene	0.000	0.000	Trace	0.000
2-Phenyl Naphthalene	0.000	0.000	0.000	0.000
Fluoranthene	Trace	Trace	0.020	Trace
Pyrene	Trace	Trace	0.015	Trace
Triphenylenre	Trace	Trace	Trace	Trace
Total Tar, mg	8.295	2.117	1.432	1.387
Sample Volume, dscf[b]	0.31	0.31	0.31	0.31
Total Tar Concentration, gr./dscf	27	6.8	4.6	4.5

Notes:

[a] Data reported by EERC in mg and converted to grains.

[b] Data reported by EERC in dry Nm^3 and converted to dry standard cubic feet (dscf).

6.1.4.3 *Reported Conclusions*

The EERC generally concluded that the data presented from the 2 weeks of testing show that the tar reforming catalyst has the potential to reduce tars in the syngas with the catalyst beds operating in the range of 670 to 840°F. Most commercial tar-cracking catalysts operate at much higher temperatures. Some of the tar collection methods made it difficult to specifically quantify the level of tar reduction across the bed as a whole or for individual species. (Appendix D, page 137)

Product Gas Composition

The EERC concluded the following comparing product gas compositions for Week 1 (Appendix D, page 111) and Week 2 (Appendix D, page 123).

The reduction in carbon monoxide concentrations, together with an increase in hydrogen and carbon dioxide showed that the catalyst is promoting the WGS shift reaction. The EERC also presented data showing a reduction in product gas water content downstream of the catalyst beds, further supporting this conclusion. For both Week 1 and Week 2 testing, the EERC noted that removal of carbon monoxide was greater than would be expected by WGS reaction alone. However, the lack of detailed information on the catalyst did not allow the EERC to explain this observation.

The EERC also observed that methane concentrations showed no significant change as a result of the catalyst beds and concluded that the catalyst does not promote either methanation or steam reforming (of methane).

Condensate and Tar Sampling Results

Table 6-44 shows the Week 1 upstream and downstream condensate TOC results, which indicate an increase condensate TOC after the catalyst beds. The EERC were unable to make any conclusions from these data, but made the following statement:

“The outlet TOC was significantly higher than the inlet during both the baseline testing and the time periods when the TCCB was online. It is also possible (as indicated by Test 6A-3) that the catalyst is breaking down larger organic structures into smaller water-soluble compounds, which would further confound the results of this analysis.” (Appendix D, page 116)

The EERC also provided the GC/MS results of the combined liquid and solid samples collected in the condensers for Week 1. The EERC made the following conclusions:

“The total tars in both the liquid and solid samples were shown to be significantly reduced from the baseline run. Of great significance is the demonstrated reduction of naphthalene during the testing. For both the solid and liquid samples, naphthalene was observed to be reduced by a factor of 10 from baseline testing to the final test runs…These results also confirm that sampling of quench water alone is not adequate to quantify the levels of tar in the syngas or reduction across the TCCB (sic.: tar reformer), because these levels are an order of magnitude lower than the levels found in the solid samples.” (Appendix D, page 116)

Table 6-45 shows the Week 2 upstream and downstream condensate TOC results. The EERC noted that total reduction in TOC ranges from 16.5% to as high as 95.1% and this outcome supports the conclusion that the TCCB has been effective in reducing tar. (Appendix D, page 134)

Table 6-46 shows the Week 2 tar reforming bomb sample results. The EERC did not draw any conclusions from the bomb sample results, but notes that the results showed tar-reducing trends.

6.2 Emery Energy Company

This section summarizes the data and conclusions for plasma reforming tests conducted by Emery, with details provided in the facility test report (Appendix G). As discussed in Section 4, the purpose of tar reforming is to convert organics into additional hydrogen and carbon monoxide. Emery owns and operates a gasification demonstration plant in Laramie, Wyoming, and testing was conducted at this plant to demonstrate plasma tar reforming.

6.2.1 Test Description

Gasification and product gas reforming tests with coal and coal/biomass blended feedstocks were conducted at Emery's demonstration plant during the weeks of June 17 and July 8, 2013. The plant consists of a fixed-bed gasifier with a plasma tar reformer, as shown on Figure 6-5. The test plan, provided in Table 6-47, aimed to evaluate the reformer at steady-state, with product gas generated from each of six feedstocks/feedstock blends.

Table 6-47: Emery Test Plan

Test Identifier	Feed Mixture Ratios	Run Duration (hrs)	Operational State	Fuel Feed Rate (lb/hr)
Test 1 Startup	100 wt% PRB coal	12	Startup and lineout	0
Test 1	100 wt% PRB coal	37	Test at steady-state operation	250
Feedstock Transition	70 wt% PRB coal/30 wt% raw wood	12	Transition and lineout	250
Test 2	70 wt% PRB coal/30 wt% raw wood	34	Test at steady-state operation	250
Test 3 Startup	30 wt% PRB coal/70 wt% raw wood	12	Startup and lineout	0
Test 3	30 wt% PRB coal/70 wt% raw wood	37	Test at steady-state operation	250
Feedstock Transition	100 wt% raw wood	12	Transition and lineout	250
Test 4	100 wt% raw wood	34	Test at steady-state operation	250
Test 5 Startup	50 wt% PRB coal/50 wt% railroad	12	Startup and lineout	0
Test 5	50 wt% PRB coal/50 wt% railroad	37	Test at steady-state operation	250
Feedstock Transition	100 wt% railroad ties	12	Transition and lineout	250
Test 6	100 wt% railroad ties	34	Test at steady-state operation	250

Note: All PRB coal referenced in the table is from Black Thunder mine in Wyoming.

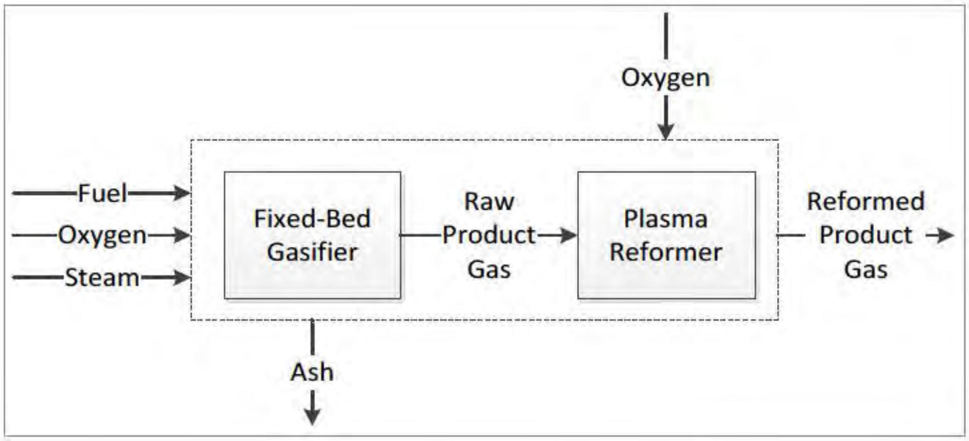


Figure 6-5: Simplified Emery Schematic

Gasifier Operations – Emery's fixed-bed gasifier was an ASTM International (ASTM) Section 1, Division VIII code pressure vessel rated for 125 psig, with the feed inlet on the top and the ash removal on the bottom. The product gas exit was located in the upper third of the vessel. The gasifier was heated during startup using a burner on the bottom third of the vessel. There was also an ash grate and a feed system for oxygen and steam inside on the bottom head of the vessel. The plan was to operate the gasifier at temperatures ranging from 1,500 to 1,800°F in the lowest portions of the bed and exit gas temperatures ranging from 400 to 800°F. Oxygen was to be fed to provide 0.55 pound of oxygen per pound of coal and 0.33 pound of oxygen per pound of biomass. Steam was to be fed to maintain 0.70 pound of steam per pound of fuel. The system has no particulate or tar control systems upstream of the plasma reformer.

Reformer Operations – The Ceramatec proprietary tar reforming system was configured to create a plasma in three successive reactive zones. Plasma was created between knife-type GlidArc electrodes arranged symmetrically about the centerline of the reformer section. Product gas was forced through the plasma zone through orifice plates, which serve as a mounting for the electrodes. Oxygen was introduced above the first set of electrodes to re-heat the product gas bringing the reformer temperature into optimum range. After each plasma section, the gas was sent through a packed bed filled with a nickel-based oxygen buffer.

Product Gas Sampling and Analysis – Product gas at the reformer inlet, also referred to as the gasifier outlet, was monitored with a NOVA continuous emission monitoring system (CEMS) for hydrogen, oxygen, methane, carbon monoxide, and carbon dioxide on a dry basis. Product gas at the reformer outlet was monitored by a bank of CEMs, which also included hydrogen, oxygen, methane, carbon monoxide, and carbon dioxide on a dry basis, but operated and logged independent of Emery's NOVA CEMS.

Multiple integrated gas samples were extracted concurrently at the reformer inlet and at the reformer outlet for each test. Each sample period represents a sample "run" of the corresponding test condition. Integrated gas samples were collected for three types of analysis: tar analysis samples collected in impingers, product gas analysis samples collected in bags, and condensate TOC samples collected in bottles. Emery's test report focused discussions on tar analysis, though other analyses results are included in appendices to their report.

Tar analysis samples were extracted through an in-duct filter to exclude any tars condensed at the sample location. Samples could not be drawn isokinetically at these locations; therefore, only gaseous species analysis was performed, eliminating this potential bias. Samples were sparged through isopropyl alcohol to limit undesirable reactions in the collection impingers, and were subsequently metered through dry gas meters. The sampling train was subsequently recovered and analyzed gravimetrically for semivolatile tars and moisture, and chemically for speciated composition. Chemical analyses included quantitative analysis for toluene and naphthalene by GC/flame ionization detector (FID) and qualitative analysis for a broad range of tar components by GC/MS.

6.2.2 Test Results

Due to operational difficulties with both the reformer and the gasifier, only two feedstocks/feedstock blends were tested: 100 wt% PRB coal and 70 wt% PRB coal/30 wt% raw wood. PRB coal was obtained from Arch Coal's Black Thunder mine. Emery sourced wood from a local wood processor; samples were identified as "pine." These tests were completed during the week of June 17, 2013. Operations during the week of July 8, 2013 failed to achieve steady-state test conditions, as detailed in Appendix G, and further runs were cancelled.

A variety of operational difficulties were encountered while running Emery's combined gasifier/reformer test facility. These difficulties affected system stability and certain parameters such as the oxygen-to-fuel ratio and the steam-to-fuel ratio. Large variability in process parameters were encountered during the course of integrated sampling of the reformer inlet and reformer outlet for each feedstock/feedstock blend. As a result, test conditions varied from run to run within each test. Reported test conditions must be treated with caution with respect to the variety of conditions encountered, as detailed in Appendix G.

6.2.2.1 *Feedstock Analysis*

The feedstock analysis consisted of proximate, ultimate, and heating value analyses. Table 6-48 provides the feedstock analysis for the as-fed 100 wt% PRB coal and 70 wt% PRB coal/30 wt% raw wood fuels. Because the coal and raw wood were not blended prior to feeding the gasifier, samples of "blended" feed could not be obtained. The table values were calculated based on the actual proportion of each feedstock that was fed into the gasifier and the as-fed analysis of each feedstock.

Table 6-48: Emery Feedstock and Feedstock Blend Fuel Analysis

Proximate, Ultimate, and Heating Value Analyses of Blended Feeds
Facility: Emery, Technology: Plasma Reformer, Coal: PRB Sub-bituminous

Feedstock Type and Analysis	Test Cases	
Coal Type	PRB Coal[a]	PRB Coal[a]
Biomass (wt%)	Coal Only	30
Proximate Analysis	wt%	
Moisture	26.69	21.57
Volatile Matter	33.40	45.61
Fixed Carbon	34.40	28.78
Ash	5.51	4.04
Ultimate Analysis	wt%	
Coal Type	PRB Coal[a]	PRB Coal[a]
Biomass (wt%)	Coal Only	30
Ultimate Analysis	wt%	
O	12.25	19.74
S	0.35	0.26
Moisture	26.69	21.57
Ash	5.51	4.04
Heating Valve, HHV (Btu/lb)	8,857	8,479

Note: [a] Typical analysis received from Arch Coal for Black Thunder mine.

6.2.2.2 *Gasifier and Reformer Operations*

Operating parameters for the gasifier were presented by Emery representing each fuel tested in an aggregate, not segregated by each integrated sampling run. Table 6-49 provides a summary for key gasifier and reformer operating parameters, representing 165 minutes of operation during 100% PRB coal tests and 390 minutes for 70 wt% PRB coal/30 wt% raw wood tests. Although no data were tabulated for 70 wt% PRB coal/30 wt% raw wood feed rate in lb/hr, Emery separately reported this feed rate as 250 lb/hr in Appendix G. Neither gasifier bed temperatures nor gasifier exhaust temperatures were summarized in Emery's test report. The range of the data reported are indicative of unstable operations, with respect to many operating parameters, notably: gasifier pressure, gasifier oxygen flow, and gasifier steam flow. The summary data presented by Emery fall outside of a typical +/- 10% operating window for steady-state operations.

Operations were stopped twice for reformer cleanout during these tests, about 3 hours prior to the first run on the 100 wt% PRB coal test and after the second run on the 100 wt% PRB coal test. Blockage in the reformer was thought to be causing increased pressure in the gasifier. Emery attributed this blockage to particle entrainment, causing pressure drops of up to 10 psi across the first section of the reformer. The increased pressure in the gasifier led to problems feeding steam and oxygen to the gasifier.

Table 6-49: Emery Operating Parameters

Operating Parameters for Emery Tests
Facility: Emery/Technology: Plasma Reformer/Coal: PRB Sub-bituminous

	100% PRB Coal Test			30% Raw Wood Test		
Parameters	**Minimum**	**Maximum**	**Average**	**Minimum**	**Maximum**	**Average**
Gasifier Fuel Feed (lb/hr)	211.65	211.65	211.65	Not provided	Not provided	Not provided
Gasifier Pressure (psia)	7.39	13.86	11.41	3.27	20.01	14.56
Gasifier O_2 Flow (scfm)	19.76	20.79	20.28	0.17	21.19	18.89
Steam Flow (scfm)	-1.66	208.87	32.13	-1.47	40.15	2.91
Reformer O_2 Flow (scfm)	13.07	14.13	13.59	10.62[a]	17.41[a]	13.02[a]
Reformer Outlet Temperature (°F)	1,356	1,495	1,465	1243[a]	1607[a]	1498[a]
Reformer Pressure (psia)	11.88	13.68	12.88	11.38[a]	13.68[a]	12.01[a]

Note: [a] The 70 wt% PRB coal/30 wt% raw wood reformer operating conditions represented 720 minutes of operation, a significantly longer duration than represented by associated gasifier operating conditions.

Product gas flow entering and exiting the reformer is summarized in Table 6-50, with the same reference periods used for the gasifier and reformer operating parameters. Flow recorded for the 70 wt% PRB coal/30 wt% raw wood test at the reformer inlet location do not appear consistent with observed gasifier operations with the attendant operating parameters. This discrepancy is likely due to clogged differential pressure taps on the reformer inlet flow meter.

Table 6-50: Product Gas Flow through the Reformer

Product Gas Flows for Emery Tests
Facility: Emery/Technology: Plasma Reformer/Coal: PRB Sub-bituminous

	100% PRB Coal Test			30% Raw Wood Test		
Flow	**Minimum**	**Maximum**	**Average**	**Minimum**	**Maximum**	**Average**
Reformer Inlet Flow (scfm)[a]	462.13	685.83	573.86	87.66	128.26	113.40
Reformer Outlet Flow (scfm)[a]	518.54	801.62	620.88	381.78	754.66	585.92

Note: [a] Reported by Emery with units scfh in tabulations and with units of scfm on figures. Units of scfm are consistent with other tabulated flows and with the reported fuel inputs, and are presumed correct.

6.2.2.3 *Product Gas Composition*

Composition of the product gas entering and exhausting the reformer was monitored on a dry basis with CEM. CEM data were logged to a data acquisition system and reported for each integrated sample run. Normalized product concentrations at the inlet and outlet of the reformer are provided in Table 6-51 for 100% PRB coal and 70 wt% PRB coal/30 wt% raw wood runs, respectively, on a dry basis. Oxygen was not detected in either reformer inlet or outlet gases. Nitrogen was not monitored.

Table 6-51: Emery Dry and N_2- Free Product Gas Composition at Reformer Inlet and Outlet

	100 wt% PRB Coal					
	Run 1		Run 2		Run 3	
Species	Ref Inlet	Ref Outlet	Ref Inlet	Ref Outlet	Ref Inlet	Ref Outlet
H_2 (%mol)	22.53	31.46	38.51	29.75	33.62	30.50
CO (%mol)	36.55	39.07	34.90	35.38	33.52	29.94
CO_2 (%mol)	38.50	26.34	24.41	32.29	30.29	37.17
CH_4 (%mol)	2.43	3.13	2.18	2.59	2.57	2.38
H_2:CO Molar Ratio	0.62	0.81	1.10	0.84	1.00	1.02
Product Gas Heating Value, HHV dry basis (Btu/scf)	216	260	260	237	243	220
	70 wt% PRB Coal/30 wt% Raw Wood					
Species	Run 4		Run 5		Run 6	
	Ref Inlet	Ref Outlet	Ref Inlet	Ref Outlet	Ref Inlet[a]	Ref Outlet
H_2 (%mol)	39.57	36.68	37.57	30.75		30.62
CO (%mol)	43.14	39.07	45.69	44.25		38.80
CO_2 (%mol)	15.17	21.80	14.77	22.98		28.40
CH_4 (%mol)	2.11	2.44	1.97	1. 93		2.19
H_2:CO Molar Ratio	0.92	0.94	0.82	0.69		0.79
Product Gas Heating Value, HHV dry basis (Btu/scf)	289	270	290	263		247

Note: [a] Sampling failure on H_2 and CO_2 CEM.

Integrated samples of product gas were collected at the reformer inlet and reformer outlet. A summary of the integrated sampling results for moisture, gravimetric tars, and for toluene and naphthalene by GC/FID are provided in Table 6-52. GC/FID results are provided to represent chemical speciation. GC/MS results indicated similar trends for a variety of semivolatile organic compounds (SVOCs), but were not calibrated to a reference gas; these are omitted here, but presented on an area-count basis in Appendix G.

Table 6-52: Summary of Integrated Sampling Results at the Reformer Inlet and Outlet

Analysis of Product Gas at Reformer Inlet and Outlet Facility: Emery, Technology: Plasma Reformer, Coal: PRB Sub-bituminous						
100 wt% PRB Coal Test						
	Run 1		Run 2		Run 3	
Species	Ref Inlet	Ref Outlet	Ref Inlet	Ref Outlet	Ref Inlet	Ref Outlet
Moisture (%mol)	18.9	47.7	22.0	55.7	42.6	54.2
Gravimetric Tars[a] (grains/wscf)	29.8	3.61	98	3.48	46.9	0.98
C_7H_8[b] (Wet ppbm)	15.2	0.29	2.24	0.00	9.7	0.00
$C_{10}H_8$[b] (Wet ppbm)	8.22	0.00	0.922	0.266	2.80	0.129
70 wt% PRB Coal/30 wt% Raw Wood						
	Run 4		Run 5		Run 6	
Species	Ref Inlet	Ref Outlet	Ref Inlet	Ref Outlet	Ref Inlet	Ref Outlet
Moisture (%mol)	18.1	42.6	30.6	27.0	11.6	34.4
Gravimetric Tars[a] (grains/wscf)	54.4	2.16	38.2	1.15	104	4.01
C_7H_8[b] (Wet ppbm)	0.684	0.300	0.00	0.686	1.64	0.00
$C_{10}H_8$[b] (Wet ppbm)	0.57	0.388	0.00	0.356	0.647	0.246

Notes:

[a] Reported in units of grams/dscm; converted to grains/wscf for consistency within this report.

[b] Reported in units of micrograms/dscm; converted to wet ppbm for consistency within this report.

dscm = dry standard cubic meter

ppbm = parts per billion by mole

wscf = wet standard cubic feet

6.2.2.4 *Gasifier Residue Sample Analysis*

The primary focus of Emery testing was the effectiveness of the reformer. As a result, no evaluation was made of the characteristics of gasifier residues.

6.2.3 Reported Conclusions

Emery completed gasification and reforming tests feeding two fuels: 100 wt% PRB coal and 70 wt% PRB coal/30 wt% raw wood and presented the following conclusions in their test report (Appendix G):

- Tar compounds were greatly reduced across the reformer based on gravimetric tar analysis and based on chemical tar analysis. Gravimetric tar analysis indicate a reduction in tar concentration of 93% for the 100 wt% PRB coal test and 95% for the 70 wt% PRB coal/30 wt% raw wood test. Chemical tar analysis by GC/MS indicate an average reduction of tar concentration of 92% for the 100 wt% PRB coal test and 70% for the 70 wt% PRB coal/30 wt% raw wood test.

- The lack of particulate control upstream of the reformer impacted operational reliability. During the second week of attempted testing, operation with damaged plasma electrodes in the first stage of reforming exacerbated plugging and pressure increases. This is further discussed in Section 7.

6.3 NCCC

This section summarizes data and conclusions for gasification testing conducted at the NCCC, with details provided in the CCAT/ARCADIS facility test report (Appendix F). NCCC is part of the Power Systems Development Facility, located in Wilsonville, Alabama and is operated by Southern Company Services, Inc. (a division of the Southern Company).

6.3.1 Test Description

Gasification testing was conducted at NCCC from September 5 to September 17, 2012. As shown in Table 6-53, the test plan consisted of gasifying coal only and six coal/biomass feedstock blends over approximately 200 hours.

Table 6-53: NCCC Test Plan

Test Identifier	Feed Mixture Ratios	Run Duration (hrs)	Operational State
1	Coal only	24	Transition to oxygen-blown
2	Coal only	4	Steady state
3	Coal + 10% torrefied biomass	24	Steady state
4	Coal + 20% torrefied biomass	24	Steady state
5	Coal + 30% torrefied biomass	24	Steady state
6	Coal + 10% raw biomass	26	Transition to raw pine
7	Coal + 10% raw biomass	24	Steady state
8	Coal + 20% raw biomass	24	Steady state
9	Coal + 30% raw biomass	24	Steady state

Actual testing consisted of three coal-only runs, five runs with torrefied biomass/coal feedstock blends, and three runs with raw biomass/coal feedstock blends. For the feedstock blends, testing was performed using PRB sub-bituminous coal from Arch Coal's Black Thunder mine and southern pine from New Biomass Energy, LLC. Both raw and torrefied southern pine were used, and both were pelletized by New Biomass Energy.

Gasifier Operations – NCCC operates a TRIG™, which was designed by KBR to operate as a fluid-bed combustor or as a gasifier in either air-blown or oxygen-blown mode. For testing, NCCC operated the TRIG™ in oxygen-blown gasification mode at approximately 164 psig, with the average temperature of product gas exiting the gasifier at 1,700°F. A simplified facility schematic is shown on Figure 6-6.

In oxygen-blown mode a significant portion of the air (which is typically supplied as the oxidant) was replaced by pure oxygen. In addition, nitrogen was used in the gasification process at NCCC as a conveying gas in the feed systems, for fluidization of solids through the system, and for instrumentation purging. As a result, nitrogen was present in the product gas exiting the gasifier. For the ash entrained in the product gas, the coarse ash was recycled through the gasifier, and the fine ash was filtered through a PCD. A slipstream of particulate-free product gas was recycled at NCCC to aid in coarse ash transport through the system.

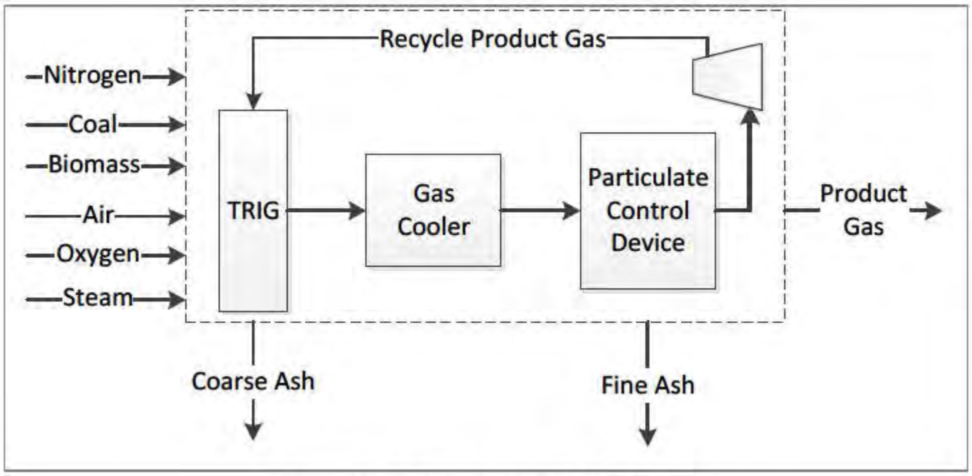


Figure 6-6: Simplified NCCC Schematic

Feed System – The feed capacity of the TRIG™ at NCCC is 50 tpd, which is approximately 10 times the size of the TRDU at EERC. NCCC operated two separate feed systems for injecting biomass and coal, respectively. The biomass feed system consists of a lock hopper with two pressurized vessels, and a variable speed mechanical rotary device for dispensing biomass into the discharge line. The coal feed system is a proprietary lock-hopper design that has no moving parts and uses conveying gas (nitrogen) to control the feed rate. Features of this feeder are provided in Appendix F. Each feed type (coal and biomass) was fed into the gasifier separately at rates controlled by the operator. The targeted feed rate was 3,000 lb/hr; the targeted feed mixture ratios and run durations are provided in Table 6-53.

Sampling and Analysis – Extensive solids and gas sampling and analysis were performed during gasification. Product gas composition was monitored continuously with online gas analyzers for seven constituents (carbon monoxide, hydrogen, carbon dioxide, nitrogen, methane, ethylene, and argon). Product gas flow was also measured continuously. Trace species in the wet product gas were measured via Draeger tubes, impingers, and condensate collected once per test run. Feedstock and ash samples were collected four times daily during the test and analyzed for proximate analysis, ultimate analysis, heating value, ash metals, and particle size distribution. LOI was also measured of the coarse and fine ash samples. These results are summarized in Section 6.3.2 below and detailed in Appendix F.

6.3.2 Test Results

For this summary, product gas composition values were averaged over a steady-state period. When only point values were available (i.e., for trace species samples that were collected only once per test run), the values are used to represent the entire steady-state period. In addition, although three coal-only tests were run, only one is presented in this summary to serve as the coal-only baseline. Time-dependent data, including the three coal-only test runs, are included in Appendix F.

6.3.2.1 *Feedstock Analysis*

The feedstock analysis consisted of a proximate, ultimate, heating value, and ash analyses. Table 6-54 and Table 6-55 provide the feedstock analysis for the as-fed raw and torrefied biomass feedstock blends, respectively. Because the coal and biomass were not blended prior to entering the gasifier, samples of "blended" feed could not be obtained. The values provided in the tables below were calculated based on the actual proportion of each feedstock that was fed into the gasifier and the as-fed analysis of each feedstock. The tables also provide the feed mixture ratios tested. Discrepancies between the planned and actual test ratios resulted from feeder control system interlocks and the averaging of the measured feed rates of each feeder. These differences are discussed in detail in Appendix F. The ash oxides presented in the tables below for the ash analysis are important to how the ash behaves within gasifier (e.g., ash agglomeration temperature); additional reported oxides are grouped as "other." The complete feedstock analyses are provided in Appendix F.

Table 6-54: NCCC Feedstock Analyses of Coal Only and Coal and Raw Southern Pine Blends

Proximate, Ultimate, Heating Value and Ash Analyses of Southern Pine (Raw) and Coal Blended Feedstocks
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous

Analyses	**Biomass Percent for each Test Case by Weight (%)**			
	Coal Only	**11.7**	**19.8**	**28.3**
Proximate Analysis	wt%			
Moisture	17.96	16.79	15.99	15.13
Volatile Matter	36.06	40.50	43.56	46.79
Fixed Carbon	37.66	35.23	33.57	31.81
Ash	8.33	7.47	6.89	6.27
Ultimate Analysis	wt%			
C	54.46	53.83	53.40	52.94
H	3.76	3.95	4.08	4.22
N	0.89	0.80	0.74	0.68
O	14.29	16.87	18.64	20.51
S	0.32	0.29	0.27	0.24
Moisture	17.96	16.79	15.99	15.13
Ash	8.33	7.47	6.89	6.27
Heating Value, HHV (Btu/lb)	9,294	9,191	9,120	9,045
Ash Analysis as Oxides	wt%			
CaO	21.05	21.15	21.23	21.33
Fe_2O_3	5.82	5.87	5.92	5.97
MgO	4.55	4.58	4.61	4.64
P_2O_5	1.40	1.43	1.46	1.49
K_2O	0.77	0.83	0.88	0.95

Proximate, Ultimate, Heating Value and Ash Analyses of Southern Pine (Raw) and Coal Blended Feedstocks
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous

	Biomass Percent for each Test Case by Weight (%)			
Analyses	**Coal Only**	**11.7**	**19.8**	**28.3**
SiO_2	38.68	38.55	38.44	38.30
Na_2O	1.52	1.51	1.50	1.49
Other	26.20	26.07	25.97	25.84

Note: Values were calculated based on actual percentages fed into the gasifier and the as-fed analysis of each feedstock.

Table 6-55: NCCC Feedstock Analyses of Coal Only and Coal and Torrefied Southern Pine Blends

Proximate, Ultimate, Heating Value and Ash Analyses of Southern Pine (Torrefied) and Coal Blended Feedstocks
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous

	Biomass Percent for each Test Case by Weight (%)					
Analyses	**Coal Only**	**15.7**	**17.3**	**19.3**	**20.0**	**28.7**
Proximate Analysis	wt%					
Moisture	17.96	16.37	16.20	16.01	15.93	15.05
Volatile Matter	36.06	39.33	39.67	40.07	40.23	42.04
Fixed Carbon	37.66	36.80	36.71	36.60	36.56	36.08
Ash	8.33	7.51	7.42	7.32	7.28	6.83
Ultimate Analysis	wt%					
C	54.46	54.79	54.82	54.86	54.88	55.06
H	3.76	3.95	3.97	3.99	4.00	4.10
N	0.89	0.81	0.80	0.79	0.79	0.75
O	14.29	16.30	16.51	16.76	16.85	17.97
S	0.32	0.28	0.28	0.27	0.27	0.25
Moisture	17.96	16.37	16.20	16.01	15.93	15.05
Ash	8.33	7.51	7.42	7.32	7.28	6.83
Heating Value, HHV (Btu/lb)	9,294	9,345	9,351	9,357	9,360	9,388
Ash Analysis as Oxides	wt%					
CaO	21.05	21.24	21.26	21.28	21.29	21.42
Fe_2O_3	5.82	5.79	5.78	5.78	5.77	5.75
MgO	4.55	4.55	4.55	4.55	4.55	4.55
P_2O_5	1.40	1.46	1.47	1.48	1.48	1.52
K_2O	0.77	1.04	1.07	1.11	1.12	1.30
SiO_2	38.68	38.57	38.56	38.54	38.54	38.46
Na_2O	1.52	1.53	1.54	1.54	1.54	1.55
Other	26.20	25.82	25.78	25.72	25.70	25.44

Note: Values were calculated based on the actual percentage fed and the as-fed analysis of each feedstock.

6.3.2.2 *Gasifier Operations and Product Gas Composition*

Approximately 200 hours of testing were completed with the operating system mainly functioning properly. As stated above, product gas composition was monitored continuously with online gas analyzers for seven constituents. Table 6-56 and Table 6-57 provide the steady-state product gas compositions for the raw and torrefied biomass blends, respectively. Dry gas composition data were obtained from GC samples collected between the gas cooler and the PCD (shown on Figure 6-6). The product gas composition was calculated on a nitrogen free and dry (moisture-free) basis. The TRIG™ product gas flow rates averaged 18,623 lb/hr for the raw biomass cases and 19,766 lb/hr for the torrefied biomass cases and represent net gas flow after product gas recycle. Additional details regarding flow rates and product gas composition are provided in Appendix F.

Table 6-56: NCCC Analysis of Product Gas Composition and Heating Values for Coal Only and Coal and Raw Southern Pine Blends

Dry and N_2-Free Product Gas Composition and Heating Value for Southern Pine (Raw) and Coal Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

Duration, Composition, and Heating Values	Biomass Percent for each Test Case by Weight (%)			
	Coal Only	11.7	19.8	28.3
Steady-state Duration (hrs)	4.0	4.2	4.5	4.0
Dry and N_2-Free Product Gas Composition	(%mol)			
H_2	33.5	32.6	32.0	31.0
CO	23.1	23.7	23.4	21.7
CO_2	39.5	39.1	39.5	41.7
CH_4	3.9	4.7	5.1	5.6
H_2:CO Molar Ratio	1.45	1.38	1.37	1.43
Product Gas Heating Value, HHV dry basis (Btu/scf)	105	110	112	107
Product Gas Energy Flow, HHV dry basis (MMBtu/hr)	21.44	22.94	23.02	21.27

Table 6-57: NCCC Analysis of Product Gas Composition and Heating Values for Coal Only and Coal and Torrefied Southern Pine Blends

Dry and N_2-Free Product Gas Composition and Heating Value for Southern Pine (Torrefied) and Coal Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

Duration, Composition, and Heating Values	Biomass Percent for each Test Case by Weight (%)					
	Coal Only	15.7	17.3	19.3	20.0	28.7
Steady-state Duration (hrs)	4.0	5.0	4.2	5.5	4.2	3.6
Dry and N_2-Free Product Gas	(%mol)					
H_2	33.5	35.2	36.1	33.2	33.3	32.9
CO	23.1	20.8	21.4	23.0	22.9	24.5
CO_2	39.5	39.8	38.5	39.3	39.5	37.4

Dry and N_2-Free Product Gas Composition and Heating Value for Southern Pine (Torrefied) and Coal Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

Duration, Composition, and Heating Values	Biomass Percent for each Test Case by Weight (%)					
	Coal Only	15.7	17.3	19.3	20.0	28.7
CH_4	3.9	4.2	4.0	4.5	4.4	5.3
H_2:CO Molar Ratio	1.45	1.69	1.69	1.44	1.45	1.34
Product Gas Heating Value, HHV dry basis (Btu/scf)	105	106.	113	110	110	125
Product Gas Energy Flow, HHV dry basis (MMBtu/hr)	21.44	24.37	25.64	24.53	24.31	28.11

In addition to the constituents provided in the tables above, trace amounts of other organic and inorganic species were measured in the product gas as follows:

- Impinger samples were collected from the product gas to measure volatile and SVOCs (i.e., tars) and ammonia.
- Draeger tubes were used to measure trace amounts of ammonia, hydrochloric acid, and hydrogen cyanide.
- An online gas analyzer measured hydrogen sulfide concentrations.
- Condensate samples were collected to measure ammonia, TOC, and COD dissolved in condensed moisture from the product gas.

Results of the trace species analyses are provided in Table 6-58 and Table 6-59 for the raw and torrefied biomass and coal blends, respectively. All trace species samples were collected from only one coal-only test. This coal-only case is provided in both tables.

Table 6-58: NCCC Trace Species Analysis of Product Gas for Coal and Raw Southern Pine Blends

Analysis of Product Gas Samples from Gasification of Southern Pine (Raw) and Coal Feedstock Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

Duration and Analysis	Biomass Percent for each Test Case by Weight (%)			
	Coal Only	11.7	19.8	28.3
Steady-state Duration (hrs)	7.0	4.2	4.5	4.0
Impinger Samples, wet basis	ppmv			
NH_3	1,771	2,118	2,024	1,554
C_6H_6	922	765	615	994
$C_{12}H_{10}$	0	12	7	12
$C_{12}H_8$	0	22	16	34
$C_{16}H_{10}$ (fluroanthene)	9	6	2	3

Analysis of Product Gas Samples from Gasification of Southern Pine (Raw) and Coal Feedstock Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

	Biomass Percent for each Test Case by Weight (%)			
Duration and Analysis	**Coal Only**	**11.7**	**19.8**	**28.3**
$C_{13}H_{10}$	0	3	0	3
$C_{10}H_8$	113	430	873	1,564
$C_{14}H_{10}$	5	13	8	11
$C_{16}H_{10}$ (pyrene)	4	5	2	2
Draeger Tube Samples	ppmv			
NH_3	--	4,800	2,000	--
HCl	6	0	0	6
HCN	14	6	5	5
Online Gas Analyzer	ppmv			
H_2S	566	639	600	527
Condensate Samples	mg/L			
NH_3	7,070	5,860	4,960	4,390
COD	592	173	205	157
TOC	60	46	45	41

Note: -- = No sample collected

Table 6-59: NCCC Trace Species Analysis of Product Gas for Coal Only and Coal and Torrefied Southern Pine Blends

Analysis of Product Gas Samples from Gasification of Southern Pine (Torrefied) and Coal Feedstock Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

	Biomass % for each Test Case by Weight (%)			
Duration and Analysis	**Coal Only**	**17.3**	**20.0**	**28.7**
Steady-state Duration (hrs)	7.0	4.2	4.2	3.6
Impinger Samples, wet basis	ppmv			
NH_3	1,771	2,090	2,386	2,593
C_6H_6	922	831	548	790
$C_{12}H_{10}$	0	11	6	13
$C_{12}H_8$	0	24	12	31
$C_{16}H_{10}$ (fluroanthene)	9	5	3	3
$C_{13}H_{10}$	0	5	0	3
$C_{10}H_8$	113	138	247	976
$C_{13}H_{10}$	5	20	8	11
$C_{16}H_{10}$ (pyrene)	4	4	3	3
Draeger Tube Samples	ppmv			

Analysis of Product Gas Samples from Gasification of Southern Pine (Torrefied) and Coal Feedstock Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

	Biomass % for each Test Case by Weight (%)			
Duration and Analysis	**Coal Only**	**17.3**	**20.0**	**28.7**
NH_3	--	3,500	4,125	4,250
HCl	6	--	1	6
HCN	14	0	0	--
Online Gas Analyzer	ppmv			
H_2S	566	588	601	607
Condensate Samples	mg/L			
NH_3	7,070	5,600	5,560	5,970
COD	592	270	153	258
TOC	60	48	44	51

Note: -- = No sample collected

6.3.2.3 *Gasifier Residue Sample Analysis*

Several samples of gasification residues were collected during each test case. Coarse ash samples were collected from the bottom of the gasifier riser. The fine ash was collected from the PCD. The results for the average values of LOI, carbon content (from the ultimate analysis), and heating value for each test case are provided in Table 6-60 and Table 6-61 for the raw and torrefied cases, respectively. The coal-only test case has been included as baseline value in both tables. In addition, one coarse and one fine ash sample from five test cases were submitted for further analysis of metals, including heavy metals. The samples were analyzed using the TCLP and the leachate concentrations were compared to federal criteria to determine if the material would be considered hazardous under RCRA for disposal purposes. Results of the TCLP analyses are provided in Table 6-62 and compared to the hazardous characteristic criteria for the eight heavy metals regulated under RCRA to determine if the material would be considered hazardous for disposal purposes. As shown, all results are below the applicable regulatory levels. All solid sample results are provided in Appendix F.

Table 6-60: NCCC Analysis of Gasifier Residue (Ash) for Coal Only and Coal and Raw Southern Pine Blends

Analysis of Ash Samples from Gasified Southern Pine (Raw) and Coal Feedstock Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

	Biomass Percent for each Test Case by Weight (%)			
Duration and Analysis	**Coal Only**	**11.7**	**19.8**	**28.3**
Steady-state Duration (hrs)	4.0	4.2	4.5	4.0
Fine Ash Analysis				
LOI (wt%)	16.65	18.06	19.41	18.86
Carbon Content (wt%)	15.52	16.75	17.84	17.21
Heating Value, HHV (Btu/lb)	2,312	2,501	2,696	2,635

Analysis of Ash Samples from Gasified Southern Pine (Raw) and Coal Feedstock Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

Duration and Analysis	Biomass Percent for each Test Case by Weight (%)			
	Coal Only	11.7	19.8	28.3
Coarse Ash Analysis				
LOI	0.40	0.56	1.02	0.73
Carbon Content	0.32	0.03	0.38	0.03
Heating Value, HHV (Btu/lb)	50	39	207	39

Table 6-61: NCCC Analysis of Gasifier Residue (Ash) for Coal Only and Coal and Torrefied Southern Pine Blends

Analysis of Ash Samples from Gasified Southern Pine (Torrefied) and Coal Feedstock Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

Duration and Analysis	Biomass Percent for each Test Case by Weight (%)					
	Coal Only	15.7	17.3	19.3	20.0	28.7
Steady-state Duration (hrs)	4.0	5.0	4.2	5.5	4.2	3.6
Fine Ash Analysis						
LOI (wt%)	16.65	11.72	14.75	16.14	15.39	18.96
Carbon Content (wt%)	15.52	10.43	14.05	14.68	14.55	17.76
Heating Value, HHV (Btu/lb)	2,312	1,643	2,162	2,155	2,246	2,723
Coarse Ash Analysis						
LOI (wt%)	0.40	0.53	0.45	0.04	0.78	0.66
Carbon Content (wt%)	0.32	0.35	0.35	0.03	0.68	0.58
Heating Value, HHV (Btu/lb)	50	657	559	110	472	312

Table 6-62: NCCC TRIG™ Test TCLP Analysis of Ash Samples

TCLP Analysis of Ash Samples from Gasified Southern Pine (Raw), Southern Pine (Torrefied) and Coal Feedstock Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

Biomass Type, Duration, and Analysis	Biomass Percent for each Test Case by Weight (%)					RCRA MCLs
	Coal Only	11.7	28.3	17.3	28.7	
Biomass Type	None	Southern Pine Raw	Southern Pine Raw	Southern Pine	Southern Pine	NA
Steady-state Duration (hrs)	4.0	4.2	4.0	4.2	3.7	NA
Fine Ash TCLP Analysis, Metal	mg/L					RCRA MCLs
As	<0.25	<0.25	<0.25	0.06	0.056	5
Ba	4.5	4.7	13	10	13	100
B	10	11	15	14	14	NE

TCLP Analysis of Ash Samples from Gasified Southern Pine (Raw), Southern Pine (Torrefied) and Coal Feedstock Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

Biomass Type, Duration, and Analysis	Biomass Percent for each Test Case by Weight (%)					RCRA MCLs
	Coal Only	11.7	28.3	17.3	28.7	
Cd	<0.20	<0.20	<0.20	<0.20	<0.20	1
Cr	<0.25	<0.25	<0.25	<0.25	<0.25	5
Pb	<0.20	<0.20	<0.20	<0.20	<0.20	5
Hg	<0.020	<0.020	<0.020	<0.020	<0.020	0.2
Ni	<2.5	<2.5	<2.5	<2.5	<2.5	NE
Se	<0.25	<0.25	<0.25	<0.25	<0.25	1
Ag	<0.25	<0.25	<0.25	<0.25	<0.25	5
V	0.34	0.52	0.27	0.42	0.51	NE
Zn	<2.5	<2.5	<2.5	<2.5	<2.5	NE
Coarse Ash TCLP Analysis, Metal	mg/L					RCRA MCLs
As	<0.25	<0.25	<0.25	<0.25	<0.25	5
Ba	1.4	1.4	1.4	1.5	1.4	100
B	<7.5	<7.5	<7.5	<7.5	<7.5	NE
Cd	<0.20	<0.20	<0.20	<0.20	<0.20	1
Cr	<0.25	<0.25	<0.25	<0.25	<0.25	5
Pb	<0.20	<0.20	<0.20	<0.20	<0.20	5
Hg	<0.020	<0.020	<0.020	<0.020	<0.020	0.2
Ni	<2.5	<2.5	<2.5	<2.5	<2.5	NE
Se	<0.25	<0.25	<0.25	<0.25	<0.25	1
Ag	<0.25	<0.25	<0.25	<0.25	<0.25	5
V	<0.25	<0.25	<0.25	<0.25	<0.25	NE
Zn	0.2	0.3	0.34	0.29	0.37	NE

Note: NE = MCL not established

6.3.2.4 *Mass and Energy Balance*

As stated in the introduction to Section 6, a mass and energy balance was performed as a quality measure. The results are summarized below in Table 6-63 and Table 6-64 and provided in detail in the facility test report (Appendix F). Table 6-63 and Table 6-64 provide the mass inputs and outputs for the raw and torrefied biomass blend test cases, respectively. As shown in these tables, the mass balance closure for both the raw and torrefied biomass blends were all above 90%.

Table 6-63: NCCC Process Stream Data for Mass Balance Summary for Coal Only and Coal and Raw Southern Pine Blends

Process Stream Data for Southern Pine (Raw) and Coal Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous

Duration, Inputs, and Outputs	**Biomass Percent for each Test Case by Weight (%)**			
	Coal Only	**11.7**	**19.8**	**28.3**
Steady-state Duration (hrs)	4.0	4.2	4.5	4.0
Inputs	lb/hr			
Coal	3,400	3,552	3,386	2,784
Biomass	0	472	835	1,100
Air	3,007	3,013	3,121	3,064
O_2	2,293	2,371	2,357	2,231
N_2	7,042	7,178	7,163	6,911
Steam	3,899	3,974	3,927	4,020
Total Mass Input	**19,640**	**20,560**	**20,790**	**20,110**
Outputs	lb/hr			
Product Gas	18,184	18,733	18,723	18,412
Fine Ash	279	210	261	235
Coarse Ash	55	125	82	57
Total Mass Output	**18,518**	**19,068**	**19,066**	**18,703**
Mass Balance Closure, Output to Input Ratio (%)	94.3	92.7	91.7	93.0

Table 6-64: NCCC Process Stream Data for Mass Balance Summary for Torrefied Southern Pine Blends

Process Stream Data for Southern Pine (Torrefied) and Coal Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous

Duration and Process Stream Data	**Biomass Percent for each Test Case by Weight (%)**					
	Coal Only	**15.7**	**17.3**	**19.3**	**20.0**	**28.7**
Steady-state Duration (hrs)	4.0	5.0	4.2	5.5	4.2	3.6
Inputs	lb/hr					
Coal	3,400	3,401	3,203	3,348	3,170	3,201
Biomass	0	632	671	799	792	1,288
Air	3,007	3,208	3,224	3,226	3,275	3,224
O_2	2,293	2,450	2,341	2,380	2,379	2,544
N_2	7,042	7,751	7,422	7,175	6,880	6,747
Steam	3,899	4,635	4,140	3,994	3,911	3,942
Total Mass Input	**19,640**	**22,077**	**21,001**	**20,921**	**20,407**	**20,946**

Process Stream Data for Southern Pine (Torrefied) and Coal Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous

Duration and Process Stream Data	Biomass Percent for each Test Case by Weight (%)					
	Coal Only	15.7	17.3	19.3	20.0	28.7
Outputs	lb/hr					
Product Gas	18,184	20,535	19,634	19,721	19,383	19,555
Fine Ash	279	281	364	271	273	275
Coarse Ash	55	60	14	81	88	86
Total Mass Output	**18,518**	**20,876**	**20,011**	**20,073**	**19,744**	**19,916**
Mass Balance Closure, Output to Input Ratio (%)	94.3	94.6	95.3	95.9	96.8	95.1

As discussed in the introduction to Section 6, CCAT calculated the carbon conversion and cold gas efficiency for testing at NCCC as part of the overall mass and energy balance analysis. The calculated values for carbon conversion and cold gas efficiency are provided in Table 6-65 and Table 6-66 for the raw and torrefied cases, respectively.

Table 6-65: NCCC Carbon Conversion and Cold Gas Efficiency for Coal Only and Coal and Raw Southern Pine Blends

Carbon Conversion and Cold Gas Efficiency vs. Southern Pine (Raw) and Coal Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

Duration, Conversion, and Efficiency	Biomass Percent for each Test Case by Weight (%)			
	Coal Only	11.7	19.8	28.3
Steady-state Duration (hrs)	4.0	4.2	4.5	4.0
Carbon Conversion (%)	97.7	98.4	97.9	98.0
Cold Gas Efficiency (%)	67.8	62.5	59.6	61.6

Table 6-66: NCCC Carbon Conversion and Cold Gas Efficiency for Coal Only and Coal and Torrefied Southern Pine Blends

Carbon Conversion and Cold Gas Efficiency vs. Southern Pine (Torrefied) and Coal Blends
Facility: NCCC, Technology: TRIG™, Coal: PRB Sub-bituminous, Temperature: 1,699°F, Pressure: 164 psig

Duration, Conversion, and Efficiency	Biomass Percent for each Test Case by Weight (%)					
	Coal Only	15.7	17.3	19.3	20.0	28.7
Steady-state Duration (hrs)	4.0	5.0	4.2	5.5	4.2	3.6
Carbon Conversion (%)	97.7	98.7	97.6	98.2	98.2	98.0
Cold Gas Efficiency (%)	67.8	66.9	69.7	64.2	66.4	66.9

6.3.3 Reported Conclusions

NCCC successfully completed gasification testing of two biomass types at three different ratios with coal under steady-state gasifier conditions. The following conclusions were provided in the facility test report, which is provided as Appendix F.

Although both biomass feedstocks had the same source (southern pine), the physical characteristics (i.e., grindability, particle size distribution, and heating value) of the torrefied biomass were closer to the PRB coal than to the raw biomass. As shown in Table 6-55, the main components of the product gas were formed within a narrow range for all nine test cases. The H_2:CO molar ratio of the product gas ranged from 1.34 to 1.69 and was fairly consistent with the various biomass feed fractions. However, the effects of many independent operating variables (e.g., steam and oxygen-to-fuel ratios) were difficult to determine because the intentional changes were not independent of the principle fuel variables.

Several trace species were detected in the product gas. Generally, the highest concentrations of ammonia were in the coal-only test cases, with the lowest concentrations observed in the raw biomass feedstock blends. Ammonia levels tended to increase with higher percentages of torrefied biomass and decrease with higher percentages of raw biomass. Of the acids present in the product gas, hydrogen sulfide was detected at the most significant concentrations; this was likely due to the much higher sulfur level in coal than in the biomass. Based on these observations, all acid and base contaminants would need to be removed before the syngas is processed into liquid fuel to avoid fouling the catalysts in the FT reactors. The extent of gas cleaning will depend on the application of the syngas (e.g., for power, liquids, chemicals).

No discernible relationship was observed between benzene concentrations in product gas and the biomass feed percentage for either biomass type. Of the tar species detected in the product gas, naphthalene is the most prevalent. Due to the higher proportion of volatile matter, biomass is expected to produce more tars than coal (torrefied wood contains less volatile matter than raw wood). Tar levels increased with higher percentages of biomass for both raw and torrefied feedstock blends. Product gas from feedstock containing torrefied biomass contained significantly fewer tars than gas from raw biomass blends. The lowest tar concentrations were observed in the coal-only sample. Based on these observations, tars would need to be reformed into syngas or removed from the product gas to avoid fouling the FT equipment and catalyst for liquid fuel production.

Results of the leaching and pH analyses of the coarse and fine ash are well below the federal criteria; therefore, the ash would not be considered hazardous waste for disposal purposes under RCRA. For all test cases most of the total carbon (>99%), LOI (>98%), and heating value (92 to 99%) lost from the gasifier was observed in the fine ash, not the coarse ash. This is attributed to most of the coarse ash being recycled through the gasifier, while most of the fine ash is captured in the PCD after only one pass through the gasifier.

The carbon conversion was fairly consistent for all oxygen-blown tests, ranging from 97.6 to 98.7% (as shown in Table 6-65 and Table 6-66). The conversion of feedstocks to product gas was quantified by cold gas efficiency, which ranged from 59.6 to 69.7% for all tests. The cold gas efficiency appears to be slightly lower for the raw biomass tests, averaging 61.2%, compared to 66.8% for the average torrefied biomass tests and 67.8% for the coal-only test case. These results may be attributed to the lower heating value and energy density of raw biomass compared to torrefied biomass and coal; however, there is no apparent trend with biomass feed percentage for either feedstock.

6.4 TRI

This section summarizes data and conclusions provided by TRI for pilot testing of its two-step steam reforming and partial oxidation gasification process, which was conducted at its process demonstration unit (PDU). Complete details are provided in TRI's facility test report (Appendix I). CCAT's interpretation of the data and conclusions is provided in Section 7.1.4. The TRI PDU is located in Durham, North Carolina. Testing was conducted at this facility to generate data on product gas, ash, and operating conditions to enable a mass and energy balance around TRI's two-step process.

6.4.1 Test Description

Two tests were performed using MSW/lignite coal and raw wood/lignite coal feedstock blends. The test plan consisted of gasifying blends of 75% MSW and 75% Raw Wood with 25% lignite for 24 hours each test. These tests were performed on December 13 to 14 and December 15 to 16, 2014, respectively. The MSW/coal test achieved 12 hours of steady-state operations, and the wood/coal test achieved 11.25 hours of steady-state operations.

Steam Reformer and Partial Oxidation Operations – As described in Section 4, the TRI steam reformer is a unique proprietary process that uses indirectly heated fluidized beds with superheated steam as the main fluidizing medium to achieve the conversion of carbonaceous feedstocks into syngas. The two-step process includes steam reforming as the first step and partial oxidation gasification in the "carbon trim cell" (CTC) as the second step. Partial oxidation is used to the degree necessary to adjust the H_2:CO molar ratio required for the downstream FT synthesis process.

The TRI steam reformer has been sized to process up to 4 dtpd (dry tons per day) of biomass feedstock, with a moisture content of 10% or less. Electrical heater banks provide the endothermic energy required for the steam reforming, and bed material within the reformer is fluidized with superheated steam, nitrogen, and oxygen using a distribution grid installed in the bottom of the reformer vessel. Target reformer operating conditions were temperature 1,400 ± 25°F and pressure 44.2 ± 16.2 psia. A primary cyclone is suspended (not shown on Figure 6-7) inside the steam reformer to capture bed material and larger char particles from the syngas and return them to the steam reformer -bed through a dipleg. The steam reformer is fitted with level, density, temperature, and pressure measurement instrumentation (Appendix I).

A secondary cyclone installed in the syngas discharge from the reformer collects ash/char elutriated from the steam reformer bed and routes it to the CTC. The CTC is a refractory-lined cylindrical vessel fitted with a sparger-style fluidization grid. Within the CTC, partial oxidation is undertaken to convert the residual carbon to product gas and to manipulate the H_2:CO molar ratio to the precise level required for the desired downstream FT synthesis process. A tertiary cyclone is installed in the syngas discharge from the CTC to collect fine ash-laden char elutriated from the bed. The cyclone dipleg transfers the ash into a steel drum via a set of lock-hoppers. A set of lock-hopper valves is provided on the CTC for discharge of bed material during maintenance shutdowns. The CTC is also fitted with level, density, temperature, and pressure measurement instrumentation. Heaters are used to superheat the fluidization steam and to pre-heat the nitrogen for the gasification process. The target CTC temperature was 1,500 ± 50°F.

Figure 6-7 shows a simplified block diagram for a two-stage steam reforming process followed by CTC, with input and output streams.

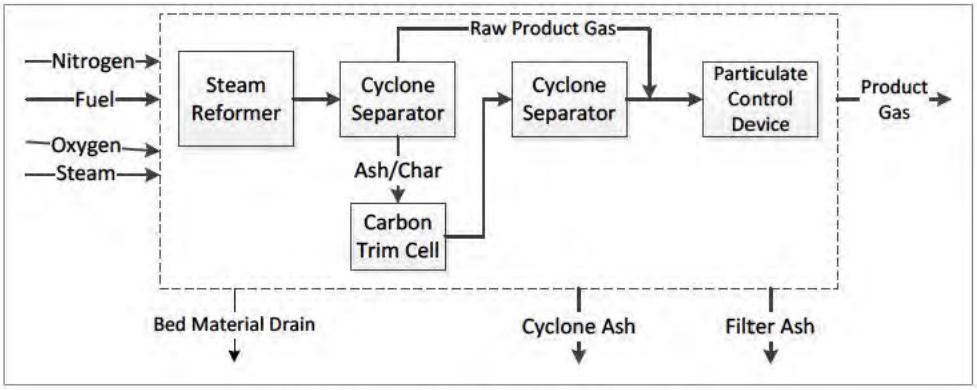


Figure 6-7: Simplified TRI Schematic

Feed Systems – The proprietary feed system is a volumetric device capable of handling a wide range of carbonaceous feedstock, including the coal-blended feed material required by the CCAT test plan. TRI's feed system can continuously deliver feedstocks to the steam reformer at a rated capacity of 3.5 dtpd. The feeder uses a three-stage hydraulic piston system to develop a solid feedstock plug of a defined mass and pressure to form the seal between the pressurized reformer and the atmospheric biomass day bin and to increase the biomass pressure to steam reformer pressure. As the feedstock plug forms the primary seal, one of the three pistons is always in a closed position, which prevents a plug blow-out if the plug becomes unstable and provides additional safety against syngas leaks. This system is described in detail in Appendix I.

Sampling and Analysis – Sampling of product gas included TRI in-house devices and third-party analysis. Below are various analyses performed during 75%/25% MSW/coal and 75%/25% wood/coal two-step steam reforming followed by partial oxidation testing.

<u>Product Gas Composition Analysis</u> – The primary syngas component data is measured by continuously operated micro-GC's, which are integrated into the distributed control system and historian, and function as a core control parameter for the operators. While the micro-GC quantifies the fixed gases, a gas chromatograph with a flame ionization detector (GC-FID) for BTEX and a gas chromatograph with sulfur chemiluminescence detector (GC-SCD) are used to quantify sulfur compounds

<u>Higher Hydrocarbon (tar) Analysis</u> – Analysis of Tedlar® bag grab samples and thermal desorption tubes was used to measure tars in the product gas. Tedlar® bag grab samples were collected at the combined syngas line. A syringe pump was used to remove gas sample from the bag and transferred to the thermal desorption tubes. The tube analyses were performed by a third-party laboratory using NIOSH method 2549. The tubes, which were used with a blend of sorbents to capture the target organic compounds (polyaromatic hydrocarbons), were heated to 570°F to release the compounds and then analyzed using (GC-MS). Tedlar® bag grab samples were also analyzed for BTEX by GC-FID.

<u>Other Contaminants Analysis</u> – Sulfur species in the bag samples, such as H_2S and COS, were measured by SRI using a GC-SCD. The same bag samples were used to fill Gastec tubes to measure other

contaminants in the product gas. Gastec tubes are capable of detecting hydrochloric acid, hydrogen cyanide, and ammonia at low concentrations. Samples were taken periodically throughout the test campaign when the process was at stable operating conditions. Significant interferences were encountered during the MSW/coal blend test using Gastec tubes resulting in non-detect readings.

Feedstock Overview – The testing at TRI was conducted on MSW/coal (75%/25%) and wood/coal (75%/25%) feedstock blends by weight. TRI used lignite coal from Falkirk Mine, North Dakota for testing. The lignite coal was provided by Baranko Brothers, Inc./Center for Coal Technology, North Dickinson, North Dakota. MSW (sorted to remove inorganic materials [e.g., metal, glass, other inert materials]) and wood feedstocks were provided by TRI. The feedstock blends were prepared for testing at TRI's waste service partner's Henderson, North Carolina facility. First, the MSW and wood were sized using a shredder, then weighed and spread on the floor. Next, a layer of coal was added to create the ratio required for testing. The blends were mixed using mechanical loaders, and once the blend was determined satisfactory for testing, the material was mechanically conveyed to fill super sacks, weighing approximately 550 to 650 pounds each.

6.4.2 Test Results

6.4.2.1 *Feedstock Analyses*

The feedstock analysis consisted of proximate, ultimate, heating value, and ash analyses. The "as fed" analyses for the blended feedstock are provided in Table 6-67. Blended feedstock samples were collected from the top, middle, and bottom of each super sack and composited into a single sample for each fuel type. For the ash analysis as oxides, only those constituents that are important to the ash agglomeration properties (specific to the steam reforming technology) are provided in the Table 6-67, below.

Table 6-67: TRI Feedstock Analyses of MSW/Coal and Wood/Coal Blends

Proximate, Ultimate, Heating Value and Ash Analyses of MSW/Coal and Wood/Coal Blends
Facility: TRI, Technology: Steam Reforming, Coal: Falkirk Lignite

	Biomass Percent for each Test Case by Weight (%)	
Analyses	**MSW (75%)**	**Wood (75%)**
Proximate Analysis	wt%	
Moisture	12.28	17.37
Volatile Matter	72.80	62.52
Fixed Carbon	8.12	15.35
Ash	6.80	4.76
Ultimate Analysis	wt%	
C	46.13	44.90
H	5.48	4.59
N	0.28	0.34
O	28.57	27.87
S	0.14	0.17
Moisture	12.28	17.37

Proximate, Ultimate, Heating Value and Ash Analyses of MSW/Coal and Wood/Coal Blends
Facility: TRI, Technology: Steam Reforming, Coal: Falkirk Lignite

	Biomass Percent for each Test Case by Weight (%)	
Analyses	**MSW (75%)**	**Wood (75%)**
Ash	6.80	4.76
Heating Value, HHV (Btu/lb)	7,893	7,155
Ash Analysis As Oxides (wt%)		wt%
CaO	36.13	21.82
MgO	2.25	5.57
Fe_2O_3	1.33	13.93
Na_2O	4.09	8.37
K_2O	1.64	4.64
SiO_2	26.31	18.57
P_2O_5	0.41	0.53
Other	27.84	26.58

6.4.2.2 *Steam Reforming and Partial Oxidation Operations and Product Gas Composition*

Two tests were conducted at TRI with 12 hours of steady-state operations for the MSW/coal test and 11.25 hours of steady-state operations for the wood/coal test. During testing, TRI recorded real-time gas analyses, temperatures, pressures, and electrical power input for the electrical heater used at the steam reformer. During the MSW/coal test, the steam reformer was operated at 1,404°F and 44.3psia on average, and the CTC was operated at 1,581°F and 42.4 psia on average. During the wood/coal test, the steam reformer was operated at 1,397 °F and 44.0 psia on average, and the CTC was operated at 1,536°F and 42.1 psia on average. The average product gas flow during MSW/coal and wood/coal testing was 854 and 822 lb/hr, respectively.

The primary dry basis product gas component data were measured by continuously operated micro-GC over the entire steady-state period for hydrogen, carbon monoxide, carbon dioxide, nitrogen, methane, hydrogen sulfide, ethylene, ethane, and propene. Table 6-68 presents the calculated dry and nitrogen-free basis product gas composition, H_2:CO molar ratio, dry basis product gas heating value and product gas energy flow. Details on the product gas flowrates and composition are provided in Appendix I.

Table 6-68: TRI Analysis of Product Gas Composition and Heating Value for MSW/Coal and Wood/Coal Blends

Dry and N_2-Free Product Gas Composition for MSW/Coal and Wood/Coal Blends
Facility: TRI, Technology: Steam Reforming, Coal: Falkirk Lignite, Temperature: 1,401°F, Pressure: 44.1 psia

	Biomass Percent for each Test Case by Weight (%)	
Duration, Composition, and Heating Values	**MSW (75%)**	**Wood (75%)**
Steady-state Duration (hrs)	12.0	11.25
Dry and N_2-Free Product Gas Composition		mol%
H_2	40.10	43.31

Dry and N_2-Free Product Gas Composition for MSW/Coal and Wood/Coal Blends
Facility: TRI, Technology: Steam Reforming, Coal: Falkirk Lignite, Temperature: 1,401°F, Pressure: 44.1 psia

Duration, Composition, and Heating Values	Biomass Percent for each Test Case by Weight (%)	
	MSW (75%)	Wood (75%)
CO	18.20	19.10
CO_2	28.60	29.58
CH_4	13.10	8.01
H_2:CO Molar Ratio	2.20	2.27
Product Gas Heating Value, HHV dry basis (Btu/scf)	224	162
Product Gas Energy Flow, HHV dry basis (MMBtu/hr)	3.04	2.13

In addition to product gas composition, other trace species in product gas were measured for both the MSW/coal and wood/coal tests. Sample results for the three trace species analyses are provided in Table 6-69.

Table 6-69: TRI Trace Species Analysis of Product Gas for MSW/Coal and Wood/Coal Blends

Trace Species Analysis for MSW/Coal and Wood/Coal Blends
Facility: TRI, Technology: Steam Reforming, Coal: Falkirk Lignite, Temperature: 1,401°F, Pressure: 44.1 psia

Duration and Analyses	Biomass Percent for each Test Case by Weight (%)	
	MSW (75%)	Wood (75%)
Steady-state Duration (hrs)	12	11.25
GC-SCD Analysis, dry basis	ppmv	
Hydrogen Sulfide	770	893.6
Carbonyl Sulfide	0	0
Methyl Mercaptan	1.97	0
Ethyl Mercaptan	0	0
Carbon Disulfide	0.25	0
Thiofuran	17	10.7
Other Sulfur (as H_2S)	16.8	17.7
Gastec Tube Analysis, wet basis	ppmv	
Ammonia	ND	405
Hydrogen Chloride	ND	ND
Hydrogen Cyanide	ND	110
Thermal Desorption and GC-FID Analysis, dry basis	ppmv	
Benzene	6,007.80	918.43
Toluene	1,103.27	270.32
Chlorobenzene	0.02	0.02
Ethylbenzene	1.50	1.1

Trace Species Analysis for MSW/Coal and Wood/Coal Blends
Facility: TRI, Technology: Steam Reforming, Coal: Falkirk Lignite, Temperature: 1,401°F, Pressure: 44.1 psia

Duration and Analyses	Biomass Percent for each Test Case by Weight (%)	
	MSW (75%)	Wood (75%)
Xylene	148.43	20.43
Styrene	7.30	3.7
n-Propylbenzene	0.02	0.07
1,3,5-Trimethylbenzene	0.09	0.09
1,2,4-Trimethylbenzene	0.14	0.02
Naphthalene	0.03	0.58
2-Methylnaphthalene	0.16	0.05
Cyclopentene	1.70	1.7
Thiophene	4.80	5.3
Pyridine	1.10	0.76
2,3-Benzofuran	1.20	0.53
Phenol	2.00	0.67
Indene	4.80	1.7
Total	7,284.36	1,225.45

Note: ND = not detected

6.4.2.3 *Steam Reformer and Partial Oxidation Solid Ash Residue Sample Analysis*

In addition to the product gas composition, solid ash residue samples were collected, and included cyclone ash and filter ash (see Figure 6-7). Cyclone ash is collected from gas exiting the CTC and filter ash is collected from the combined gas stream from the steam reformer and particulate free gas from the CTC. The samples were analyzed for ultimate analysis and ash analysis as oxides. Table 6-70provides data for the cyclone ash and filter ash average carbon content, LOI and heating value.

Table 6-70: TRI Analysis of Steam Reformer Residue (cyclone ash and filter ash) for MSW/Coal and Wood/Coal Blends

Analysis of Ash Samples from Gasified MSW/Coal and Wood/Coal Feedstock Blends
Facility: TRI, Technology: Steam Reforming, Coal: Falkirk Lignite, Temperature: 1,401°F, Pressure: 44.1 psia

	Biomass Percent for each Test Case by Weight (%)	
Duration and Analyses[a]	**MSW (75%)**	**Wood (75%)**
Steady-state Duration (hrs)	12.0	11.25
Cyclone Ash Analysis [a]		
Heating Value [b], HHV (Btu/lb)	8,667	7,217
Filter Ash Analysis [a]		
Heating Value [b], HHV (Btu/lb)	8,125	10,837

Notes:

[a] Due to confidentiality, LOI and carbon content of Cyclone Ash and Filter Ash data are not included in this table.

[b] TRI did not provide the heating value of cyclone ash and filter ash. The heating value was calculated using four methods: Dulong, Boie, Grummel and David, and Mott and Spooner. The average from the four methods is reported here.

6.4.2.4 *Mass and Energy Balance*

As stated in the introduction to Section 6, a mass and energy balance was performed as a quality measure. The results are summarized below in Table 7 and provided in detail in the facility test report (Appendix I). Table 6-71 provides the mass inputs and outputs for the MSW/coal and wood/coal test cases.

Table 6-71: TRI Process Stream Data for Mass Balance Summary for MSW/Coal and Wood/Coal Blends

Process Stream Data for MSW/Coal and Wood/Coal Blends
Facility: TRI, Technology: Steam Reforming, Coal: Falkirk Lignite, Temperature: 1,401°F, Pressure: 44.1 psia

	Biomass Percent for each Test Case by Weight (%)	
Feedstock Type and Mass Balance	**MSW (75%)**	**Wood (75%)**
Steady-state Duration (hrs)	12.0	11.25
Mass Inputs	lb/hr	
Fuel	348.53	317.31
Oxygen, Steam and Nitrogen [a]	512.26	509.53
Total Mass Input	**860.79**	**826.84**
Mass Outputs	lb/hr	
Product Gas [b]	853.50	821.99
Cyclone Ash and Filter Ash [c]	27.87	19.58
Total Mass Output	**881.37**	**841.57**
Mass Balance Closure, Output to Input Ratio (%)	**102.39**	**101.78**

Notes:

[a] Due to confidentiality, mass flow rate of oxygen, steam and nitrogen is provided as an aggregate.

[b] Product gas flow rate was calculated by subtracting filter ash from combined stream of reformer and CTC output reported by TRI.

[c] Due to confidentiality, the mass flow rate of Cyclone Ash and Filter Ash is provided as an aggregate. Cyclone ash includes bed material drain. Bed material drain was 1.03 lb/hr for MSW/coal test and 0 lb/hr for wood/coal test.

TRI provided carbon conversion and cold gas efficiency for testing at its facility as part of the overall mass balance analysis; however, for consistent presentation of results, CCAT calculated the carbon conversion and cold gas efficiency as described in the introduction to Section 6. The calculated values for carbon conversion and cold gas efficiency for MSW/coal and wood/coal steam reforming tests are provided in Table 6-72.

Table 6-72: TRI Carbon Conversion and Cold Gas Efficiency for MSW/Coal and Wood/Coal Blends

Carbon Conversion and Cold Gas Efficiency vs. MSW/Coal and Wood/Coal Feedstock Facility: TRI, Technology: Steam Reforming, Coal: Falkirk Lignite, Temperature: 1,401°F, Pressure: 44.1 psia		
	Biomass Percent for each Test Case by Weight (%)	
Duration, Conversion, and Efficiency	**MSW (75%)**	**Wood (75%)**
Steady-state Duration (hrs)	12.0	11.25
Carbon Conversion (%)	91.05	90.19
Cold Gas Efficiency, HHV (%)[a]	110.33	93.96

Note: [a] BTEX and H_2S were not included in cold gas efficiency calculations.

6.4.3 Reported Conclusions

TRI was able to achieve constant steady-state operation of the steam reforming reactor using the MSW/coal and wood/coal feedstock blends. The following conclusions were provided in TRI's facility test report, which is provided as Appendix I.

TRI successfully completed more than 50 hours of gasification using MSW/coal blends and 24 hours using wood/coal blends.

During testing, the TRI PDU generated valuable operating data showing that the tests could be extended to a longer duration campaign that would support and validate a coal-blend gasifier commercial design. This trial accomplished the overall goals stated in the test plan, including the following specific accomplishments:

- The average product gas composition was generally: 22 to 24% Hydrogen, 10 to 11% carbon monoxide, 4 to 7% methane, 16% carbon dioxide, and 38 to 42% nitrogen; and the average product gas flow rate ranged between 822 to 854 lb/hr.
- Demonstrated that the syngas composition can be maintained at a nominal H_2 to CO molar ratio of ~2.0 or between 1.8 and 2.2, with the actual steady-state average ratios being 2.2.
- Measured the tar composition using thermal desorption tubes and GC-FID techniques, with trial tar composition being much higher for MSW, near 7,200 ppmv, versus wood, near 1,200 ppmv.
- The overall carbon conversion was 91% for MSW blends and 90% for wood blends.
- Quantified the cold gas efficiencies of 110% for the MSW-blend and 94% for the wood-blend.

- Estimated the speciation of sulfur using GC-SCD. Measurement of chlorine and nitrogen speciation using Gastec tubes was reliable for the wood-coal product gas, but ineffective for the MSW-coal product gas due to significant interferences in the product gas.

- Confirmed the steam, nitrogen and oxygen consumption using the mass and energy balances.

- Provided a comparison of carbon conversion and cold gas efficiency between results of MSW/coal blend and wood/coal blend feedstocks with past TRI MSW and wood results, respectively, which showed that these metrics were similar between the baseline and coal-blended feedstock results.

6.5 WPC

The WPC test facility, owned by a Canadian company, Alter NRG Corp. (Alter NRG), is located in Madison, Pennsylvania. Testing was conducted at this plant to generate data on product gas, slag, and operating conditions to enable a mass and energy balance around the gasifier.

This section summarizes data and conclusions provided by WPC for pilot gasification tests conducted at their demonstration plant. WPC provided a full test report to the project team upon completion of the testing. The non-proprietary version of WPC's test report is provided as Appendix H. CCAT's interpretation of the data and conclusions is provided in Section 7.5 of this report.

6.5.1 Test Description

Three tests were performed using coal/MSW feedstock blends: Test 1 (50% MSW), Test 2 (75% MSW), and Test 3 (100% MSW). These tests were consistent with the test plan provided in Table 6-73 and were performed on July 18, August 7, and August 20, 2013, respectively. Each test was conducted over an approximate 8-hour period, which included 2 hours of heat up and 6 hours of steady-state operation.

Table 6-73: WPC Test Plan

Test Number	Primary Feed (wt%)	Run Duration (hrs)	Feed rate (lb/hr)		
			Primary	Metallurgical Coke	Flux Materials
1	50% MSW	8	800	200	382
2	75% MSW	8	800	200	200
3	100% MSW	8	800	200	200

Note: % MSW refers to the percent of the primary feedstock that is simulated MSW.

Gasifier Operations – The plasma gasification vitrification reactor (PGVR) at WPC is a fixed-bed, refractory-lined, and-water cooled vessel (Figure 4-4). The primary feed is supported on a bed of course metallurgical coke, which surrounds a single plasma torch. The well, at the bottom of the PGVR collects the molten slag created by the inorganic and inert materials contained in the feed. Flux additives, such as silica (sand or glass) or calcium (limestone) based materials, are used to optimize the chemical composition of the resulting slag to assist its flow out of the vessel.

The gasifier was operated in oxygen enriched air blown mode at approximately atmospheric pressure and with an exit temperature of approximately 2,000°F. Oxygen and air were injected as oxidants and as a means of controlling temperature. Nitrogen was added as an instrument purge gas. Figure 6-8 shows a simplified schematic for a PGVR, with input and output streams.

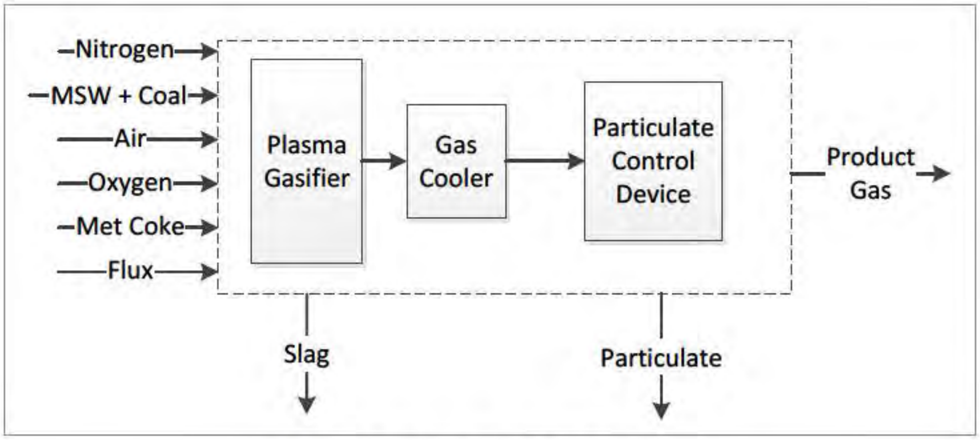


Figure 6-8: Simplified WPC Schematic

Feed Systems – WPC operated two separate feed systems for injecting the feedstock blends, metallurgical coke, and flux materials into the PGVR, as described below. Each feed system was equipped with an airlock to prevent air infiltration.

- A weigh-belt feed system was operated continuously to introduce the primary feed materials (coal and MSW blends).
- A skip hoist was used intermittently to feed the flux materials and metallurgical coke.

The two feed systems operated independently at predetermined rates based on the planned mix ratios provided in Table 6-73, above.

Sampling and Analysis – On-line gas analysis was performed with a mass spectrometer as well as with independent analyzers for carbon monoxide, hydrogen, and oxygen. The two WPC mass spectrometers took a measurement every 2 minutes and measured fixed gases and some trace species. These instruments were used along with process temperatures to assess the performance of the gasifier and adjust the various process inputs as necessary.

For each test, WPC collected samples during three discrete 30-minute periods for offsite, laboratory analysis. These samples included bag samples and isokinetic particulate samples of the product gas, as described below. On-line composition data were verified by the bag samples, which were independently tested by a third-party laboratory. Not only is third-party sampling more accurate, it is more definitive because the sample is a product gas mixture taken over a timed period, which is a more representative sample than the instantaneous measurements.

<u>Bag Samples</u> – WPC collected bag samples of the raw product gas from ports at the top of the gasifier. Because the sample ports had a tendency to plug, it was necessary to use alternative sample ports in the

duct downstream of the gas cooler. Due to the presence of additional nitrogen introduced as an equipment purge, it was necessary to adjust the nitrogen composition in the calculations for those tests where alternative sampling ports were used. The bag samples were submitted for laboratory analysis using ASTM Standard D1946 test method for fixed gases, including hydrogen, carbon monoxide, carbon dioxide, methane, nitrogen, and oxygen. Trace species, including benzene, carbonyl sulfide, hydrogen sulfide, ammonia, hydrochloric acid, and hydrogen cyanide in the product gas were also measured using the principles of USEPA Method 26A.

Isokinetic Samples – Isokinetic sampling was conducted downstream of the initial product gas quench vessel to collect particulate matter. Filterable particulate matter (FPM) and condensable particulate matter (CPM) were sampled using a modified California Air Resources Board Method 5 procedure. The mass of particulate carryover, entrained in the product gas, was calculated by adding FPM results from laboratory analyses and the physical measurement from the quench water solids.

Slag Samples – During each test, the gasifier well was tapped using an oxygen lance to create slag flow and to collect discrete slag samples for further analyses.

Feedstock Overview – The testing at WPC was conducted on coal/MSW feedstock blends. WPC used PRB sub-bituminous coal from Eagle Butte Mine, Wyoming. For MSW, WPC was not licensed to handle waste; therefore, an MSW was created to simulate the chemical composition of a typical United States MSW. The simulated MSW was prepared by blending 70% fuel pellets, 12% glass cullet, and 18% water. The fuel pellets contained cellulose fiber (60 to 80%), paper fillers (5 to 12%), and polymers (15 to 30%) and were obtained from Greenwood Energy of Green Bay, Wisconsin. The target composition for a typical MSW, provided by CCAT, is listed in Table 6-74. In addition, the ultimate and chlorine analyses of coal, simulated MSW, and the target typical MSW are presented. Throughout the remainder of this report, the simulated MSW will be referred to simply as MSW.

Table 6-74: Ultimate and Chlorine Analyses of Primary Feed Components and Target MSW

Constituents	PRB Coal (wt%)	Simulated MSW (wt%)	Target Typical MSW (wt%)
Moisture	26.46	21.68	20.00
Ash	4.09	14.45	15.00
C	51.51	42.90	37.14
H	3.66	3.94	5.19
O	13.43	16.36	20.98
N	0.62	0.50	0.84
C	NA	NA	0.72
S	0.23	0.16	0.12

6.5.2 Test Results

6.5.2.1 *Feedstock Analyses*

The "as fed" analyses and heating values for the blended feedstock are provided in Table 6-75. The analyses and values are based on feeder measurements obtained during steady-state operation periods, and an analysis of the individual feedstock components. The feedstock components include primary feed (coal, MSW), metallurgical coke, and flux materials. Therefore, the analyses below differ from the individual feedstock analyses presented above and provided in Appendix B. For the ash analysis, only those constituents that are important to the slagging properties are provided in the table below, with the remaining reported oxides grouped as "other." The primary constituents are silica from the glass cullet and calcium from limestone, both added as flux materials to reduce the melting temperature of ash and reduce the viscosity of slag. The flux materials consisted of approximately equal parts glass cullet and limestone. In Table 6-75, the calcium carbonate and magnesium carbonate composition of the flux materials is presented as calcium oxide and magnesium oxide respectively.

Table 6-75: WPC Analyses of Blended Feedstock (MSW, Coal, Metallurgical Coke, and Flux Materials)

Proximate, Ultimate, Heating Value and Ash Analyses of MSW and Coal-blended Feedstocks
Facility: WPC, Technology: Plasma, Coal: PRB Sub-bituminous

	Test Cases (MSW wt%)		
Analyses	**50**	**75**	**100**
Proximate Analysis	wt%		
Moisture	14.8	16.1	14.9
Volatile Matter	28.2	36.9	40.7
Fixed Carbon	20.9	19.4	14.9
Ash	36.2	27.7	29.4
Ultimate Analysis	wt%		
C	36.2	40.6	39.5
H	2.4	2.9	2.9
N	0.4	0.4	0.4
O	9.9	12.2	12.7
S	0.2	0.2	0.2
Moisture	14.8	16.1	14.9
Ash	36.2	27.7	29.4
Heating Value[a], HHV (Btu/lb)	6,104	6,875	6,702
Ash Analysis as Oxides	Component wt% of Total Ash		
CaO	41.5	35.0	33.0
MgO	2.8	2.5	2.4
Fe_2O_3	0.9	0.8	0.5
Na_2O	6.9	7.8	8.2

Proximate, Ultimate, Heating Value and Ash Analyses of MSW and Coal-blended Feedstocks Facility: WPC, Technology: Plasma, Coal: PRB Sub-bituminous			
	Test Cases (MSW wt%)		
Analyses	**50**	**75**	**100**
K_2O	0.5	0.4	0.4
SiO_2	42.9	47.5	49.6
Al_2O_3	3.5	4.5	4.5
TiO_2	0.4	0.7	0.8
Other	0.6	0.8	0.6

Note: [a] The heating values of feedstocks were calculated by CCAT based on flow rate and the heating values of constituents provided by WPC.

6.5.2.2 *Gasifier Operations and Product Gas Composition*

Testing was conducted over three days, with approximately 6 hours of steady-state gasifier operations for each test. During testing, WPC recorded real-time gas analyses, temperatures, pressures, and torch power.

Product gas compositions were determined by analyzing bag samples; these data were reported on a dry basis by WPC for each coal/MSW blend. The Project Team converted these data to a standard reporting basis for this report (i.e., %mol hydrogen, carbon monoxide, carbon dioxide, and methane), while excluding moisture and all other fixed gases analyzed. Similarly, the product gas heating value was reported by WPC for each coal/MSW blend. The Project Team combined this with value mass balance data to determine product gas energy flow. The results in Table 6-76 are presented in a summary format; data were averaged over three discrete steady-state sampling periods for each test. Details on the product gas compositions for individual tests are provided in Appendix H.

Table 6-76: WPC Analysis of Product Gas Composition and Heating Value

Dry and N_2-Free Product Gas Composition vs. Simulated MSW and Coal Blends Facility: WPC, Technology: Plasma, Coal: PRB Sub-bituminous, Temperature: 2,079°F, Pressure: 14.7 psia			
	Test Cases (MSW wt%)		
Duration and Analyses	**50**	**75**	**100**
Steady-state Duration (hrs)	6.5	7.0	6.25
Dry and N_2-Free Product Gas Composition		(%mol)	
H_2	25.27	33.74	37.83
CO	47.89	40.84	45.55
CO_2	24.33	21.64	14.83
CH_4	2.51	3.79	1.79
H_2:CO Molar Ratio	0.53	0.83	0.83
Product Gas Heating Value, HHV dry basis (Btu/scf)	184	211	196
Product Gas Energy Flow, HHV dry basis (MMBtu/hr)	4.49	5.86	4.73

Bag samples were collected from the raw product gas, and the following trace species concentrations were determined: ammonia, hydrochloric acid, hydrogen cyanide, hydrogen sulfide, carbonyl sulfide, and benzene. Sample results are provided in Table 6-77.

Table 6-77: WPC Trace Species Analysis of Product Gas for MSW and Coal Blends

Analysis of Product Gas from Gasification of MSW and Coal Feedstock Blends
Facility: WPC, Technology: Plasma, Coal: PRB Sub-bituminous, Temperature: 2,079°F, Pressure: 14.7 psia

	Test Cases (MSW wt%)		
Duration and Analyses	**50**	**75**	**100**
Steady-state Duration (hrs)	6.5	7.0	6.25
Trace Species, dry basis		ppmv	
NH_3	668	786	387
HCl	12.8	20.0	18.2
HCN	51.4	57.3	10.1
H_2S	9.6	<1.0	170.6
COS	32.8	15.3	32.9
C_6H_6	0.11	0.21	0.07

6.5.2.3 *Gasifier Residue Sample Analysis*

In addition to the product gas composition, isokinetic samples were collected from the product gas to analyze particulate matter. During gasification, non-gaseous residue exits the gasifier in the form of slag through the gasifier tapping hole and in the form of particulate matter entrained in the product gas. Table 6-78 provides data for the particulate matter, including averaged LOI, carbon content and heating value. This table also provides the CPM determined from the Modified California Air Resources Board Method 5. Condensable particulates are indicative of the amount of tar contained in the product gas downstream of the initial quench. Details on the particulate flow rates and mass of particulate removed from the system are provided in Appendix H.

Table 6-78: WPC Analysis of Gasifier Residue (Particulate) for MSW & Coal Blends

Analysis of Particulate Samples from Product Gas of MSW and Coal Feedstock Blends
Facility: WPC, Technology: Plasma, Coal: PRB Sub-bituminous, Temperature: 2,079°F, Pressure: 14.7 psia

Duration and Analyses	Test Cases (MSW wt%)		
	50	75	100
Steady-state Duration (hrs)	6.5	7.0	6.25
Particulate Analysis (FPM)			
LOI[a] (wt%)	15.54	24.04	34.75
Carbon Content (wt%)	5.33	12.30	19.40
Heating Value[b], HHV (Btu/lb)	500	1,869	2,947
Condensable Particulate Matter (Grains/dscf)			
Inorganic + Organic	0.8	0.06	2.16

Notes:

[a] LOI data were not provided by WPC. The information presented here is reported as (1- ash fraction), which was determined by the laboratory analysis.

[b] The heating value of particulate matter was not provided by WPC. The heating value was calculated using four methods: Dulong, Boie, Grummel and David, and Mott and Spooner. The average from the four methods is reported here.

A solid sample analysis was performed using samples of slag collected from each test. These samples were analyzed using the TCLP. The results provided in Table 6-79 are the average of three samples analyzed for each test. The leachate concentrations were compared to the hazardous characteristic criteria for the eight metals regulated under RCRA to determine if the material would be considered hazardous for disposal purposes. As shown, all results are below the applicable regulatory levels. All solid sample results are provided in Appendix H.

Table 6-79: WPC Slag Sample TCLP Results for RCRA Metals

Metal	Test 1 50% MSW	Test 2 75% MSW	Test 3 100% MSW	RCRA LIMIT
	(mg/L)			
Ag	0.080	0.020	ND	5
As	ND	ND	ND	5
Ba	0.087	0.057	ND	100
Cd	ND	ND	ND	1
Cr	0.150	0.066	ND	5
Hg	ND	ND	ND	0.2
Pb	ND	ND	ND	0.4
Se	ND	ND	ND	1

Note: ND = not detected above the laboratory detection limit

6.5.2.4 *Mass and Energy Balance*

A full heat and material balance (HMB) for the pilot gasifier was performed by WPC and included in the confidential version of WPC's test report. The confidential HMB used computer simulations for the product gas composition, based on feedstock analyses and operating data from the pilot testing. The mass balance data presented below is also contained in the confidential report, but separately from the full HMB. The data have been approved by WPC for presentation in this report.

Table 6-80 presents a mass balance summary, based on average flows determined from pilot test measurements and third-party sampling. The information presented below is not intended to reproduce the WPC's HMB in its entirety, rather provide a summary of the mass accounted for during the actual pilot tests. It should be noted that the mass balance provided in Table 6-80 is a forced (calculated) balance, in that the actual slag flow and the product gas moisture were not measured. The slag flow was calculated based on mass of inert materials fed to the gasifier and estimation of the partitioning of the inerts, some of which report to the gas phase. The product gas moisture was then calculated by difference to force the inputs and outputs to balance.

Table 6-80: WPC Process Stream Data for Mass Balance Summary for MSW and Coal Blends

Process Stream Data for Mass Balance Summary for MSW and Coal Feedstock Blends
Facility: WPC, Technology: Plasma, Coal: PRB Sub-bituminous, Temperature: 2,079°F, Pressure: 14.7 psia

	Test Cases (MSW wt%)		
Duration, Inputs, and Outputs	**50**	**75**	**100**
Steady-state Duration (hrs)	6.5	7.0	6.25
Inputs	lb/hr		
O_2	288	264	208
Air	477	497	506
N_2	94	112	170
MSW + Coal	805	898	811
Metallurgical Coke	98	106	102
Flux	379	212	187
Total Mass Input	**2,141**	**2,089**	**1,984**
Outputs	lb/hr		
Particulate Carryover[a]	130	74	112
Product Gas	1,711	1,757	1,606
Slag[b]	300	258	266
Total Mass Output	**2,141**	**2,089**	**1,984**

Notes:

[a] Particulate carryover was determined by adding quench water solids and FPM collected via isokinetic sampling. This sampling was challenging due to the high velocities in the product gas duct, which created suction. During testing, it was determined that FPM data were inconclusive because impinger water was pulled into the duct.

[b] Slag output for the mass balance was calculated by WPC by difference, as it was not practical to measure the slag flow rate during testing. The values were checked by comparing to the total slag removed from the well during each test.

As discussed in the introduction to Section 6, CCAT calculated the carbon conversion and cold gas efficiency for testing at WPC as part of the overall mass and energy balance analysis. Carbon conversion was based on the carbon content of particulate carryover and the carbon content of feedstocks, as provided by WPC, and the carbon content of the slag was assumed to be zero. CCAT calculated the cold gas efficiency based on the higher heating value of product gas provided by WPC and the higher heating value of blended feedstocks listed in Table 6-75. Blended feedstocks included primary feed (MSW and coal) plus metallurgical coke. Because the flux did not contain any organic carbon, it was not part of cold gas efficiency or carbon conversion calculations. Table 6-81 provides the calculated values for carbon conversion and cold gas efficiency.

Table 6-81: WPC Carbon Conversion and Cold Gas Efficiency for MSW and Coal Blends

Carbon Conversion and Cold Gas Efficiency vs. MSW and Coal Blends
Facility: WPC, Technology: Plasma, Coal: PRB Sub-bituminous, Temperature: 2,079°F, Pressure: 14.7 psia

	Test Cases (MSW wt%)		
Duration, Conversion, and Efficiency	**50**	**75**	**100**
Steady-state Duration (hrs)	6.5	7.0	6.25
Carbon Conversion (%)	98.5	98.2	95.0
Cold Gas Efficiency (%)	57.9	70.6	64.2

6.5.3 Reported Conclusions

WPC was able to achieve constant steady-state operation of the PGVR using the coal/MSW primary feedstock, along with the metallurgical coke and flux materials. The following conclusions were provided by WPC:

- The simulated MSW materials closely matched the CCAT-requested chemical composition for MSW (refer to Table 6-74). The blended primary feedstock represented three possible scenarios at a commercial waste and CTL facility.

- The product gas generated during each test contained adequate energy (Btu/scf) and H_2:CO molar ratio for the production of liquid fuels from this feed material. On average, the energy content of the dry product gas was 197 Btu/scf. During testing, it was determined that particulate carryover (FPM data) was inconclusive because impinger water was pulled into the product gas duct. Isokinetic sampling for particulate matter was challenging at WPC's demonstration plant due to the suction created by high velocities in the product gas duct.

- Slag formed in the well, as expected, and was successfully tapped during each test run. Slag samples for each test were sent for analysis using the TCLP. Five of the eight metals regulated under RCRA were below the laboratory detection limit for all three tests. The three detected metals were all below the RCRA limits, as shown in Table 6-79.

- A comparison of the actual test data to the values predicted by computer simulation was provided. There are notable differences between the simulated and actual cases with respect to the product gas composition. Generally, the simulations predicted a higher carbon monoxide concentration and higher heating value. It is important to recognize that the simulation takes the reactions to equilibrium while the actual pilot conditions are non-equilibrium.

- Mass and energy balance calculations were performed for each test run using the average of the three steady-state operating periods providing data at several distinct operating points with respect to feed rate, product gas composition and temperature.

7. Test Results Discussion

This section presents the Project Team's evaluation of test results based on observation of the actual tests and review of test data, as well as qualitative findings presented in the facilities' quarterly or final reports. The Project Team evaluated the results within the context of the Phase 2 project objectives (Section 3). Broadly stated, the key objective was to investigate the performance of gasification technologies when co-feeding various biomass feedstocks and domestic coal. Each facility-specific subsection below also includes concerns with regard to data validity and summarizes the team's conclusions, noting their relevance to DLA Energy.

As with any pilot or demonstration testing, there are inherent differences between smaller scale units and full-size commercial units. The scale, type of gasifiers, and the range of feedstocks tested in Phase 2 varied widely. For example, at NCCC the TRIG™ handled feedstock in excess of 4,000 lb/hr, while at EERC the EFG handled approximately 10 lb/hr. Therefore, when assessing test results for potential application to large-scale, commercial operations, it is important to recognize each facility's unique considerations relating to scale and pilot plant equipment design. In some cases, gasifier operation and sampling procedures did not meet data quality objectives; therefore, these results are considered inconsistent and/or unreliable. This section does not dwell on these cases unless there appear to be inherent issues of the feedstock/equipment combinations for full-scale applications.

The Project Team identified six key parameters on which to base the discussion of results for each facility: feedstock handling, product gas composition, product gas tars, solid residue removal, carbon conversion, and cold gas efficiency. The relevance of these six parameters is briefly discussed below.

1. **Feedstock Handling** – Because the emphasis was on multiple feedstocks, the handling properties (e.g., particle size, flow ability, friability, and density) of the feedstocks should be compatible and not present obvious problems for the gasifier. For example, materials of vastly different size or density have the potential to separate in the feed system or inside the gasifier. The Project Team's observations on feedstock handling are primarily qualitative.

2. **Product Gas Composition** – An optimal product gas H_2:CO molar ratio is beneficial in the context of CBTL plant design. In general, a ratio of 2:1 is desirable; however, this will depend on the specific FT synthesis reactor (e.g., catalyst, reactor type, temperature) and the end products desired.

   The ratio achieved for a gasifier is largely dependent on the H:C molar ratio of the feedstock and the amount of steam added to the gasification process. If the product gas H_2:CO ratio is lower than optimal for the FT synthesis process, a catalytic WGS reactor can be used upstream of the FT reactor to adjust for this. Theoretically, if a gasifier is able to produce the ideal ratio (i.e., 2:1), the WGS reactor would not be required. However, it should be noted that the objective of the testing program was primarily focused on achieving stable gasifier operations using coal/biomass blends and did not target achieving a specific H_2:CO molar ratio.

3. **Product Gas Tars** – For the purpose of this report, tars are defined as any organic compound with a molecular weight greater than benzene (78 g/mol). They are produced during the pyrolysis phase of gasification and are generally undesirable in the product gas due the potential to plug downstream equipment and reduce the performance of an FT synthesis reactor. Remaining tars and particulates

downstream of the gasifier (i.e., in the raw gas) must be condensed or reformed using the appropriate equipment prior to catalytic unit operations such as the FT synthesis or WGS. In high-temperature slagging units (such as EFG and plasma), tars will usually be thermally cracked in the gasifier and tar removal in the downstream process may not be needed.

4. **Solids Removal** – To achieve true steady-state operations, solid residue in the form of ash or slag must flow continuously from the gasifier. These residues typically are collected directly from the gasifier (i.e., slag, ash), as well as through a product gas cleaning system (i.e., PCD for fine ash). Coal and biomass feedstocks have different ash chemistry, which affect properties such as ash fusion temperature and slag viscosity. In addition, the stability/mobility of potential pollutants in the solid residue may be an important factor for the disposability of the material, (i.e., whether the material has hazardous characteristics).

5. **Carbon Conversion** – This is the relative measure of carbon in the feedstock converted to carbon in the product gas during the gasification process. Typically, the carbon conversion for a gasifier is above 90%. Any carbon remaining in solid residues either is a wasted resource or must be collected and recycled back to the gasifier. A low carbon conversion may be caused by excessive carryover of char as particulates in the product gas. Gross differences in carbon conversion may be indicative of differences in the conversion of individual feedstocks.

6. **Cold Gas Efficiency** – This is the ratio between the energy content in the product gas compared to the energy in the feedstock. During gasification, a portion of the chemical energy in the feedstock is consumed in exothermic reactions and thus, converted into thermal energy. This is a critical parameter in the design of a CBTL plant because the FT process relies on the chemical energy in the syngas alone. A cold gas efficiency target of 80% is typical for a large-scale, oxygen-blown commercial gasifier (Higman and van der Burgt, 2008), although it is not expected that small demonstration plants would reach that level.

Systematic Approach to Reviewing the Data – The general plan for all facilities was to begin feeding the desired fuel blends for a given test run, then bring the gasifier to steady-state operation, and then collect representative operating data and samples. For each test a mass balance was performed using both measured quantities and calculated values. As a data quality measure, the project team filtered out the tests with low steady-state run time (less than 2 hours) and with poor mass balance closure (determined as the ratio of outputs/inputs outside the range 80 to 120%).

Most of the test data reviewed by the Project Team relates to product gas composition, carbon conversion, and cold gas efficiency. The Project Team first reviewed the general range of the data for each set of tests, then compared the coal-only data to the data for the varying coal/biomass and coal/shale gas mixtures. Finally, the impact of different types of biomass was assessed. Where review of the data indicated an expected or unexpected relationship, the Project Team used plots of the data to explain these observations. If the relationships were not expected, a possible cause is generally suggested.

For the product gas composition, one of the key parameters is the steam/carbon input, which typically has a positive correlation with the H_2:CO molar ratio because of the WGS reaction. Therefore, to allow for this relationship, the H_2:CO molar ratio is plotted against the steam to fuel carbon ratio. Similarly, the oxygen to fuel carbon ratio typically has a negative correlation with the cold gas efficiency. Therefore, cold gas efficiency was plotted against the oxygen to fuel carbon ratio when assessing the effect of different feedstocks on the gasifiers.

Variability of Gasifier Operations – The performance of any gasifier depends on many operating parameters in addition to the nature of the feedstock. Key parameters include the steam to fuel carbon ratio, the oxygen to fuel carbon ratio, and the operating pressure and temperature. Ideally, these parameters would be held constant while the feedstocks are varied so the effects of adding biomass to coal could be observed. As with most demonstration plants, holding these inter-related parameters constant was a challenge for some facilities, particularly across the range of tests and feed blends requested by the Project Team. As a result, the Project Team spent considerable effort discerning which results were attributable to feedstock changes and which were simply the effects of changes in key gasifier inputs.

The remainder of this section discusses results from each facility that performed project testing.

7.1 EERC

Testing at the EERC took place in two gasifiers, one based on an EFG design and one based on KBR's TRIG™ design (the TRDU, which is a small-scale version of the TRIG™). Section 7.1.1 discusses results associated with the EFG testing, and Section 7.1.2 focuses on the TRDU testing. Detailed descriptions of these demonstration units are provided in Appendix C and Appendix D.

7.1.1 EFG

The key objective of testing EERC's EFG was to evaluate the gasification of feedstocks and coal blends similar to those tested on EERC's TRDU in order to remove system-specific variables from the feedstock evaluation. Sixty-one tests were conducted on the EFG.

- 17 tests were conducted in 2012 on blends of Rosebud PRB coal with raw and torrefied southern pine.
- 35 tests were conducted in 2013 on blends of Antelope PRB coal with woody biomass, corn stover, aquatic biomass, and shale gas.
- 9 tests were conducted in 2014 as part of the ICCI testing and used Illinois Gateway Coal blended with raw and torrefied corn stover. The EERC reported the ICCI testing separately; however, because many of the discussion points apply across all EFG work and not to a specific group of tests, the discussion of ICCI testing is grouped with the other EFG work in this section.

Ten test runs with steady-state run times of less than 2 hours and two test runs with mass balance closure of greater than 120% are not included in this discussion. The following discussion focuses on high-level trends rather than detailed comparisons between individual tests. The data presented here are used to highlight certain trends or emphasize specific discussion points.

Two data quality issues that affect the ability to draw meaningful conclusions from the EFG data are 1) solid fuel flow measurements and 2) the variability in gasifier operations. Both issues are described below, followed by the Project Team's interpretation of observed testing and reported data.

Solid Fuel Flow Measurements – The fuel feed rate to the gasifier was determined by loss-in-weight of the feeder scale over time. The EERC acknowledges problems in scale calibration, resulting in significant differences when compared to intermittent refill weights throughout testing. In early tests this difference was 20% to 30%. Because neither method was deemed highly accurate, the feed flow rate reported was the average of these two calculations. As a result, the fuel feed rates reported in Table 6-14 and the derived values for carbon conversion and cold gas efficiency reported in Table 6-16 should be considered as approximations.

Variability of Gasifier Operations – The EFG was operated at essentially a constant pressure of 250 psig. However, gasifier temperatures, steam to fuel carbon and oxygen to fuel carbon ratios varied significantly. This variability was observed in some cases even when testing only coal or testing one type of coal blended with one type of biomass. There are many reasons for the variability, including manipulation of oxygen input to achieve temperature control or to influence the reducing atmosphere and subsequent slag freezing potential. The practical challenges in operating the EFG and achieving steady-state performance for coal/biomass blends are explained by the EERC in its test reports (Appendix C and Appendix D).

The operating conditions and the gaseous inputs for all EFG tests on coal/biomass blend are summarized as:

- Temperatures range from 2,140 to 2,805°F
- Steam to fuel carbon ratio ranges from 0.80 to 1.39
- Oxygen to fuel carbon molar ratio ranges from 0.42 to 0.89

It is likely that this variability in operating conditions would directly affect the product gas composition and cold gas efficiency results from the gasifier. As a result, differences in gasifier performance cannot be clearly attributed to the addition of biomass or to the different types of biomass. The variability of the gasifier inputs described above was more pronounced in the 2012 testing using Rosebud PRB coal and recycled product gas than in the subsequent tests using Antelope PRB and IL No.6 coals.

7.1.1.1 *Feedstock Handling*

As described in Section 6, feedstock preparation and handling presented several challenges for the EFG. These challenges were predominantly associated with the mechanics of the actual feed system and typically did not prevent testing from being conducted. Some noted challenges included: excessive heating of the feedstock during grinding operations, varied lock hopper refill cycle times based on feedstock flow characteristics, free flow of feedstock past the metering screw feeder, irregular differential pressure across the feed line, and the tendency of feeder free flow during back pulsing of the gasifier exit. The most difficult feedstock blend was switchgrass with Antelope PRB coal. Based on pretesting observations and the significant free-flowing during the attempted transition to the switchgrass blends, the EERC decided to discontinue testing with switchgrass. While the other feedstock handling issues did not prevent testing, the issues caused shorter run durations than expected in some cases.

During the course of testing, the EERC attempted to resolve feeder issues as they occurred. However, the EERC provided limited information on specific feed system modifications and troubleshooting in any of its final reports. Issues of feed handling for the EFG were a function of the generic nature of the demonstration plant equipment. It is understood that gasifier feeding systems for commercial-scale operations will be designed for specific feedstocks and that demonstration plants are generally designed for a wide range of possible feedstocks.

7.1.1.2 *Product Gas Composition*

In general, the product gas from the EFG coal/biomass tests is characterized by:

- Very low methane content. Virtually all the coal/biomass tests indicate no methane in the product gas, with the exception of the Knight Hawk Illinois coal/torrefied wood blend, which contained 0.51 percent by volume (%vol) on a dry nitrogen-free basis. The very low methane results are expected for a high-temperature, slagging gasifier such as the EFG.

- An H_2:CO molar ratio that varies widely, ranging from 0.45 to 1.63. As expected, the product gas H_2:CO molar ratio shows a positive response to the steam to fuel carbon ratio, however, no correlation was observed between the percent biomass and product gas H_2:CO molar ratio.

The project team also reviewed the effect of product gas recycle for all the sub-bituminous coal tests, including coal only and biomass blends. In the 2012 testing (Phase 1) product gas was recycled to the gasifier, while in the 2013 testing (Phase II) the EFG was operated without recycle. The project team observed that recycle corresponded to consistently lower product gas H_2:CO molar ratio:

- 2012 : Range of 0.45 to 1.33 and average 0.86
- 2013 : Range of 0.98 to 1.31 and average 1.25

One potential cause for this could be that the product gas was dried before being recycled, favoring the reverse WGS reaction and lowering the H_2:CO molar ratio. Note that the ICCI tests used bituminous coal and therefore were not compared to the sub-bituminous coal for this purpose.

To investigate the effect of different types of biomass on the product gas composition, the Project Team sorted the 2012 data according to biomass type. Figure 7-1 shows a plot of the product gas H_2:CO molar ratio against the steam to fuel carbon ratio, with the data grouped into coal-only, aquatic biomass blends (algae and water hyacinth), and terrestrial biomass blends (southern pine, corn stover). To avoid potential effects due to coal rank and product gas recycle, only the 2013 Antelope PRB coal tests are plotted. Based on these plots, the aquatic biomass results in a higher H_2:CO molar ratio than either the coal-only or the coal/terrestrial biomass blends. There is no apparent reason for this difference based on the ultimate analysis of the feedstocks, so it is possible something specific to aquatic biomass effects the product gas composition.

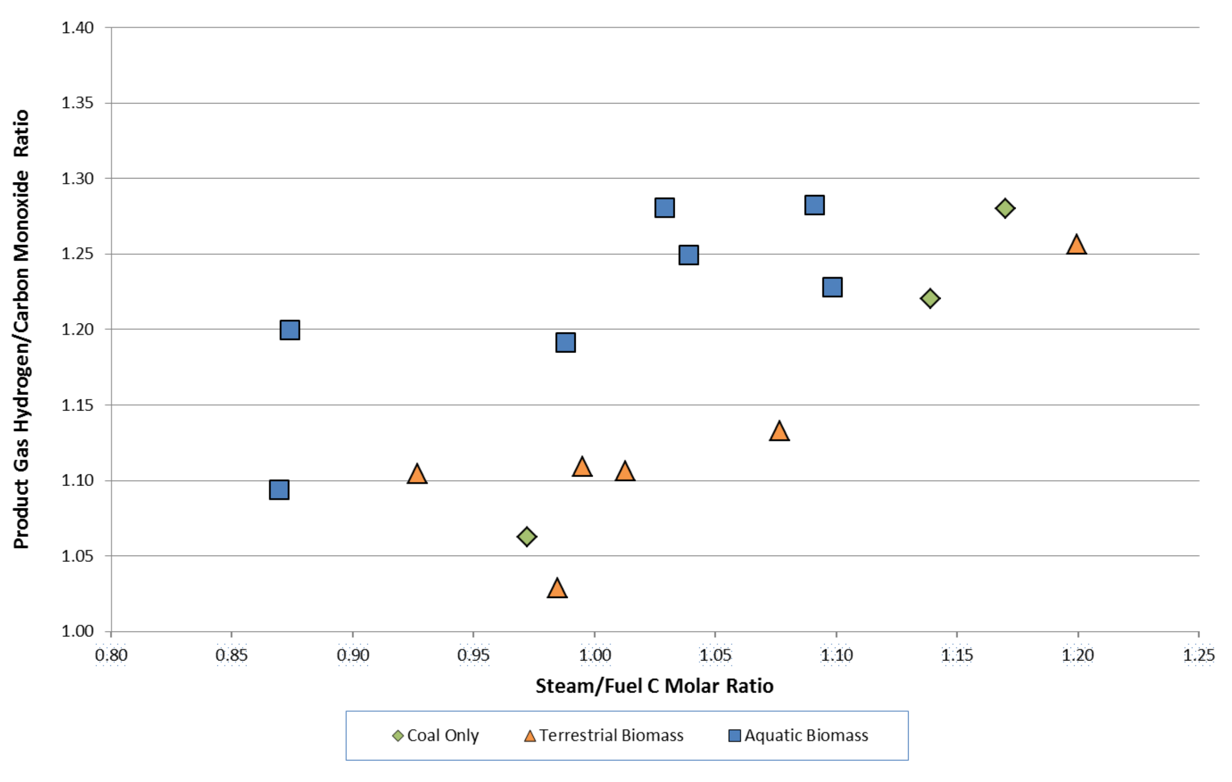


Figure 7-1: Product Gas H_2:CO Molar Ratio for Antelope Coal/Biomass Blends

For the EFG tests on coal/shale gas, the product gas is characterized by:

- H_2:CO molar ratio that is consistently higher than the coal/biomass tests, ranging from 1.18 to 1.72. This relationship is consistent with the stoichiometry of the gasifier, given that reforming of hydrocarbons leads to more hydrogen than the gasification reactions undergone by coal or biomass.

- Methane content that varies greatly, from 0.0% vol to 9.2% vol, depending on injection location of the shale gas.

Figure 7-2 shows the product gas H_2:CO molar ratio for Antelope PRB coal blended with both biomass and shale gas, with shale gas results broken down by injection location. It appears that shale gas injected into the flame zone results in higher H_2:CO ratio than for shale gas injected into the quench zone. There is no significant difference in the H_2:CO ratio for the quench zone injection and biomass tests.

To investigate this further, Figure 7-3 plots selected product gas results by shale gas heat input and injection location. Tests with injection into the flame zone show no methane in the product gas, indicating complete reforming of the hydrocarbons. However, the four tests with quench zone injection show significant methane in the product gas, which is proportional to the amount of shale gas in the feedstock. This indicates significant slippage of hydrocarbons from the gasifier when injected into the quench zone. Either temperature or residence time are insufficient to reform the hydrocarbons at the quench location.

In addition, for the shale gas that was injected into the flame zone, a positive relationship was observed between shale gas input and the product gas H_2:CO molar ratio.

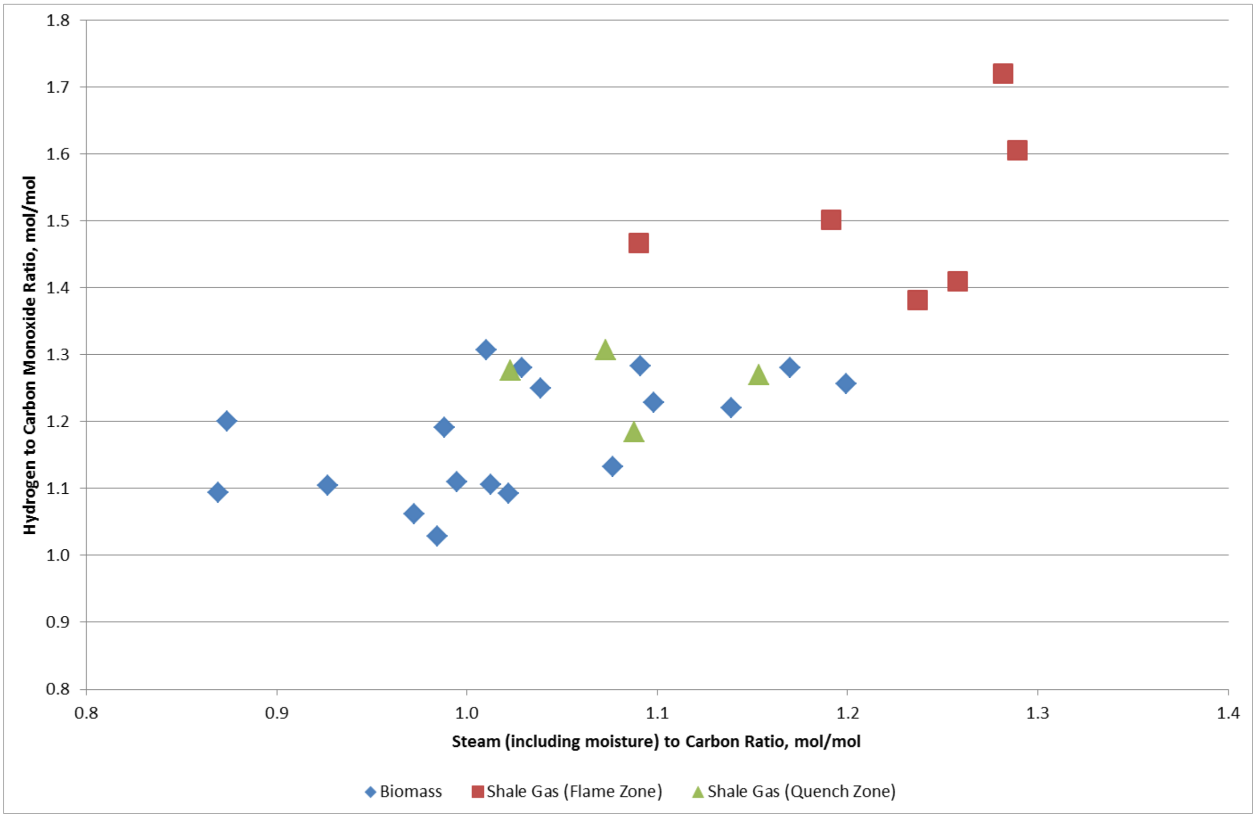


Figure 7-2: Product Gas H_2:CO Molar Ratio for EFG, Antelope PRB Coal/Biomass, and Shale Gas Tests

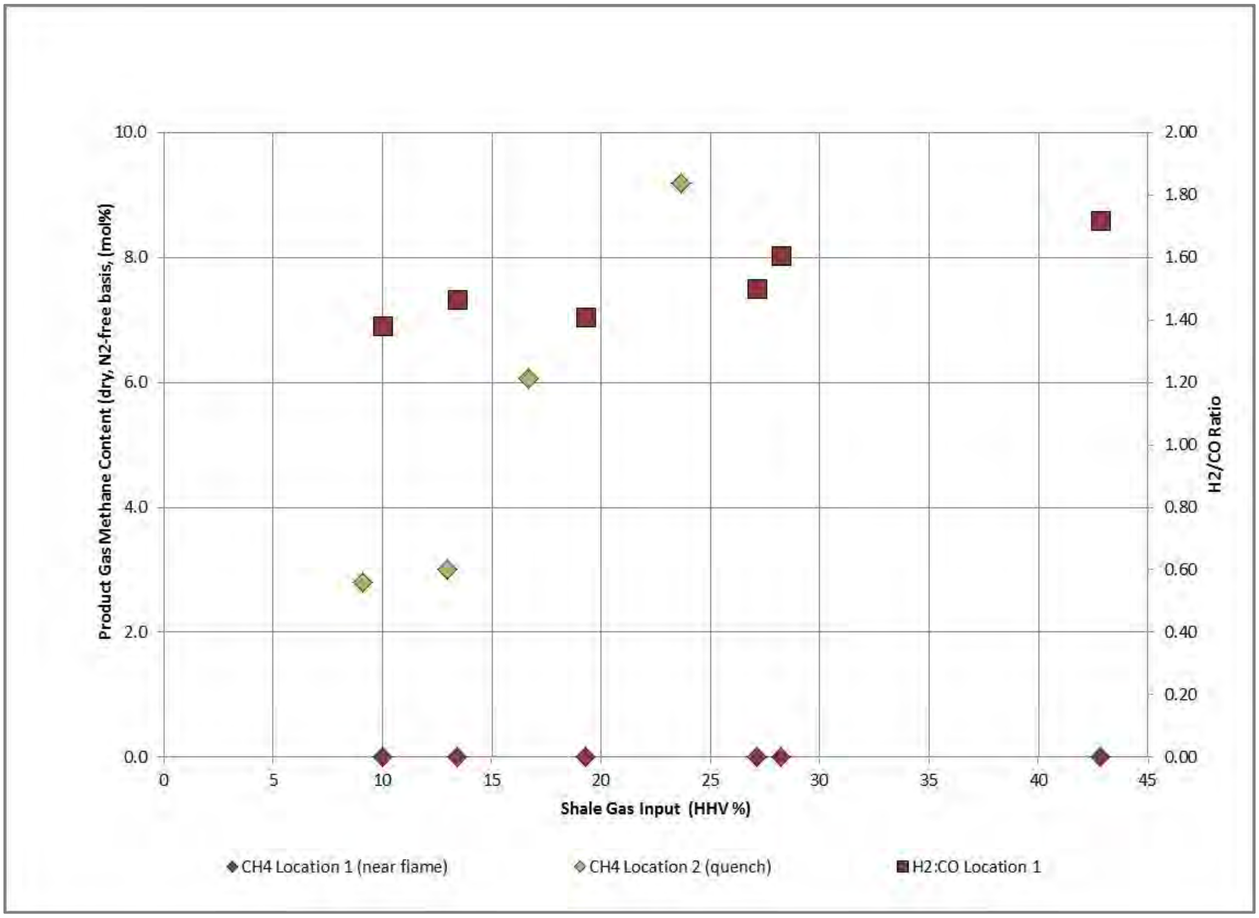


Figure 7-3: Product Gas Methane for EFG, Antelope PRB Coal/Shale Gas Tests

7.1.1.3 *Product Gas Tars*

The test plan for EFG included measurement of total organic carbon (TOC) in the product gas condensate (referred to as quench water in the EERC test reports). The intention was that these measurements would infer product gas tar levels. However, the only portion of the condensate tested was the aqueous phase, and thus TOC data can only indicate water soluble organics in the product gas. As solidified tars and organic condensate were not systematically collected, the TOC data are considered only a partial indicator of the actual tar levels.

The production of tars is associated with both coal and biomass gasification. The Project Team expected coal/biomass blends, which have higher volatile matter, to generate more tar than coal-only and this may be evident in the TOC results. However, when condensate TOC was plotted against changes in feedstock volatile matter, no significant trend was observed. The Project Team also compared TOC to oxygen to fuel carbon ratio and no trend was observed.

The condensate TOC from the full set of coal/biomass tests is summarized as follows:

- Coal-Only, from 4.9 to 65 mg/L, with one outlier at 500 mg/L
- Coal/Terrestrial biomass, from 14.7 to 876 mg/L

- Coal/Aquatic biomass, from 5.8 to 22.9 mg/L
- Coal/Shale Gas, from 8 to 38 mg/L

Although the results vary widely, it appears that coal/aquatic biomass blends produce less water soluble organics in the product gas than coal blended with terrestrial biomass. The coal/shale gas results are generally in line with coal-only tests.

7.1.1.4 *Solids Removal*

Fly ash captured in the PCD was removed via a lock hopper, as needed. Particulate samples are associated to some extent with an individual test, but some of the fly ash became entrained in the slag flow; therefore, it is not possible to provide definitive results for each test. These limitations are presented here to show how they affect the mass balance. As a result of these limitations, assumptions were made about the flow rate and chemistry of the slag and fly ash streams.

Although the EFG is a slagging gasifier, slag flow was not continuous in all tests. During several tests, the slag hardened in the reactor tube. These events were attributed to feeder and other operational issues and were not associated with any particular feedstock.

For large-scale gasifiers, continuous solids removal is required for successful gasifier operation. At the demonstration scale, the issues may be addressed in a non-continuous manner, as was the case at the EERC. For the EERC's EFG, the system must be partially cold and fully depressurized before the slag and ash can be removed from the slag pot. As a result, slag samples were not associated with individual tests. Therefore, no information was obtained on the slagging properties and slag chemistry for individual feedstocks tested.

7.1.1.5 *Carbon Conversion*

As described above under solids removal, the techniques available for continuous ash removal will affect the accuracy of the carbon conversion results. The carbon content of solid residues from the gasifier was based solely on LOI analyses of the filter ash collected from the PCD. The EERC assumed that LOI of the PCD ash is equivalent to carbon content. However, non-carbon components may be present in the PCD ash samples, which could bias carbon conversion. This is in addition to bias caused by fly ash entrained with the slag and not represented in the PCD samples.

The carbon conversion results may be summarized as follows:

- Coal-only and coal/biomass blends: All results were above 98%, with two exceptions;
  - Knight Hawk Illinois coal/torrefied southern pine (93%)
  - Antelope PRB coal/aquatic biomass (97%)

There was no consistent pattern of operating conditions concerning the lower carbon conversion for these two feedstocks.

- Coal/shale gas blends: All results were above 99%

Carbon conversion in the EFG is consistently high, which is typical for a slagging, high-temperature gasifier.

7.1.1.6 *Cold Gas Efficiency*

The cold gas efficiency for the various EFG tests on coal-only and coal/biomass blends was found to be highly variable. The results may be summarized as follows:

- Coal-only: cold gas efficiency was 43 to 87% (average 63%)
- Coal/biomass blends: cold gas efficiency was 45 to 84% (average 59%)

In order to determine whether the variation in cold gas efficiency can be attributed to feedstock changes or whether it is more a function of the oxygen to fuel carbon ratio entering the gasifier, cold gas efficiency was plotted against biomass percent and against oxygen to fuel carbon ratio. No obvious relationship exists with biomass percent, but the cold gas efficiency shows a negative linear response with the oxygen to fuel carbon ratio. Figure 7-4 shows this relationship for all tests using Antelope PRB Coal/Aquatic biomass blends. Similar comparisons can be made for the other biomass types, showing that oxygen input, rather than biomass content had the dominant effect on cold gas efficiency for the EFG tests.

In reviewing the effect of biomass type, the project team found that the cold gas efficiency for coal/aquatic biomass blends appears to be consistently lower than for coal/terrestrial biomass blends. This is shown on Figure 7-5 where cold gas efficiency is plotted according to biomass type. This result may be due to higher ash and moisture in the aquatic feedstocks.

The cold gas efficiency for coal/shale gas blends was significantly lower than the coal-only or the coal/biomass blends.

- Coal/shale gas blends: cold gas efficiency was 43 to 64% (average 53%)

These lower values are consistent with the response to higher oxygen input, rather than different feedstock types.

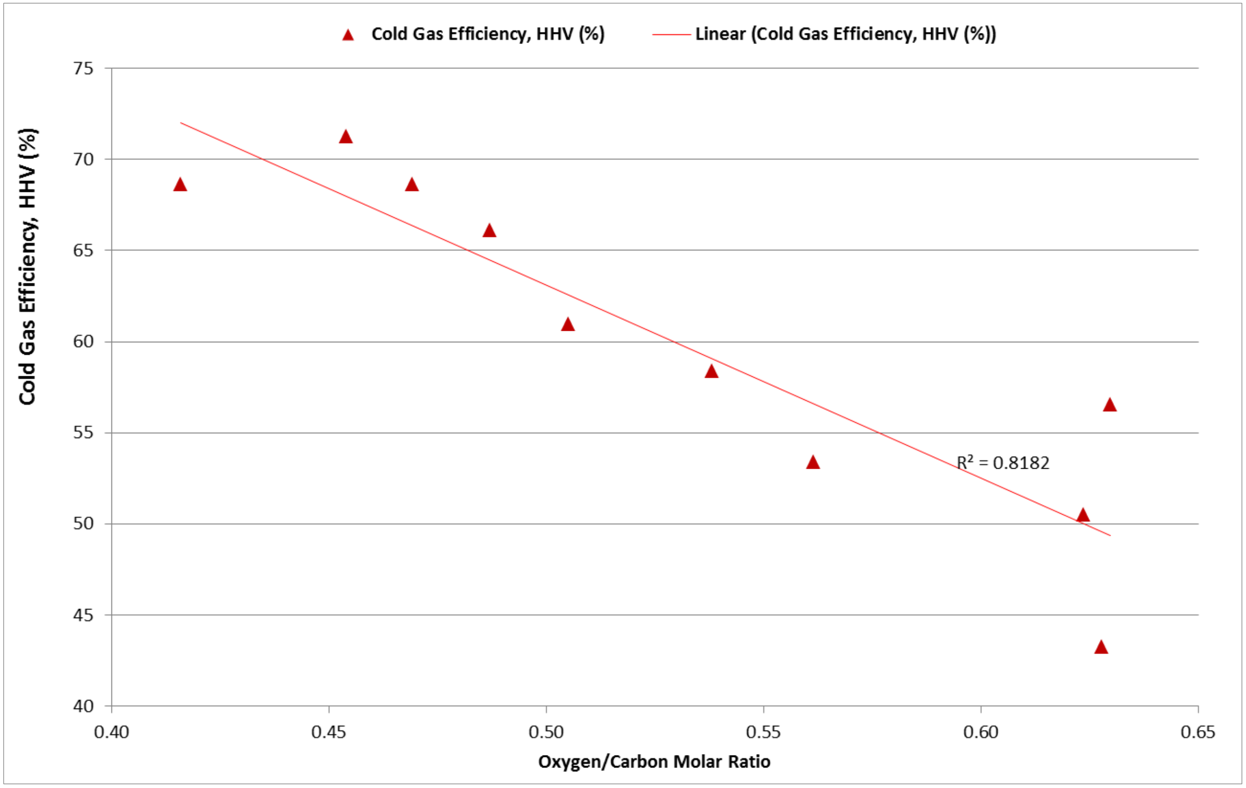


Figure 7-4: Cold Gas Efficiency versus Oxygen to Fuel Carbon Molar Feed Ratio for Antelope PRB Coal/Aquatic Biomass Blends

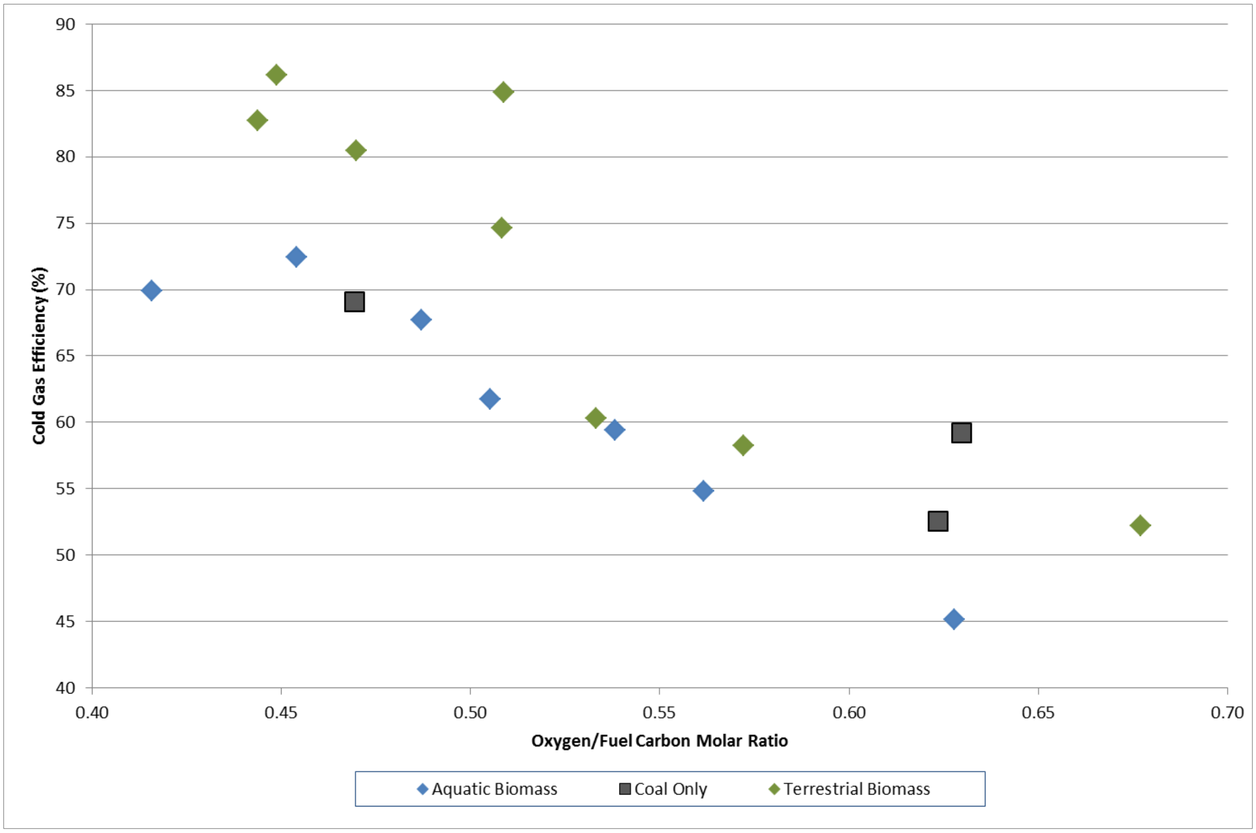


Figure 7-5: Cold Gas Efficiency versus Oxygen to Carbon Molar Ratio for Antelope PRB Coal/Biomass Tests

7.1.1.7 *Summary of Results*

Notwithstanding a number of mechanical feeding issues, the EERC was able to feed most of the planned feedstocks into the EFG and gasify the material successfully. The following points summarize the testing and the available, verifiable results.

Biomass tests

- Up to 30% by weight of six terrestrial and aquatic biomass types were successfully blended with PRB sub-bituminous coal, fed into the EFG, and gasified. In addition, corn stover was blended with IL No. 6 bituminous coal. A feed of 100% torrefied southern pine was also fed to the gasifier.

- The product gas H_2:CO molar ratio was strongly correlated to the steam to fuel carbon ratio for the biomass tests, as expected due to the WGS shift reaction at the high temperatures (approximately 2,500 to 2,700°F) for these tests. The ratio ranges from 0.45 to 1.63.

- The product gas H_2:CO molar ratio appears to be substantially lower for the 2012 tests in which product gas was recycled back to the gasifier.

- Insufficient data were collected to make conclusions about the formation of tars during these tests. By analyzing the condensate TOC data, a loose correlation suggests that blends with aquatic biomass may produce less tar than blends with terrestrial biomass.

- Carbon conversion was greater than 98% for all but two of the tests.

- Cold gas efficiency varied widely for coal/biomass blends, and appears to be closely related to changes in the oxygen to fuel carbon ratio, rather than the amount of biomass added. However, cold gas efficiency for coal/aquatic biomass blends appears to be consistently lower than coal/terrestrial biomass blends, even when allowing for differences in oxygen input. The cold gas efficiency ranges from 43 to 87%.

Shale gas tests

- Two types of simulated shale gas (rich and lean), representing up to 42% of the HHV, were injected at two locations of the EFG and co-fed with PRB sub-bituminous coal. Both types of shale gas were reformed to syngas successfully when injected into the flame zone. When injected into the quench zone, significant methane slippage was observed.

- The product gas H_2:CO molar ratio for the shale gas tests was, on average, higher than the coal/biomass tests, ranging from 1.18 to 1.72. This higher ratio appears to be a response to higher steam input.

- Carbon conversion was greater than 99% for all coal/shale gas tests.

- Cold gas efficiency was significantly lower for the coal/shale gas than for coal/biomass tests, ranging from 43 to 64% (average 53%). However, these lower values are consistent with the response to higher oxygen input, rather than different feedstock types.

The EFG test results do not show significant differences among feedstock types or percent mixture with the various types of coal used. This does not mean that differences do not exist but that the variability/instability in the system's operating parameters dominated/had greatest effect on the results.

The Project Team concludes from the testing on the EERC's EFG that if coal and biomass mixtures are fed into the gasifier in a reasonably steady fashion, the EFG is able to gasify a wide range of feedstocks and produce a product gas that can be used in an FT reactor after product gas cleanup and the necessary shift reactions.

7.1.2 TRDU

The two key objectives for testing the EERC's TRDU were to evaluate the gasification of feedstocks and coal blends similar to those tested on the EFG and on a transport gasifier 10 times larger than EERC's at NCCC.

Sixty-eight different tests were completed on the TRDU from February 2012 to September 2013 (Table 6-24). The tests were conducted during continuous operation of the gasifier in five distinct run periods lasting from 5 to 9 days. Most of the test data appear to be valid and useable based on the mass closure and steady-state duration, with some exceptions, noted below:

- The two tests with 10% raw southern pine ran at a steady state of 2 hours or less and have been excluded from subsequent discussion of the TRDU tests.

- The reported as-fed proximate analysis and heating value for the corn stover blends are not consistent with what is expected based on the percent mixtures with coal. For example, the fixed carbon for the 20% biomass blend is higher than for both the 10% and 30% biomass blends. However, because there were only three corn stover tests, all results were used in this analysis.

Variability of Gasifier Operations – As mentioned in the introduction to Section 7, there would ideally be minimal variation of key inputs from test to test, particularly with tests in the same run period. Gasifier pressure was constant for all tests at 120 psig, while other key parameters varied as follows:

- Average gasifier temperature was 1,700°F, but ranged from 1,550 to 1,850°F.
- The molar ratio of oxygen to fuel carbon ranged from 0.4 to 0.6.
- The molar ratio of steam to fuel carbon ranged from 0.6 to 1.5.

How these parameters may affect gasifier output (product gas) is discussed below. Results of the biomass tests and shale gas tests are generally discussed separately due to the differences in the type of materials and the manner in which they were fed to the gasifier.

7.1.2.1 *Feedstock Handling*

The EERC was able to mill all biomass and coal feedstocks tested and blend them at or very close to the target ratios. Initially, the feed rate of the 10% raw pine blend was difficult to control. After minor modifications were made to the feeder, all feedstocks were successfully fed to the gasifier. The feeder plugged at the beginning of the 30% used railroad ties test, but after a slight interruption, feeding resumed without incident for the remainder of the test. The feed rates for most tests fell within the target of 400 to 450 lb/hr; the range was 300 to 500 lb/hr. For the shale gas tests, the EERC was able to deliver simulated lean and rich shale gases to the gasifier using a system of calibrated mass flow controllers for each component gas. No significant feeding issues were encountered. The actual amount of shale gas blended with coal was within one or two percentage points of the target amounts in 15 of the 17 shale gas test cases. In two 30% target lean gas tests, the actual amount of gas injected was less than 26% on an HHV basis.

7.1.2.2 *Product Gas Composition*

The four main components of product gas are hydrogen, carbon monoxide, carbon dioxide, and methane. The dry, nitrogen-free concentration of each gas is plotted by biomass mass feed percentage on Figure 7-6 and by shale gas HHV feed percentage on Figure 7-7. Carbon dioxide concentration had the widest spread, ranging from 36 to 56%. The range for all gases appears to be represented at all coal/biomass blends tested (i.e., biomass percentage is not a predictor of product gas composition).

For liquid fuels production, the most important components are hydrogen and carbon monoxide and the ratio of one to the other. The product gas H_2:CO molar ratio for the TRDU tests, varied over a wide range as follows:

- Coal-only: Range of 1.46 to 1.93
- Coal/biomass blends: Range of 1.09 to 1.82

There was a strong correlation of increasing H_2:CO molar ratio with increasing steam to fuel carbon ratio. The “steam” in this analysis includes feedstock moisture in addition to the injected steam. The correlation is strongest with the terrestrial biomass types (Figure 7-6), particularly with raw and torrefied southern pine tests. The H_2:CO molar ratio was generally higher with blends of aquatic biomass than with blends of terrestrial biomass. The data for these two sets of biomass types are shown on Figure 7-6.

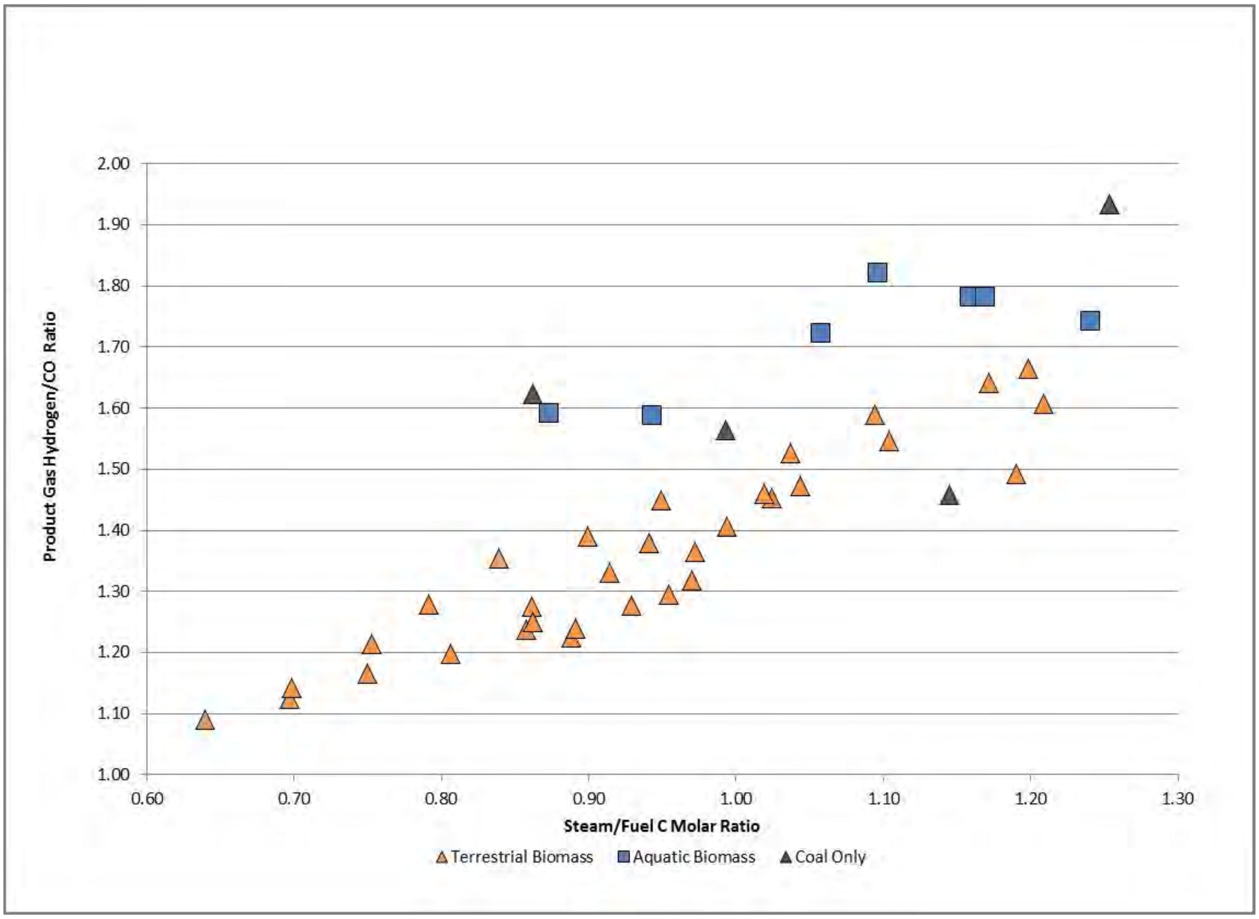


Figure 7-6: Product Gas H_2:CO Molar Ratio for Coal/Biomass Blends, based on Biomass Type

For the TRDU coal/biomass tests, significant methane content was present in the product gas. The dry, nitrogen-free methane content of the product gas may be summarized as follows:

- Coal-only: Range of 5.7 to 6.3%
- Coal/ aquatic biomass blends: Range of 6.0 to 7.1%

- Coal/ terrestrial biomass blends: Range of 4.3 to 7.8%

For the coal/shale gas blends, the product gas H_2:CO molar ratio was considerably higher (Range of 1.86 to 2.32), but this was consistent with the response to steam input.

For the shale gas tests, injection location appears to affect the amount of hydrocarbons reformed in the gasifier. This is illustrated by plotting methane concentration in dry product gas by the amount of shale gas injected at each location shown on Figure 7-7. This shows the highest "slippage" at Location 2, significantly less at Location 3, and even less at Location 1. Because Location 2 is higher up in the gasifier riser than the other injection locations, there is less time for the shale gas to be reformed and converted to syngas.

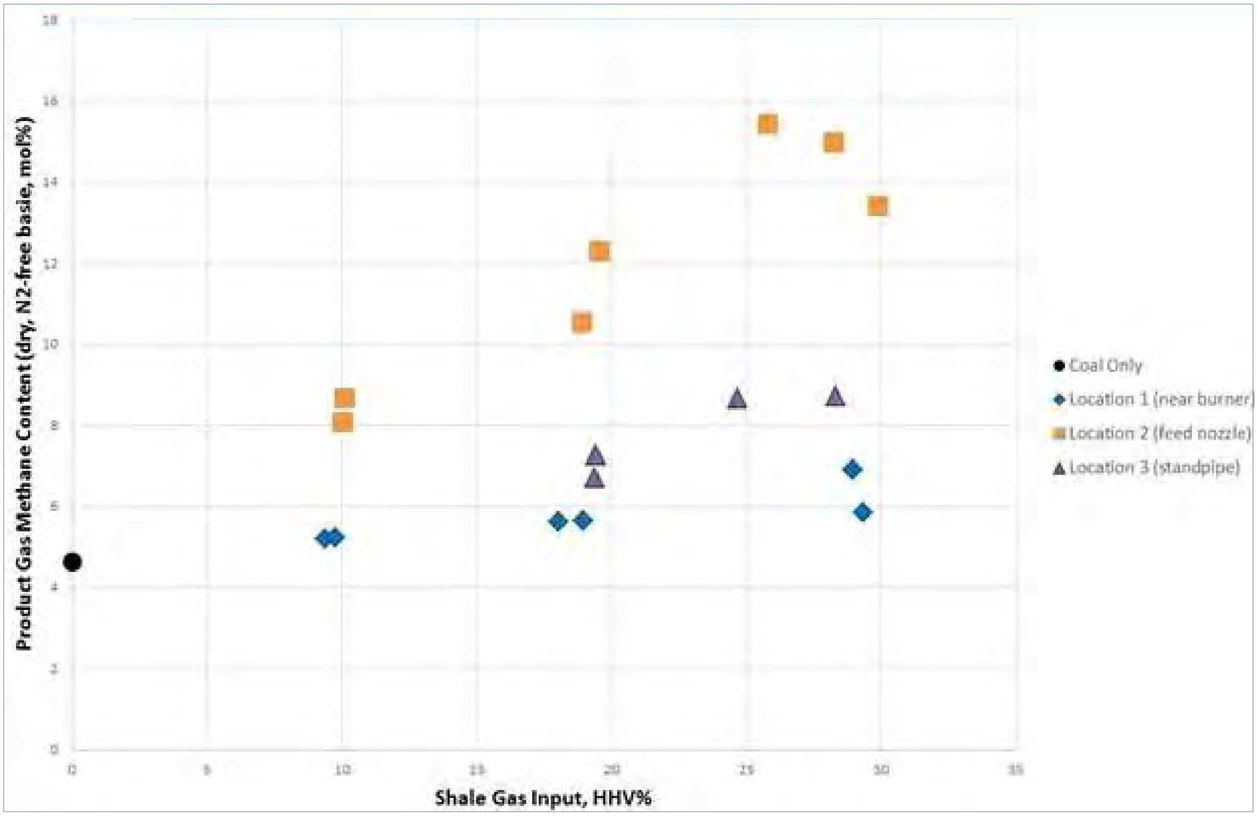


Figure 7-7: Product Gas Methane versus Shale Gas Input by Injection Location

7.1.2.3 *Product Gas Tars*

The biomass blends tested were lower in fixed carbon, but higher in volatile matter compared to the coal-only test. Since volatile matter is a source of tars that may be produced in the TRDU, it was planned to collect data that would infer tar levels. Total organic carbon in product gas condensate and Draeger tube samples for toluene were measured. However, because these measurements were not correlated to the amount of product gas produced, there is too much uncertainty to make any reasonable statements about tar formation during these tests. Additional testing using specific tar sampling protocols would be needed to determine if there is a relationship between particular biomass types and the formation of tars in a transport gasifier.

7.1.2.4 *Solids Removal*

No bed deposition or agglomeration issues were encountered in any TRDU tests, including tests with feedstocks containing elevated levels of sodium, calcium, potassium, or phosphorus. Filter ash was routinely removed from the PCD during operation of the gasifier and measured. Removal rates ranged from 20 to 92 lb/hr. Coarse ash removed from the standpipe was not quantified, but the EERC assumed a removal rate of 2.1 lb/hr for all cases based on experience. However, for most tests, coarse ash removal was not required and, in fact, due to the low ash content of most biomass types used, additional silica sand was added to maintain the solids inventory in the standpipe. The standpipe samples contained high levels of silica, which indicates that it is unlikely that the bed material was at steady state during each test run. While coarse ash removal was included in calculating the mass balance closure for each test, the effect of using the assumed value is negligible. The presence of inert bed material in standpipe ash could also dilute the samples analyzed for metals and hazardous leachable metals (TCLP). However, given that most TCLP metals were not detected in all standpipe ash samples, the effect of any dilution on the hazardous characteristic of the ash material is negligible.

7.1.2.5 *Carbon Conversion*

The following issues highlight the challenge of accurately determining carbon conversion for the TRDU.

- Carbon content of solid residues from the gasifier was based on LOI analyses of the filter ash collected from the PCD. EERC assumed that LOI is equivalent to carbon content. However, non-carbon components in the samples may be included in the LOI results, which would bias the carbon conversion calculation.

- Coarse ash from the standpipe was not analyzed for LOI. As noted above, little if any coarse ash was removed during the TRDU tests. Based on previous EERC experience, the carbon content of coarse ash is negligible because most of the coarse ash is recirculated through the gasifier. However, the relatively large mass of bed material means that large changes in carbon inventory are possible with relatively minor changes in carbon concentration. Detailed analysis of the fuel inputs and product gas outputs as well as the oxygen to fuel ratio indicate that carbon inventory, likely in the form of char, may have been changing from test to test and even within a test period. Changes in this inventory during a test represent non-steady-state conditions and bias the calculation of carbon conversion.

Calculated carbon conversion ranged from 71.6 to 98.7% for all scenarios tested (average 94.3%). Carbon conversion was significantly lower for the two tests of IL No. 6 coal/raw southern pine blends, likely because of the lower fuel reactivity of bituminous coal compared with the lower rank coals. No distinction in carbon conversion is attributed to the biomass percentage for biomass co-firing.

For the shale gas tests, carbon conversion was slightly lower for the Location 1 (burner) injection tests than for the other injection sites. It is unclear whether this is attributable to the shale gas injection location or a run order effect associated with the specific test program (e.g., changes in carbon inventory).

7.1.2.6 *Cold Gas Efficiency*

The dry product gas higher heating values for the TRDU are relatively low due to dilution with nitrogen, ranging from 65 to 160 Btu/scf for all tests. Cold gas efficiency results were also relatively low, ranging from 29.5 to 68.3% for all scenarios tested (average 51.7%). The results may be summarized as follows:

- Coal-only: cold gas efficiency was 45 to 58%
- Coal/biomass blends: cold gas efficiency was 28 to 59%
- Coal/shale gas blends: cold gas efficiency was 51 to 68%

The highest cold gas efficiency was typically in the shale gas tests (Location 2), while the lowest cold gas efficiency was in the algae, switchgrass, and corn stover tests. As mentioned in the introduction to Section 7, cold gas efficiency is typically expected to decrease with increasing oxygen to fuel carbon ratio. However, no significant correlation was evident for the coal/biomass or the coal/shale gas blends. To illustrate this point, Figure 7-8 shows cold gas efficiency versus oxygen to fuel carbon ratio for the coal/terrestrial biomass tests. It is clear from the scatter of the plots that that the cold gas efficiency is not responding to oxygen as expected over this range. This lack of correlation may be due to the low range oxygen to fuel carbon ratio used for these TRDU tests.

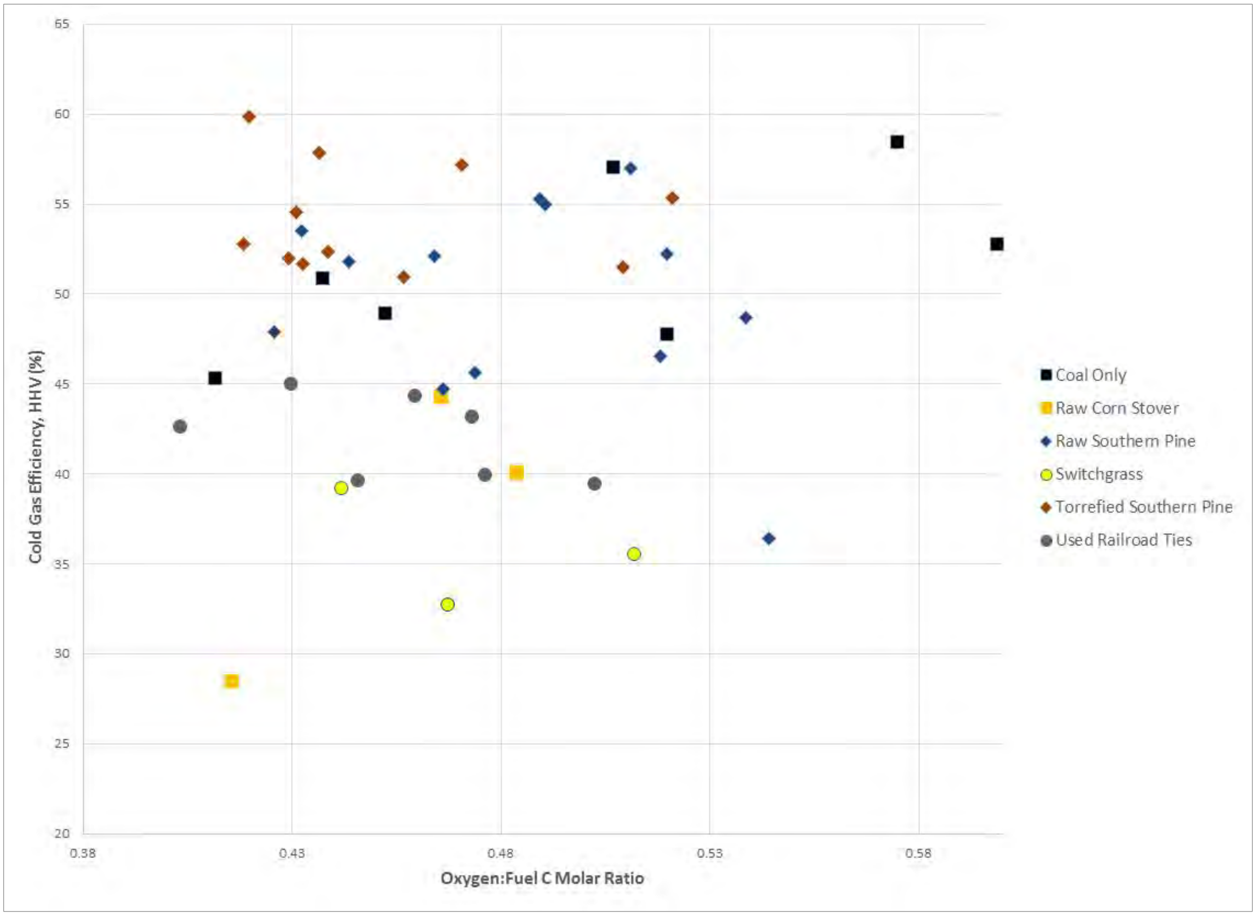


Figure 7-8: Cold Gas Efficiency versus Oxygen to Fuel Carbon Ratio, TRDU Coal, and Terrestrial Biomass Tests

Another measure of gasifier efficiency is the amount of dry syngas produced per unit mass of feedstock (syngas to fuel). The range for all tests was 6.3 to 13.2 scf/lb. Similar to cold gas efficiency, the ratio was greatest for the raw and torrefied pine and shale gas tests, and lowest for the algae, switchgrass, and corn stover tests.

For the coal/shale gas blends, cold gas efficiency is dependent upon shale gas injection location. The lowest CGEs with shale gas injection were observed at Location 1; these results were indistinguishable from the coal only tests. As mentioned under product gas composition, the most effective reforming of shale gas occurred at Location 1 (burner). Methane in product gas contributes to HHV, so methane slippage observed with the Location 2 tests favors high CGE.

7.1.2.7 *Summary of Results*

All TRDU tests produced syngas that could potentially be used to produce liquid fuels after typical downstream processing. The TRDU is a complex system with many factors affecting performance and efficiency, including steam and oxygen inputs, operating temperature, duration of each test, and run order. Some general observations about the biomass and shale gas tests follow.

Biomass tests

- Up to 30% by weight of eight biomass types were successfully blended with PRB coal, fed to the TRDU, and gasified.

- The product gas H_2:CO molar ratio ranged from 1.1 to 1.8 and was strongly correlated to the steam to fuel carbon ratio for most biomass tests. This provides evidence that the WGS reaction occurred even at the relatively low operating temperatures of the TRDU (compared to the EFG). Aquatic biomass blends appeared to show higher product gas H_2:CO molar ratio than similar tests using terrestrial biomass. A significant amount of methane was observed in the product gas (4.7 to 7.8% dry, nitrogen-free).

- Insufficient data were collected to make conclusions about the formation of tars during these tests by analyzing the condensate TOC data.

- Carbon conversion for most tests was greater than 90% (average 94%). With the exception of low carbon conversion with bituminous coal, no differences were observed based on feedstock type.

- Cold gas efficiency ranged from 29.5 to 61.2% (average 49%). Cold gas efficiency was highest for the torrefied pine tests and lowest for blends with algae, switchgrass, and corn stover. However, it is uncertain if the results can be attributed to biomass type.

- No correlation was evident between cold gas efficiency and oxygen to fuel ratio. The consumption of oxygen does not appear to be the primary driver to cold gas efficiency on the TRDU at the conditions tested.

- The results indicate changes in fixed carbon inventory in the bed material result in changes in product gas output and cold gas efficiency. The tests generally did not run long enough for the bed material to reach steady state. This could bias the reported carbon conversion numbers.

Shale gas tests

- Up to 30% (by HHV) of two types of simulated shale gas (rich and lean) were injected at three locations of the TRDU and gasified with lignite.

- The H_2:CO molar ratio for the shale gas tests was higher than for the biomass tests. This is consistent with the higher steam to carbon ratio present during the shale gas tests.

- Injection at Location 1 (near burner, bottom of mixing zone) appears to offer the greatest opportunity for reforming shale gas into syngas due to higher retention time and temperature. Methane slippage was lowest when shale gas was injected at the burner (Location 1).

- Carbon conversion for most tests was greater than 90% (average 96%).

- Cold gas efficiency ranged from 51 to 68% (average 61%).

7.1.3 Tar Reforming

The objective of tar reforming tests at the EERC was to evaluate the performance of a novel catalyst to reform tars at modest temperatures, between 670 and 840°F. A total of 23 tests were performed utilizing a fixed bed catalyst.

- 8 tests were performed in 2013 using product gas slipstream from TRDU tests gasifying Rosebud PRB coal/biomass mixtures.

- 15 tests were performed using product gas slipstream from TRDU tests gasifying Falkirk Lignite with simulated shale gas injected into the TRDU.

The test program was intended to evaluate the catalyst at varying temperatures and gas throughputs. For our evaluation, fine distinctions between test conditions could not be reasonably evaluated due to the following:

- Inadequate measurement and/or control of catalyst bed temperatures; average bed temperatures were found to vary up to 477°F by location within the bed during steady-state runs

- Large differences in inlet gas composition between parametric runs

- Lack of experimental controls to account for run history

A variety of conditions may have contributed to catalyst degradation during a series of tests including blinding, chemical deactivation, and thermal deactivation. No evidence was noted of physical blinding of the beds. A single event was noted for oxygen intrusion to the catalyst bed coincident with a temperature spike followed by a notable change in condensed tar characteristics. Further, catalyst mass gains that may be attributable to adsorption leading to either deactivation or blinding was noted; however, the scope of this test program did not allow for detailed investigation. Finally, it is clear from both the average catalyst bed temperatures and the average individual location measurements within the catalyst beds that portions of the catalyst routinely exceeded the operational temperature window of 840°F with average temperatures as high as 1,051°F recorded.

7.1.3.1 *Product Gas Composition*

The product gas composition was noted to markedly change across the tar reforming system. Tests bypassing the tar reforming system did not significantly increase the H_2:CO molar ratio. During Week 1 coal/biomass tests, the H_2:CO molar ratio increased from a range of 1.3 to 1.6 at the tar reforming inlet to 3.9 to 9.5 at the tar reforming system outlet. During Week 2 coal/shale gas testing, the H_2:CO molar ratio increased from a range of 1.8 to 2.3 at the tar reforming inlet to 5.3 to 13.3 at the tar reforming system outlet. Carbon monoxide concentrations were found to decrease significantly while hydrogen concentrations were found to increase slightly. There was insufficient increase in hydrogen concentration to account for the decrease in carbon monoxide with WGS reaction as the primary driver. Net loss of syngas (i.e., carbon monoxide plus hydrogen) from the product gas is consistent with the observed reduction in cold gas efficiency across the tar reforming system.

7.1.3.2 *Product Gas Tars*

A number of difficulties were encountered in determining tar concentrations including the partition of tars between liquid and solid phases and the differences in sample time and volume between tar reforming system inlet and outlet. Two tests were sampled concurrently at the inlet and outlet of the tar reforming system with a bomb apparatus. Though dismissed by the EERC, analysis of these bomb samples represent the most valid data of whole gas byproducts available from this test series; no substantive grounds were provided by the EERC for suspecting these data. Gasification byproduct components quantified in these two tests are listed in Table 6-46. The byproduct components are dominated by methanol and benzene at both the tar reforming system inlet and outlet. Neither of these compounds is considered a tar. Nevertheless, significant methanol and benzene reductions were observed in the first test, before the oxygen intrusion event, while no significant change in methanol and benzene were observed in the second test, after the oxygen intrusion event. A small amount of tar was identified in both bomb tests. As with the methanol and benzene, significant tar reduction was observed in the first test while no significant reduction was observed in the second test.

7.1.3.3 *Cold Gas Efficiency*

Cold gas efficiency is expected to improve with reforming as byproduct gases are converted to hydrogen, carbon monoxide, and methane. The change in cold gas efficiency is difficult to assess because the reactions in the reformer are not expected to be volume neutral on either a wet or dry basis. While dry gas concentration was provided by the EERC at both the inlet and outlet of the tar reforming system, dry gas flow was only measured at the outlet of the tar reforming system. Nitrogen concentration was measured along with hydrogen, carbon monoxide, methane, and carbon dioxide at both the inlet and outlet of the tar reforming system. Since no nitrogen was added between extraction from the TRDU and exhaust from the tar reforming test stand, it is reasonable to use nitrogen as a normalizing gas to account for volume changes. On this basis, the tar reforming system inlet heating values varied from 132 to 220 British thermal units per dry standard cubic feet (Btu/dscf) nitrogen for Week 1 coal/biomass tests and from 198 to 320 Btu/dscf nitrogen for Week 2 coal/shale gas tests. Tar reforming system outlet heating values varied from 98 to 185 Btu/dscf nitrogen for Week 1 coal/biomass tests and from 172 to 289 Btu/dscf nitrogen for Week 2 coal/shale gas tests. No test exhibited an improvement in gas heating value and, therefore, there was no improvement in cold gas efficiency across the tar reforming system for any test. Baseline tests bypassing the tar reforming system exhibited 3.4 to 15.6% reduction in cold gas efficiency. Tests through the tar reforming system exhibited 2.8 to 36.4% reduction in cold gas efficiency with a median reduction of 9.8%. The balance of evidence suggests tar reforming during this test series resulted in a significant degradation in cold gas efficiency.

7.1.3.4 *Summary of Results*

The evaluation of the novel catalyst was limited by the conditions tested. However, in aggregate, the catalyst appears to have some activity at the conditions tested. While it appears some byproducts, including tars, are influenced by the catalyst, it is unclear whether these compounds are reformed to carbon monoxide and hydrogen, undergo condensation or addition reactions, or are simply adsorbed by the catalyst. There was no measureable net increase in carbon monoxide and hydrogen due to this catalyst at the conditions tested. None of the tests indicated a net improvement in cold gas efficiency as a result of the tar reforming system; a median decrease on 10% was observed for all tests.

7.2 Emery

Tests at Emery were intended to evaluate the Ceramatec reformer installed on Emery’s fixed bed gasifier pilot plant. The objective was to reform tars into usable syngas for FT synthesis. A total of two of the six tests planned at Emery were conducted.

- Reforming of PRB coal product gas with three integrated sampling runs.
- Reforming of 30% raw wood/ 70% PRB coal product gas with three integrated sampling runs.

Tests produced short periods of nominally steady-state operation but most tests failed due to operational difficulties. The reformer was further compromised by mechanical failure in the reformer potentially compromising the effectiveness of plasma generation in some of the test runs. Analysis of operations and reforming results are presented in Sections 7.2.1 through 7.2.5. A summary of these results and their relevance to DLA Energy is provided in Section 7.2.6.

7.2.1 Feedstock Handling

The feedstock for the reformer system was the product gas delivered from the gasifier. Though the reformer was intended to be installed in a hot, particulate-free flow, the reformer was installed in a moderately cool flow with no particulate control. There was a significant buildup in backpressure, presumably related to ash and tar buildup observed in the reformer, that was the principal cause of operational problems with both the reformer and the gasifier.

7.2.2 Product Gas Composition

The overall product gases delivered to the reformer were very low in hydrogen relative to carbon monoxide. These product gases would likely require pre-treatment to optimize FT synthesis. However, the Emery tests were intended to evaluate the reformer, not the gasifier itself. The reformer does not appear to consistently raise or lower the H_2:CO molar ratio.

7.2.3 Product Gas Tars

All runs performed at Emery, regardless of steady-state status, exhibited a marked reduction in gravimetric tars. This is largely thought to be an artifact of tar buildup in the reformer consistent with the pressure buildup in the reformer. Both toluene and naphthalene concentrations were quantified and both exhibited significant reductions across the reformer. It is not possible to determine from this analysis whether toluene and naphthalene were reformed into product gas, oxidized, or if they were further condensed to higher molecular weight compounds.

7.2.4 Solids Removal

The Ceramatec, Inc. reformer had no provisions for solid removal aside from routine maintenance to remove plugged oxygen buffer packing. Soot blowing for ash removal would not have been effective even if such provisions had been included due to the random packing of the oxygen buffer installed. Refractory tars would be difficult to remove physically and would likely require unacceptably high temperatures to combust; the most effective control would likely be to maintain temperatures to prevent condensation at all times.

7.2.5 Cold Gas Efficiency

The overall objective of the reformer was to destroy tar compounds while creating more usable fuel from those tars; this objective is analogous to improving cold gas efficiency through the reformer and presents the results of independently collected grab samples for the two runs considered steady-state.

Table 7-1: Grab Sample Dry Product Gas Composition

Dry, N_2-Free Product Gas Composition for Emery Tests
Facility: Emery, Technology: Plasma Reformer, Coal: PRB Sub-bituminous

	100% PRB Coal Test			**30% Raw Wood Test**		
Parameters	**Run 3 Inlet**	**Run 3 Outlet**	**Change**	**Run 4 Inlet**	**Run 4 Outlet**	**Change**
H_2 (% v)	23.7	12.1	-11.7	26.38	21.98	-4.40
CO (%v)	44.1	39.0	-5.1	55.89	52.6	-3.29
CO_2 (%v)	24.5	43.6	19.1	10.88	20.77	9.89
CH_4 (%v)	5.3	4.1	-1.2	4.2	3.07	-1.13
H_2:CO Molar Ratio	0.54	0.31		0.47	0.42	
Product Gas Heating Value, HHV dry basis (Btu/scf)	273	207	-67	309	272	-36

The grab samples consistently indicate a reduction in both hydrogen and carbon monoxide concentrations across the reformer. The increase in carbon dioxide concentration is consistently higher than the decrease in carbon monoxide concentration providing strong evidence for the net combustion of tar compounds. The energy density of the product gas declines significantly across the reformer consistent with the dilution caused by net tar combustion reactions. Due to the combination of transient operations and measurement failures, Run 3 from the 100% PRB Coal test provides the only reliable reformer inlet and outlet flow measurements. The energy content of the product gas (i.e., the product of product gas energy density and product gas flow) decreased through the reformer. As a result, cold gas efficiency was not improved across the reformer.

7.2.6 Summary of Results

Tests on the Ceramatec, Inc. reformer were successfully completed using both 100% PRB coal and 30% raw wood blend product gases from the Emery gasifier. The electrode failures encountered at Emery may have affected overall reformer performance but were not considered critical by the developer. Overall, there was some evidence that tars were being destroyed to some extent in the reformer. There was no clear indication, however, that tars were reformed to syngas (i.e., hydrogen and/or carbon monoxide) or to other low molecular weight fuel gases. Cold gas efficiency was not improved across the reformer.

The Emery tests produced results specific to the installation tested. Operational issues encountered in the test were consistent with tar and particulate buildup in the reformer. As the reformer was intended for installations that were particulate free, no extension can reasonably be made with respect to pressure drop for installations with appropriate pre-treatment. Further, there is insufficient information regarding the root cause of the electrode failures to conclude anything about the contribution of product gas quality to the damage.

7.3 NCCC

The testing conducted at NCCC was on a TRIG™ gasification system similar in design to the TRDU at EERC, but approximately 10 times larger. The gasifier was operated in oxygen-blown mode with various mixtures of PRB coal with raw southern pine and torrefied southern pine. The objective of feeding two biomass types at three different ratios with coal under steady-state gasifier conditions was achieved. The Project Team discussed in detail with NCCC the procedures and methods used for generating the test data and sample results from the testing performed at NCCC. As discussed below, the test data appear to be valid and useable. Two steady-state periods were recorded during each of the 10% and 20% target tests with torrefied pine due to some operational problems during those tests. One steady-state period was recorded for all the other tests. These variances from the test plan were duly recorded by the facility operators and did not affect data quality.

7.3.1 Feedstock Handling

NCCC was able to grind both the raw and torrefied pine pellets in their mill system to successfully feed coal and biomass to the gasifier from separate feeders. The torrefied biomass behaved closer to coal than the raw material. The target percentage of biomass co-feed was not achieved in every case. The greatest variance was at the lower (i.e., 10% biomass target feed blend), particularly with the torrefied pine. This was due to mechanical limitations of the biomass feeder at low speed. These mechanical limitations are not limitations of the feeder technology, but of the specific pilot plant and test conditions. The discrepancy in biomass feed fraction affects the comparability of the NCCC tests with other pilot plant tests at low biomass feed fractions. The discrepancy does not affect the validity of the results.

7.3.2 Product Gas Composition

As shown on Figure 7-9, the concentrations of the four major product gas components fell within a fairly narrow range for the nine test scenarios. H_2:CO ratios ranged from 1.34 for the 29% torrefied biomass blend to 1.69 for the 16 to 17% torrefied biomass blends with no clear trends based on feedstock type or percentage.

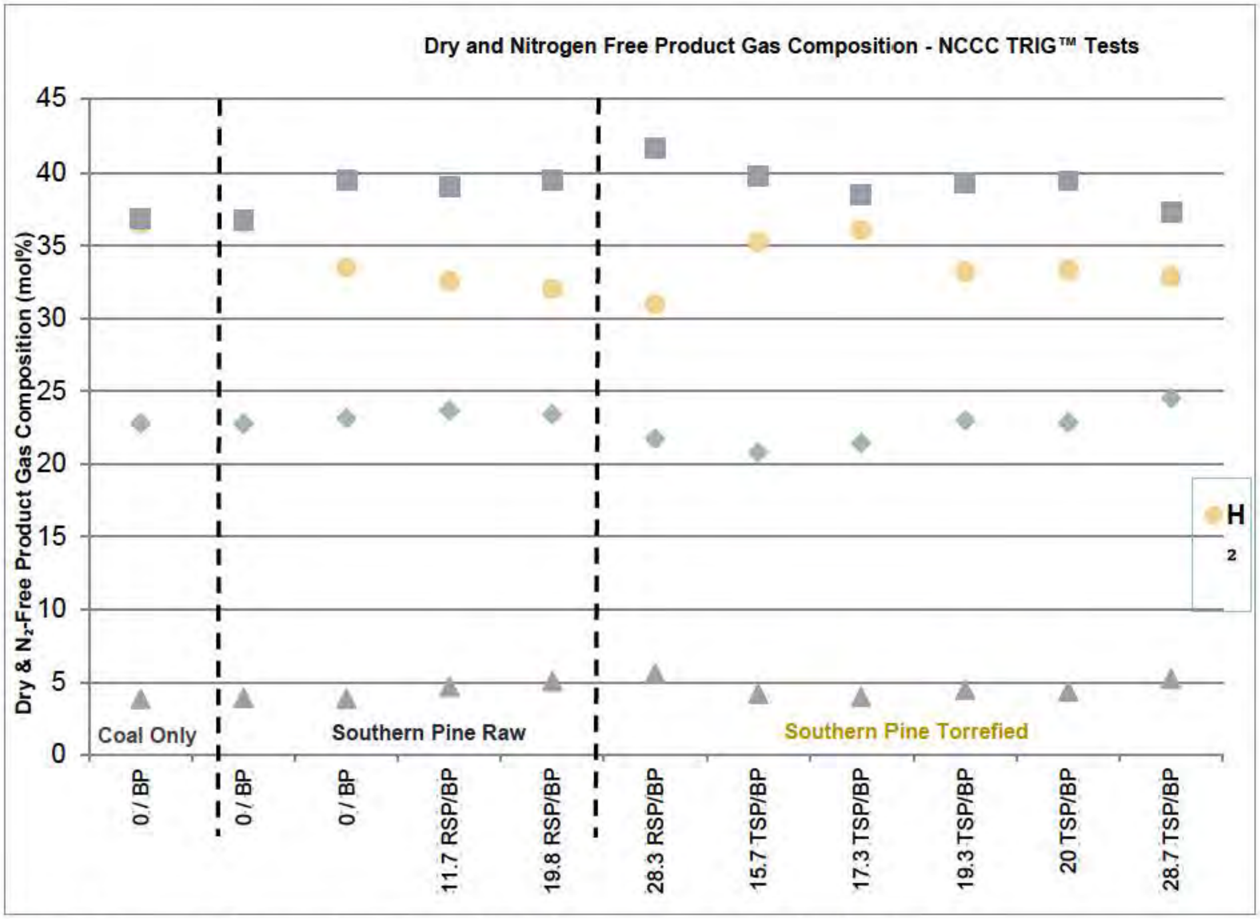


Figure 7-9: Dry and Nitrogen-free Product Gas Composition – NCCC TRIG™ Tests

The dry nitrogen-free composition contains nominally 40% carbon dioxide, re-enforcing the importance of carbon dioxide removal in limiting the FT synthesis reactor size while maintaining a constant space velocity. In the NCCC TRIG™ system, the carbon dioxide composition is much higher than what would be expected on a commercial scale. Because the NCCC TRIG™ system is much smaller in scale, the heat loss is much greater per volume of product gas generated than what it would be at a commercial scale. In addition, significant amounts of nitrogen are introduced at near ambient temperatures, which require additional heat to maintain reactor temperatures. Therefore, more feedstock needs to be combusted to maintain the operating temperature required.

The steam input was estimated using a hydrogen balance based on fuel inputs, product gas outputs, and residuals outputs because the steam measurement system was not considered accurate over the entire measured range encountered during the tests. This approach is circular resulting in no degrees of freedom in the hydrogen balance; it cannot be used to identify or qualify measurement accuracy or missing inputs or outputs. Because hydrogen is a very small portion of the overall mass, this approach is not likely to significantly impact the overall mass balance. However, steam-derived process metrics, such as steam to fuel ratio, carry greater uncertainty.

There was a strong correlation of increasing hydrogen to carbon monoxide ratio with increasing steam to fuel carbon ratio, which is expected as a result of WGS reactions. Also as expected, the $CO:CO_2$ ratio generally decreased with increasing steam to fuel ratio. In both cases, the strongest correlation was with the torrefied pine tests.

With regard to the effect of product gas recycle, approximately 5% of the total product gas generated was recycled to the gasifier to fluidize bed material in the standpipe and provide transport gas through the seal leg and J-leg. This lowered the amount of nitrogen used to maintain fluidization and transport bed materials. Nitrogen dilutes the product gas. This may affect thermal efficiency and cold gas efficiency depending on the amount of heat required to re-heat recycled gases. It is expected that a commercial-scale transport gasifier will replace most nitrogen with recycled gas, thereby greatly reducing the dilution observed at NCCC.

7.3.3 Product Gas Tars

As shown on Figure 7-10, tar levels increased with higher percentages of biomass for both raw and torrefied feedstock blends. Product gas from feedstock containing torrefied biomass contained significantly fewer tars than gas from raw biomass blends. The lowest amounts of tars were observed in the coal-only sample.

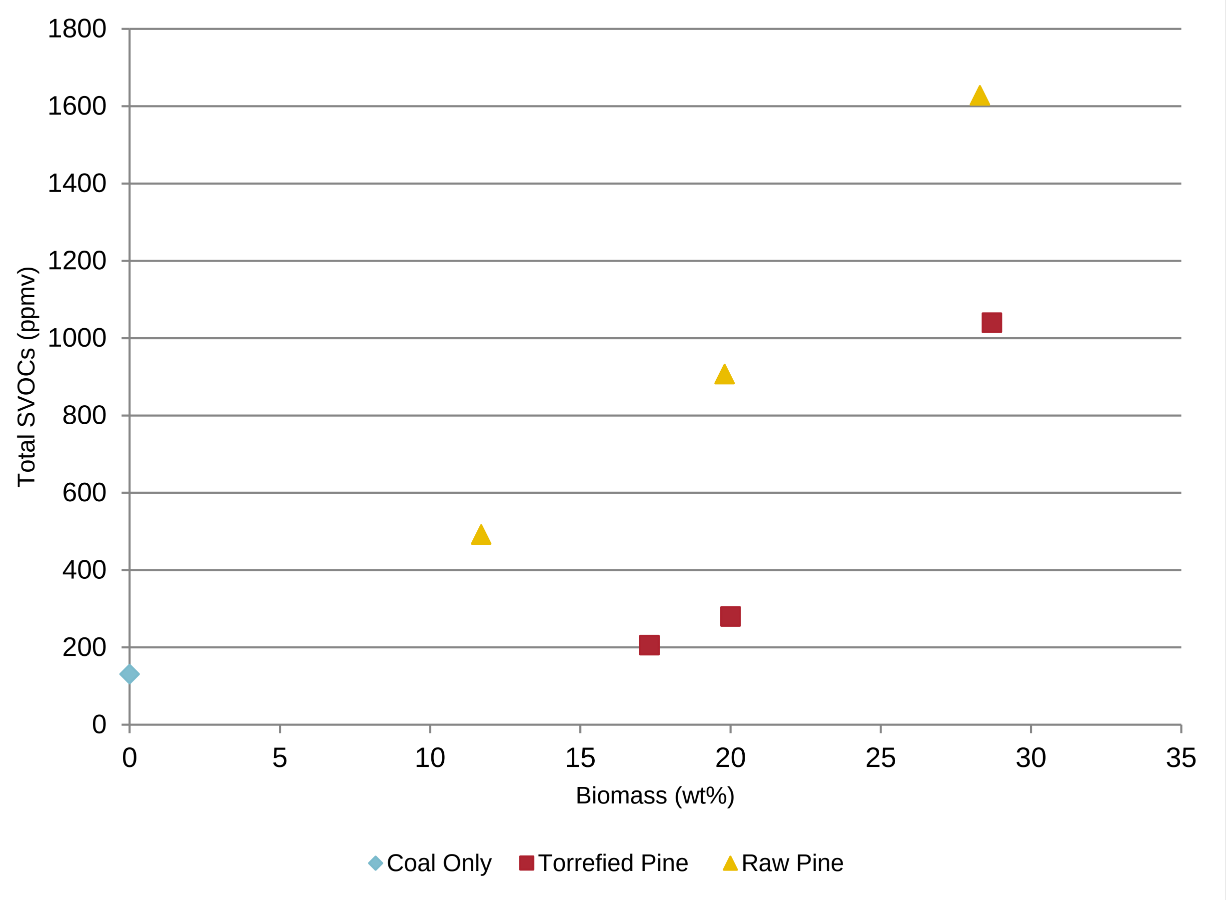


Figure 7-10: Concentration of Tars in Product Gas

7.3.4 Solids Removal

Given the time required for the bed material to equilibrate within the TRIG™, it is unlikely that the bed material was at steady state during each test run. Evidence of this is the declining silica composition of the coarse ash (CCAD) samples with run order as the initial silica sand bed material was gradually lost from the system. This has minimal impact on the overall mass balance because an ash balance was used to estimate the CCAD discharge based on fuel ash inputs and fine ash (CFAD) outputs. Although the inventory of the bed material (e.g., silica sand, ash, char, unreacted feed) may not have been at steady state during each test run, the low carbon concentration in the CCAD samples would result in minimal impact to the carbon balance and carbon conversion efficiency calculated for each test.

7.3.5 Carbon Conversion

Carbon conversion was about 98% (97.6 to 98.7%) for all scenarios tested with no distinction attributed to feedstock type or biomass percentage. Most (>99%) of the total carbon lost from the gasifier was in the fine ash, not the coarse ash. This is attributed to the design of the TRIG™ where most of the coarse ash is recirculated through the gasifier while most of the fine ash is captured in the PCD after one pass through the gasifier.

7.3.6 Cold Gas Efficiency

Heat loss from the system was assumed to be 3.5 MMBtu/hr for all tests rather than being calculated from the energy balance. This value was based on prior energy balance closure results at this facility and not upon measurements of heat loss. Errors in this estimate can affect the utility of the energy balance in identifying sources and sinks that may not be reflected in the energy balance. Heat losses affect the operation of the gasifier and will likely affect cold gas efficiency with all other conditions being equal. The use of the estimated heat loss in the energy balance does not affect the calculation of cold gas efficiency values reported in Section 6.3.2.4, which relies on the fuel and product gas heating value.

The dry product gas higher heating value ranged from 102 to 126 Btu/scf for all tests. The values are relatively low due to dilution with nitrogen. Cold gas efficiency ranged from 59.6 to 69.7% for all tests. The cold gas efficiency appears to be slightly lower for the raw biomass tests than for the torrefied biomass and coal only test cases. These results may be attributed to the lower heating value and energy density of raw biomass compared to torrefied biomass and coal; however, there is no apparent cold gas efficiency trend with biomass feed percentage for either feedstock. No correlation was found between cold gas efficiency or fixed carbon and the oxygen to fuel carbon ratio for any biomass type.

7.3.7 Summary of Results

The objective of feeding two biomass types at three different ratios with coal under steady-state gasifier conditions was achieved.

- The handling properties of torrefied pine were closer to that of coal compared to raw pine.

- Use of separate feeders obviates the need for blending and potentially offers greater flexibility on the types of biomass feedstocks that can be used. Whether or not a single or dual feed system is used for a commercial scale gasifier, the feed system would need to be designed to optimize reliable operation for use with specific types of feedstock.

- No clear trends based on feedstock type or percentage were observed in product gas composition or carbon conversion.

- Cold gas efficiency appears to be slightly lower for the raw biomass tests than for the torrefied biomass and coal only test cases, but no correlation was observed between CGE and biomass percentage for either type of biomass.

- Feedstocks containing torrefied pine produced fewer tars than those containing raw pine as would be expected from the devolatilization of wood during the torrefaction process.

- Although slight differences in the concentration of metals were observed in coarse ash and fine ash from the different feedstocks, there was no evidence of agglomeration or formation of ash deposits in the gasifier during any of the tests with the various feedstock blends.

- Adequate data were collected to allow comparison with the testing of similar feedstock mixtures at the smaller scale EERC gasifier in Section 7.3.8. In addition, the data collected by NCCC were used by DOE NETL for modeling and for validation of the models.

7.3.8 Comparison of Tests on TRDU and TRIG^{TM}

The transport gasifier was the only technology tested at different scales as part of this program. As noted earlier, the TRIG™ at NCCC is approximately 10 times larger than the pilot scale TRDU at EERC, based on feed throughput (400 versus 4,000 lb/hr for the tests in this program). Total mass throughput was approximately 14 times higher (1400 to 1500 lb/hr for the TRDU vs 19,000 to 22,000 lb/hr for the TRIG™). This was due to larger amounts of nitrogen (14 times the TRDU), air (18 times the TRDU), and steam (20 times the TRDU) used in the tests on the TRIG™. Product gas output was approximately 12 times higher for the TRIG™ (average. 18,700 lb/hr) than for the TRDU (average. 1,550 lb/hr). The differences in scale between inputs and outputs to the two gasifiers can be understood by the differences in mass balance closure (average 108% for the TRDU and 93% for the TRIG™).

There were two other significant operational differences between the two systems.

- At NCCC, coal and biomass were fed from separate feed systems so blending of the different feedstocks was not necessary. This did not appear to have any effect on gasifier performance.

- A small portion of the product gas was recycled to the gasifier at NCCC while EERC operated the TRDU with no recycle.

Figure 7-11 and Figure 7-12 allow for ready comparison of key parameters for tests with the same types of feedstocks, i.e. PRB coal with raw and torrefied southern pine. Figure 7-11 shows a plot of the H_2:CO molar ratio vs steam to fuel carbon ratio. The same trend of increasing H_2:CO with increasing steam to carbon is evident with both systems. However, the steam to carbon ratio for the tests on the TRIG™ is nearly double that for the tests on the TRDU. Also, the range of H_2:CO molar ratio was much narrower for the TRIG™ tests (1.3 to 1.7) than for the TRDU tests (1.1 to 1.6).

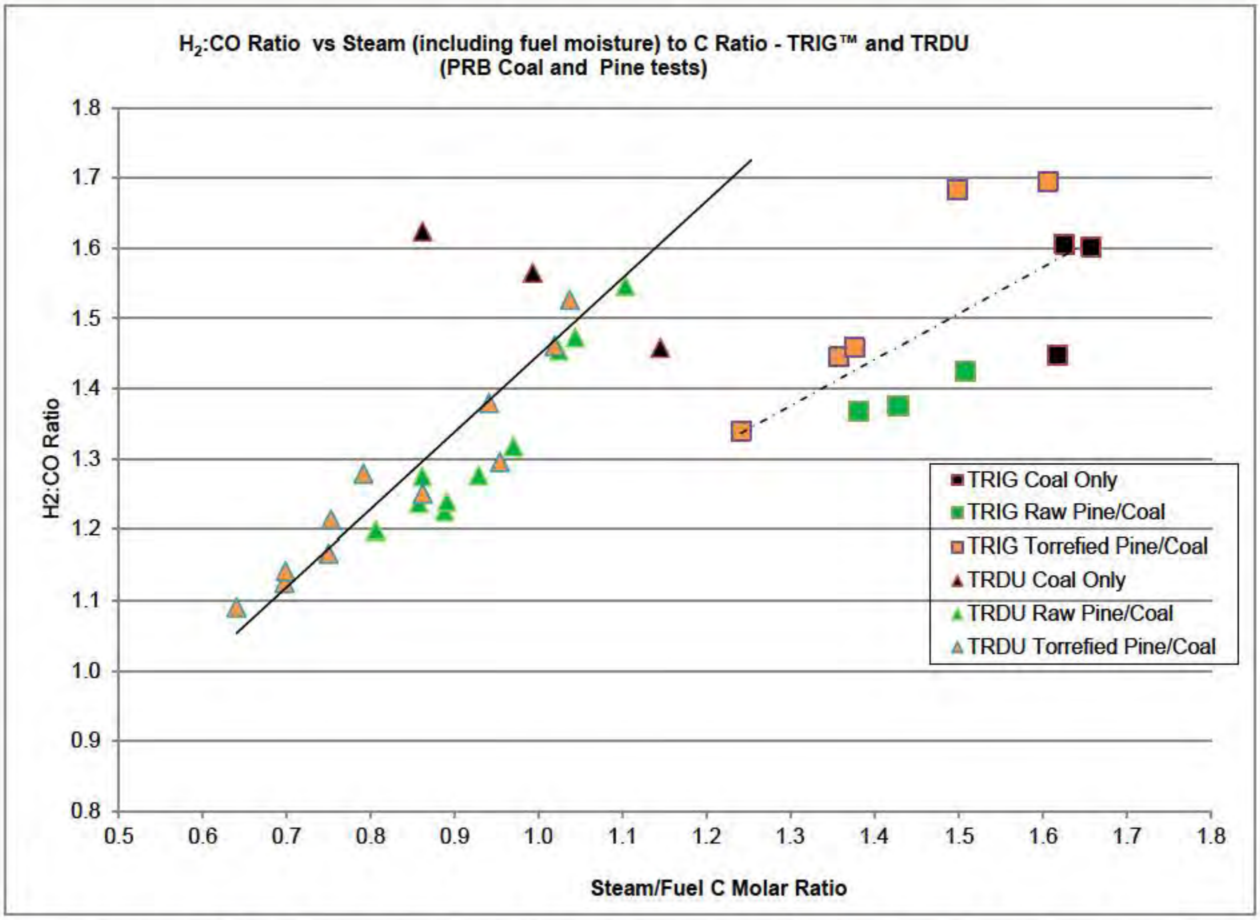


Figure 7-11: H_2:CO Molar Ratio versus Steam to Carbon Ratio – TRIG™ and TRDU PRB Coal and Pine Tests

Figure 7-12 shows a plot of cold gas efficiency vs. oxygen to fuel carbon ratio. There is no apparent trend between the two parameters for the tests with either gasifier. The range of values for both parameters was broader for the TRDU than for the TRIG™. The TRIG™ generally operated in a higher oxygen to carbon ratio than the TRDU. This could indicate that it is easier to control steady-state operating conditions on a larger system than on a smaller one. In addition, the cold gas efficiency was greater than 60% for all coal only and torrefied pine/coal blends on the TRIG™, while only one of the 28 tests on the TRDU had a CGE greater than 60%.

The tests show that the greater efficiencies expected with a larger system were achieved.

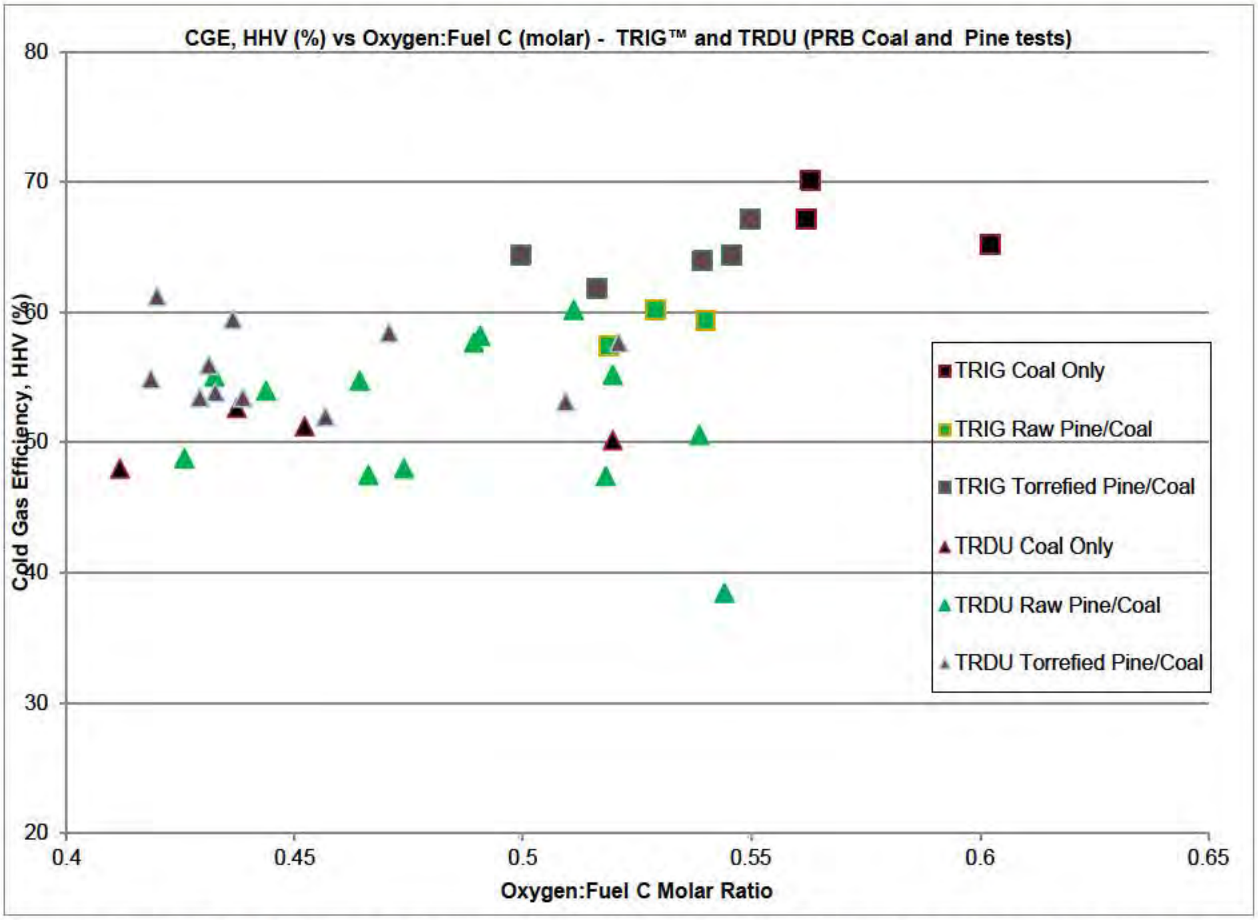


Figure 7-12: Cold Gas Efficiency HHV (%) versus Oxygen to Fuel (molar) - TRIG™ and TRDU PRB Coal and Pine Tests

7.4 TRI

The primary objective at TRI was to demonstrate the operation of TRI's PDU, comprised of the steam reformer and CTC, while feeding two biomass types at a single ratio with coal under steady-state gasifier conditions. TRI's test objective was to operate the steam reformer and CTC to achieve average H_2:CO molar ratio of 2.0 or in the range of 1.8 to 2.2. Operating parameters were maintained in the manner to achieve such desired ratio of H_2:CO. As discussed below, the test data appear to be valid and useable with some caveats.

Both the steam reformer and CTC, a partial oxidation unit, were able to operate near test plan conditions (see Section 6.4 and Figure 7-13). For the MSW/coal blend the reformer operated at 1,404°F and 44.3 psia and the CTC operated at 1,581°F and 42.4 psia, which are very close to the test plan. For the wood/coal blend the reformer operated at 1,397°F and 44.0 psia and the CTC operated at 1,536°F and 42.1 psia, which are very close to the test plan. The average reformer bed temperature remained close to the target temperature of 1,400°F and the CTC remained close to the target temperature of 1,500 to 1,550°F. The steam reformer and CTC average freeboard pressures were steady over the duration of the test run, There was a slight upwards creep on the overall gasifier pressure that resulted from gradual accumulation of solids and tars in the hot filter vessel, which caused filter blinding and subsequent backpressure. In spite of the changes in the blend feedstock density, moisture and feed rate, reformer and CTC temperature remained fairly steady.

Steam serves as both a fluidizing medium in the reformer bed and as a reactant. Both tests used very low oxygen to carbon and fairly high steam to carbon molar ratios, which is typically how a steam reformer operates. All of the steam input was fed into the reformer and oxygen was fed into the reformer and the CTC. The split of oxygen into the reformer and CTCs was not provided. The oxygen flow into the CTC was adjusted manually to yield a combined product gas H_2:CO molar ratio within the range of 1.8 to 2.2. Nitrogen was mainly used to fluidize the bed material in the reformer and CTC.

7.4.1 Feedstock Handling

TRI was able to feed both MSW/coal and wood/coal blend in a fairly consistent manner. The MSW/coal blend and the wood/coal blend steady-state feed rate averages were 349 lb/hr and 317 lb/hr, respectively. Because MSW/coal and wood/coal blends were both heterogeneous mixtures, the density and moisture content varied from one super sack to another and even within a single super sack. These variations are why the feed rate differed slightly from the test plan rate of 330 lb/hr. One of the major advantages of the TRI gasifier system is the large fluidized bed of the steam reformer that absorbs even wide fluctuations in feedstock properties and feed rate to maintain a stable operating temperature, pressure, product gas flow and product gas composition (see Appendix I for steady-state feed rate, temperature, and pressure charts). Figure 7-13 and Figure 7-16 show the MSW/coal and wood/coal feedstock blends tested at TRI. The MSW/coal blend was more heterogeneous due to the heterogeneous nature of MSW feedstock.

Figure 7-13: As-fed Blended 75%/25% MSW/Coal Feedstock

Figure 7-14: As-fed Blended 75%/25% MSW/Coal Feedstock

7.4.2 Product Gas Composition

The product gas generated from the steam reformer and CTC had stable composition, despite the heterogeneous nature of the MSW in the feedstock blend and the variability in feed rate. The H_2:CO molar ratio averaged 2.20 for the MSW blend and 2.27 for the wood blend over the duration of the trial. A cobalt catalysis FT synthesis reactor is often preferred when H_2:CO molar ratio is close to 2. The dry nitrogen-free composition contains 28.6% and 29.6% carbon dioxide for the MSW/coal and wood/coal tests, respectively, which seems slightly high compared to what would be expected from a steam reforming process. One reason could be that some feedstock was combusted in the reformer to supply some of the heat to the gasifier in addition to the heat supplied from the electrical heater. The dry product gas heating value (HHV) was higher for the MSW/coal blend (224.1 Btu/scf) compared to the wood/coal blend (162.0 Btu/scf) which is most likely due to the plastics in the MSW/coal feedstock blend. It is expected that product gas heating value will be higher at commercial-scale if TRI replaces most of the nitrogen used for the reformer bed with recycled product gas or steam, thereby greatly reducing the dilution observed at the TRI PDU.

7.4.3 Product Gas Tars

As shown in Table 6-69 in Section 6.4, product gas from the MSW/coal feedstock contained significantly higher level of tars than gas from the raw wood/coal feedstock. The total tar from MSW/coal was 1,277 ppmv and from raw wood/coal was 307 ppmv. The higher tars production from MSW/coal could be due to feedstock composition, e.g. MSW/coal feedstock had higher volatile matter of 72.8% compared to 62.5% in the wood/coal blend.

7.4.4 Solids Removal

Solid residue removal included bed material drained from the steam reformer, cyclone ash from the CTC and filter ash from the particulate control device. There were no reported issues in removal of solid residue. The ash balance mass closure was 52.8% for the MSW/coal test and 31.9% for the wood/coal test. This is most likely due to ash residue accumulation in the reformer bed in the TRI PDU. In commercial scale units, ash balance closure should be closer to 100% because the beds will achieve steady state due to continuous operation. The particulate control device collected approximately 92% and 98% of total solid residues for the MSW/coal and wood/coal blend tests, respectively.

7.4.5 Carbon Conversion

Carbon conversion for the MSW/coal and wood/coal feedstock blends was 91% and 90%, respectively. At a commercial scale, TRI expects carbon conversion of 98%. For both MSW/coal and wood/coal test, most of the carbon contained in the solid residue was in the filter ash, about 95.4% and 98.6% respectively. There are a number of pilot scale related attributes that affect the carbon conversion at this demonstration scale that will not be limitations at commercial scale:

- There is no internal cyclone in the CTC because the inside diameter is too narrow to install that device.
- The shallow angle of the dust bowl in the secondary cyclone due to size of the unit causes re-entrainment of separated char particles.
- Feedstock heterogeneity, primarily due to the MSW component, and particle size distribution variability from batch to batch has a greater impact on carbon conversion at the PDU scale due to the relatively low throughput as compared to the commercial unit with a high throughput.

7.4.6 Cold Gas Efficiency

There were slight differences between cold gas efficiency reported by TRI and calculated by CCAT. TRI reported CGE for the MSW/coal and wood/coal tests were 131% and 124% while CCAT calculated CGEs of 110% and 94%, respectively. TRI included BTEX and H_2S in their CGE calculations, but CCAT did not. Because steam reformer technology is indirectly heated, feedstocks are not combusted to supply the heat needed for gasification, therefore very little carbon dioxide would be expected in the product gas composition compared to non-steam reforming gasification processes. This is why the steam reforming process has higher cold gas efficiency compared to other gasification processes. The cold gas efficiency would be expected to be slightly higher at commercial scale due to higher carbon conversion and lower heat loss in a commercial scale compared to the TRI PDU. CGE should not be higher than 100%; one of the reasons it came out higher than 100% could be due to bias in the dry product gas flow rate or the solid feed rate. The cold gas efficiency was much lower for the raw wood biomass tests than for the MSW biomass test case. These results may be attributable to the lower heating value of the raw wood compared to the MSW used in these tests. The heating value of MSW can vary depending on moisture and degree of sorting. Due to confidentiality of process operations data, comparisons between CGE and oxygen to fuel and steam to fuel ratios are not presented. Lower heat loss at commercial scale should not affect the commercial scale gross cold gas efficiency because gasification heat needed would be supplied externally via a pulse combustor. With the pulse combustor, no additional feedstock need be combusted as is typically done to sustain a steady state in small-scale gasifiers, which results in a higher carbon dioxide composition in product gas.

7.4.7 Summary of Results

The objective of gasifying two feedstock types at a single ratio with coal under steady-state gasifier conditions was achieved.

- Both MSW/coal and wood/coal blend feedstocks handled well in the TRI system. Due to the more heterogeneous nature of MSW, MSW/coal had slightly more variability in feed rate compared to wood/coal, but the variability did not affect the operating temperature, pressure, product gas flow rate and product gas composition.
- Product gas H_2:CO molar ratio was 2.20 and 2.27 for MSW/coal and wood/coal blends, respectively, which is slightly higher than expected, but close to the desired ratio in the range of 1.8 to 2.2. Wood/coal blend had slightly higher H_2:CO molar ratio than expected due to higher moisture content in the feedstock than the MSW/coal blend.
- The MSW/coal feedstock testing produced more tars than the raw wood/coal feedstock test.
- Ash agglomeration did not impair steam reforming and CTC operation. The controls in place were adequate to manage agglomeration issues.
- Carbon conversion for the MSW/coal and wood/coal blend tests were similar at 91% and 90%, respectively.
- The MSW/coal blend test had a much higher cold gas efficiency than the raw/coal blend (110% and 94%, respectively).
- The TRI PDU gasifier is scaled based on TRI's commercial designs and, therefore, generates data that TRI applies, to produce performance guarantees for commercial units. The operating parameters of the PDU, such as pressure, temperature, and fluidization velocity, were the same for TRI's commercial black liquor applications in facilities at Norampac, Canada. The spent liquor gasifier is designed to process 127 tons per day of black liquor solids (at 40% moisture content) in a single reformer vessel with four pulsed combustion heaters (TRI, 2014b).

7.5 Westinghouse

The objective of testing at WPC was to evaluate coal/MSW feedstock blends in a plasma gasifier with the potential for application in a small-scale coal/waste-to-liquids facility. Three tests were conducted at WPC using PRB coal blended with MSW (50%, 75%, and 100% MSW by weight). All tests met the run time duration and mass balance closure requirements (based on mass balances provided by WPC).

Based on the review of WPC's test data, the Project Team identified two data quality issues that affect their ability to draw meaningful conclusions from the data. These relate to particulate carryover and variability in feedstock composition. Both issues are described below followed by the Project Team's interpretation of observed testing and usable data.

Particulate Carryover and Composition Results – As mentioned in Section 6.5, the product gas contains gasification residues, including FPM and CPM. Typically, these contain high molecular-weight vapors that condense to form tars when cooled. Based on the test report from Westinghouse and the Project Team's own observations, an experimental error was identified in the determination of these gasifier residues.

Accurate Method 5 sampling relies on extracting the product gas isokinetically, which was not achieved. WPC acknowledged this problem, stating that isokinetic particulate sampling was challenging due to the high velocities in the syngas duct. For the CPM results, a further problem was encountered: loss of impinger water containing the collected CPM.

Due to these compounding factors, the CPM and particulate composition data reported in Table 6-78 and the total particulate carryover reported in Table 6-80 are not reliable numbers and any conclusions or trends observed should be treated with caution.

Trends in Feedstock Composition – The first thing to observe about the feedstock analysis, shown in Table 6-75, is that the three blends are remarkably similar, without any clear trend across the tests. In order to compare the reactive feedstocks (primary feed plus coke), a flux-free analysis of each blend (coal, simulated MSW RDF, met coke) is shown on Figure 7-15.

As expected, this shows a trend of decreasing carbon and increasing ash as the MSW portion of the blend is increased. The heating value, which is largely dependent on carbon content, decreases accordingly. Hydrogen, which is low for both coal and MSW, is essentially steady across all blends. It is notable that the heating value of the blended feedstock decreases only slightly with the addition of more MSW. This is because the simulated MSW used for these tests is high in carbon, low in moisture, and low in ash. This leads to a relatively high HHV, similar to the as-received value for PRB coal. Since feedstock composition shows minimal variation, the changes observed in the product gas composition over the three tests, are also expected to be minor.

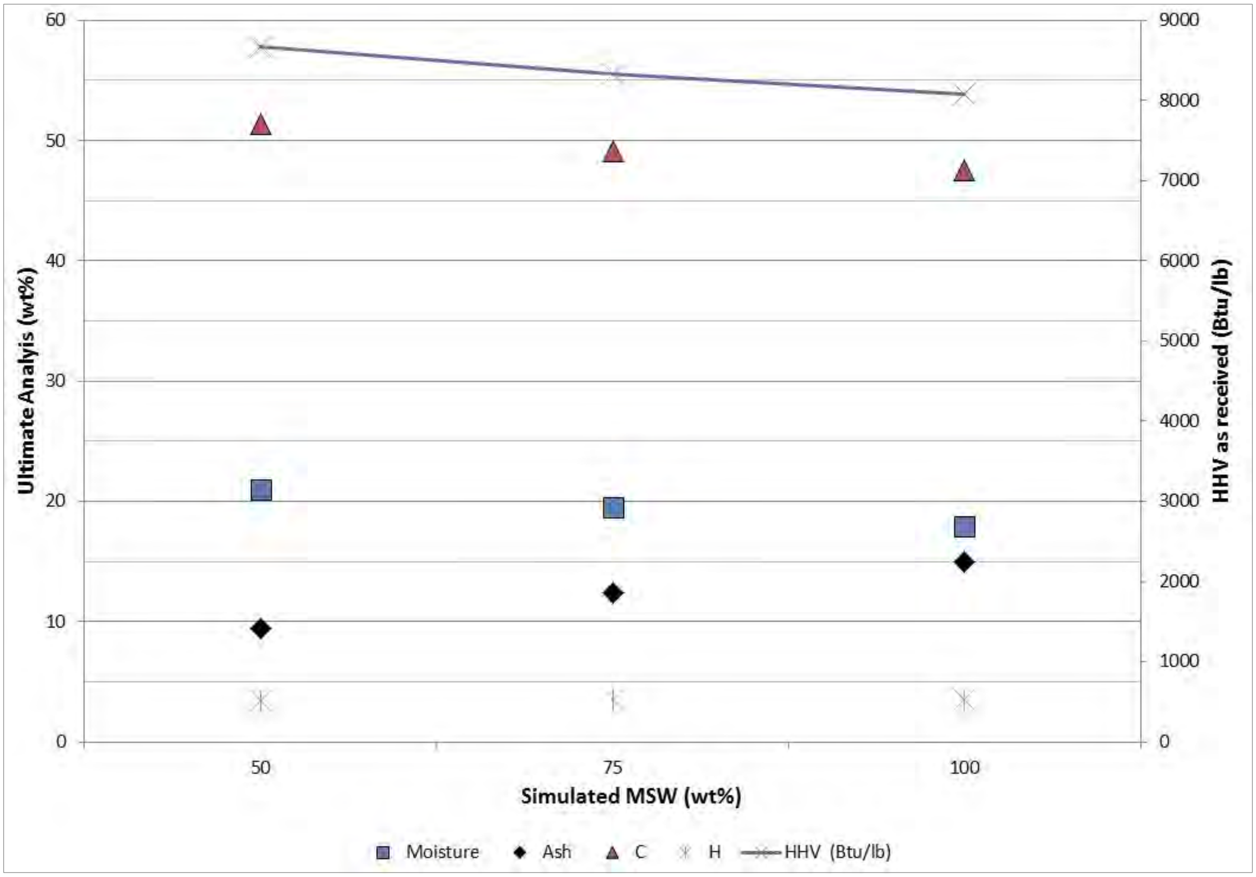


Figure 7-15: Flux-free Ultimate Analysis for (PRB Coal/MSW) Tests 1, 2, and 3

7.5.1 Feedstock Handling

The coal/MSW feedstock blends appeared free flowing and well mixed. The pellets ranged from approximately ½ to 1½ inches, and the coal was of similar size. Figure 7-16 shows the 75% MSW feedstock blend for Test 2. Note that the fuel pellets are a pelletized RDF, in a narrow particle size range. It had been densified by Greenwood Energy to mix well with coal for co-firing. Therefore, while this feedstock had similar composition to an MSW RDF feedstock, it was more highly processed RDF feedstock than typically used in the municipal waste management industry.

Figure 7-16: 75% Simulated MSW/Coal Blend for Test 2

7.5.2 Product Gas Composition

The product gas composition, heating value, and H_2:CO molar ratio data are presented in Table 6-76. In general, the product gas from the Westinghouse plasma gasifier using coal/MSW feedstock is characterized by:

- HHV (184 to 211 Btu/scf dry basis)
- Low H_2:CO molar ratio (0.53 to 0.83)
- Medium to high carbon dioxide content (14.8 to 24.3%vol dry, nitrogen-free)
- Low methane content (1.8 to 3.8%)

The low heating value is typical of an air blown or air/oxygen blown gasifier due to dilution with nitrogen. The low H_2:CO molar ratio is consistent with gasification of hydrogen lean feedstocks. In a commercial scale plant this would necessitate a WGS reactor to bring the ratio closer to 2.0 prior to FT synthesis. It is understood that steam may be injected into the WPC gasifier to potentially achieve a higher H_2:CO molar ratio, but this was not the focus of these tests.

Although some carbon dioxide is inevitable from gasification of carbon rich feedstocks, it is generally undesirable in high concentrations. Carbon dioxide in the product gas was relatively high (14.8 to 24.3%vol dry, nitrogen free). This is partially due to the design limitations of the test gasifier, which in turn requires more combustion to maintain temperatures throughout the vessel. Another factor is the calcining of carbonates in the flux, which produces carbon dioxide.

The presence of methane is undesirable since it does not participate in the FT reactions and reduces overall efficiency of the process. Methane from the WPC gasifier was low (1.8 to 3.8%), as would be expected from a high temperature gasifier with raw gas leaving at 2,079°F. During the test, operators adjusted secondary oxygen flow to control the gas exit temperature above 2,000°F, and minimize methane in the product gas.

Figure 7-17 below, shows product gas compositions (hydrogen, carbon monoxide, carbon dioxide, and methane) and heating value for each test. Note that both composition and heating value are presented here on a dry, nitrogen-free basis so the heating values differ from those shown in Table 6-76.

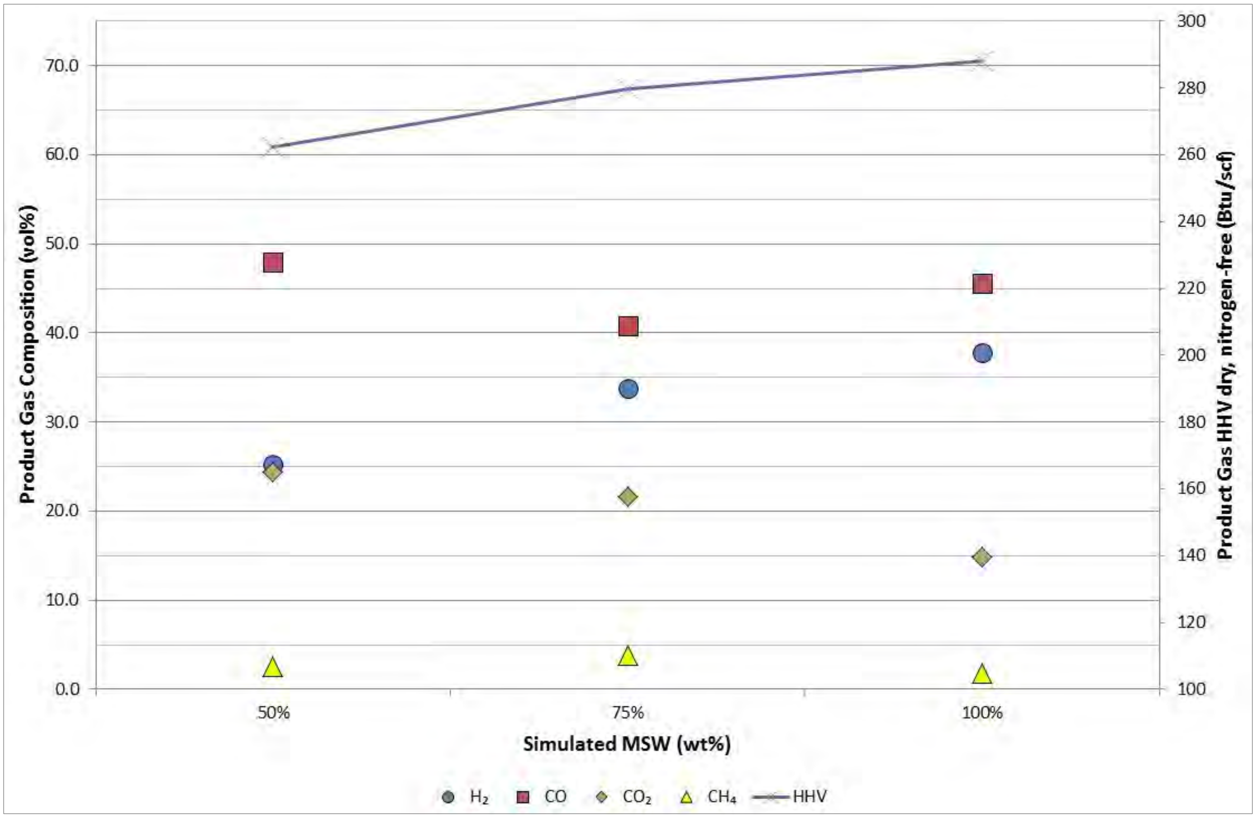


Figure 7-17: Product Gas Composition (Dry, Nitrogen-Free) versus Coal/MSW blends

These results suggest that increased MSW content in the feedstock corresponds to progressively higher hydrogen and lower carbon dioxide. This is consistent with changes in feedstock, which show a corresponding increase in hydrogen to carbon ratio. The trend for carbon monoxide and methane are less conclusive since successive step changes are not in the same direction.

7.5.3 Product Gas Tars

Tar production was controlled by maintaining high temperature throughout the WPC gasifier. Tar level in the product gas is indicated by the CPM collected using Method 5 sampling. As mentioned above, the Method 5 sampling was compromised and, therefore, the data presented in Table 6-78 are not reliable. Furthermore, it is reasonable to expect that some higher molecular weight tar compounds were condensed in the initial quench vessel. There is no record in the test report of the methods for collection of quench water solids or quench water organics, and the test report does not specify composition of the material collected in the quench vessel. For these reasons no meaningful conclusions can be drawn from the test data, except that tars were present in the product gas.

7.5.4 Solids Removal

The slag was successfully tapped and flowed continuously for at least part of each test period. In order to ensure correct slag chemistry a large amount of flux was added to the feedstock. The flux ratio (mass of flux per mass of primary feed) for the test gasifier was 0.47, 0.24, and 0.23 for Tests 1, 2 and 3 respectively (Table 7-2). This approach affects both the efficiency of the gasifier and the product gas composition, in terms of the energy consumed to melt the flux material and the additional carbon dioxide created from the limestone ($CaCO_3$) portion of the flux. These effects are reflected in the cold gas efficiency and the product gas composition.

Slag TCLP results in Table 6-79 showed that RCRA metals were either not detected, or were detected well below RCRA limits. Solids removed as particulate carryover are discussed below under carbon conversion.

7.5.5 Carbon Conversion

Table 6-81 indicates that Tests 1 and 2 had very high carbon conversion; 98.5 and 98.2%, respectively. These figures are typical of what a slagging gasifier should achieve. Test 3 conversion was 95.0%, which indicates that 5% of the carbon entering the gasifier exited in the particulate carryover.

Particulate analysis shows that carbon content increased with increasing MSW in the feedstock (Table 6-78). It can be speculated that MSW components with lower densities than coal are more easily entrained in the gas flow and removed prior to complete reaction. It is not possible to verify this conclusion with the results provided by WPC. The carbon conversions quoted above were calculated by the Project Team based on the WPC mass flows and the carbon content of the FPM and feedstock. As mentioned previously, the FPM data are not considered reliable.

7.5.6 Cold Gas Efficiency

The results presented in Table 7-2 (58%, 71%, and 64% for Tests 1, 2, and 3, respectively) were calculated by the Project Team based on Westinghouse's reported data. Generally, the cold gas efficiency is low compared to what would be expected in a commercial scale gasifier. One factor contributing to cold gas efficiency is the amount of energy absorbed converting the flux material to molten slag. Table 7-2 shows the flux ratio for the three tests. Although the results are not conclusive it seems likely that the cold gas efficiency results are related to the high flux requirements of the pilot gasifier rather than limitations in reactivity of the feedstocks. Note that the energy input from the plasma torch is also lower for Test 1.

Table 7-2: Cold Gas Efficiency versus MSW and Coal Blends

Cold Gas Efficiency, Torch Power and Flux Ratio versus Test Case

	Test Cases (MSW wt%)		
Duration, Conversion, and Efficiency	**50**	**75**	**100**
Flux ratio (mass of flux per mass of primary feed)	0.47	0.24	0.23
Torch Power input (MMBtu/hr electrical)	0.98	1.09	1.10
Cold Gas Efficiency (%)	57.9	70.6	64.2

7.5.7 Summary of Results

The tests conducted at WPC demonstrated the plasma gasifier' s ability to handle a mixed feed of simulated MSW and PRB coal. Because of the relatively homogenous nature of the fuel pellets, additional testing on actual MSW RDF would be recommended for a commercial coal/MSW RDF co-feeding gasifier.

- The gasifier operated smoothly, producing a gas that is suitable for FT liquids production, after typical downstream processing. The gas was low in heating value due to the dilution effect of nitrogen and had a H_2:CO molar ratio ranging from 0.53 to 0.83. Test 3 (100% MSW) product gas had the lowest methane, lowest carbon dioxide, and highest H_2:CO molar ratio.

- The general trend was for higher hydrogen, lower carbon dioxide, and higher HHV in the product gas with increasing MSW. These observations are not consistent with the changes in feedstock composition alone. It is likely that some of the product gas variations were due to the addition of flux materials and the operation of the test gasifier, in addition to feedstock variation.

- Insufficient data were collected to make conclusions about the formation of tars during these tests.

- Carbon conversion was lower than expected (95%) for Test 3 (100% MSW), although this may be due to particulate collection issues.

8. Life-cycle Analyses

As part of this project, CCAT contracted with NETL to develop one techno-economic model and two techno-economic reports for 50,000 bpd CBTL facilities based on EFG and TRIG™ technologies. The techno-economic model incorporates a process model for both EFG and TRIG™. This techno-economic model is provided as Appendix L, and the reports are provided as Appendix M and Appendix N. The reports show that CBTL using coal and biomass, along with carbon dioxide capture and management, can produce jet fuels with GHG emissions that meet the Section 526 requirement that alternative fuels have no greater GHG emissions than petroleum-based fuels. Section 8.3 summarizes the LCA results from the NETL reports, and Section 9 summarizes the economic results.

The Section 526 conventional petroleum jet fuel baseline value is defined as 88.41 g CO_2e/MJ LHV (Section 526 baseline value; NETL, 2008). This value includes certain life cycle stages, which NETL used in their EFG and TRIG™ LCAs: crude acquisition, transport and refining, and jet fuel transport and end use (combustion of the jet fuel). The Section 526 baseline value is an aggregate of LCA GHG emissions, taking into account the extraction, transport, and refining of crude oil from both domestic and foreign locations based on 2007 crude oil data.

An important goal of the LCA for this project was to identify operations unique to CBTL that contained unknown process variables. These variables require further research, development, and demonstration so that technological risks can be reduced. The modeling of hypothetical scenarios was necessary to support this goal. To design the life cycle model, conceptual CBTL plant configurations (scenarios) were selected by NETL and the Project Team, using various combinations of coal and biomass to maximize production of FT jet fuel.

This section provides an overview of LCAs and how the Project Team uses LCAs. It also describes NETL's life cycle models for EFG and TRIG™ based on different CBTL scenarios, and provides NETL's modeling results for GHG emissions with regard to Section 526 compliance, as well as a summary of process modeling results. This section also provides the Project Team's modeled LCAs based on facility testing and using a specific model provided by NETL. The modeled facility LCA results are also discussed with regard to Section 526 compliance.

This section is organized as follows:

- Section 8.1 – LCA Overview: Describes the components of an LCA and the five major stages included in NETL's LCA model.
- Section 8.2 – Overview of NETL's Life Cycle Model for EFG and TRIG™: Describes NETL's model and provides the model boundaries and approach that apply to both the EFG and TRIG™ modeling scenarios.
- Section 8.3 – NETL's LCA Modeling of an EFG and TRIG™: Summarizes NETL's modeling of hypothetical EFG scenarios, including life cycle GHG emission results, process results, conclusions, and Project Team recommendations for technological development and additional modeling.

- Section 8.4 – CCAT's LCA modeling of Gasification Technologies Tested: Describes CCAT's use of NETL's FT process model (FT Black Box Model) to perform cradle-to-grave LCAs for gasification technologies and feedstocks not addressed by the NETL models using actual gasification test data.

- Section 8.5 – Section 526 Optimization Modeling: Describes CCAT's use of NETL's Section 526 Optimization Modeling Tool to perform LCAs that allow for three additional adjustable parameters compared to NETL's techno-economic model. These additional parameters (biomass percentage, venting of captured carbon dioxide, and adjustments to the plant efficiency) provide an opportunity to use the model to generate GHG emissions results closer to the Section 526 baseline value.

8.1 LCA Overview

LCA refers to a series of methods used to assess the environmental flows and burdens associated with the production of a specific product or service. LCA involves modeling various production processes that comprise the full life cycle of the product or service and includes all environmental releases and processes beginning with the extraction of raw materials through to the final disposal of the product or end of the processes being modeled. The LCA can help determine the process or product with the least environmental impact.

LCAs can be broad or focused. Broad-scope LCAs consider various input materials and energy, along with outputs of pollutants, products, byproducts, solid waste, and various other flows. Broad-scope LCAs are appropriate for considering a wide array of environmental effects that could result from the production of a product or product suite, with potential considerations ranging from explicit emissions to effects on the biosphere. Alternatively, focused LCAs are well suited for products or services where a decision may be made based on quantified life cycle inputs or emissions. The LCAs for this project are focused LCAs that assess GHG and other emissions from hypothetical CBTL facilities to determine whether they are potentially capable of producing a Section 526-compliant jet fuel.

8.1.1 Greenhouse Gases

GHGs are atmospheric gases that increase the rate at which the earth's atmosphere absorbs and/or retains heat. GHGs include numerous gases that can be released into the atmosphere from natural or anthropogenic sources. USEPA regulates GHG emissions, and in 2010, issued a final rule, which established an approach for addressing GHG emissions from stationary sources and established GHG emission thresholds. The final rule addresses the following GHGs: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

With respect to the LCAs presented in this report, the quantification of life cycle GHG emissions focused on carbon dioxide, methane, nitrous oxide, and sulfur hexafluoride. These pollutants are generated during the production of alternative liquid fuels from coal and biomass. Hydrofluorocarbons and perfluorocarbons are not generated in large quantities during the alternative liquid fuels production modeled for this project, and therefore, are not presented in this report.

Because each GHG has a unique atmospheric lifetime and heat-trapping potential, the global warming potential (GWP) concept was developed to allow the comparison of the ability of each greenhouse gas to trap heat in the atmosphere relative to carbon dioxide over a specified time horizon (Environment Canada, 2015). Often, and in the case of this project, GHG emissions are calculated in terms of how much carbon dioxide would be required to produce a similar warming effect over the specified time horizon. This is called the carbon dioxide equivalent value and is calculated by multiplying the amount of gas by its associated GWP.

For this project, the carbon dioxide equivalent was calculated using the GWPs of each GHG from the 2013 Intergovernmental Panel on Climate Change Fifth Assessment Report (Intergovernmental Panel on Climate Change, 2013). These GWPs are provided in Table 8-1, below. The default GWPs used in the LCAs for this project were calculated based on the 100-year timeframe.

Table 8-1: 2013 IPCC Global Warming Potential Factors

GHG	20 Year	100 Year (Default)	500 Year
CO_2	1	1	N/A
CH_4	85	30	N/A
N_2O	264	265	N/A
SF_6	17,500	23,500	N/A

Source: Adapted from NETL, 2014b, Table A-2.

8.1.2 Major Life Cycle Stages and Sub-stages

LCAs typically consider five major life cycle stages, which also include various sub-stages; these are described below and shown on Figure 8-1. Both NETL and CCAT used the sub-stages listed below to conduct the various LCAs for this project.

Raw Material Acquisition – Construction and operations activities associated with the extraction of coal from a mine, and the production and harvesting of biomass. This stage also includes land use requirements and GHG emissions associated with land use changes that result from the conversion of land from existing conditions, in support of relevant raw material acquisition activities. This life-cycle stage includes the following sub-stages:

- Coal mining, surface
- Biomass production and field chipping
- Biomass direct land use change
- Biomass indirect land use change

Raw Material Transport – Construction and operation activities associated with the transport of coal and biomass from the downstream boundary of raw material acquisition to the energy conversion facility. Raw material transport includes the construction and operation of trains and trucks used to transport feedstock, but does not include the construction of main line rails or roadways. Torrefaction facility construction and operations are also included for scenarios that use torrefaction. The Raw Material Transport life cycle stage includes the additional transport of raw biomass to the torrefaction facility, as well as the emissions associated with the torrefaction of chipped and pelletized biomass. This life-cycle stage includes the following sub-stages:

- Transport of coal to the CBTL plant
- Transport of chipped biomass to the CBTL plant or torrefaction facility
- Biomass torrefaction
- Biomass transport from the torrefaction facility to the CBTL plant

Energy Conversion – The process by which feedstock is converted into product fuels. This stage includes construction and operation activities associated with the conversion process, as well as carbon management. As such, energy conversion considers construction and operation of the CBTL plant and carbon dioxide transport pipelines. This life-cycle stage includes the following sub-stages:

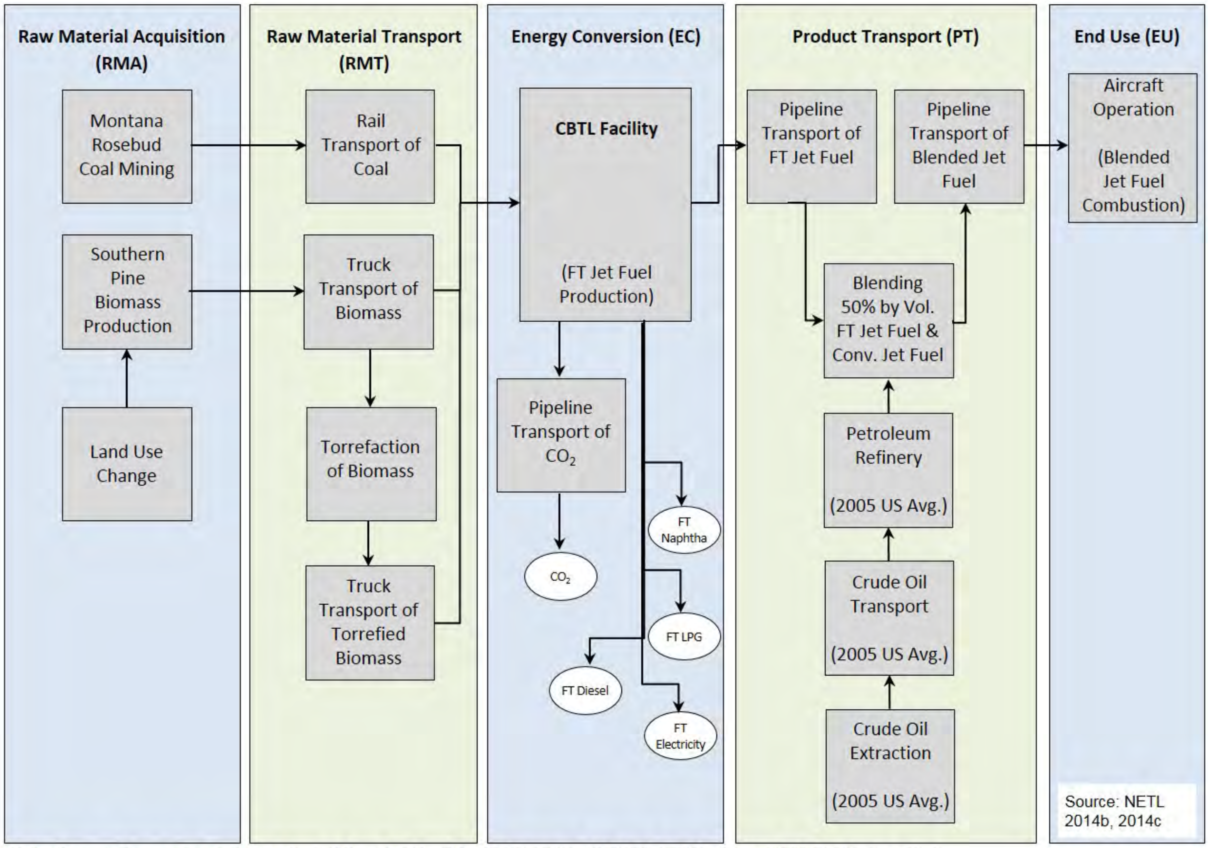
- Biomass drying
- CBTL plant construction
- CBTL plant operations (includes carbon dioxide compression)
- Carbon dioxide pipeline transport to EOR/saline aquifer
- Carbon dioxide used for EOR/saline aquifer displacement credit
- Liquefied petroleum gas (LPG) displacement credit
- Naphtha displacement credit
- Diesel displacement credit
- Electricity displacement credit

Product Transport – Construction and operation activities associated with the transport of product jet fuel from the downstream boundary of the CBTL plant to the point of end use. This includes select pipelines and, for sensitivity analysis, trucks used for the transport of blended jet fuel. Within this study, product transport also includes upstream emissions associated with the production and transport of conventional petroleum jet fuel, which is blended with FT jet fuel within this life cycle stage. This life-cycle stage includes the following sub-stages:

- Transport of FT jet to blending facility
- Blending of 50/50 FT and conventional jet fuel, and conventional jet fuel production
- Transport of blended jet fuel to airport

End Use – Construction and operation of a jet airplane, which consumes blended jet fuel produced within the scope of the LCAs for this project. This life-cycle stage includes the following sub-stages:

- Airplane operation (fuel combustion)
- Airplane construction



Source: NETL 2014b, 2014c

Note: Energy Conversion column adapted from NETL: CO_2, FT Naphtha, FT LPG, FT Diesel, and FT Electricity added.

Figure 8-1: Life Cycle Stages for LCA Modeling

8.2 Overview of NETL's Life Cycle Model for EFG and TRIG™

As part of this project, NETL was contracted to develop various models for both the EFG and TRIG™ designs that could be used to complete a life cycle analysis. These models included a technology/process model, a life cycle model, and an economic model. The technology/process model was developed and used to provide input for both the life cycle and economic models. This section provides information about the technology/process and life cycle models that apply to both the EFG and TRIG™, and Section 9 discusses the economic model. The information in this section includes the model boundaries, modeling approach, co-product management, key modeling assumptions, and environmental parameters. The hypothetical scenarios, validation, results, conclusions, and recommendations for the EFG and TRIG™ are summarized in Section 8.3.

NETL used the technology/process and life cycle models to estimate the LCA of a CBTL plant for hypothetical scenarios using coal only and various combinations of coal and woody biomass in either a single gasifier or two separate gasifiers. The information presented in this section is summarized and adapted from the reports generated by NETL as a result of developing those models (Comprehensive Analysis Reports; NETL, 2014b, 2014c). NETL developed these reports under contract to CCAT as part of the project. The Comprehensive Analysis Reports are provided as Appendix M and Appendix N, respectively.

8.2.1 Life Cycle Model Boundaries

NETL established the following boundaries for both EFG and TRIG™ modeling scenarios:

- **Geographic system boundary** includes all regions where modeled facilities would be located: the southeastern United States for most facilities and processes, the Powder River Basin in Montana for coal extraction, and the Permian Basin in Texas for enhanced oil recovery and long-term carbon storage.

- **Temporal system boundary** is a 30-year operating period.

- **Material system boundary** includes all physical processes and procedures in the five major life cycle stages that were considered to support the modeled LCAs, as shown on Figure 8-1.

- **Functional unit** is the basis of comparison for an LCA and is used to express GHG emission results from life cycle stages. Typically, a functional unit is defined based on the desired end product from a process. In the NETL LCA study, the desired end product is 50/50 blended jet fuel. The blend is necessary because jet fuel produced from CBTL does not meet fuel property specifications required by jet aircraft. The functional unit of this analysis is the combustion of 1 mega joule (MJ) of lower heating value (LHV), 50/50 blended FT jet fuel and petroleum jet fuel. All results are expressed based on this functional unit. One MJ LHV of blended jet fuel is equivalent to 29.39 milliliters or 22.98 grams of blended jet fuel. GHG emissions can be expressed as energy, volume, or mass of blended jet fuel. In this report, the GHG emission results are presented in grams of carbon dioxide equivalent (CO_2e) emission from life cycle stages per MJ LHV of 50/50 blended jet fuel combusted.

8.2.2 LCA Modeling Approach

To perform LCA modeling for both the TRIG™ and EFG, the following models were used: process model, life cycle environmental model, economic model (described in Section 9), and CBTL jet fuel model, as shown on Figure 8-2.

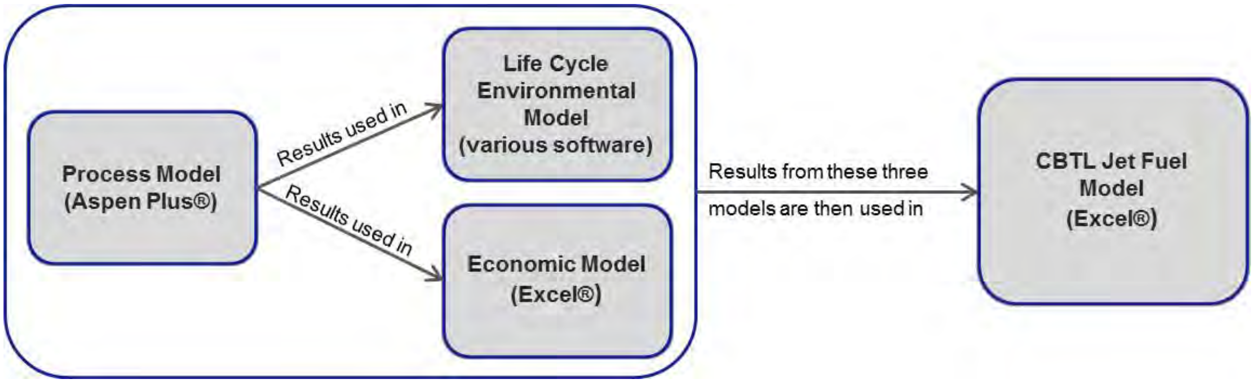


Figure 8-2: Specific Models used in LCA Modeling

Process Model – Provided process-level evaluations of the various scenarios based on the low, high, and expected required selling price (RSP) of FT jet fuel. Results from this model were used to inform the models for the life cycle and economic analyses (Section 9).

Life Cycle Environmental Model – Provided evaluations regarding the environmental impacts for each scenario. Results from the process model were input into a life cycle environmental model, which incorporated the system boundaries described in Section 8.2.1.

Economic Model – Provided evaluations regarding the economic implications for each scenario (see Section 9).

CBTL Jet Fuel Model – Allowed the results from the process, life cycle environmental, and economic models to be combined into one model that summarized the results.

8.2.3 Co-product Management

CBTL FT liquid jet fuel production creates “co-products” in addition to the FT liquid jet fuel (e.g., FT diesel, FT naphtha, FT LPG, electricity, carbon dioxide). As part of an LCA, it is necessary to divide the environmental impacts between the product and co-products. The two methods used to do this are system expansion allocation and energy allocation. The International Organization for Standardization 14040 series suggest using system expansion allocation when possible, and in cases where this is not possible, using the energy allocation method (International Organization for Standardization 2006).

System Expansion Allocation – This allocation method assumes co-products produced from the CBTL plant displaces equivalent GHG emission if produced conventionally. Table 8-2 provides the displacement values used in this study for co-products (FT diesel, FT naphtha, FT LPG, electricity and carbon dioxide).

Energy Allocation – Environmental impacts are divided among the products according to how much the desired (FT jet) products contribute to total energy produced from the total products which included FT jet, FT diesel, FT naphtha, FT LPG and electricity.

For both the EFG and TRIG™ LCAs, system expansion allocation was used for the reasons described below.

- Energy allocation cannot be used to divide the burdens between electricity and captured carbon dioxide at the CBTL plant boundary because there is not a physical basis for comparing electrical energy to a mass of carbon dioxide.

- Although energy can be used as a basis for allocating environmental impacts between the electricity and liquid fuel that exit the boundary of a CBTL plant, this would require comparing two forms of energy – electricity and the heat of combusted diesel or jet fuel.

- An MJ of electricity accounts for the efficiency losses of thermoelectric power generation, while, within the boundaries of this study, 1 MJ of combustion heat does not account for the efficiency of converting heat to useful work. Because an MJ of electricity and an MJ of heat from combusted fuel do not provide equivalent services, the use of energy allocation to divide the environmental impacts among co-products is not the most effective method. In addition, it is possible to test the conclusions of an analysis across all possible end use efficiencies (i.e., to demonstrate quantitatively that a technology or policy option results in lower environmental burdens regardless of the end use efficiency of the two types of energy).

As described by NETL (2014b, 2014c), system expansion expands the boundaries of an LCA until the functional unit is the only product that exits the system, and all other co-products are contained within the system. For system expansion to be effective, it is often necessary to include the displacement of a parallel supply chain within the system boundaries. Displacement assumes that a co-product displaces a product having the same function, but is produced by a different process, typically at an unrelated facility. The primary advantage of system expansion is that it evaluates the change in environmental burdens from producing the alternative product and entering it into the marketplace. Drawbacks include the complex interactions of market supply and demand that may negate any real-world displacement from occurring. Table 8-2 provides the displacement values used for the CBTL co-products in this study.

Table 8-2: Displacement Values Used for System Expansion Allocation Method

Co-product (units)	Low	Expected	High	Source[a]
Electricity ($kg\ CO_2e/\ MWh$)	AEO 2035 U.S. Grid Mix: 558	2010 U.S. Grid Mix: 605	Fleet Coal: 1,049	NETL, 2011
Diesel ($kg\ CO_2e/\ kg$)	U.S. Consumption Mix: 0.75		Non-North American Crude Mix: 0.81	NETL, 2008
Naphtha ($kg\ CO_2e/\ kg$)	0.65			PE, 2006
LPG ($kg\ CO_2e/\ kg$)	1.41			NETL, 2008
Captured CO_2 ($kg\ CO_2e/\ kg$)	0.09			NETL, 2013

Notes:

[a] Information in this table, including sources are from Table 1-4 of NETL's Comprehensive Analysis Reports (NETL, 2014b, 2014c).

kg = kilograms

MWh = megawatt hour

8.2.4 Key Modeling Assumptions

NETL's LCA modeling for both the EFG and TRIG™ was based on the assumptions provided below in Table 8-3.

Table 8-3: Key Modeling Assumptions

Primary Subject	Default Value
Study Boundary	
Temporal Boundary	30 years
Region	Southeastern United States and Permian Basin, Texas
CBTL Plant Capacity (combined products)	50,000 bpd
Technology/Process	
Gasification System	EFG gasification TRIG™ gasification
Carbon Capture Technology	2-Stage Selexol™
Carbon Capture Rate	EFG: 91% (85-94%) TRIG™: 88% (81-90%)
Sulfur Recovery	Claus unit
Syngas Conversion	FT reactors

Primary Subject	Default Value
FT Catalyst	Iron
Overhead Gas Carbon Removal	Methyldiethanolamine unit
Product Separation	Cryogenic separation
CBTL Product Suite	FT jet fuel, FT diesel, FT naphtha, FT LPG
Electricity Production	Gas turbine, heat recovery steam generator
Cooling	Cooling tower
Environmental	
Coal Feedstock	Montana rosebud sub-bituminous coal
Coal Heating Value	9,079 Btu/lb (LHV), as fed to CBTL plant
Biomass Feedstock	Southern pine biomass
Biomass Cultivation Period	13 years
Biomass Pretreatment	Chip/microchip and grind, pelletization, or torrefaction
Biomass Heating Value	6,514 Btu/lb (LHV), as fed to CBTL plant
Land Use Type	Converted cropland and pastureland
Land Use Scope	Direct and Indirect GHG emissions
Coal Transport Distance	1,600 miles
Raw Biomass Transport Distance	Field to CBTL plant: 40 miles (one way); Field to torrefaction: 50 miles (one way)
CO_2-EOR CO_2 Transport Distance	775 miles
FT Jet Fuel Pipeline Transport Distance	225 miles
FT/Conventional Fuels Blending Ratio	1:1 (volume)
Blended Jet Fuel Pipeline Transport Distance	245 miles
Blended Jet Fuel Truck Transport Distance	50 miles (one way)
CO_2 Pipeline Leakage Factor	3,843 kg/mi-yr

Source: Compiled from Table 1-7 in NETL, 2014b, 2014c.

8.2.5 Environmental Parameters

The following adjustable environmental parameters in Table 8-4 were used in NETL's LCA modeling for both the EFG and TRIG™:

Table 8-4: Adjustable Environmental Parameters

Environmental Parameters	Expected Value (min; max)
Coal mine methane (scf of methane/ton of coal at mine mouth)	8 (4; 40)
Biomass yield as harvested (kg/acre-yr)	6,350 (2,993; 7, 620)
Chip type (0 = conventional chipper; 1 = microchipper)	0 (0; 1)
Rail distance (miles)	1,600 (1,280; 1,920)

Environmental Parameters	Expected Value (min; max)
Biomass truck distance: farm to CBTL or farm to torrefaction facility (miles)	40 (20; 50)
Biomass truck distance: torrefaction facility to CBTL plant (mile)	50 (40; 60)
CBTL plant operations scenario or FT Jet RSP Case (0.2 = low/high and 0.6 = expected)	0.6 (0.2; 0.2)
CO_2 pipeline distance (mile)	775 (620; 930)
CO_2 pipeline loss rate (kg/mi-yr)	3,843 (384.3; 38,430)
Blended jet fuel transport pipeline length (mile)	225 (180; 270)
Blended jet fuel transport scenario (1 = 100% pipeline; 0 = 60% pipeline and 40% truck transportation)	0 (0; 1)
Diesel displacement type (1 = U.S. consumption mix; 2 = U.S. import mix)	1 (1; 2)
Diesel displacement factor	1 (1; 1)
CO_2 displacement type (1 = natural dome)	1 (1; 1)
CO_2 displacement factor	1 (1; 1)
Electricity displacement type (1 = 0.6; 2 = 0.2; 3 = 0.2)	0.6 (0.2; 0.2)
Electricity displacement factor	1 (1; 1)

Source: Compiled from Table 1-6 in NETL, 2014b, 2014c.

8.3 NETL's LCA Modeling of an EFG and TRIG™

NETL's LCA modeling of an EFG and TRIG™ are summarized here and described in detail in Appendix M and Appendix N, respectively. The model was used to estimate the LCA of a CBTL plant for hypothetical scenarios using coal only and various combinations of coal and woody biomass for either a single gasifier or two separate gasifiers. This section summarizes the scenarios modeled, modeling validation, key modeling results, and the Project Team's recommendations based on these results. A simplified CBTL plant configuration adapted from NETL (2014b, 2014c) EFG and TRIG™ LCA modeling is shown on Figure 8-3.

For the TRIG™, NETL originally conducted modeling for 14 scenarios, and during the development of this report, NETL conducted additional modeling. This additional modeling does not affect the results presented in this report; therefore, for ease of presentation, only the original 14 TRIG™ scenarios are discussed below. Details of the original 14 TRIG™ models and additional modeled scenarios are provided in Appendix N.

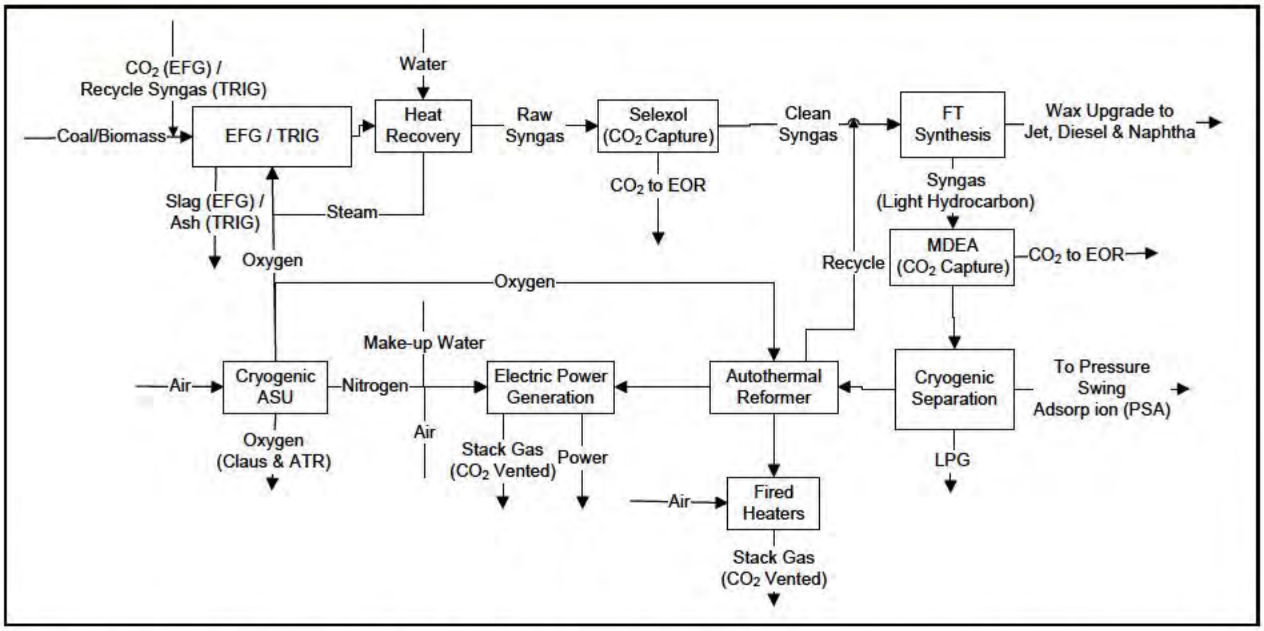


Figure 8-3: Simplified CBTL Plant Configuration for EFG and TRIG™ Techno-economic Model

8.3.1 Modeling Scenarios for EFG

Based on the established modeling boundaries described in Section 8.2.1, LCAs were performed for 10 hypothetical CBTL FT jet fuel production scenarios (Table 8-5) for a conceptual facility in the southeastern United States. This location was selected for its proximity to the harvested southern yellow pine, a short-rotation woody crop that was used for the nine scenarios with biomass (Scenario 1 used only coal).The biomass pretreatment methods are provided in Table 8-5, along with the percent of biomass feed by weight. The biomass mass percentage was based on dried and prepared feedstocks. For nine of the 10 scenarios, coal and biomass were co-fed into a single EFG. For Scenario 10, the same type of EFG was used; however, coal and biomass were fed into separate gasifiers. All scenarios were based on indirect liquefaction with a slurry iron catalyst FT synthesis reactor and an carbon dioxide capture approach using both Selexol™ and methyldiethanolamine-based processes.

In addition to the differences described above, key differences among the scenarios included the feed rate, percentage of biomass, and the use of dry and ground biomass preparation for the conventional chipping scenarios versus pelletization and/or torrefaction for the other scenarios, as shown in Table 8-5.

Detailed feedstock analysis (proximate, ultimate and heating value), feedstock preparation method (e.g., torrefaction process, drying, grinding), CBTL process configuration and CBTL LCA modeling methodology used in this study are provided in Appendix M.

Table 8-5: Conceptual EFG CBTL Scenarios Modeled for LCA

Scenario Number	Scenario Name	Biomass Pretreatment Method
1	100% Coal	Not applicable
2	10% Biomass, Chipped	Dry and grind from raw wood chips
3	30% Biomass Chipped	Dry and grind from raw wood chips

Scenario Number	Scenario Name	Biomass Pretreatment Method
4	10% Biomass, Torrefied	Torrefaction of chipped wood
5	30% Biomass, Torrefied	Torrefaction of chipped wood
6	10% Biomass, Pellets	Pelletization of raw wood
7	30% Biomass, Pellets	Pelletization of raw wood
8	10% Biomass, Torrefied Pellets	Torrefaction, then pelletization
9	30% Biomass, Torrefied Pellets	Torrefaction, then pelletization
10	10% Biomass, Torrefied Pellets, Separate Gasifiers	Torrefaction, then pelletization

Notes:
Biomass percent (wt) is the percent as fed into the gasifier, not as received into the plant.
For pretreatment methods that do not involve torrefaction, biomass remains in a raw state for feeding/testing.

8.3.2 Modeling Scenarios for TRIG™

Based on the established modeling boundaries described in Section 8.2.1, LCAs were performed for 14 hypothetical CBTL FT jet fuel production scenarios (Table 8-6) for a conceptual facility in the southeastern United States. This location was selected for its proximity to the harvested southern yellow pine, a short-rotation woody crop that was used for the 13 scenarios with biomass (Scenario 1 used only coal). The biomass pretreatment methods are provided in Table 8-6, along with the percent of biomass feed by weight. The biomass mass percentage was based on dried and prepared feedstocks. Thirteen of the 14 scenarios used a single transport gasifier, and Scenario 6 used the same type of transport gasifier for coal, but included a separate ClearFuels® gasifier for biomass, followed by a nickel-based catalyst dual-fluid bed (Ni-DFB) tar reformer. All scenarios were based on indirect liquefaction with a slurry iron catalyst FT reactor and a carbon capture approach using both Selexol™ unit and methyldiethanolamine-based carbon dioxide capture.

In addition to the differences described above, key differences among the scenarios included the feed rate, percentage of biomass, and the use of dry and ground biomass preparation for the conventional chipping scenarios (Scenarios 2, 3, and 7) versus pelletization and/or torrefaction for the other scenarios, as listed in Table 8-6.

Detailed feedstock analysis (proximate, ultimate and heating value), feedstock preparation method (e.g., torrefaction process, drying, grinding), CBTL process configuration, and the CBTL LCA modeling methodology used in this study are provided in Appendix N.

Table 8-6: Conceptual TRIG™ CBTL Scenarios Modeled for LCA

Scenario Number	Scenario Name	Biomass Pretreatment Method
1	100% Coal	Not applicable
2	10% Biomass, Chipped	Dry and grind from raw wood chips
3	20% Biomass, Chipped	Dry and grind from raw wood chips
4	10% Biomass, Torrefied	Torrefaction of chipped wood

Scenario Number	Scenario Name	Biomass Pretreatment Method
5	20% Biomass, Torrefied	Torrefaction of chipped wood
6	10% Biomass, Microchipped, Separate Gasifiers with Tar Reformer	Microchipped raw wood
7	30% Biomass, Chipped	Dry and grind from raw wood chips
8	30% Biomass, Torrefied	Torrefaction of chipped wood
9	11.7% Biomass, Pellets	Pelletization of raw wood
10	19.2% Biomass, Pellets	Pelletization of raw wood
11	28.3% Biomass, Pellets	Pelletization of raw wood
12	16.5% Biomass, Torrefied Pellets	Torrefaction, then pelletization
13	19.6% Biomass, Torrefied Pellets	Torrefaction, then pelletization
14	28.3% Biomass, Torrefied Pellets	Torrefaction, then pelletization

Notes:

Biomass percent (wt) is the percent as fed into the gasifier, not as received into the plant.

For pretreatment methods that do not involve torrefaction, biomass remains in a raw state for feeding/testing.

8.3.3 Modeling Validation for EFG and TRIG™

EFG – Six of the 10 EFG scenarios (Scenario 1 and Scenarios 6 through 10) were validated based on project test data from EERC. A primary objective of this validation process was to determine whether the modeled performance predictions were consistent with the test observations. To do this, a version of the EFG model was created that corresponded to the EERC test conditions, including feed stream compositions and flows. A data regression was then performed to fit the gasifier heat loss, carbon conversion, and chemistry model to the experimental data. This corrected model was then used to validate the scenario modeling. The model validation process and results are provided in Appendix M.

TRIG™ – Seven of the 14 TRIG™ scenarios (Scenario 1 and Scenarios 9 through 14) were validated based on project gasification test data from NCCC. Ultimate validation would depend on data from operation of the Kemper County power plant being commissioned in Mississippi and expected to capture 65% of the carbon dioxide produced for EOR. A primary objective of this validation process was to determine whether the modeled performance predictions were consistent with the test observations. To do this, a version of the TRIG™ model was created that corresponded to the NCCC test conditions, including feed stream compositions and flows. A data regression was then performed to fit the gasifier heat loss, carbon conversion, and chemistry model to the experimental data. This corrected model was then used to validate the scenario modeling. The model validation process and results are provided in Appendix N.

8.3.4 Results and Discussion for EFG and TRIG™

This section summarizes the main EFG and TRIG™ process modeling and LCA results for the modeled scenarios. Results are provided for the five major life cycle stages with a focus on Section 526 compliance; detailed results for the sub-stages are provided in Appendix M and Appendix N for the EFG and TRIG™, respectively.

8.3.4.1 *Process Results and Discussion for EFG and TRIG™*

Key results of the CBTL process modeling that impact the overall GHG emissions from the process model are discussed below. The results provided are based on a plant design capacity of 50,000 bpd of FT liquids and an expected plant capacity factor of 90%. The FT liquids consisted of about 49% FT jet fuel, 10% FT diesel fuel, 34% FT naphtha, and 7% FT LPG by volume. For EFG scenarios carbon dioxide captured from the CBTL plant for EOR sequestration was 85 to 94% and for TRIG^{TM} scenarios carbon dioxide captured from the CBTL plant for EOR sequestration was 81 to 90%. The predicted process results for the expected case (Table 8-3 and Table 8-4) for the modeled scenarios are summarized below and in Table 8-7 and Table 8-8 for the EFG and TRIG™, respectively. Complete process results are provided in Section 5 of Appendix M and Appendix N, and include water usage, net electricity production, carbon balance, and major auxiliary loads. Major auxiliary loads in a CBTL plant include air separation, carbon dioxide compressors, the Selexol™ unit, hydrocarbon recovery/refrigeration, and oxygen compression.

CBTL Plant Energy Efficiency

- CBTL plant energy efficiency decreases slightly when chipped biomass and pelletized biomass percentages increase, and plant energy efficiency increases when torrefied biomass and torrefied pelletized biomass percentages increase. These results occur because chipped biomass and pelleted biomass have lower heating values compared to torrefied biomass and torrefied pelletized biomass and therefore require more energy to convert to syngas. The amount of feedstock necessary to produce a barrel (bbl) of FT liquid is provided in Table 8-7 for EFG and Table 8-8 for TRIG™. Because of the lower heating value of raw biomass, an increased amount of feedstock input (coal plus chipped/pelletized biomass) is necessary to produce 50,000 bpd of FT liquids compared to the scenarios in which torrefied biomass (coal plus torrefied/torrefied pellets biomass) were used.

Export Electricity

- With the EFG, the only scenario that resulted in a net export of electricity and displacement of GHG emissions associated with the purchase of power from the electric grid is the 30% Torrefied Pellets Biomass Scenario that produced export electricity of 11 megawatts electrical (MWe).

- With the TRIG™, export electricity is higher for the torrefied biomass and torrefied pellets biomass scenarios compared to the chipped biomass and pelletized biomass scenarios. This is because lower overall feedstock inputs and lower grinding energy are required for the torrefied biomass scenarios.

Water Consumption

- With the EFG modeling:
    - The 100% Coal Scenario consumes the least amount of water compared to the coal/biomass scenarios.
    - Water consumption is predicted to increase as the biomass percent increases.

  - The Separate Gasifiers Scenario (10% torrefied pellets) consumes more water than 100% coal, 10% chipped and 10% torrefied pellets scenarios, but less water than the other six biomass scenarios.

- With the TRIG™ modeling:
  - As biomass percentages increase, water consumption decreases.
  - The torrefied chipped biomass scenarios consume virtually the same amount of water as the chipped biomass scenarios, and the torrefied pelletized biomass scenarios consume slightly less water than the pelletized biomass scenarios.
  - The Separate Gasifiers Scenario (10% microchipped biomass with tar reformer) consumes more water than the other 13 scenarios.

Table 8-7: EFG CBTL Plant Process Summary

Process Summary	100% Coal	10% Bio, Chipped	30% Bio, Chipped	10% Bio, Torrefied	30% Bio, Torrefied	10% Bio, Pellets	30% Bio, Pellets	10% Bio, Torrefied Pellets	30% Bio, Torrefied Pellets	10% Bio, Torrefied Pellets, Sep. Gasifiers
Coal: Montana Rosebud, As Received (tons/day)	29,864	28,227	24,495	27,248	21,607	27,754	22,896	26,812	20,707	26,973
Biomass: Southern Pine, As Received (tons/day)	0	4,106	13,743	2,391	7,313	2,435	7,749	2,353	7,008	2,367
Plant Energy Efficiency, HHV (%)	50.8	49.6	46.8	50.6	50.6	50.3	49.8	51.0	51.9	50.7
Export Electricity (MWe)	0	0	0	0	0	0	0	0	11	0
CO_2 Captured and Compressed (tons/day)	30,234	30,785	33,060	30,620	31,405	30,504	31,068	30,159	30,008	30,335
Coal/Biomass Feed (as received) Needed per Barrel of FT Liquid (tons)	0.597	0.647	0.765	0.593	0.578	0.604	0.613	0.583	0.554	0.587
CO_2 Captured and Compressed (tons/bbl FT liquid)	0.605	0.616	0.661	0.612	0.628	0.610	0.621	0.603	0.600	0.607
Water Withdrawal (barrel/barrel FT liquid)	5.96	6.08	6.38	6.19	6.52	6.22	6.62	6.05	6.17	6.15
Water Consumption (barrel/barrel FT liquid)	5.43	5.54	5.81	5.64	5.94	5.66	6.03	5.51	5.62	5.60

Source: Compiled from NETL, 2014b.

Table 8-8: TRIG™ CBTL Plant Process Summary

Process Summary	100% Coal	10% Bio, Chipped	20% Bio, Chipped	30% Bio, Chipped	10% Bio, Torrefied	20% Bio, Torrefied	30% Bio, Torrefied	10% Bio, Micro-chipped, Sep. Gasifiers	11.7% Bio, Pellets	19.2% Bio, Pellets	28.3% Bio, Pellets	16.5% Bio, Torrefied Pellets	19.6% Bio, Torrefied Pellets	28.3% Biomass, Torrefied Pellets
Coal: Montana Rosebud, as Received (tons/day)	28,121	28,121	25,637	23,022	27,173	23,927	20,743	28,652	27,298	25,208	22,620	25,098	24,104	21,343
Biomass: Southern Pine, as Received (tons/day)	4,091	4,091	8,391	12,917	2,733	5,415	8,048	4,320	3,274	5,422	8,082	4,490	5,319	7,626
Plant Energy Efficiency HHV (%)	53.0	53.0	52.7	52.3	53.6	54.0	54.4	51.7	53.5	53.7	53.9	54.1	54.2	54.7
Export Electricity (MW_e)	203	203	183	162	223	227	231	197	228	233	239	235	238	246
CO_2 Captured and Compressed (tons/day)	31,100	31,100	31,334	31,581	30,846	30,823	30,808	29,401	30,857	30,845	30,829	30,306	30,204	29,925
Coal/Biomass Feed (as received) Needed per Barrel of FT Liquid (tons)	0.644	0.644	0.681	0.719	0.598	0.587	0.576	0.659	0.611	0.613	0.614	0.592	0.588	0.579
CO_2 Captured and Compressed (tons/bbl FT liquid)	0.622	0.622	0.627	0.632	0.617	0.616	0.616	0.588	0.617	0.617	0.617	0.606	0.604	0.599
Water Withdrawal (barrel/barrel FT liquid)	7.00	7.00	6.83	6.66	7.02	6.89	6.75	7.16	7.09	7.04	6.98	6.87	6.81	6.66
Water Consumption (barrel/barrel FT liquid)	6.37	6.37	6.22	6.07	6.40	6.27	6.15	6.52	6.45	6.41	6.36	6.25	6.20	6.07

Source: Compiled from NETL, 2014c.

8.3.4.2 *Total Life Cycle GHG Emission Results for EFG and TRIG™*

The key results for total life cycle GHG emissions are summarized below and shown on Figure 8-4 and Figure 8-5 for the EFG and TRIG™, respectively. These figures show results for the minimum, maximum, 5th, 25th, median, mean, 75th, and 95th percentiles.

- With EFG modeling, the mean and median GHG emissions from the 100% Coal Scenario with CCS using EOR were below the Section 526 baseline value of 88.41 g CO_2e/MJ. For the nine scenarios that included biomass, the total range of GHG emissions is below the Section 526 baseline value of 88.41 g CO_2e/MJ.

- With TRIG™ modeling, the total range of GHG emission results for all 14 scenarios are below the Section 526 baseline value.

- The Separate Gasifiers Scenario (10% torrefied pellets) in the EFG modeling produces nearly the same range of GHG emissions as the 10% Torrefied Pellets Biomass Scenario.

- With the TRIG™ modeling, the 100% Coal and Separate Gasifiers (10% microchipped biomass with tar reformer) scenarios are predicted to produce the highest GHG emissions of the scenarios modeled.

- With both the EFG and TRIG™ modeling:

    - As the biomass (chipped, pellets, torrefied, torrefied pellets) percentages increase from 10 to 30%, median GHG emissions decrease by approximately 25 g CO_2e/MJ.

    - Torrefied biomass scenarios result in slightly lower GHG emissions compared to raw biomass scenarios, although the ranges largely overlap.

- The validated total GHG emission results are within 1.6% and 1.7% of the modeled results for the EFG and TRIG™, respectively. Validated results are provided in Appendix M and Appendix N for the EFG and TRIG™, respectively.

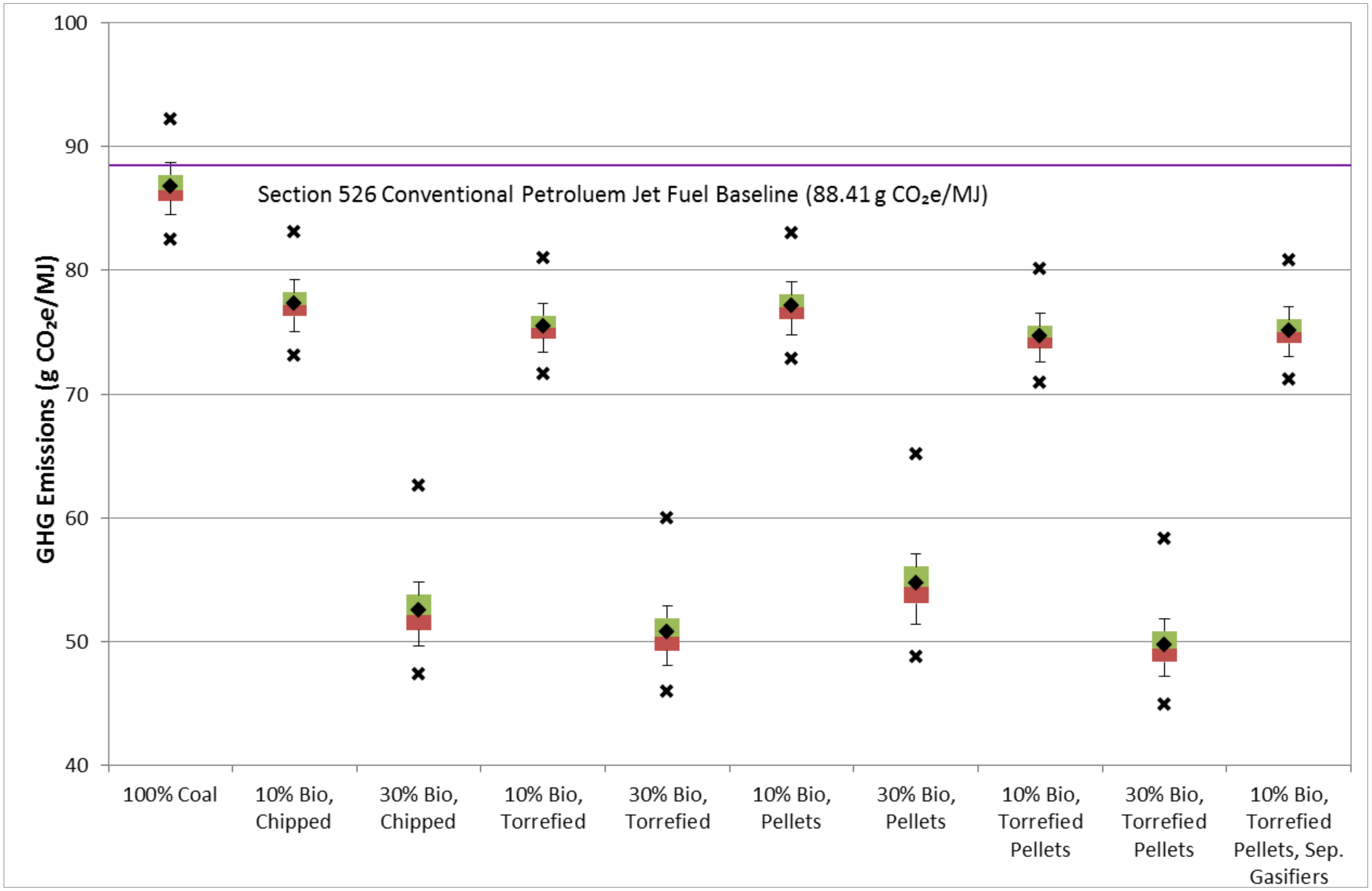


Figure 8-4: EFG Total Life Cycle GHG Emissions

Source: NETL, 2014b
Key:
Black diamond = mean (average)
Green bar = 75th percentile
Red bar = 25th percentile
X = minimum and maximum
Point where green and red bars meet = 50th percentile (median)
Whisker = 5th and 95th percentile

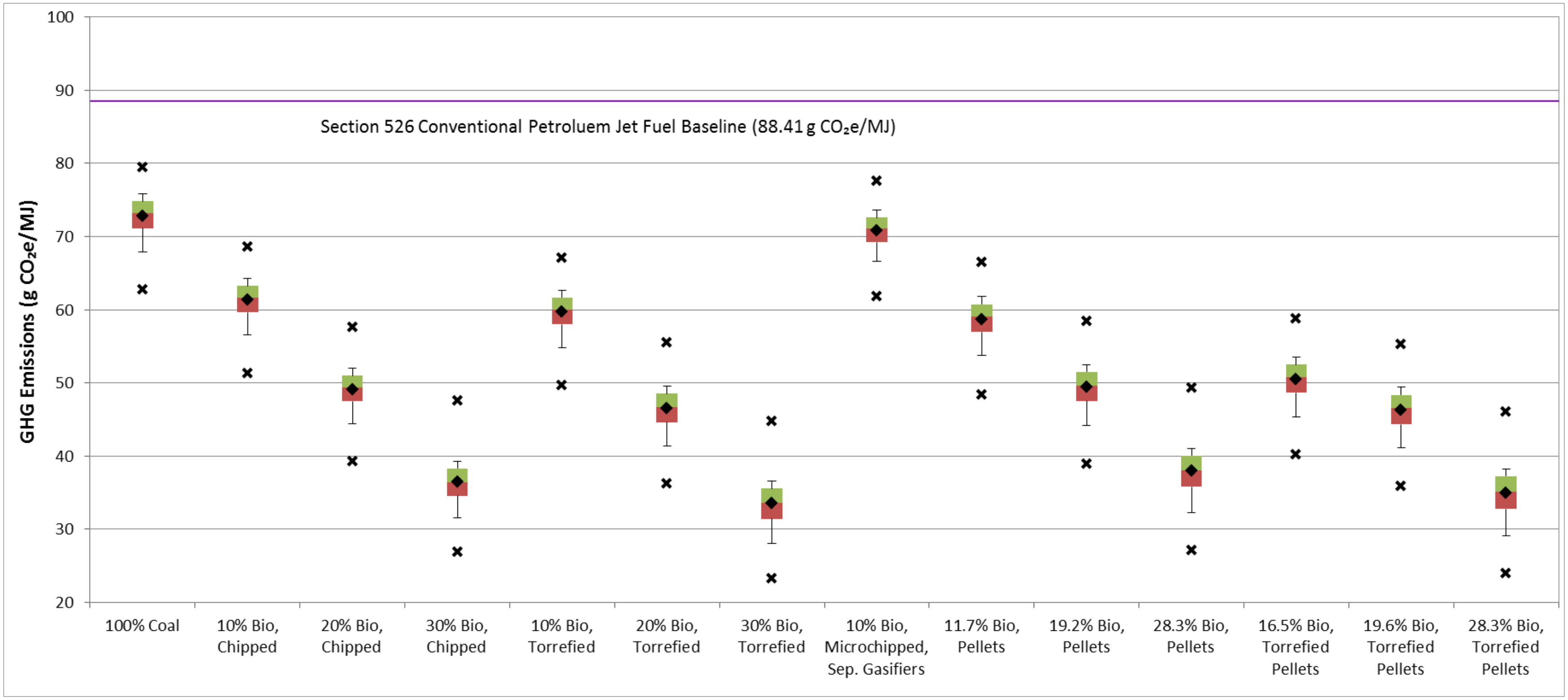


Figure 8-5: TRIG™ Total Life Cycle GHG Emissions

Source: NETL, 2014c

Key:
Black diamond = mean (average)
Green bar = 75th percentile
Red bar = 25th percentile
X = minimum and maximum
Point where green and red bars meet = 50th percentile (median)
Whisker = 5th and 95th percentile

8.3.4.3 *GHG Emission Results for Expected Case for EFG and TRIG™*

The expected case (Table 8-3 and Table 8-4) GHG emission results for the five major life cycle stages are summarized below and provided in Table 8-9 and Table 8-10. These tables also show the relative percent difference in total GHG emissions compared to the Section 526 baseline value and relative percent difference in total GHG emissions from coal only to coal/biomass scenarios.

- **Raw Material Acquisition** – Biomass has by far the largest impact on reducing GHG emissions. Increased woody biomass percentages in the feedstock result in lower GHG emissions, which is primarily the result of a biomass production GHG emissions credit from the raw material acquisition stage. The GHG emissions credit occurs because carbon dioxide is absorbed from the atmosphere during biomass production.

- **Raw Material Transport** – This stage has fairly stable GHG emissions in most cases. GHG emissions decrease as the raw chipped and pelletized biomass percentages increase, but increase as torrefied chipped and pelletized biomass percentages increase. The model includes the GHG emissions from the torrefaction facility and two transportation penalties. Not only does torrefaction require the additional transport of biomass to the torrefier, but also requires shipping a significantly larger quantity of raw biomass to the torrefier than would be shipped directly to the CBTL plant to achieve the same percentage of biomass by weight. This increased shipment size is not offset by the higher energy density of the torrefied product compared to raw biomass.

- **Energy Conversion –** This stage has a relatively low GHG emissions factor in most scenarios. GHG emissions increase as the chipped and pelletized biomass percentages increase; however, the opposite is true for torrefied and pelletized torrefied biomass. Torrefied and pelletized torrefied biomass have a higher energy content, which increases the energy efficiency of the CBTL plant. This results in increased net electricity production and less carbon dioxide generation, which results in lower GHG emissions in the energy conversion stage.

- **Product Transport and End Use –** These stages have the largest positive GHG emissions by far, but product transport (7.34 g CO_2e/MJ) and end use (72.69 g CO_2e/MJ) life cycle GHG emissions are the same for all scenarios. Of the five major LCA stages, these two stages take place after FT fuel production, and are not impacted by the earlier processes of manufacturing product gas. Because the life cycle GHG emissions (totaling 80.03 g CO_2e/MJ) from product transport and end use are the same for all cases, the sum of emissions from the first three major life cycle stages must be less than or equal to 8.38 g CO_2e/MJ to meet the Section 526 baseline value of 88.41 g CO_2/MJ. The FT jet fuel product design specification is the same for all of the scenarios; therefore, the 50/50 blended jet fuel quantity is the same. Approximately 97.4% of the product transport GHG emissions result from conventional petroleum jet fuel production (extraction, transport, and refining of crude) and blending the 50/50 FT jet and petroleum jet fuels. Approximately 99.96% of the end use GHG emissions result from the combustion of blended jet fuel.

- **Total GHG Emissions –** Results for all modeled EFG and TRIG™ scenarios are below the Section 526 baseline value, and total GHG emissions are lower for both torrefied and pelletized torrefied biomass scenarios compared to both chipped and pelletized biomass scenarios. For similar scenarios, total GHG emissions are lower with the TRIG^{TM} than with the EFG. Based on the process configuration and assumptions used for modeling, the TRIG™ shows higher CBTL plant energy efficiency resulting in more export power compared to the EFG CBTL plant configuration. More export power means a higher electricity displacement credit for the TRIG™ LCA compared to the EFG LCA.

Table 8-9: EFG Average Life Cycle GHG Emissions for the Major Life-Cycle Stages and Percent Differences

LCA Major Stages [a]	100% Coal	10% Bio, Chipped	30% Bio, Chipped	10% Bio, Torrefied	30% Bio, Torrefied	10% Bio, Pellets	30% Bio, Pellets	10% Bio, Torrefied Pellets	30% Bio, Torrefied Pellets	10% Bio, Torrefied Pellets, Sep. Gasifiers	Baseline Value
Raw Material Acquisition	2.00	-10.57	-40.03	-10.24	-35.43	-10.50	-37.74	-10.07	-33.93	-10.14	6.82
Raw Material Transport	5.47	5.26	4.80	6.34	8.09	5.17	4.49	6.24	7.75	6.28	1.28
Energy Conversion	-0.68	2.57	7.74	-0.68	-1.94	2.40	7.94	-1.53	-4.10	-1.03	5.75
Product Transport	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	0.95
End Use	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	73.62
Total GHG Emissions ($g\ CO_2e/MJ$)	**86.82**	**77.29**	**52.54**	**75.45**	**50.75**	**77.10**	**54.72**	**74.66**	**49.74**	**75.14**	**88.41**
GHG Emission Percent Differences (%)											
Below Baseline Value	1.8	12.6	40.6	14.7	42.6	12.8	38.1	15.6	43.7	15.0	NA
Below 100% Coal Scenario	NA	11.0	39.5	13.1	41.5	11.2	37.0	14.0	42.7	13.5	NA

Notes:

[a] Sub-stages for each major stage are provided in Section 8.1.2.

Table 8-10: TRIG™ Average Life Cycle GHG Emissions for the Major Life-Cycle Stages and Percent Differences

LCA Major Stages [a]	100% Coal	10% Bio, Chipped	20% Bio, Chipped	30% Bio, Chipped	10% Bio, Torrefied	20% Bio, Torrefied	30% Bio, Torrefied	10% Bio, Micro-chipped, Sep. Gasifiers	11.7% Bio, Pellets	19.2% Bio, Pellets	28.3% Bio, Pellets	16.5% Bio, Torrefied Pellets	19.6% Bio, Torrefied Pellets	28.3% Biomass, Torrefied Pellets	Baseline Value
Raw Material Acquisition	2.03	-10.53	-23.72	-37.59	-11.91	-25.59	-39.02	-11.12	-14.52	-25.38	-38.83	-20.86	-25.09	-36.86	6.82
Raw Material Transport	5.55	5.21	4.86	4.49	6.49	7.41	8.31	5.32	5.10	4.80	4.43	7.10	7.38	8.18	1.28
Energy Conversion	-14.77	-13.41	-12.05	-10.49	-14.93	-15.34	-15.80	-3.41	-11.90	-10.01	-7.71	-15.80	-16.04	-16.40	5.75
Product Transport	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	0.95
End Use	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	73.62
Total GHG Emissions (g CO$_2$e/MJ)	**72.83**	**61.30**	**49.12**	**36.43**	**59.68**	**46.51**	**33.52**	**70.82**	**58.71**	**49.43**	**37.92**	**50.46**	**46.28**	**34.95**	**88.41**
GHG Emission Percent Differences (%)															
Below Baseline Value	17.6	30.7	44.4	58.8	32.5	47.4	62.1	19.9	33.6	44.1	57.1	42.9	47.7	60.5	NA
Below 100% Coal Scenario	0.0	15.8	32.6	50.0	18.1	36.1	54.0	2.8	19.4	32.1	47.9	30.7	36.5	52.0	NA

Notes:

[a] Sub-stages for each major stage are provided in Section 8.1.2.

8.3.5 Conclusions and Recommendations for EFG and TRIG™

This section provides the key conclusions for the modeled EFG and TRIG™ scenarios and recommendations for further technological research and development and additional scenario analysis.

8.3.5.1 *Key Conclusions for NETL's EFG and TRIG™ Modeling*

For EFG

- For 9 of the 10 scenarios, total GHG emissions are below the Section 526 baseline value over the entire distribution of modeled results. With the EFG modeling, the mean and median of the 100% Coal Scenario are below the baseline value, with only the upper tail (values at the 75th percentile or greater) above the baseline.

- The use of torrefied wood resulted in somewhat lower GHG emissions versus scenarios using raw wood chips or pellets at the same biomass percentage.

- The range of GHG emissions was not significantly different with the Separate Gasifiers Scenario (10% torrefied pellets) compared to the other10% biomass scenarios modeled.

For TRIG™

- For all 14 scenarios, total GHG emissions, including the maximum, are below the Section 526 petroleum baseline value.

- With the TRIG™ Separate Gasifiers Scenario (10% microchipped biomass with tar reformer), the ClearFuels® gasifier and the Ni-DFB tar reformer require significant fuel gas for heating, and because this system operates at essentially atmospheric pressure, the overall efficiency of this scenario is lower than any of the other modeled scenarios. Direct GHG emissions from the CBTL plant for this scenario are 64% higher than the 100% Coal Scenario. This is because the combustion emissions from fuel gas required to heat the ClearFuels® gasifier and the Ni-DFB tar reformer are vented to the atmosphere. With respect to life cycle GHG emissions, this scenario results in comparatively higher emissions than the other modeled biomass scenarios, but still shows a net benefit over the 100% Coal Scenario.

For both EFG and TRIG™

- Biomass carbon uptake during southern pine production is an important factor in the overall life cycle emissions from CBTL FT jet fuel.

- As the percentage of biomass increases, life cycle GHG emissions decrease. Based on the modeling results, the scenarios that use 30% biomass to generate FT fuels are predicted to have the lowest overall life cycle GHG emissions, while the 100% Coal scenario produces the highest overall life cycle GHG emissions. The reduction of GHG emissions associated with the increased biomass percent are primarily due to the change in land usage for the cultivation of southern pine. Incorporating biomass reduces life cycle GHG emissions because total carbon emissions are partially offset by the uptake of atmospheric carbon during biomass cultivation.

- The validated total GHG emission results are within 1.6% and 1.7% of the modeled results for both the EFG and TRIG™, respectively. Validated results are provided in Appendix M and Appendix N, respectively.

8.3.5.2 *NETL's Recommendations for Technological Development for EFG*

The 10 modeled EFG scenarios involved assumptions for both process performance and equipment costs (see Section 9 for the economic analysis). Much of the operational equipment for these scenarios is commercially available, and performance costs are known with a fairly high degree of confidence. However, several operations that were modeled are not currently used commercially, and a few of the technologies have not been proven viable for use at a commercial scale. For these reasons, additional research, development, and demonstration (RD&D) are necessary to improve performance and cost projections for the operations and technologies described below:

- In this analysis, bench-scale grinding equipment is used for the cost estimate and grinding mill throughput. Biomass grinding to a particle size of 100 microns is not commercially practiced. Grinding energy data should be obtained for machinery larger than the bench-scale equipment used in this analysis to provide a better estimate of potential cost and throughput of the grinding mill.

- Obtain information for various torrefaction reactor processes in order to better estimate energy and economics of the torrefaction process.

8.3.5.3 *NETL's Recommendations for Technological Development for TRIG™*

- The 14 modeled scenarios involved assumptions for both process performance and equipment costs (see Section 9 for the economic analysis). Much of the operational equipment for these scenarios is commercially available and performance costs are known with a fairly high degree of confidence. However, several operations that were modeled are not currently used commercially and a few of the modeled technologies have not been proven viable for use at a commercial scale. For these reasons, additional RD&D is necessary to improve performance and cost projections for the operations and technologies described below:

- In this analysis bench-scale grinding equipment is used for the cost estimate and grinding mill throughput. Biomass grinding to particle sizes of 200-400 microns is not commercially practiced. Grinding energy data should be obtained that is larger than the bench-scale equipment used in this analysis to provide a better estimate of the potential cost and throughput of the grinding mill.

- Identify and evaluate various torrefaction reactor processes in order to better estimate the economics of torrefaction of biomass.

- The TRIG^{TM} gasifier in this analysis was based on the projected commercial-scale Kemper County power plant. Currently there is no commercial TRIG^{TM} gasification process operating. In order to have a better estimate of process and cost, data should be obtained once the commercial Kemper County power plant is operating.

8.3.5.4 *Project Team Recommendations for Additional EFG and TRIG™ Scenario Analysis*

Based on results for the modeled scenarios, the modeling output could potentially evaluate the feasibility of any of the EFG and TRIG™ scenarios, given careful attention to design and economic parameters that inform life cycle GHG emissions and cost considerations (see Section 9 for the economic analysis). However, further analysis is recommended to determine the following:

- For the EFG, CBTL process modifications that would potentially reduce the amount of carbon dioxide captured and sequestrated that would reduce costs while still complying with Section 526 requirements. The use of carbon capture increasing the percentage for carbon captured and sequestered does not appear to be necessary.

- For the TRIG™, the percent of total captured carbon dioxide that could be vented while still complying with Section 526.

- For the EFG and TRIG™, the minimum percent of carbon dioxide that needs to be capture and sequestered to meet the Section 526 baseline value for each scenario.

- For the EFG and TRIG™, the minimum percent of biomass blended with coal that could meet the Section 526 baseline value without CCS.

Due to potential limited availability of biomass necessary for a commercial-scale plant in centralized locations, the Project Team recommends the following for both the EFG and TRIG:

- Increase the biomass transport distance from the 40 miles assumed in this study. Determine the maximum distance feedstocks could be transported to a CBTL plant and meet the Section 526 baseline value.

8.4 CCAT’s FT Black Box Modeling of Specific Gasification Technologies Tested

8.4.1 FT Black Box Process Model Overview

CCAT contracted with NETL to develop an FT black box model capable of calculating carbon dioxide emissions from the energy conversion life cycle stage of a conceptual FT liquids production facility. The model is based on 50,000 bpd of total liquid product using raw product gas compositions obtained from project tests or a hypothetical set of inputs that meets the model’s constraints. Although the model was developed for large-scale FT liquids production, the predicted GHG emissions are linearly scalable and therefore, can apply to a smaller scale production capacity (NETL, 2015a). The FT liquids consist of about 74% jet fuel, 17% diesel fuel, 6% LPG, and 2% naphtha by volume. This model addresses only technical processes of the FT facility and is independent of the type of gasifier or feedstocks used to generate the raw product gas (referred to as Raw Syngas Composition in the model). The model does not provide any cost data for economic analysis. The model provides “gate-to-gate” emissions data to allow the Project Team to conduct cradle-to-grave life cycle GHG emissions analyses of transportation fuel production systems using different gasification technologies and feedstocks than previously used by NETL (discussed in Section 8.3). The model has three primary outputs: 1) volume of specific FT liquids produced; 2) syngas requirements; and 3) the associated GHG emissions. Figure 8-6 shows the detailed FT plant configurations used in FT black box model.

Details of how the model works and can be used are provided in Appendix O. There are four major user inputs to the model, three of which pertain to operational services, such as steam and oxygen, which may be shared between the gasifier island and other parts of the facility. The most important input is raw product gas composition coming from the gasifier. The model allows the user to specify percentage of captured carbon dioxide vented, percentage of FT tail gas recycle, power generation source (gas turbine or boiler), and supplemental utilities. Model outputs include GHG emissions from the FT plant, GHG emissions from supplemental utilities usage, FT liquid product flows (jet, diesel, naphtha and LPG), pipeline carbon dioxide for EOR, net export power (electricity), and total raw syngas required to produce liquid fuel and net export power.

One constraint of NETL's model is that the raw product gas input must have an H_2:CO molar ratio of 1.1:1 or less. For instance, the FT black box model is not suitable for TRI steam reforming technology, which is designed to produce product gas with a H_2:CO molar ratio of approximately 2.1. Approximately one-sixth of the 145 test cases from all gasifiers tested for this project yielded ratios less than or equal to 1.1. These test cases were those performed on the TRDU, EFG, TRIG™ and WPC gasifiers. All but four of the EFG and one of the TRDU test cases were previously run in NETL's more rigorous EFG and TRIG™ models (Section 8.3). The FT black box model results for the WPC tests are presented below. The five scenarios tested at EERC with results suitable for the model are: 30% corn stover with PRB; 10% mixture of water lettuce and water hyacinth with PRB; 10% torrefied southern pine with IL No. 6 coal; and 30% torrefied southern pine with IL No. 6 coal on the EFG; and the 15% torrefied southern pine with PRB on the TRDU. Other scenarios could be modeled to approximate GHG emissions from other feedstock combinations, but syngas H_2:CO molar ratios would need to be artificially adjusted to the 1.1 ratio.

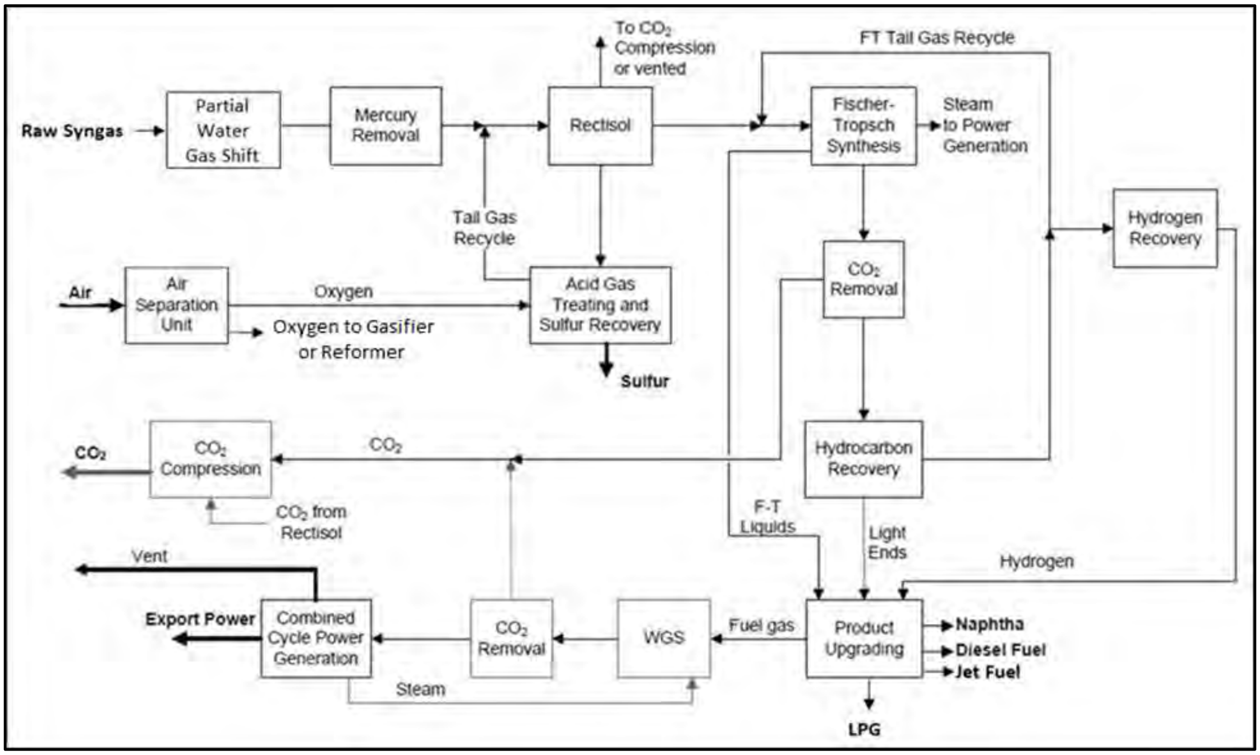


Figure 8-6: NETL FT Black Box Model Process Diagram

8.4.2 Cradle-To-Grave LCA using FT Black Box Model

To enable the user to calculate a cradle-to-grave life cycle value for a particular CBTL configuration, NETL provided life cycle GHG emissions associated with each of the life cycle stages upstream and downstream of the FT box (Appendix O, Table 5-1). These emission factors are the same as those used in the LCA work NETL performed previously, as described in Section 8.3. Because NETL did not model all the feedstocks tested in this program, the Project Team estimated GHG emission factors of several feedstocks for the Raw Material Acquisition and Transportation life cycle stages using data obtained from literature and the Greenhouse Gases, Regulated Emissions, and Energy in Transportation model (GREET model). These are presented in Table 8-11. To calculate a cradle-to-grave LCA, the input and output flows from the FT black box model must be scaled so all results are expressed on the basis of the same functional unit (i.e., the combustion of 1 MJ LHV of blended jet fuel at 50/50 by volume). Because the FT black box model does not calculate the quantity of gasifier feedstock needed, these quantities needed to be calculated. To assess how the FT black box model performed compared to the more rigorous model NETL used for the EFG and TRIG™, the FT black box model was run using inputs from a coal-only validated TRIG^{TM} scenario that NETL previously modeled (Section 8.3). The raw syngas composition, gasifier steam balance, sour water flow from gasifier, oxygen requirement for the gasifier, FT recycle percent, and supplemental electrical utilities inputs to FT black box model were provided by NETL for that coal-only validated scenario. The GHG emissions predicted from both models were very close (72.6 g CO_2e/MJ for the TRIG™ model and. 71.0 g CO_2e/MJ for the FT black box model). The slight variation in results could be due to the difference in FT liquid density and energy content of the FT liquids used in each model.

Table 8-11: GHG Emission Factors for Raw Material Acquisition and Transportation

LCA GHG Emission Factors	Value	Source
MSW Landfill and MSW to RDF Production GHG Emissions (kg CO_2e/kg)	-0.4775	Based on Landfills with Landfill Gas Recovery and Flaring (considered National Average Case) (USEPA, 2015)
Met Coke Production GHG Emissions (kg CO_2e/kg)	0.5354	GREET Model (https://greet.es.anl.gov/)
Flux (Limestone) Production GHG Emissions(kg CO_2e/kg)	0.0802	Limestone Quarrying and Processing: A Life-Cycle Inventory. (Natural Stone Council, 2008) Emission Factors for Greenhouse Gas Inventories (USEPA, 2014)
Corn Stover Production GHG Emissions (kg CO_2e/kg)	-0.0720	GREET Model
MSW Transportation GHG Emission (kg CO_2e/kg)	0.0441	Based on Landfills with Landfill Gas Recovery and Flaring (considered National Average Case) (USEPA, 2015)
Met Coke Transportation (kg CO_2e/kg per mile)	0.0076	GREET Model (assuming same emission as lime transportation)
Flux (Limestone)Transportation (kg CO_2e/kg per mile)	0.0076	GREET Model (assuming same emission as lime transportation)
Corn Stover Transportation GHG Emissions (kg CO_2e/kg per mile)	0.0053	GREET Model

8.4.3 WPC LCA Overview

As described in Section 6.5, pilot-scale gasification testing was conducted at the WPC test facility in Madison, Pennsylvania. Three tests were performed using coal/MSW feedstock blends at weight percent of: Test 1 (50% MSW), Test 2 (75% MSW), and Test 3 (100% MSW) (see Table 8-12). The data from these tests were used as inputs to the FT black box model to project the LCA for a commercial-scale plasma gasifier. Before using the test data, adjustments were made to account for heat loss, use of nitrogen as transport gas, and carbon conversion for a commercial-scale WPC gasifier. In addition, because the pilot-scale unit did not achieve equilibrium, the raw product gas composition was adjusted to simulate equilibrium conditions. The adjusted corrected data, which was used as input to run the FT black box model was provided by WPC but not included in this section due to confidentiality. As modeled, the WPC gasifier does not require steam injection nor is it required for drying feedstocks. Therefore, the steam generated from heat recovery units is surplus that can be used in a steam turbine to generate electricity. Lacking specific heat recovery data from WPC, it was assumed 25% heat recovery from the raw syngas is converted into steam (NETL, 2015b). WPC product gas must be compressed to 580 psia at a temperature of 379°F, which is accounted for as supplemental utilities (electrical) input to the model.

Other user inputs were set as follows:

- Percent of Captured CO_2 Vented was set to 0% to be consistent with the NETL 2014 TRIG™ and EFG models.

- The percent of FT tail gas recycled to FT reactor (referred to as Percentage of Recycle Gas to FT in the model) was selected by trial and error to be 46%. At this percentage, the net export power generated from the FT plant is positive or greater than zero, which is consistent with the NETL 2014 TRIG™ and EFG models. Note that if the FT tail gas recycle percentage is increased, the feedstock requirement and net export power both decrease.

- Supplemental Utilities Used for Gasifier Island: Electricity for the plasma torch and product gas compression.

Table 8-12: WPC CBTL Scenarios Modeled for LCA

Scenario Number	Scenario Name	MSW Pretreatment Method
1	50% MSW	Sorted and converted to RDF
2	75% MSW	Sorted and converted to RDF
3	100% MSW	Sorted and converted to RDF

8.4.3.1 *WPC GHG Emissions Results*

The FT black box model GHG emission results for the five major life cycle stages are summarized below and provided in Table 8-13. This table also shows the life cycle sub-stages and the relative percent difference in total GHG emissions compared to the Section 526 baseline value.

- **Raw Material Acquisition** – Using MSW has a great impact on reducing lifecycle GHG emissions. This is primarily the result of avoiding methane and carbon dioxide emissions associated with landfilling MSW at a landfill that recovers and flares landfill gas. The emissions avoidance credit would be much larger for MSW associated with a landfill that does not recover landfill gas (-1.359 compared to. -0.4789 kg CO_2e/kg MSW). The credit shown below is based on the lower value. The model does not provide a credit for the biogenic portion of the MSW, which would provide additional reduction in the predicted GHG emissions.

- **Raw Material Transport** – This stage accounts for a relatively small amount of total GHG emissions. GHG emissions increase as MSW percentages increase.

- **Energy Conversion** – This stage includes GHG emissions from construction and operation activities of the CBTL plant, including the conversion of FT tail gas into electric power (Section 8.1.2). The various displacement credits for byproducts are shown in Table 8-13. The credit for electricity displacement relates to net power production and therefore is minimal for all WPC cases.

- **Product Transport and End Use** – These stages have the largest positive GHG emissions by far, and are the same for all three scenarios. The FT liquid product slate is the same for all three WPC scenarios; therefore, the 50/50 blended jet fuel quantity is the same.

- **Total GHG Emissions** – The total GHG emissions for the three modeled WPC scenarios are below the Section 526 baseline value, ranging from 27% below for the 50% MSW scenario to 54% below for the 100% MSW scenario.

Table 8-13: Life Cycle GHG Emissions from CCAT Test Data from WPC Plasma (46% FT Recycle, 0% CO_2 Vented)

LCA Stages	50% MSW	75% MSW	100% MSW
LCA Major and Sub-stages	g CO_2e/MJ LHV		
Raw Material Acquisition	**-20.25**	**-33.26**	**-47.20**
Coal Mining, Sub-Bituminous (Montana Rosebud)	0.48	0.25	0.00
MSW, Landfill Emission Avoidance	-22.61	-35.63	-49.59
Met Coke Production	1.62	1.70	1.78
Flux Production (Limestone)	0.25	0.42	0.61
Raw Material Transport	**5.45**	**6.51**	**7.66**
Rail Transport of Coal to CBTL Plant	1.99	1.03	0.00
Transport of MSW to CBTL Plant	2.09	3.29	4.58
Met Coke Transportation	0.16	0.17	0.18
Flux Transportation (Limestone)	1.21	2.02	2.90
Energy Conversion	**-0.88**	**-0.25**	**0.40**
CBTL Plant Operations (includes CO_2 Compression)	9.65	9.68	9.62
CBTL Facility Construction	0.01	0.01	0.01
CO_2 Displacement – Natural Dome	-7.85	-7.92	-7.98
LPG Displacement	-1.05	-1.05	-1.05
Naphtha Displacement	-0.21	-0.21	-0.21
Diesel Displacement – U.S. Consumption Mix	-1.92	-1.92	-1.92
Electricity Displacement - 2010 Mix	-1.45	-0.79	-0.03
CO_2 Pipeline Transport to EOR/Saline Aquifer	1.93	1.95	1.96
Product Transport	**7.08**	**7.08**	**7.08**
Transport of FT Jet to Blending Facility	0.05	0.05	0.05
Blending of FT and Conventional Jet Fuel Profile	6.90	6.90	6.90
Pipeline Transport of Blended Jet Fuel to Airport	0.12	0.12	0.12
End Use	**72.72**	**72.72**	**72.72**
Airplane Operation (Fuel Use)	72.72	72.72	72.72
Total GHG Emissions	**64.11**	**52.79**	**40.65**
Percent Difference from Petroleum Baseline (%)	-27.5	-40.3	-54.0

Table 8-14 provides process summary data. Due to the availability and quantity of MSW feedstock, the process summary data are provided based on a 3,000 bpd CBTL plant rather than a 50,000 bpd plant.

Table 8-14: WPC CBTL Process Summary for 3,000 bpd plant

Process Summary	50% MSW	75% MSW	100% MSW
Coal: Montana Rosebud, as Received (tons/day)	1,001	519	0
Biomass: MSW, as Received (tons/day)	1,003	1,581	2,200
Export Electricity (MWe)	2	1	0
CO_2 Captured and Compressed (tons/day)	2,244	2,265	2,280
Coal/Biomass Feed (as received) Needed per Barrel of FT Liquid (tons/bbl FT liquid)	0.67	0.70	0.73
CO_2 Captured and Compressed (tons/bbl FT liquid)	0.75	0.76	0.76

8.4.4 Conclusions and Recommendation for WPC

The key conclusions from the FT black box modeling results are that each WPC scenario is predicted to fall well below the Section 526 baseline value and that increasing MSW percentage has the most impact on reducing lifecycle GHG emissions. A better estimate for syngas heat recovery should be obtained based on WPC's commercial gasifier design. If possible, it is worthwhile to determine the GHG emissions from an actual plant using WPC technology and to validate the model using those data. Because the FT black box model does not provide economic information, economic modeling is recommended to better understand the economic viability of a commercial-scale CBTL plant using WPC's plasma gasification technology.

8.4.5 TRI Two-step Steam Reformer with Partial Oxidation LCA using FT Black Box Model

The FT black box model is not suitable for TRI steam reforming technology, which is operated to produce product gas with a H_2:CO molar ratio of approximately 2.1. In addition, at this ratio, it is likely that a cobalt catalyst would be more suitable for the FT synthesis reactor than the iron catalyst used in the black box model. Although the input product gas composition can be adjusted to fit the model constraints, the LCA and process summary results would not to be representative of a commercial configuration of a CBTL plant using TRI steam reforming technology. To properly model life cycle GHG emissions from the TRI system, significant modifications to the FT black box model would be required or a different LCA model should be used.

8.5 Section 526 Optimization Modeling

The Project Team contracted NETL to develop a Section 526 Screening and Optimization tool. The model and tool documentation (NETL 2015c) are presented in Appendix P. NETL's previous EFG and TRIG^{TM} CBTL LCA models show that life cycle GHG emissions for all of the scenarios modeled and validated would fall well below the Section 526 baseline value of 88.41 g CO_2e/MJ with aggressive CCS (>90% capture as discussed in Section 8.3 and NETL, 2014b, 2014c). The goal of the screening tool is to enable the adjustment of key parameters/assumptions to determine a minimum set of conditions that would enable a facility to just meet the Section 526 petroleum baseline value. Key questions the model is designed to answer are:

1. For a given scenario (technology and feedstock blend), what is the CCS breakeven point (i.e., how much carbon dioxide captured from a CBTL plant could be vented to the atmosphere to minimize the amount of sequestration required to meet Section 526)?

2. Is there a minimum proportion of a certain biomass type that can be gasified with coal that will meet Section 526 without sequestration of captured carbon dioxide?

This tool provides modeling flexibility, specifically:

- The ability to choose different types of coal and biomass, as well as customized proportions of those feedstocks. The CBTL GHG Optimization Tool gives users the ability to choose from three coal types (IL No. 6 bituminous coal, Montana Rosebud sub-bituminous coal, or North Dakota lignite) and three biomass types (southern pine, switchgrass, or MSW).

- The ability to vent a user-specified percentage of the captured carbon dioxide without compression and sequestration. This option also affects total export power from the facility because as the amount of carbon dioxide compressed decreases, the electricity necessary for compression decreases and the electricity available for export increases. Additionally, as percentage of vented carbon dioxide increases, the carbon dioxide displacement credit decreases because less carbon dioxide is transported to EOR. From an LCA perspective, increased venting of carbon dioxide increases the direct emissions from the facility, but also increases the export power displacement credit.

- The ability to adjust the overall efficiency of the facility operation. NETL defines the efficiency of a configuration as the energy out of the facility (FT liquid fuels and net electricity produced) divided by the energy in (coal and biomass), on an HHV basis. The default value is the optimal efficiency calculated for a given configuration. Therefore, users can only reduce the efficiency from the design value. Lower plant efficiency can reduce net export electricity and increase the amount of feedstock fed to the plant. Plant efficiency decreases as biomass percentage increases. The worst-case efficiency is calculated assuming 30% biomass and 0% venting. Facility output is assumed to be 50,000 bbd liquid product and cannot be adjusted in this model.

This increased flexibility is provided by linearized relationships based on the NETL LCA discussed in Section 8.3 and two previous NETL reports (NETL, 2011; NETL 2014d); referred to as Zero S Diesel and CTL Baseline in Table 8-15. These previous NETL reports provide the framework for the linear relationships used for this optimization tool. The reports also state that the cases that can be screened/optimized are limited to the coal, biomass, and gasifier combinations that were previously modeled. Combinations that have not been previously modeled and published by NETL are not available for selection in the tool. An additional limitation is that feed inputs for the gasifier plant are on an as-received basis, while the feed input to the model is on a dry basis. For example, the as-received moisture of raw southern pine is 43.3%. Thus, even at 100% biomass, the model will include coal in the feed on a dry basis to account for the lost moisture (pers. comm. Booz Allen Hamilton, August 7, 2015).

The tool has two “modes” of operation. The screening mode will allow users to vary inputs like biomass percentage, carbon dioxide vented, and plant efficiency, while the optimization mode uses Excel’s Solver functionality and maximum/minimum input parameter ranges to optimize the CBTL facility configuration. Both modes are based on linearized relationships based on the cases provided in the reports cited above and in Table 8-15. In both modes, the tool summarizes results at the same level of detail as provided in NETL's techno-economic model (Appendix L). Because biomass percentages greater than 30% are beyond the boundary of the tool's accuracy and the uncertainty of model output increases at higher biomass percentages, running the model in the screening mode is advised over the optimization mode is advised to provide an order of magnitude approximation of the amount of biomass needed for smaller scale facilities to avoid sequestration of carbon dioxide.

Utilizing MSW has a great impact on reducing lifecycle GHG emissions. This is primarily the result of credits from the biogenic portion of the feedstock and avoiding methane and carbon dioxide emissions associated with landfilling MSW, The emissions avoidance credit is -0.4789 kg CO_2e/kg MSW at a landfill that recovers and flares landfill gas and -1.359 kg CO_2e/kg MSW associated with a landfill that does not recover landfill gas. The model does not account for the credit from the biogenic portion of MSW and as a result provides a conservative estimate of GHG emissions for MSW. To determine the potential benefit of using MSW, the model results presented here assume that the MSW used would otherwise be sent to a landfill that recovers and flares landfill gas.

Table 8-15: Coal, Biomass, and Gasifier Combinations

Coal	Biomass	Gasifier	Recycle (R) or Once-Through (O)	Reference
IL No. 6	–	Shell[1]	R	CTL Baseline
	–	Siemens[2]	O	Zero S Diesel
	–	Siemens	R	Zero S Diesel
	Switchgrass	Siemens	O	Zero S Diesel
	Switchgrass	Siemens	R	Zero S Diesel
	MSW	Siemens	O	Zero S Diesel
	MSW	Siemens	R	Zero S Diesel
Montana Rosebud (PRB)	–	EFG	R	CCAT – EFG
	–	Siemens	O	Zero S Diesel
	–	Siemens	R	Zero S Diesel
	–	TRIG	R	CCAT – TRIG
	Southern Yellow Pine[3]	EFG	R	CCAT – EFG
	Southern Yellow Pine	TRIG	R	CCAT – TRIG
	Switchgrass	Siemens	O	Zero S Diesel
	Switchgrass	Siemens	R	Zero S Diesel
	MSW	Siemens	O	Zero S Diesel
	MSW	Siemens	R	Zero S Diesel
North Dakota Lignite	–	EFG	R	CCAT – EFG
	–	Siemens	O	Zero S Diesel
	–	Siemens	R	Zero S Diesel
	–	TRIG	R	CCAT – TRIG™

Coal	Biomass	Gasifier	Recycle (R) or Once-Through (O)	Reference
	Southern Yellow Pine	EFG	R	CCAT – EFG
	Southern Yellow Pine	TRIG	R	CCAT – TRIG™
	Switchgrass	Siemens	O	Zero S Diesel
	Switchgrass	Siemens	R	Zero S Diesel
	MSW	Siemens	O	Zero S Diesel
	MSW	Siemens	R	Zero S Diesel

Notes:

[1] Shell EFG listed at SEF in model.

[2] Siemens EFG listed at FWQ (full water quench) in model.

[3] The model includes options for four preparations of Southern Yellow Pine – chipped, pelletized, torrefied, and torrefied/pelletized.

8.5.1 CCAT Screening

The Project Team ran the GHG optimization tool model for the following scenarios:

- 30% pelletized Southern Yellow Pine and PRB coal in EFG gasifier
- 30% chipped Southern Yellow Pine and PRB coal in EFG gasifier
- 30% torrefied pellets Southern Yellow Pine and PRB coal in EFG gasifier
- 30% pelletized Southern Yellow Pine and PRB coal in TRIG™ gasifier
- 30% torrefied pellets Southern Yellow Pine and PRB coal in TRIG™ gasifier
- 30% switchgrass and PRB coal in Siemens gasifier
- 30% and 75% MSW with PRB coal in Siemens gasifier (matches feedstocks tested at WPC)

Each scenario was run with no carbon dioxide vented and in optimization mode to determine the maximum percent carbon dioxide that could be vented. Each feedstock combination was also run in optimization mode with 100% carbon dioxide vented to estimate the minimum proportion biomass that could be gasified with coal that will meet Section 526 without sequestration of captured carbon dioxide. The results along with the predicted GHG emissions for the five live cycle stages are presented in Table 8-16.

For scenarios with 30% biomass, the amount of captured carbon dioxide that could be vented ranged from approximately 30% to 47%, with the results for raw southern pine lower than for switchgrass and torrefied southern pine. To be able to vent 40% carbon dioxide, the amount of MSW needed is 75%. The results for MSW with North Dakota lignite, which matches the feedstocks tested at TRI, are not presented because they are nearly identical to the results for MSW with PRB. The results for chipped and pelletized southern pine were similar with the exception that the model was not able to find a solution for the amount of biomass needed with all carbon dioxide vented for pelletized pine in the EFG.

Two trends are apparent from running the model: (1) as more carbon dioxide is vented, the carbon dioxide displacement credit and the emissions from pipeline transport of carbon dioxide decrease, and the emissions from the plant operations (labeled Energy Conversion Facility in the table) increase, (2) lowering the amount of carbon dioxide that needs to be captured, compressed to 2,200 psig, and transported for sequestration lowers the auxiliary electricity load and increases the net export power (labeled Electricity Displacement in the model) from the CBTL facility.

Table 8-16: LCA Results from GHG Model for Selected Coal, Biomass, and Gasifier Scenarios

Gasifier (w/Recycle)	EFG	EFG	EFG	EFG	EFG	EFG	EFG	EFG	EFG	TRIG	TRIG	TRIG
Coal	PRB	PRB	PRB	PRB	PRB	PRB	PRB	PRB	PRB	PRB	PRB	PRB
Biomass	Pelletized S Pine	Pelletized S Pine	Pelletized S Pine	Chipped S Pine	Chipped S Pine	Chipped S Pine	Torrefied Pellets S Pine	Torrefied Pellets S Pine	Torrefied Pellets S Pine	Pelletized S Pine	Pelletized S Pine	Pelletized S Pine
Biomass Dry Feed Mass %	30%	30%	**NS**	30%	30%	**94%**	30%	30%	**76%**	30%	30%	**82%**
Captured CO_2 Vented	0%	**30.2%**	**100%**	0%	**31.4%**	**100%**	0%	**37.4%**	**100%**	0%	**30.2%**	**100%**
Plant Efficiency, HHV	49%	49%	49%	47%	47%	48%	52%	50%	50%	54%	53%	53%
Life Cycle Stage	g CO_2e / MJ											
Raw Material Acquisition	-40.19	-40.19		-41.88	-41.88	-133.45	-35.90	-37.54	-104.73	-43.24	-43.24	-120.64
Raw Material Transport	12.85	12.85		4.88	4.88	3.33	7.51	7.85	11.72	13.16	13.16	26.20
Energy Conversion Facility	0.87	35.71		7.46	45.37	138.48	-3.69	38.06	101.39	-13.64	38.46	102.81
Product Transport	7.35	7.35		7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35
End Use	72.69	72.69		72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69
Total Cradle-to-Grave GHG Emissions	**53.58**	**88.41**	**> 88.41**	**50.50**	**88.41**	**88.41**	**47.95**	**88.41**	**88.41**	**36.31**	**88.41**	**88.41**

Gasifier (w/Recycle)	TRIG	TRIG	TRIG	FWQ	FWQ	FWQ	FWQ	FWQ	FWQ	FWQ
Coal	PRB	PRB	PRB	PRB	PRB	PRB	PRB	PRB	PRB	PRB
Biomass	Torrefied Pellets S. Pine	Torrefied Pellets S. Pine	Torrefied Pellets S Pine	Switch grass	Switch grass	Switch grass	MSW	MSW	MSW	MSW
Biomass Dry Feed Mass %	30%	30%	**72%**	30%	30%	**80%**	30%	75%	75%	NS
Captured CO_2 Vented	0%	**47.1%**	**100%**	0%	**36.8%**	**100%**	0%	0%	**40%**	100%
Plant Efficiency, HHV	54.5%	53%	53%	43%	43%	37%	43%	37%	43%	43%
Life Cycle Stage	g CO_2e / MJ									
Raw Material Acquisition	-41.05	-41.05	-100.50	-33.11	-33.11	-90.04	-11.16	-29.49	-29.52	
Raw Material Transport	7.98	7.98	11.28	3.74	3.74	3.00	3.74	3.08	3.87	
Energy Conversion Facility	-14.37	41.44	97.60	6.08	37.75	95.40	6.08	14.52	34.02	
Product Transport	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	7.35	
End Use	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	72.69	
Total Cradle-to-Grave GHG Emissions	**32.60**	**88.41**	**88.41**	**56.75**	**88.41**	**88.41**	**78.70**	**68.15**	**88.41**	**> 88.41**

NS = No Solution

Although sourcing a high percentage of woody biomass (greater than 34,000 tpd) for a large-scale CBTL facility would be very challenging and likely require prohibitively long feedstock transportation distances, this is potentially feasible for small-scale production facilities. Several small-scale liquid fuel projects currently being commissioned or built in the United States (Red Rock, Fulcrum, Enerkem, and WPC) are designed to use 100% biomass or MSW. While the NETL model is based on a large-scale facility using a maximum of 30% biomass and the uncertainty of model output increases at higher biomass percentages, the results provide an order of magnitude approximation of the amount of biomass needed for smaller scale facilities to avoid sequestration of carbon dioxide.

8.5.2 Additional NETL Economic Analysis

NETL also used its CBTL Jet Fuel Excel model to evaluate the economic impact of CCS. NETL compared the RSP for one scenario (30% chipped Southern Yellow pine with PRB in TRIG™) with 90% capture of carbon dioxide for EOR with the RSP for the same scenario venting all the captured carbon dioxide. As noted above, reducing the amount of carbon dioxide captured and compressed increases net export electricity. However, NETL found that with an expected carbon dioxide sale price of $40 per tonne, the RSP of the case with venting all carbon dioxide was 12% higher than the case with capture for EOR ($160 vs $143 per barrel). In this case, as demonstrated by the GHG Optimization tool, 44% of the captured carbon dioxide could be vented to meet Section 526, with the rest sold for EOR. By interpolating between the two NETL cases, the expected RSP would likely be closer to $150 per barrel. NETL concludes that the captured carbon dioxide is more valuable as a co-product for EOR than the incremental export electricity and marginal reduction in capital costs that can be achieved if the carbon dioxide was instead vented to the atmosphere. NETL states that these results are likely applicable to all of the TRIG™ scenarios since the various scenarios all produce roughly the same amount of carbon dioxide and the capital costs and auxiliary power demands associated with the carbon dioxide compressor block are roughly the same (Appendix N).

8.5.3 Screening Tool Conclusions and Recommendations

The GHG Optimization model is a useful tool for performing a screening level assessment, within the limitations of the model, of the amount of CCS and biomass feedstock needed to meet Section 526 with various feedstocks and limited gasifier types. The model can only run feedstock combinations of coal and MSW on the Siemens gasifier, not the steam reforming or plasma type systems used by TRI or WPC. However, the Siemens gasifier is not currently designed for use with MSW. The results indicate that less than 90% sequestration of captured carbon dioxide is necessary at the biomass or MSW percentages tested (i.e., up to 30%) to meet Section 526. The optimization tool predicts that as biomass percentage increases, more captured carbon dioxide can be vented while meeting the Section 526 baseline value. At the same biomass percentage, more carbon dioxide can be vented with torrefied wood biomass than with raw wood.

Given the limitations of running the model at greater than 30% biomass with coal, the model indicates that CBTL systems using approximately 75 to 80% biomass feedstocks could meet Section 526 requirements without sequestration of any carbon dioxide. While such high percentages are not currently practical for large-scale facilities, they appear to be feasible for small-scale facilities currently being developed and deployed by several technology providers.

NETL indicates that under the current configuration of the CBTL process in their model, the cost of carbon dioxide capture, compression and transport is more than offset by the sale price of the carbon dioxide for EOR. NETL suggests that alternative configuration of the carbon capture system could change the economic calculus. This would be worth exploring as a follow-on to the work performed for this project.

9. Economic Analyses

The reports in Appendix A discuss published information regarding the economic challenges of a 50,000 bpd scale CTL/CBTL plant's ability to attract economic investment and provide cost competitive fuels. Economics are an important component to assess the potential commercial viability of a CBTL plant producing Section 526-compliant fuel. Economic viability of a CBTL plant will be influenced by several factors, including high capital costs, scale, year-round availability of suitable biomass feedstock, and markets/off-take agreements for the products. To meet the U.S. Air Force goal of using alternative aviation fuel blends for non-contingency operations equivalent to 50% of total Air Force fuel needs (up to approximately 40,000 bpd) by 2025 (U.S. Air Force, 2013), total FT liquid production of 80,000 bpd is required (assuming 50% of total FT products yield jet fuel). Clearly, a firm quantity of alternative fuel DoD is committed to acquire is necessary to determine the scale of production projects. This need could be met by one large plant or more than one plant of smaller capacities. Commercial viability of small-scale FT liquid production has not yet been established. Additionally, upgrading raw FT products to meet jet fuel specifications becomes very expensive at small scale unless existing refinery infrastructure could be used. As noted earlier, large-scale production is considered to be greater than 30,000 bpd. Therefore, if economy of scale favors construction of a 50,000 to 100,000 bpd plant over a 20,000 bpd plant, additional markets for the excess product would be necessary to make the plant economically viable. For example, commercial aviation companies would purchase competitively priced fuel in excess of that produced to meet DoD alternative fuel needs.

A commercial CTL or CBTL plant has not been constructed in the United States; therefore, actual capital cost data are not available. (Due to differences in currency value, labor rates, and cost of materials in different parts of the world, presentation of economic data from CTL plants built in other countries is not particularly useful to this discussion.) However, two small-scale biomass-to-liquid (BTL) plants that received Defense Production Act funding have recently been commissioned in the United States – the 650 bpd Fulcrum BioEnergy waste-to-liquids facility in Nevada and the 1,000 bpd Red Rock Biofuels plant in Oregon (construction scheduled to begin in late 2015). The cost for each plant is estimated to be approximately $200 million. Cathay Pacific Airways, United Airlines, Southwest Airlines, and FedEx have invested in and/or committed to purchasing alternative fuels from these facilities (BiofuelsDigest, 2014, 2015a, 2015b).

Based on capital cost estimates for plants in the United States, the cost per daily barrel ($/dbbl) of plant fuels production capacity is expected to decrease with increased capacity and be larger for BTL/CBTL than for CTL due to higher complexity with CBTL and the limitation in size of plants using biomass as a feedstock. Estimated plant costs reported in Appendix A are about $98,000/dbbl for a 50,000 bpd CTL plant, $135,000/dbbl for a 30,000 bpd CBTL plant and $210,000/dbbl for a 2,900 bpd BTL plant.

The Project Team evaluated the economic attributes of certain modeled facilities to provide a more complete project analysis. Through this investigation, CCAT funded the creation of multiple economic analyses/models. The first model, created by NETL, produced two extensive models and two accompanying reports for large-scale (50,000 bpd) CBTL plants. The second model, created by a commercial entity, Alter NRG/WPC, provided an economic analysis and report tailored to the WPC-specific distributed-scale technology for coal/MSW RDF feedstock.

The NETL models examine "an array of economic factors and cost estimates (to calculate a) required selling price of FT jet fuel, which is the minimum price at which the products must be sold to recover the annual revenue requirement[2] (ARR) of a CBTL plant." (NETL, 2014b, 2014c) Although developing CBTL capabilities would provide a valuable emergency fuel source if petroleum became difficult to obtain, under typical circumstances CBTL fuels would need to be priced competitively to find a market and attract investment for plant construction in the absence of long-term government subsidies or purchase mandates. To NETL, "[d]etermining quality estimates of economic valuations for a CBTL plant is therefore needed to support further technological development, including demonstration and eventual commercialization." (NETL, 2014b, 2014c)

The NETL reports and models are intended to support further technological development necessary for eventual CBTL commercialization. NETL compiled information and estimates from a variety of sources in an attempt to determine the cost of either an EFG- or TRIG™-based 50,000 bpd-capacity CBTL plant processing a variety of coals and biomasses into FT jet fuel. Concept-level estimates are made for the capital and operating costs of the facilities, for sourcing and transportation of feedstocks, and for other input and process costs. The models delve into specific biomass feedstock processing methods, including pulverizing wood chips and pellets, microchipping wood chips, and torrefying wood chips and pellets. The end result for each modeled scenario is an estimated minimum price at which the products must be sold to recover the ARR. All costs for the supplied NETL models have been adjusted to a June 2011 dollar basis.

Results of certain demonstration tests performed for this project were provided to NETL, and NETL used these results (feedstock analyses, gasifier operating conditions, gasifier input and output flow data, and product gas composition) to verify or modify the technical model. Documented differences in plant operation, such as the quantity of syngas produced by certain feedstock combinations, were used to update the technical model, as discussed in Section 8.3 and in Appendix M and Appendix N. The technical model affects the cost of fuel (i.e., the RSP) in the financial/economic model. However, actual costs for feedstocks tested during the Project Team's testing program have not been fed back into the NETL financial/economic modeling.

In contrast to the economic projections of NETL's CBTL model, the Project Team also received a site- and process-specific economic report from WPC. The company, which performed a gasification test for the Project Team at its Madison, Pennsylvania demonstration facility, is currently licensing its technology to commercial operations in England, India, and China, with additional potential projects planned in Minnesota, Thailand, and other locations. Similar to the validated scenarios of the NETL models, the WPC economic analysis incorporated results of the three demonstration-scale tests into the final modeled system.

The WPC economic model differs from the NETL model in that while the RSP was an output of the NETL models, it is an input for the WPC model. The WPC model is intended for investors or potential licensers/purchasers of the technology. In the model, WPC accounts for approximately 40% of the facility's finances from the sale of fuel or electricity. The model also incorporates tipping fees for waste to be gasified and for carbon off-set credits such as those received for the WPC Tees Valley project in England. These fees are critical to the economic viability of a project using this technology.

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[2] The ARR is the annual revenue needed to pay operating costs, service debt, and provide the expected rate of return for investors.

Matched with the NETL models, the specific WPC demonstration facility case offers an expanded perspective into the viability of converting coal and biomass to liquid fuel in an economically feasible manner. However, as a result of the uncertainty inherent in economic analyses, these models are only conceptual and are not intended to be used as a guideline for future plant development. Presented below are summaries of the economic analyses/models performed under the Contract. Due to the similar nature of the two NETL reports, similar content is reported together in Section 9.1 and Section 9.2. Results from WPC's model are provided in Section 9.3. In addition, this section provides the Project Team's discussion of WPC's economic review and the Project Team's RSP analysis.

9.1 NETL Modeling Background and Assumptions for EFG and TRIG™

The economic results in this study are based on a specific CBTL configuration and specific CBTL plant location that NETL, together with Project Team input, selected for the modeling study. If the plant configuration or location of the plant changes, the economic results change. As discussed in Section 8.2.1 for this study, it was assumed the plant will be located in the southeastern United States, receive coal from the PRB in Montana, utilize an aggressive CCS process, export captured carbon dioxide to the Permian Basin in Texas for EOR, and have a plant operating life expectancy of 30 years. The material system boundaries included all physical processes and procedures in the five major life-cycle stages (Section 8.1.2, Figure 8-1). Additionally, as outlined in Section 8.2.1 and detailed below, the economic boundary included:

- Costs and costing factors associated with the production, preparation, and transport of biomass
- Delivered cost of coal
- Current market costs for energy, raw materials, labor, and debt
- Conversion of biomass and coal into liquid fuels

As a result of the lack of a commercial-scale (or even demonstration-scale) CBTL jet fuel production facility in the United States, some uncertainty exists for both technical and economic factors. The primary goals of NETL's economic modeling efforts were to provide high-level economic analysis to determine the RSP for several CBTL plant scenarios (as listed in Section 8.3.1 and Section 8.3.2 and detailed in Appendix M and Appendix N), and then to identify and quantify the impact of key economic variables on the RSP for the jet fuel product. RSP values were determined based on a combination of cost factors that account for feedstock supply, feedstock handling and preparation, CBTL plant site infrastructure/construction costs, operations and maintenance costs, process contingency, and other relevant factors. Most modeled capital and operating cost estimates were obtained from conceptual level cost algorithms that scale costs based on one or more measures of unit capacity. However, in some instances, cost estimates were based solely on vendor quotes – particularly in the scenario of the separate gasification with Rentech tar reforming. All costs were adjusted to a June 2011 dollar basis.

While many of the economic parameters in the model are based on a fixed price, others are adjustable within the model. Key fixed parameters and economic modeling assumptions used in the model are provided in Table 9-1, and a collection of key adjustable parameters is provided in Table 9-2. The parameters in Table 9-2 can be adjusted to allow "what if" type analyses. However, the "what if" analyses require the use of Palisade Corporation's @Risk 5.7 (or higher), and the adjustable parameters are limited to 17 environmental (Table 8-4) and 40 economic parameters (Appendix M and Appendix N for a complete list of parameters).

Table 9-1: Key Economic Modeling Assumptions

Primary Subject	Default Value
Biomass Chipping Method	Standard or Microchip
Natural Gas Cost	$4/Mcf
Debt/Equity Ratio	50/50
Interest Rate on Debt	8%
FT Diesel Value Relative to FT Jet Fuel	0.99
FT Naphtha Value Relative to FT Jet Fuel	0.69
FT LPG Value Relative to FT Jet Fuel	0.40

Source: NETL, 2014b, NETL, 2014c.

Table 9-2: Adjustable Economic Parameters in NETL's Techno-Economic Model

Parameters	Expected Value (min, max)
Global Capital Cost Factor	1 (0.85, 1.3)
Capital Recovery Factor	0.2365 (0.2129, 0.2602)
Labor Cost Index	1 (0.9, 1.2)
Other Owner's Costs (Fraction of TPC)[a]	0.15 (0.12, 0.18)
Taxes and Insurance (Fraction of TPC)	0.02 (0.016, 0.024)
Project Contingency	0.15 (0.1, 0.2)
FT Catalyst ($/lb)	3 (2.1, 3.9)
Coal Cost ($/ton)	36.26 (34.45, 38.07)
Raw Chipped Biomass Cost ($/dry ton)	43.6 (39.2, 48.0)
Raw Microchipped Biomass Cost ($/dry ton)	46.3 (41.7, 50.9)
Torrefied Biomass Cost ($/ton)	134.6 (121.1, 148.1)
Raw Pelletized Biomass Cost ($/dry ton)	84.04 (75.63, 92.44)
Torrefied Pelletized Biomass Cost ($/ton)	141.3 (127.2, 155.5)
CO_2-EOR Credit ($/ton)	-40 (-52, -28)

Source: NETL, 2014b, 2014c.
Note: "Other Owner's Costs" and "Taxes and Insurance" are estimated (for this model) as fraction of the "Total Plant Cost" (TPC). "Other Owners Cost" is estimated at 15% of TPC and "Taxes and Insurance" is estimated at 2% of TPC. Elements affecting the TPC are provided in Appendix M and Appendix N.

9.2 NETL Economic Modeling of an EFG and TRIG™

As previously discussed, NETL performed two techno-economic modeling exercises to quantify the viability of CBTL facilities based on EFG and TRIG™ technologies through the use of the RSP. The technology-based models (process stream information, GHG emissions, and other life-cycle emissions/effluents) are summarized in Section 8.3.4 and detailed in Appendix M (EFG) and Appendix N (TRIG™). The economic background and assumptions common to the two techno-economic models are provided in Section 9.1. The assessment from NETL for both the EFG and TRIG™ modeling efforts are summarized below. Additional supporting details for the EFG and TRIG™ models are provided in Appendix M and Appendix N, respectively.

9.2.1 Economic Results and Discussion

Figure 9-1 and Table 9-3 present the summary results for the 10 EFG-based CBTL scenarios modeled by NETL. Section 8.3.1 provides technical details of each EFG scenario. Similarly, Figure 9-2 and Table 9-4 summarize the 14 modeled TRIG™-based CBTL scenarios. Section 8.3.2 provides technical details of each TRIG™ scenario. Complete modeling results for the EFG and TRIG™ are provided in Appendix M and Appendix N, respectively. For both the EFG and TRIG™ models, using the default modeling assumptions, the RSP distributions lie completely above the 2014 first quarter spot price ($99.24/bbl) from West Texas Intermediate (WTI; scaled to 2011 dollars; Figure 9-1 and Figure 9-2). For example, the EFG 0% Biomass Scenario has an estimated 25th to 75th percentile RSP range of $133 to $155/bbl, with a mean value of $145/bbl on a crude oil equivalent basis. This corresponds to a 46% increase in the RSP over the baseline. The CBTL plant annual costs are detailed further in Table 9-3 and Table 9-4 for EFG and TRIG™, respectively. This section provides high-level key costing elements (e.g., fixed operating and maintenance cost [$MM/yr], variable operating and maintenance cost [$MM/yr], and feedstock cost). The tables also present the RSP for each of the products (FT jet fuel, FT diesel, FT naphtha, and LPG), and the mean (average) crude oil equivalent RSP for the FT jet fuel.

The NETL economic models also provide graphical RSP presentations for each scenario. A compilation of these figures is shown on Figure 9-3 for the EFG and Figure 9-4 for the TRIG™ model. Figure 9-3 shows that for the 10 modeled EFG scenarios, the capital expenditures are the most significant portion of each of the calculated RSPs. Of the 10 EFG scenarios, the 30% Chipped Biomass Scenario was the most costly. Though not apparent from the supplied figures/table, this cost is predominately a result of the fixed unit capacity of, and the capital cost of, the equipment needed to process the 30% chipped (non-torrefied) biomass. The coal and biomass cost elements have less influence on the RSP than the capital expenditures, but have the most variability from scenario to scenario. For all 10 EFG scenarios, the fixed and variable operation and maintenance costs remain fairly consistent as the biomass increases and changes type. At the 30% blend level, the cost of the biomass (both torrefied and chipped biomass) actually eclipses the cost of the coal. Similar trends are shown on Figure 9-4 for the TRIG™. However, for the TRIG™, the 10% Microchipped Biomass, Separate Gasifiers scenario ($146 RSP) is slightly more costly than the 30% Chipped Biomass (non-torrefied) scenario ($143 RSP). The capital cost of separate gasifiers is greater than the capital cost of the equipment needed to process the 30% chipped biomass.

NETL also provides a sensitivity analysis based on the stochastic models of each of the scenarios from the EFG and TRIG™ models. Figure 9-5 presents a representative example of a graphic showing the sensitivity of RSP to modeled variables from the NETL EFG report. Note that only the 10 parameters that most influence RSP are shown (in order of importance). For the 30% Torrefied Biomass Scenario presented in Figure 9-5, it is clear that the global capital cost factor plays an extremely important role in the final fuel RSP, with a correlation coefficient of 0.95. The credit for carbon dioxide EOR and the reduction in RSP with increased plant capacity have the next greatest effect on the observed variability in RSP. Biomass fuel cost has more influence on the RSP than coal cost. The other nine EFG scenarios show similar sensitivities and trends, with the only difference being the ranking (order) of the parameters. For example, at lower biomass concentrations, the cost of the biomass (non-torrefied and torrefied alike) has less and less influence on the RSP. This results in a slight shift of the top 10 or so parameters. Similarly, Figure 9-6 provides a representative example of one of the TRIG™ sensitivity analysis figures from the NETL report. Note that only the top 10 parameters are shown. Figure 9-6 shows that for the sample case presented the global capital cost factor plays an extremely important role in the calculated RSP. For all TRIG™ cases, the correlation coefficient ranged from 0.78 to 0.84. Credit for capturing carbon dioxide for use in EOR plays a much larger role in the TRIG™-based model than in the EFG model. It should be noted that the other 13 TRIG™ scenarios show similar trends as described here for the 10% Chipped Biomass Scenario. No attempt at a quantitative comparison of the EFG and TRIG™ economic models have been made.

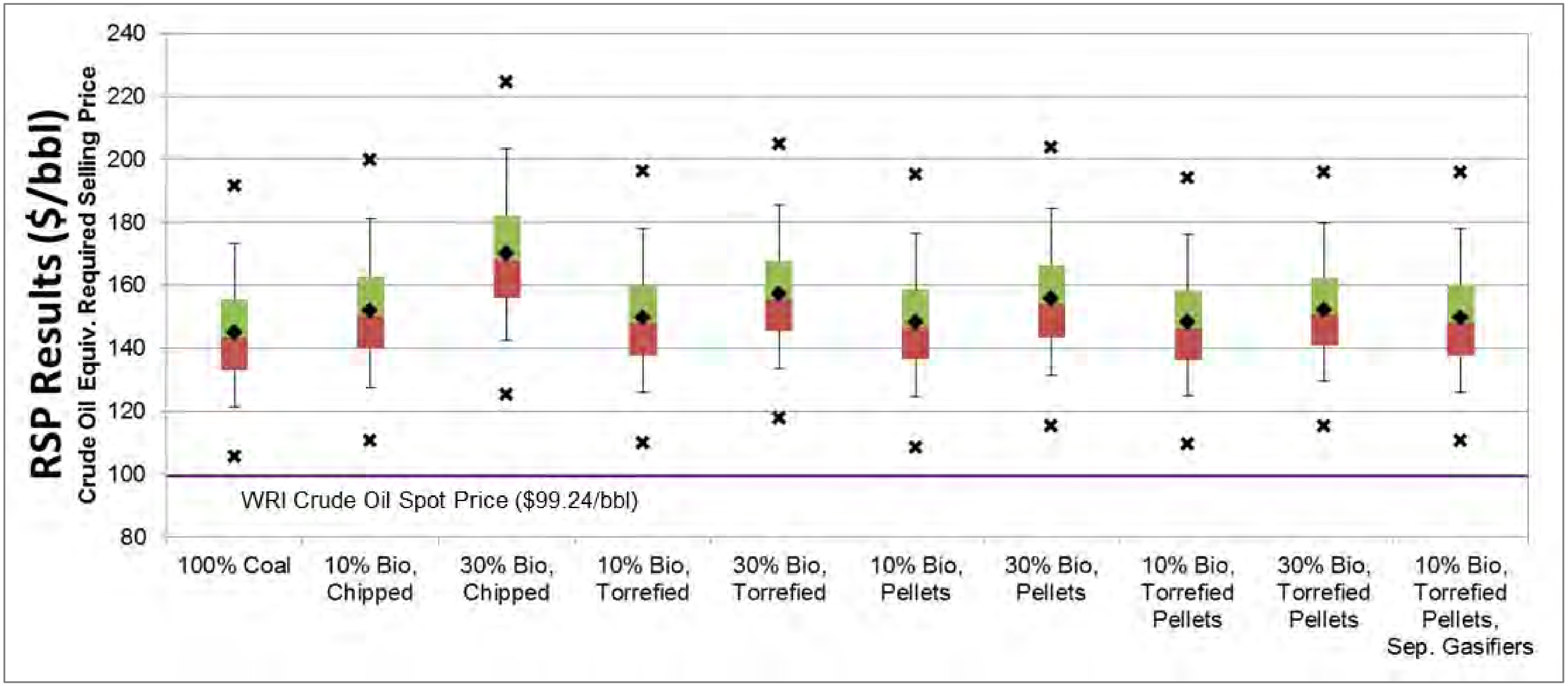

Figure 9-1: RSP Results for all EFG Scenarios

Source: NETL, 2014b
Key:
Black diamond = mean (average)
Green bar = 75th percentile
Red bar = 25th percentile
Point where green and red bars meet = 50th percentile (median)
X = minimum and maximum
Whisker = 5th and 95th percentile

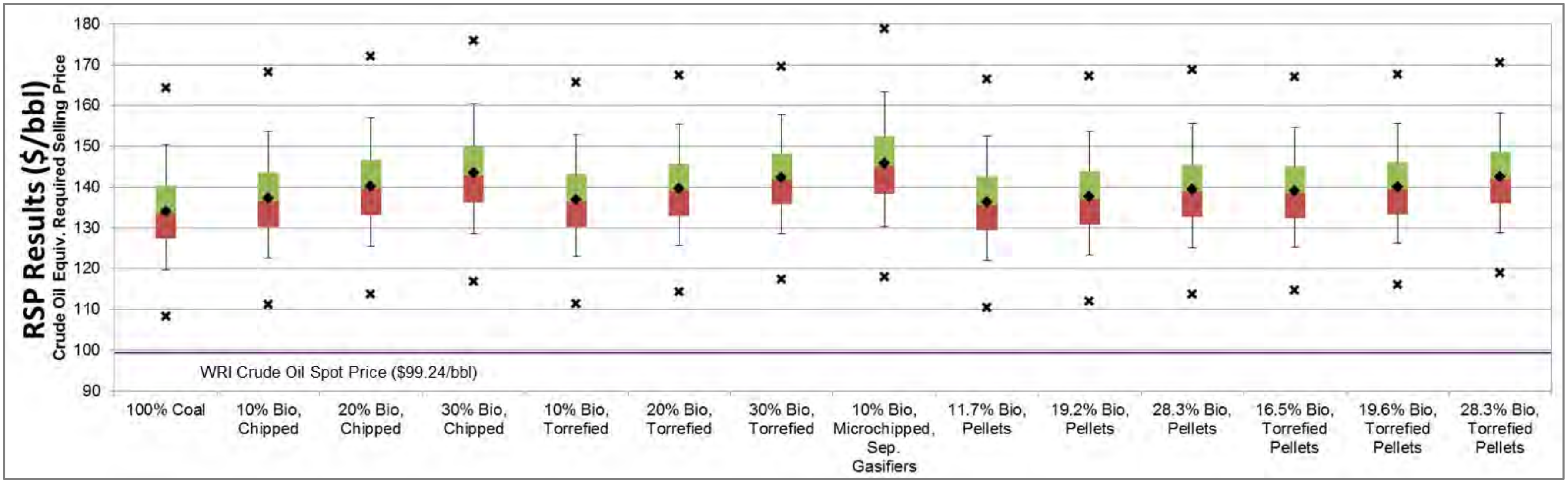

Figure 9-2: RSP Results for all TRIG™ Scenarios

Source: NETL, 2014c
Key:
Black diamond = mean (average)
Green bar = 75th percentile
Red bar = 25th percentile
Point where green and red bars meet = 50th percentile (median)
X = minimum and maximum
Whisker = 5th and 95th percentile

Table 9-3: EFG Economic Summary

Economic Summary	100% Coal	10% Bio, Chipped	30% Bio, Chipped	10% Bio, Torrefied	30% Bio, Torrefied	10% Bio, Pellets	30% Bio, Pellets	10% Bio, Torrefied Pellets	30% Bio, Torrefied Pellets	10% Bio, Torrefied Pellets, Sep. Gasifiers
Fixed Operating and Maintenance Cost ($MM/yr)	321	341	393	320	314	324	329	315	302	318
Variable Operating and Maintenance Cost ($MM/yr)	233	240	259	233	232	234	237	231	227	233
Capital Total Overnight Cost ($MM)	9,407	9,824	10,963	9,441	9,393	9,490	9,685	9,330	9,059	9,430
Coal Cost, Montana Rosebud, as Received ($MM/yr)	353	334	289	322	255	328	270	317	244	319
Biomass Cost, Southern Pine, Chips, as Received ($MM/yr)	0	32	109	0	0	63	199	0	0	0
Biomass Cost, Southern Pine, Torrefied, As Received ($MM/yr)	0	0	0	104	319	0	0	108	321	108
Power Credit ($MM/yr)	0	0	0	0	0	0	0	0	-6	0
Credit at $40/ton for CO_2 ($MM/yr)	-357	-364	-391	-362	-371	-361	-367	-356	-354	-359
Annual Revenue Required ($MM/yr)	2,310	2,422	2,711	2,384	2,508	2,364	2,481	2,361	2,429	2,384
RSP per Barrel of FT Jet Fuel ($/bbl)	167	175	196	173	182	171	180	171	176	173
RSP per Barrel of FT Diesel ($/bbl)	166	174	194	171	180	169	178	169	174	171
RSP per Barrel of FT Naphtha ($/bbl)	115	121	135	119	125	118	124	118	121	119
RSP per Barrel of LPG ($/bbl)	67	70	79	69	73	68	72	68	70	69
Crude Oil Equivalent Selling Price of FT Jet Fuel ($/bbl)	**145**	**152**	**170**	**150**	**157**	**148**	**156**	**148**	**152**	**150**

Table 9-4: TRIG™ Economic Summary

Economic Summary	100% Coal	10% Bio, Chipped	20% Bio, Chipped	30% Bio, Chipped	10% Bio, Torrefied	20% Bio, Torrefied	30% Bio, Torrefied	10% Bio, Torrefied Pellets, Sep. Gasifiers	11.7% Bio, Pellets	19.2% Bio, Pellets	28.3% Bio, Pellets	16.5% Bio, Torrefied Pellets	19.6% Bio, Torrefied Pellets	28.3% Bio, Torrefied Pellets
Fixed Operating and Maintenance Cost (FOM) ($MM/yr)	320	331	343	356	314	308	303	343	319	319	319	310	308	303
Variable Operating and Maintenance Cost (VOM) ($MM/yr)	230	232	234	236	227	225	223	238	229	229	228	225	225	222
Capital: Total Overnight Cost (TOC) ($MM)	9,161	9,284	9,392	9,512	9,023	8,884	8,750	9,747	9,128	9,098	9,071	8,899	8,856	8,716
Coal Cost, Montana Rosebud, As Received ($MM/yr)	360	332	302	271	321	282	245	338	322	297	267	296	284	252
Biomass Cost, Southern Pine, Chips, As Received ($MM/yr)	0	32	67	102	0	0	0	36	83	138	205	0	0	0
Biomass Cost, Southern Pine, Torrefied, As Received ($MM/yr)	0	0	0	0	119	236	350	0	0	0	0	205	243	349
Power Credit ($MM/yr)	-122	-111	-99	-86	-122	-124	-126	-107	-125	-127	-131	-128	-130	-132
Credit @ $40/ton for CO_2 ($MM/yr)	-364	-366	-369	-372	-363	-363	-363	-348	-363	-363	-363	-357	-356	-353
Annual Revenue Required ($MM/yr)	2,138	2,188	2,236	2,288	2,185	2,227	2,269	2,325	2,174	2,195	2,223	2,217	2,232	2,273
Required Selling Price per Barrel of FT Jet (RSP FT Jet) ($/bbl)	155	158	162	166	158	161	164	168	157	159	161	161	162	165
Required Selling Price per Barrel of FT Diesel (RSP FT Diesel) ($/bbl)	153	157	160	164	157	160	163	167	156	157	159	159	160	163
Required Selling Price per Barrel of FT Naphtha (RSP FT Naphtha) ($/bbl)	107	109	112	114	109	111	113	116	109	110	111	111	112	114
Required Selling Price per Barrel of LPG (RSP LPG) ($/bbl)	62	63	65	66	63	65	66	67	63	64	64	64	65	66
Crude Oil Equivalent Selling Price of FT Jet (COE) ($/bbl)	**134**	**137**	**140**	**143**	**137**	**140**	**142**	**146**	**136**	**138**	**139**	**139**	**140**	**143**

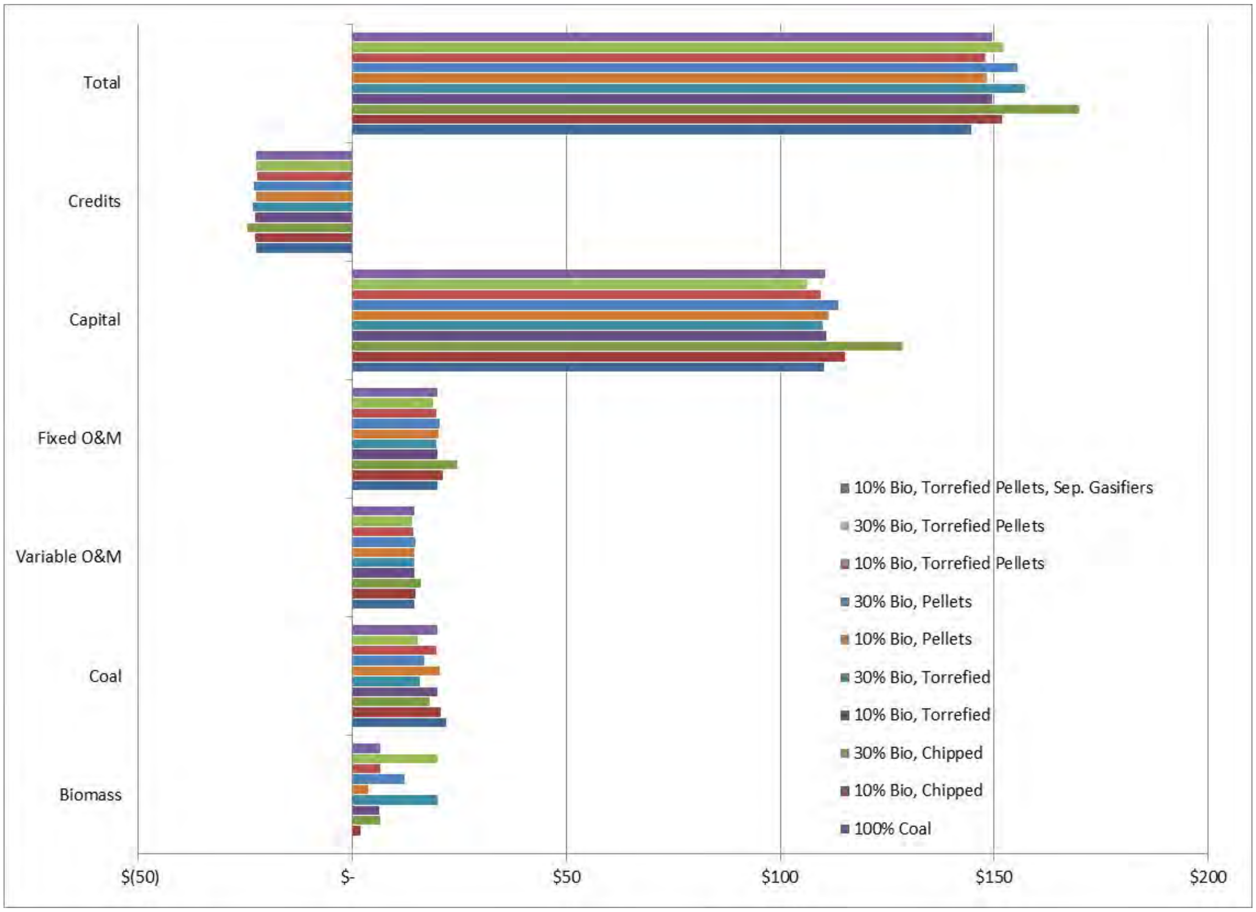

Figure 9-3: Summary of all EFG RSP Breakdowns

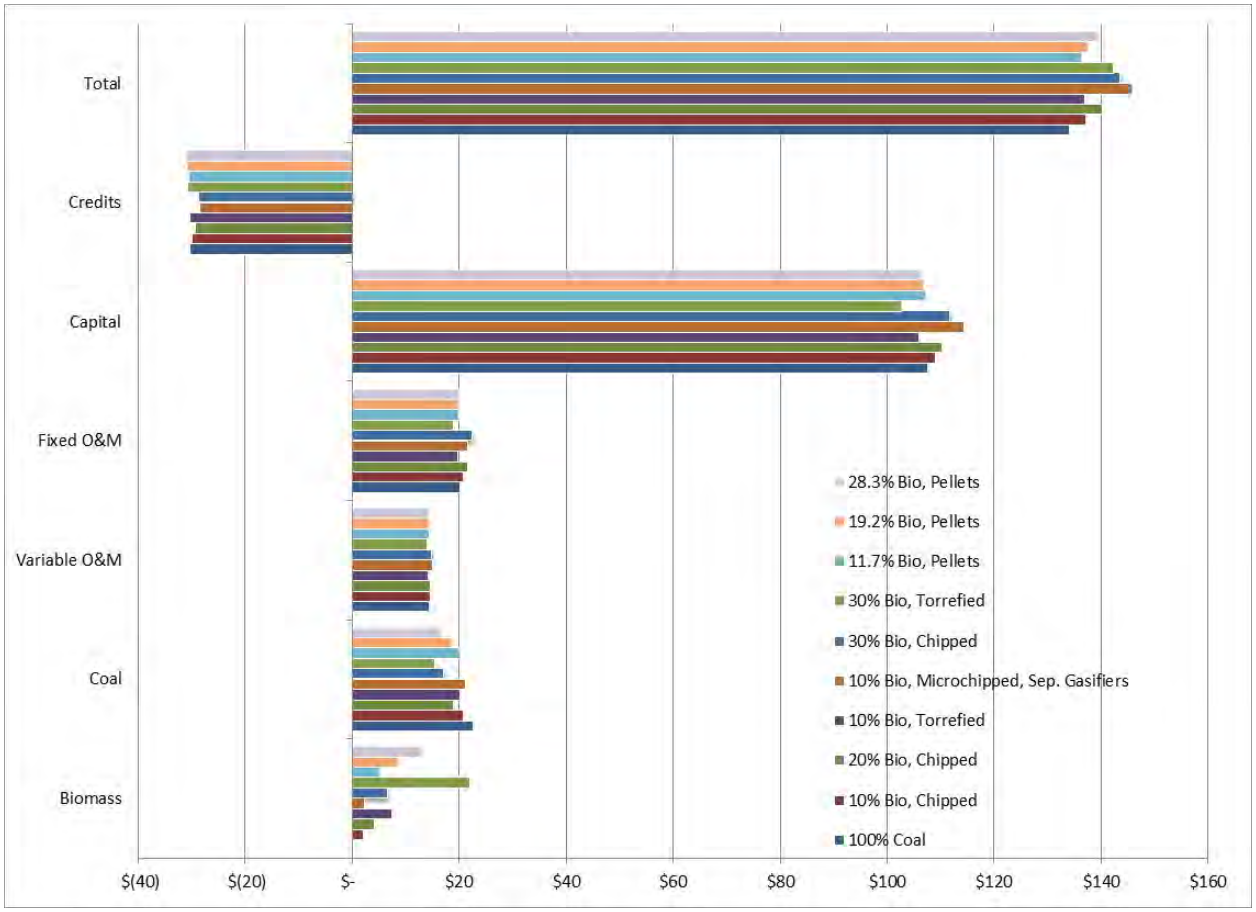

Figure 9-4: Summary of all TRIG™ RSP Breakdowns

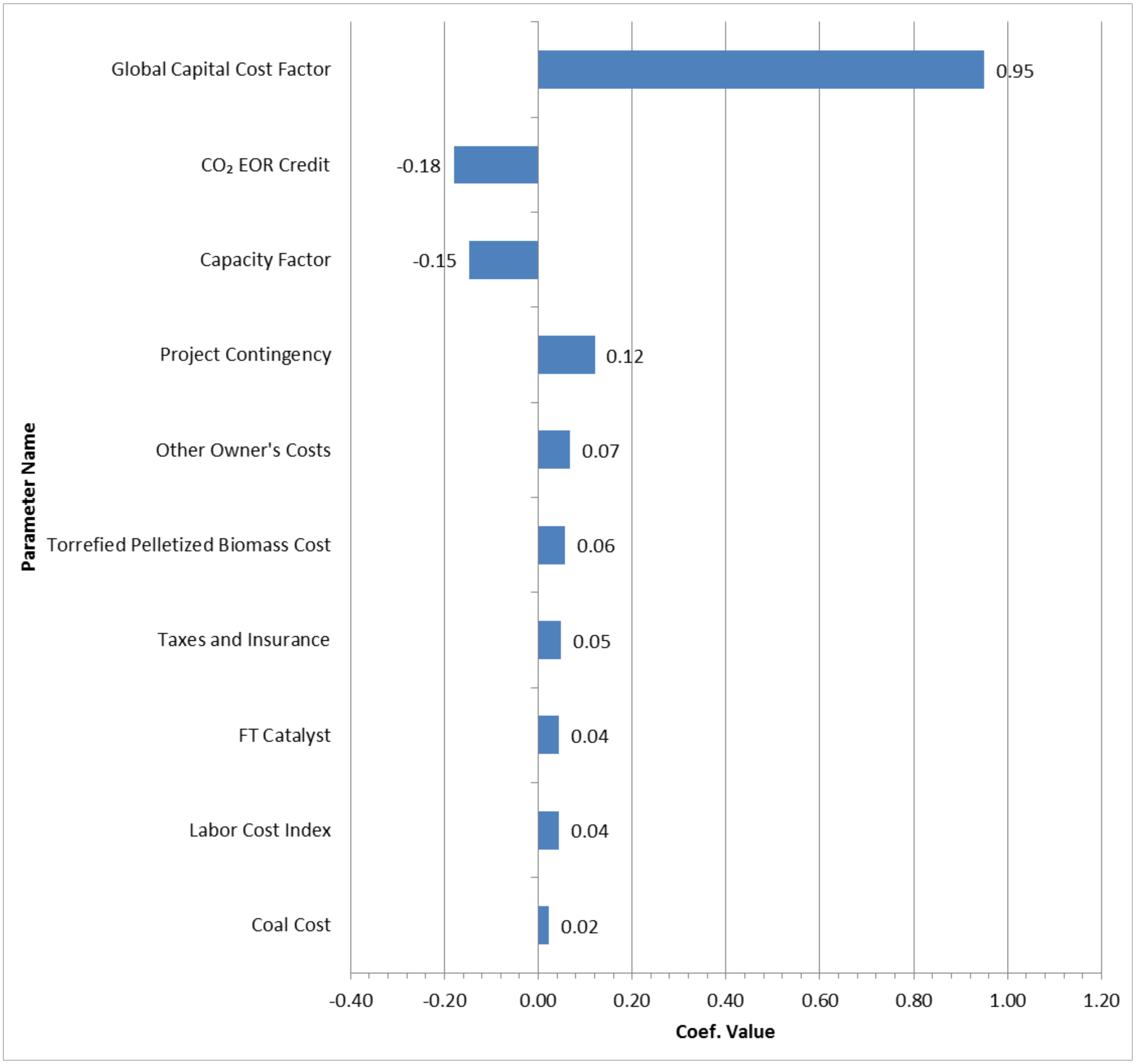

Figure 9-5: RSP Sensitivity Analysis for EFG 30% Torrefied Biomass Scenario

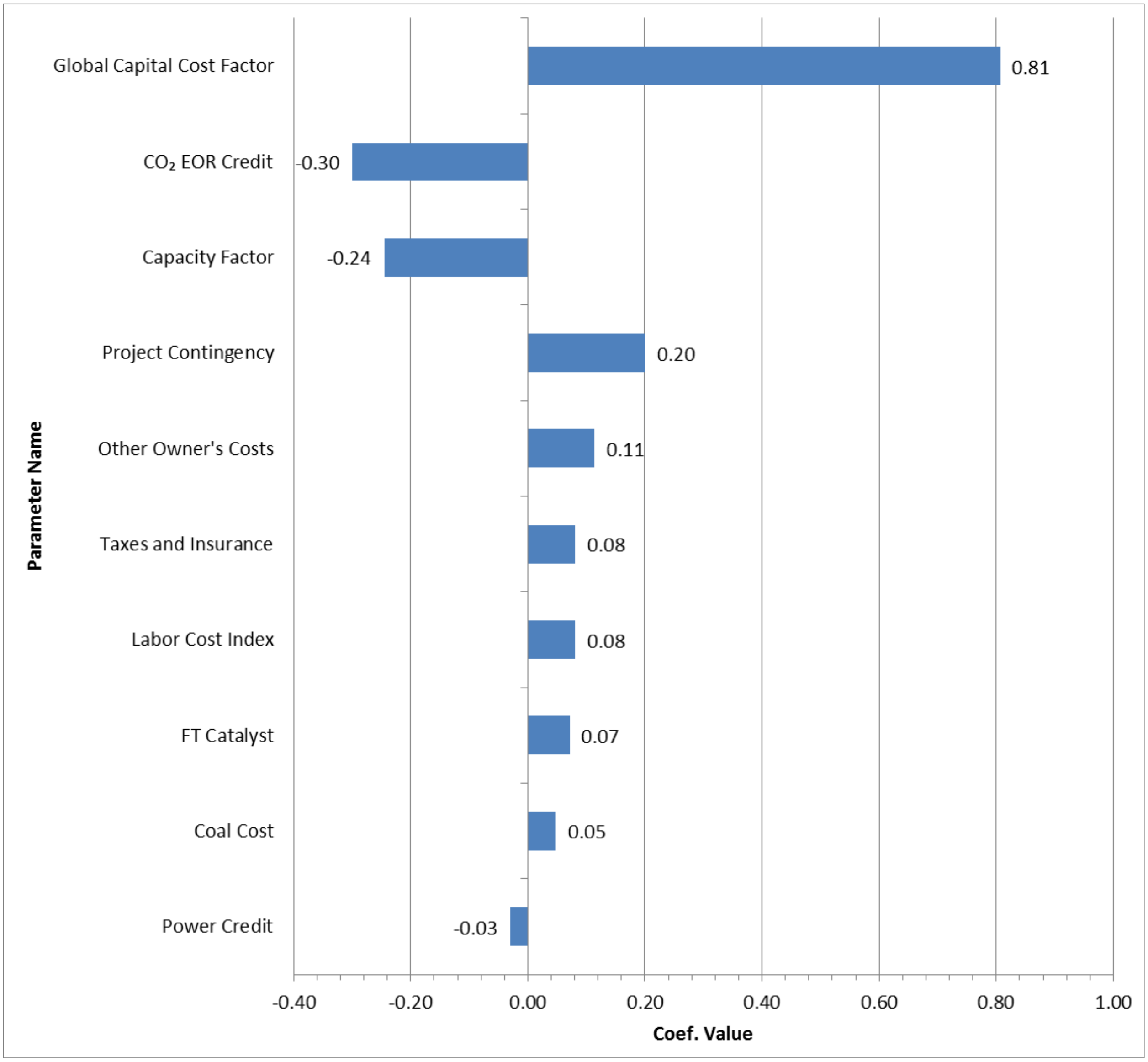

Figure 9-6: RSP Sensitivity Analysis for TRIG™ for 10% Chipped Biomass Scenario

9.2.2 Economic Conclusions

This section provides a summary of the conclusions presented by NETL in Appendix M and Appendix N, along with the Project Team’s observations. For discussion purposes, mean values are used below; the ranges for each scenario are shown on Figure 9-1 and Figure 9-2 and provided in Appendix M and Appendix N.

NETL concludes that scenarios utilizing a higher percentage of biomass generally have a greater RSP in both EFG and TRIG™ models. The following examples are from the EFG model, similar trends are observed with the TRIG™ model. For example, the mean RSP for the 30% Chipped Biomass Scenario is $170/bbl, while the mean RSP for the 10% Chipped Biomass Scenario is $152/bbl. Comparing mean values, the 30% Chipped Biomass Scenario results in a mean RSP value that is approximately $18.6/bbl higher than the 10% Chipped Biomass Scenario. Similar trends are apparent for the 30% Torrefied Biomass

Scenario (mean $157/bbl) and the 10% Torrefied Biomass Scenario (mean $150/bbl), wherein the 30% Torrefied Biomass Scenario results in a mean RSP value that is approximately $7.75 higher than the 10% Torrefied Biomass Scenario. These trends are also observed in the pelleted and torrefied/pelleted scenarios with 30% Pelleted Biomass $7.35/bbl greater than 10% Pelleted Biomass and 30% Pelleted/Torrefied Biomass $3.64/bbl greater than 10% Pelleted/Torrefied Biomass. Results that support this conclusion can be shown in a number of ways by comparing values in the above tables/figures. However, the significance of the trends is understated in the NETL report more than the Project Team thinks it should be. While the technical GHG/LCA models show increasing biomass reduces the carbon emissions, the economic models show that increasing biomass comes with increased costs – costs that are already above market baseline values. This inverse relationship between carbon emissions and cost (while not surprising) underscores the need for more robust technical models.

Based on the model results, use of torrefied biomass may result in a slight net decrease in RSP compared to chipped biomass for both the EFG and TRIG™ models. For example, based on the averaged EFG RSP values ($170/bbl for the 30% Chipped Biomass Scenario and $157/bbl for the 30% Torrefied Biomass Scenario), torrefaction results in a total cost savings of approximately $13/bbl. Similarly, for the 10% Biomass Scenarios, comparing EFG average RSP values of $152/bbl for chipped biomass to $150/bbl for torrefied biomass also results in a total cost savings of only $1/bbl. This overall cost savings is in addition to the LCA benefits described in Section 8 and the ease of feeding and handling demonstrated during testing (Sections 6 and 7).

As noted in Section 8.3, NELT's modeling results indicate that GHG emissions from all CBTL scenarios fall well below EISA requirements. Consequently, there appear to be opportunities to modify the CCS component of the CBTL plant configuration from aggressive to simple carbon capture. Previous NETL studies (e.g., NETL, 2009) indicated the inclusion of aggressive CCS would result in a 7 to 8% increase in capital costs. The potential elimination of the aggressive carbon dioxide capture configuration would also reduce operating expenses associated with the methydiethanolamine (MDEA) unit process, carbon dioxide compression and other ancillary operations. While this would lower the carbon dioxide credit, it would also potentially lower CBTL parasitic power requirements and potentially also power to be exported to the electric grid. Additional analysis and modeling would be required to quantitatively determine the economic impacts of aggressive versus simple carbon capture.

NETL also concluded that plant financing criteria are critical factors in determining the economic viability of a CBTL plant for EFG and TRIG™. At the request of the Project Team, NETL provided an alternative financing structure, based on a government loan guarantee (60% of capital financed at 4.56% interest rather than 50% of capital financed at 8.00% interest), to emphasize this point in both the EFG and TRIG™ reports. For the EFG model under the loan guarantee structure the mean values for each of the 10 EFG scenarios decreases by approximately $35/bbl (representing a 23% reduction). For example, for the EFG-based 0% Biomass Scenario, the mean RSP decreases to $111/bbl (down from $145/bbl). However, these results are still 3 to 40% higher than the 2014 spot price baseline value.

The NETL economic models also examined/compared the use of a single gasifier with "pre-mixed" fuels and the use of separate biomass/coal gasifiers. From the EFG model, NETL concludes that the cost disparity between use of a single EFG gasifier and separate gasifiers is small (less than $1.50/bbl). In the case of a CBTL plant based on the TRIG™ technology, NETL reports an increase of upwards of $4.60/bbl of jet fuel for a separate gasifier plant configuration over the use of a single gasifier. Based on the observed range of

RSP results, however, there remains considerable overlap in the RSP values among all scenarios, both for EFG and TRIG™-based models. This again highlights the uncertainty in the economic model and emphasizes the need for more robust, technical GHG/LCA models.

Lastly, the NETL economic models/reports also make several observations and conclusive remarks regarding the difference in cost associated with biomass preparation, focusing on either chipped or pelletized biomass. However, the Project Team feels that these conclusions, while valid, are of lesser importance than those highlighted above. Additional conclusions are provided in Appendix M and Appendix N.

9.3 Westinghouse Plasma Corporation

The economics of waste-to-liquids projects, and waste to energy in general, are enhanced by MSW tipping fee revenue and, therefore, are favored by higher percentages of MSW in the feedstock. However, as a feedstock, supply of MSW is subject to unique limitations, from population density to regulatory and commercial issues, which combine to limit the available supply within a given geographical area. For these reasons, the scale of proposed CBTL facilities utilizing MSW are normally distributed generation scale, in the order of 500 to 5,000 bpd. The WPC plasma gasifier is suitable for generating syngas on a distributed generation scale. This economic review is based on a facility containing one 1,000 tpd gasifier followed by an FT plant producing nominally 850 bpd total FT liquids. FT liquids are an intermediate product that would be delivered to a refinery for upgrading to end products such as FT jet and FT diesel fuels.

This section summarizes the economic review conducted by WPC and their conclusions. The complete economic review is included in the WPC report in Appendix H. Following WPC's conclusions, the Project Team provides its discussion and interpretation of results. Separately from the WPC review, the Project Team completed an RSP analysis based on the WPC economic data. The RSP analysis enables comparison with the economic models provided by NETL for other technologies. Although the modeling approach is similar, there are significant differences, such as the scale of the modeled plant and the complexity of the model.

9.3.1 Background and Assumptions

As described in Section 6.5, WPC conducted pilot tests using their PGVR to gasify a primary feedstock consisting of three coal/MSW blends. WPC used the feedstock analyses and pilot test operating data to simulate the performance of a modeled commercial scale gasifier utilizing the same coal/MSW feedstocks. WPC extended their proprietary model to include gas cleanup, heat recovery, sulfur removal, an FT reactor and tail gas power generator, resulting in a modeled CBTL plant producing FT liquids, electric power, sulfur, vitreous slag, and recovered metals. Figure 9-7 shows the inputs and outputs from the WPC modeled CBTL plant.

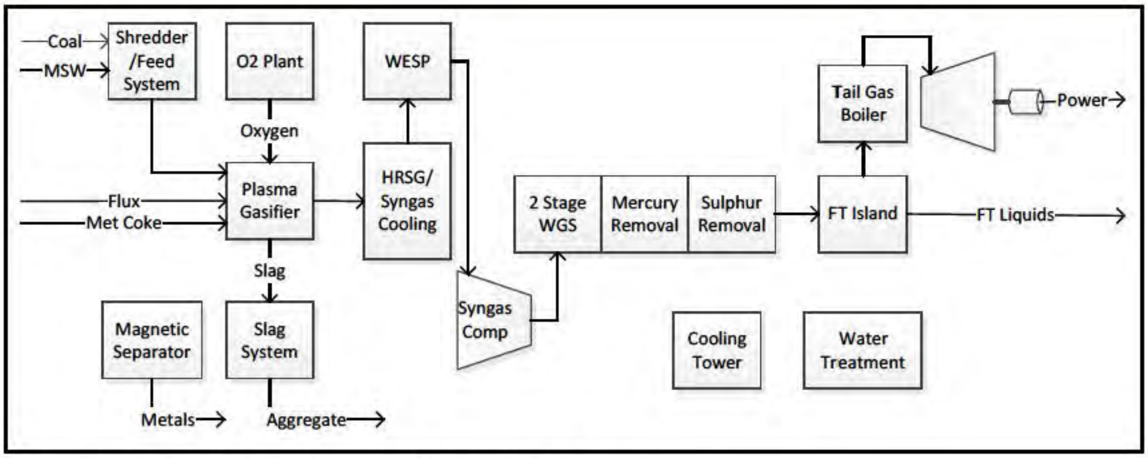

Figure 9-7: Schematic for the WPC Modeled CBTL Plant

While the pilot results were used in developing the model, the outputs of the model are based on simulated operation of a commercial-scale gasifier. The pilot and commercial gasifiers differ in several important respects. For example, the commercial gasifier design features a wide-diameter section at the top of the vessel to provide necessary freeboard for disentrainment of particulates, lower gas velocity, and increased residence time. The commercial gasifier has a much lower surface to volume ratio; therefore, it operates with a lower percentage of heat loss than the pilot plant. Other differences include the number and orientation of plasma torches. The simulation program used by WPC calculates tertiary oxygen required based on specified feedstock chemical composition and exit gas temperature and then assumes all gasification reactions proceed to equilibrium. Due to the design limitations of the pilot gasifier, reactions in the pilot test were non-equilibrium.

For the reasons stated above, the gas composition and cold gas efficiency developed for the commercial-scale gasifier are significantly different from those presented in the facility report. The mass and energy balance and capital cost for a CBTL plant corresponding to the three test cases are summarized in Table 9-5.

Table 9-5: Summary of Major Mass and Energy Balance Parameters and Capital Cost of CBTL Plant for Individual Cases

		Test Cases (MSW wt%)		
		50	75	100
Parameter	Units	Case 1	Case 2	Case 3
Inputs				
PRB Coal	tpd	450	230	-
MSW	tpd	450	690	947
Met Coke	tpd	36	37	39
Flux	tpd	38	61	87
Oxygen	tpd	435	436	440
PRB Coal HHV	Btu/lb	8,959	8,959	8,959
MSW HHV	Btu/lb	7,786	7,786	7,786

		Test Cases (MSW wt%)		
		50	75	100
Parameter	**Units**	**Case 1**	**Case 2**	**Case 3**
Outputs				
FT Liquids	bpd	877	857	839
Slag and Metals	tpd	130	178	232
Net Power Generation	MWe	15.0	14.5	14.0
Syngas HHV	MMBtu/hr	534.2	522.0	511.6
Cold Gas Efficiency		84%	83%	82%
Capital Cost				
Total Capital Cost	$MM	321.8	320.2	320.2
Cost /Unit Capacity	$/bpd	367,000	374,000	382,000

Notes:
Data are based on maximum operating capacity.

WPC estimated the capital cost and the fixed operating costs for each plant and used the model to determine annual revenue and variable operating costs. Plant location is assumed to be in the United States for purposes of equipment cost, construction, installation, and operations labor. All revenues and costs are in 2014 U.S. dollars. An escalation of 2.5% per year is applied to all revenue and operating cost items to reflect general inflation.

The economic analysis contains assumptions that are consistently applied across the three cases. These assumptions and input values are listed in Table 9-6. The revenue, operating costs, capital recovery, and debt payments were compiled in an income statement over a 30-year project life, thereby obtaining the pre-tax return on equity (ROE) for each case. Note that in the WPC economic model, all revenues and expenses are inputs, and the financial performance in terms of annual cash flow is the output. ROE is calculated from the annual equity cash flows.

Table 9-6: Major Economic Model Inputs

Input	Value
Feedstocks	
PRB Delivered Coal Cost	$36.26/ton
Oxygen	$60/ton
Met Coke	$300/ton
Flux	$13.61/ton
Revenue	
MSW Tipping Fee	$53/ton
Electricity Cost/Value	$70.59/MWh
FT Liquids Cost/Value	$110/bbl
CO_2 Credit[1]	$40/ton
Slag	$1.00/ton

Input	Value
Recovered Metals	$1.00/ton
Recovered Sulfur[2]	-
Finance Model	
Equity Financing	50%
Debt Financing	50%
Cost of Debt	6%

Notes:

[1] The model takes the carbon content for the organic waste stream (excluding met coke) and converts it to carbon dioxide. The sell price of carbon dioxide has been set by WPC to $40/ton. The rationale for doing so is discussed in the WPC Economic Review, included in Appendix H.

[2] Revenue from recovered sulfur is not considered in the model.

9.3.2 Results

Based on the model inputs provided in Table 9-6, the reported ROE was 8.02%, 14.01%, and 19.59% for Cases 1, 2, and 3, respectively. This increasing ROE primarily reflects the increase in tipping fee revenue and carbon dioxide credits with greater MSW content in the feedstock.

In addition to the ROE, WPC conducted a sensitivity analysis. Key parameters in the economic model were adjusted by +10% and -10% and the effect on ROE calculated for each adjustment.
Figure 9-8 shows the positive effects on ROE achievable by adjusting the base values of selected parameters by 10% in a favorable direction, while keeping the remaining factors constant. For example, Figure 9-8 shows the effect on ROE of a 10% increase in FT liquids price, but a 10% decrease in capital cost. For a complete review of all adjustments, both positive and negative, refer to the WPC Economic Review included in Appendix H.

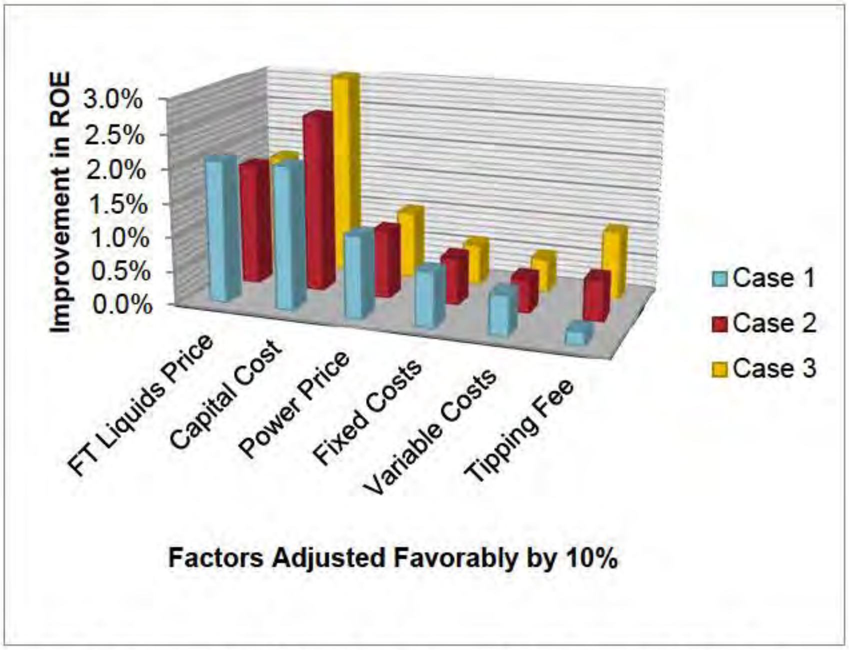

Figure 9-8: Sensitivity Analysis for Favorable Adjustment of Six Economic Factors

9.3.3 Conclusions

Based on the economic modeling, WPC provided the following general conclusions regarding waste-to-liquid (WTL) projects:

- Projects that utilize MSW or other waste products have the ability to take advantage of tipping fees as part of the revenue stream. The results of the economic model show the increase in ROE as the amount of MSW processed in a WTL facility is increased.

- For each 25% increase in MSW of a 1,000 tpd commercial facility, ROE increased by approximately 5.70%.

- Adding MSW to a WTL project may allow the project to qualify for renewable credits and certifications.

- Adding MSW to a WTL project may allow the project to be completed at a more manageable scale with more robust economic returns than traditional CTL plants.

- Adding MSW to a WTL project diverts waste away from landfills; therefore, avoiding potential environmental issues that require additional controls.

9.3.4 Project Team Discussion on the WPC Economic Review

While the WPC review covered the main economic drivers, the Project Team considers the modeling to include two discrepancies that lead to an overly optimistic outcome: the heating value of MSW and uncertainty in the environmental incentives. These are discussed below.

Heating Value of MSW – The heating value of simulated MSW used in the testing and the economic model is much higher than the United States average for non-sorted and non-processed waste[3]. The composition, and therefore, heating value of MSW is known to vary from region to region in the United States, while recycling practices also vary geographically. The as-received heating value of unprocessed MSW is typically in the range of 5,000 to 6,000 Btu/lb (HHV). However, the simulated MSW used in the pilot tests, and the economic study, had a heating value of 7,786 Btu/lb (HHV). It is unlikely an MSW source of such high heating value would be available without significant pre-processing and drying. However, the capital and operating costs required for such pre-processing are not reflected in the economic model. Essentially the model includes the energy benefits of RDF, but with a revenue stream (tipping fee) equivalent to a mixed MSW material.

The effect of using such high heating value for testing and modeling is a higher yield of syngas and FT liquids than would otherwise be possible. Because the PRB coal and simulated MSW do not vary greatly in heating value, the negative effects on the energy balance of blending more MSW in the feedstock are relatively small. However, the increased tipping fee revenue from blending more MSW in the feedstock is significant, so this discrepancy tends to produce optimistic economic projections.

Environmental Incentives – As shown in Table 9-6, WPC included revenue from carbon dioxide credits in the economic model. WPC calculated this credit by assuming that $40/ton carbon dioxide equivalent will be received in revenue based on “eligible” carbon in the feedstock. Eligible carbon was determined as 76% of all carbon in the MSW stream.

The WPC review does not describe the regulatory framework or carbon market on which this incentive is based. There is no detailed lifecycle analysis to support the WPC calculations and, therefore, the Project Team considers these values to be speculative. Under the United States Renewable Fuels Standards, pathways approved by the USEPA for producing liquid fuels from biomass (including MSW) have been established, with the biogenic portion of each batch of fuel represented by renewable identification numbers (RIN). RINs are traded on carbon markets, offering potential incentives for a CBTL plant. However, because there are no commercial WTL plants in operation, it is difficult to predict the actual value of carbon incentives on a given project.

Furthermore, USEPA approval of RINs for a CBTL plant using MSW-derived feedstock requires that the plant demonstrate best available technology for separation of recyclables including paper, cardboard, plastics, rubber, textiles, metal, and glass. Because the plant capital cost, operating cost, and the MSW tipping fee are based on feeding non-processed MSW, it is unlikely the plant, as modeled, would meet this requirement and be approved for RINs.

This $40/ton carbon dioxide carbon credit produces overly optimistic economic projections. For the purpose of this project, the environmental incentive in using an MSW-derived feedstock is investigated through the life-cycle GHG assessment in Section 8.5, with the goal of demonstrating compliance with Section 526.

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[3] The Project Team acknowledges that the chemical composition of the MSW simulated by WPC closely matched the analysis provided by the Project Team.

9.3.5 Project Team RSP Analysis

As described in the introduction to Section 9, another method of comparing economic viability of CBTL projects is the RSP of the outputs. To compare the WPC economic model with other technologies and feedstocks, an alternative RSP analysis was conducted by the Project Team. The RSP analysis uses the capital and operating cost provided by WPC as inputs and calculates the required selling price of FT liquids to cover the ARR.

The mass and energy balance for the RSP analysis is based on the WPC model. The plant consumes MSW and PRB coal as the feedstock, and produces electricity and FT liquids. In line with the WPC model, upgrading of FT liquids and CCS are not included.

Total capital cost is equal to the total installed project capital provided by WPC, which includes a 20% contingency. The economic model assumes the plant is constructed overnight and commences operation on January 1, Year 1. The RSP model was based on the work completed by NETL for CCAT on a comprehensive model of coal and biomass conversion to jet fuel (DOE/NETL-2015/1684). Debt finance is 50% of the total capital cost, repaid over 15 years with an interest rate of 8%, in equal annual payments. Equity is 50% of the total capital cost, and is based on a 20% Internal Rate of Return on Equity, an effective tax rate of 38%, with a 20-year declining balance depreciation schedule, and no investment tax credit. This financial structure results in a capital charge factor of 0.1872.

Fixed operating costs including labor, maintenance, corporate and site overhead, taxes, insurance, disposal charges, and other fixed costs were all provided by WPC. These are escalated annually with inflation (2.5%). Variable costs are the same as those used by WPC. Revenue streams including electric power sales and tipping fees are also escalated annually at 2.5%.

The Project Team did not use a stochastic model, such as the NETL approach, to arrive at a single RSP with a distribution of values. Instead, an RSP value for each year is calculated based on predicted values for feedstock and operating costs, including annual escalation. The RSP analysis uses a static model, calculating the RSP for FT liquids for each year, by setting the FT liquid revenue for each year to ensure ARR for that specific year is covered (i.e., revenues – costs = $0).

The results of the RSP analyses are shown on Figure 9-9. The RSP in Year 1 is $231, $213, and $192 for Cases 1, 2, and 3, respectively. The RSP rises steadily with time as a result of the escalation in operating costs and feedstocks. At the end of the 15-year loan period, the ARR, and therefore, the RSP for all cases decreases significantly. The financial effect of the tipping fee revenue is significant, with the RSP becoming progressively lower from Case 1 to 2 to 3, as more tipping fee revenue is available. The rate of rise in RSP for FT liquids is dependent on the inflation rate used for operating costs and feedstocks.

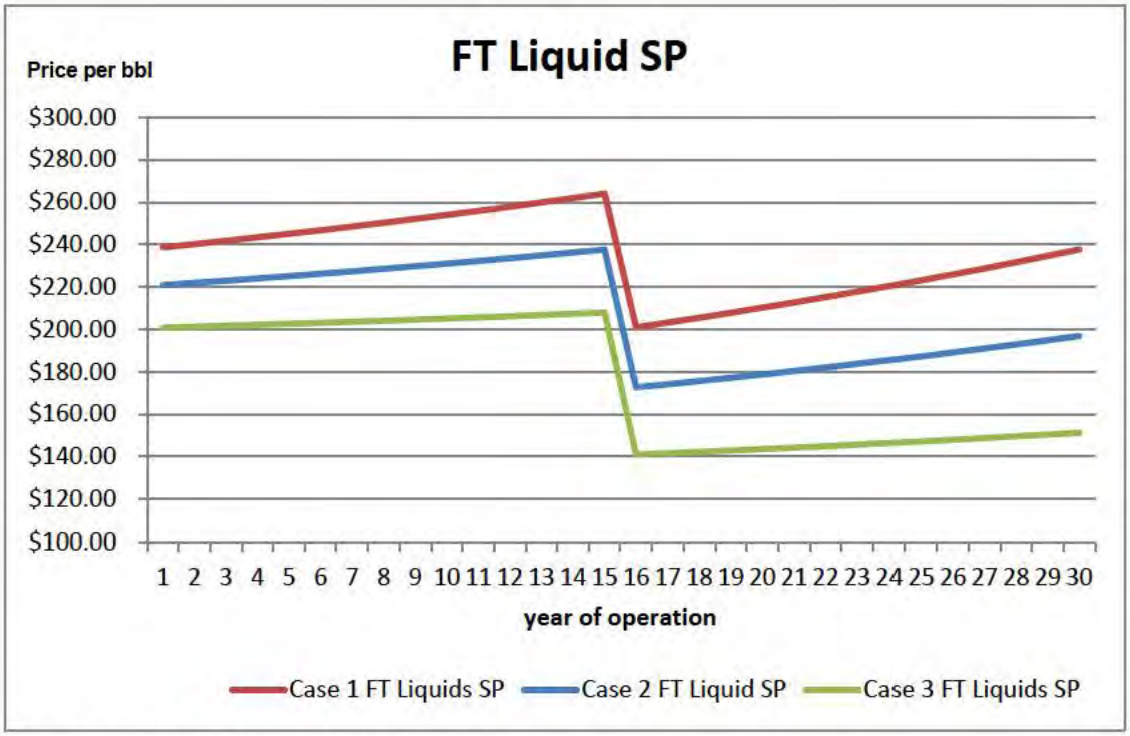

Figure 9-9: FT Liquids Required Selling Price

10. Overall Project Findings and Recommendations

Major activities performed as part of this project were:

- Demonstration testing and technical assessment of:
  - Various gasification technologies
  - Two tar reforming technologies
  - Various torrefied feedstocks
- Demonstration testing of feedstock flexibility using a range of blended coal/biomass and coal/waste feedstocks.
- Life-cycle GHG analyses of jet fuel produced from CBTL.
- Section 526 compliance analyses of jet fuel produced from CBTL.
- Economic modeling of several configurations of CBTL jet fuel production.

Major findings from each of these activities are summarized below.

10.1 Overall Project Findings

A large part of this project was directed towards investigating the technical challenges and likely commercial success of co-firing coal and biomass in a range of available gasifiers. To meet DLA Energy and the Military Advisory Panel's desire to address feedstock flexibility, more than 150 demonstration tests were conducted utilizing various combinations of coal with biomass, MSW, and shale gas with four gasification technologies. Table 10-1 lists the variety of feedstocks and gasifier technologies tested.

Table 10-1: Feedstocks and Gasifier Types used for Testing

Biomass Type	Coal Type				Gasifier Technology Type				
	PRB	Lignite	IL No. 6	Biomass Only	Entrained Flow	Transport Reactor	Fixed Bed	Steam Reformer	Plasma
Coal Only	17	3	4		10	13	1		
Raw Wood	27	1	2		12	16	1	1	
Torrefied Wood	25		2	1	12	16			
Switchgrass	3				0	3			
Shale Gas	6	8			6	8			
Natural Gas		9			0	9			
Methane	5				5				
Railroad Ties	7				0	7			
Raw Corn Stover	5		2		4	3			
Torrefied Corn Stover			3		3				
Filamentous Algae	6				4	2			
Water Hyacinth	3				1	2			

Biomass Type	Coal Type				Gasifier Technology Type				
	PRB	**Lignite**	**IL No. 6**	**Biomass Only**	**Entrained Flow**	**Transport Reactor**	**Fixed Bed**	**Steam Reformer**	**Plasma**
Water Lettuce	4				1	3			
Water Lettuce/Hyacinth Blend	3				3				
MSW	2	1		1	0			1	3
Total	**113**	**22**	**13**	**2**	**61**	**82**	**2**	**2**	**3**
Total Number of Tests	**150**				**150**				

Finding #1 – Testing performed for this project showed that mature coal gasifier technologies can operate with typical coal feedstocks co-fed with a wide range of biomass types, including soft and hard woods, energy crops, agricultural residues, aquatic plants, and certain waste materials. In addition, two small-scale gasifier technologies developed for commercial processing of waste and biomass materials were shown to operate effectively using coal/biomass and coal/MSW feedstock blends. In all scenarios, after typical downstream processing for cleanup and adjustment of H_2:CO molar ratio, the produced syngas would be suitable for the production of FT liquids.

10.1.1 Gasification

Finding #2 – All gasifiers tested were able to attain stable operations for most of the tests conducted. Key performance indicators were carbon conversion, product gas composition, particularly the H_2:CO molar ratio, and cold gas efficiency. For each gasifier type, the product gas composition generally responded in a predictable manner to key operational parameters such as steam, oxygen, temperature, and pressure. Test results show that product gas compositions could potentially produce liquid fuels using a variety of feedstocks, after necessary "shifting" of the product gas to yield a hydrogen to carbon monoxide molar ratio typically needed for the FT process. The desired ratio is dependent on FT reactor design, particularly, the type of catalyst used.

Finding #3 – Operational challenges encountered during demonstration testing were more a function of the size and generic nature of demonstration units, rather than the technologies themselves. However, the demonstration program did highlight that feedstock preprocessing and feed system design will be critical to successful development of a large-scale CBTL project.

10.1.2 Tar Reforming

Two tar reforming technologies were tested. The potential for generating additional syngas from reforming of the tars that are produced during gasification was not substantiated for the specific technologies tested.

10.1.3 Torrefaction

Finding #4 – Torrefied wood appears to offer advantages in handling and blending with coal, contains lower volatile matter (tar precursors), and potentially increases cold gas efficiency.

10.1.4 Feedstock Flexibility

With a few minor exceptions, all feedstock blends were successfully fed and gasified. The Project Team made the following general findings during the course of reviewing the demonstration test data:

<u>Finding #5</u> – The amount (percentage) of biomass/MSW fed with coal does not appear to affect gasifier performance or product gas composition for biomass feed ratios up to 30% and MSW feed ratios up to 100%.

<u>Finding #6</u> – Nuisance plants can be successfully fed and gasified and may be a cost competitive feedstock in regions where they are abundant.

<u>Finding #7</u> – Shale gas can be successfully fed and gasified and may be a cost competitive feedstock in regions where it is abundant. The co-feeding of shale gas to two types of gasifier was successful. Test results were dependent on the location that shale gas was injected into the gasifier. An optimal location was identified for each gasifier type tested.

10.1.5 Life Cycle Analysis

Detailed LCA modeling was performed for the EFG and TRIG™ gasifiers using the system expansion with co-product displacement method. Major findings from the modeling are:

<u>Finding #8</u> – All modeled CBTL scenarios, including coal-only and blends up to 30% biomass, could meet Section 526 requirements using aggressive CCS with carbon sequestration via EOR.

<u>Finding #9</u> – Biomass content in the feedstock is a key consideration with respect to life-cycle GHG emissions. Increasing the amount of biomass fed into the CBTL process reduces life-cycle GHG emissions because total emissions are partially offset by the uptake of atmospheric carbon dioxide during biomass cultivation, even with consideration for GHG emissions associated with land use changes.

- Scenarios that utilized 30% biomass to generate FT fuels had the lowest overall life-cycle GHG emissions, in the range of 38.1 to 62.1% below the baseline needed for Section 526 compliance.

- Scenarios that utilized 10% biomass feedstock were 12.5 to 32.5% below the baseline.

- The 0% Biomass Scenario (coal-only) was 1.8 to 17.6% below the baseline.

<u>Finding #10</u> – Electricity generation and carbon dioxide displacement credits from CBTL are significant contributors to lower GHG emissions.

<u>Finding #11</u> – Emissions generated from the combustion of jet fuel are by far the largest contribution to the LCA.

<u>Finding #12</u> – LCA modeling of various feedstock preparation options show:

- Use of torrefied wood provides slightly lower GHG emissions compared to use of raw wood.

- There is no significant difference in the GHG emissions and LCA between wood chips and wood pellets.

Finding #13 – Use of separate gasifiers for coal and biomass does not improve GHG emissions.

Finding #14 – Using the FT black box model, each WPC scenario is predicted to meet Section 526; increasing MSW percentage has the most impact on reducing lifecycle GHG emissions.

10.1.6 Economic Modeling

Techno-economic modeling was performed to quantify the viability of various CBTL facilities producing jet fuel. A Required Selling Price (RSP) was calculated by determining the selling price of jet fuel ($/bbl) required to cover the annual revenue requirement for the CBTL project, including all capital costs, operating costs, and financing. Note that RSP is converted into a crude oil equivalent and actually represents the equivalent crude oil price at which any given CBTL scenario would be economically viable.

Note: During this project, the price of oil varied from a high of $112/bbl in early 2011 to a low of $44/bbl in 2015 (YCharts 2015). Economic modeling scenarios in this project are compared against a first quarter 2014 price of $99/bbl for crude oil.

Major findings from the economic modeling are provided below.

Finding #15 – The base-case (coal-only) scenarios had an average RSP of $145/bbl and $134/bbl for the EFG and TRIG™ scenarios, respectively.

Finding #16 – Scenarios utilizing a higher percentage of biomass generally have a greater RSP. For example, RSP values for the 30% Chipped Biomass Scenarios have an average of $170/bbl, compared to $152/bbl for the 10% Chipped Biomass Scenarios for EFG.

Finding #17 – Scenarios utilizing torrefied biomass generally have a lower RSP. For example, RSP values for the 30% Chipped Biomass have an average of $170/bbl, compared to $157/bbl for the 30% Torrefied Biomass Scenarios for EFG.

Finding #18 – The project capital recovery factor that includes both total plant capital costs and financing costs, is the single largest factor influencing the RSP.

Finding #19 – Plant financing criteria will be critical factors in determining the economic viability of a CBTL plant. The Project Team reviewed an alternative financing structure, based on a government DOE loan guarantee scenario rather than completely private financing. For example, with alternative financing (60% of capital financed at 4.56% interest versus 50% of capital financed at 8.00% interest) the average value for each EFG scenario decreases by approximately $35/bbl (representing a 23% reduction). In addition, implementation of carbon tax or credit-related legislation would have a significant role in any analysis of economic viability.

10.2 Recommendations

Recommendation #1 – Use the data collected during this project to further evaluate CBTL.

Large amounts of data were generated during this project. More than 140 data points were measured or calculated for each of the 150 demonstration tests conducted. These data have been stored and organized in the Test Data Compilation Spreadsheet (Appendix J). It is searchable and sortable in a number of ways. For example, this tool can be used to view or graph the product gas composition for any combination of gasification systems, coals, and biomass feedstocks. This allows DLA Energy to compare and evaluate results of all the different CBTL configurations tested in this program.

Recommendation #2 – Pursue improvement of CBTL designs to optimize biomass content, CCS, and plant capital costs so that Section 526-compliant fuels are more cost competitive to produce.

LCA modeling shows that increasing percentages of biomass offers the potential to be approximately 62% below the Section 526 baseline requirement. Economic modeling shows that plants capable of achieving this are not cost competitive with conventional production of jet fuel. Therefore, opportunities could exist to modify the CBTL design to reduce the quantity of carbon dioxide captured and sequestered while still meeting the Section 526 requirement. For example, earlier NETL CBTL modeling work for diesel fuel production (2009) showed that use of a simple CCS approach (91% capture) versus an aggressive CCS approach (greater than 95% capture) would lower project capital costs approximately 7 to 9% and the RSP by 21 to 23%. However, to optimize the potential RSP, the reductions in capital costs from reducing CCS requirements/capacity would need to be balanced against both the revenue generated from the sale of carbon dioxide for EOR and the carbon displacement credit gained from the captured carbon dioxide.

Recommendation #3 – Investigate smaller, distributed-scale CBTL designs.

Utilizing higher biomass percentages would appear to reduce the need for CCS, minimizing the need for carbon dioxide sequestration. However, the technical feasibility of feeding higher biomass percentages and the availability of sufficient quantities of biomass may limit this to smaller, distributed-scale CBTL facilities. Although it may not currently be economically feasible to meet DoD jet fuel production goals with smaller, distributed-scale CBTL facilities without net-zero or positive revenue feedstocks, or without including carbon tax/credits-related legislation, the need for a secure source and the economics of producing jet fuel could change dramatically in the future. If small, commercial-scale projects currently under construction or being commissioned using technologies developed by TRI, Enerkem, and others are successful, based on performance and financial results, there is potential for small-scale CBTL/BTL facilities to be technically and commercially feasible to meet DoD alternative fuel goals by 2025.

Recommendation #4 – Encourage development of torrefaction technology.

Based on project testing, torrefied wood appears to offer advantages in handling and blending with coal, contains lower volatile matter (tar precursors), and has the potential to increase cold gas efficiency. Based on NETL modeling results, torrefaction also produces lower overall GHG emissions and a lower RSP.

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