The Potential for Renewable Gas:

Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality

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Abbreviations and Glossary

Table 1 contains a list of terms and abbreviations that will be used throughout this report.

Table 1: Abbreviations and Glossary of Terms

Term/ Abbreviation	Definition
ACEC	Advanced Cleaner Energy Credits (Michigan)
AD	Anaerobic Digestion
AGF	American Gas Foundation
Btu	British Thermal Unit
Capex	Capital Expenses
CARB	California Air Resources Board
CCX	Chicago Climate Exchange
CAR	Climate Action Registry
CEC	California Energy Commission
CDM	Clean Development Mechanism
CF	Cubic Feet
CO_2	Carbon Dioxide
CPUC	California Public Utility Commission
FTE	Full-Time-Equivalent
ECX	European Climate Exchange
GHG	Greenhouse Gases
GTI	Gas Technology Institute
LFG	Landfill Gas
MGD	Million Gallons per Day
MCF	Thousand Cubic Feet
MGGRA	Midwest Greenhouse Gas Accord
MGY	Million Gals/Year
MMSCFD	Million Standard Cubic Feet Per Day
MSW	Municipal Solid Waste
NGL	Natural Gas Liquids
Opex	Operating Expenses
NGV	Natural Gas Vehicles
PQG	Pipeline Quality Gas
Quads	1 Quadrillion (10^{15}) Btu or 1 Billion MMBtu or 1 Billion Dekatherms
RCRA	Resource Conservation And Recovery Act
REC	Renewable Energy Credits
RG	Renewable Gas
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standards
RDF	Refuse Derived Fuels
TCF	Trillion Cubic Feet
TG	Thermal Gasification
U.S.	United States
W2E	Waste-to-Energy
WCI	Western Climate Initiative
WECC	Western Area Coordinating Council
WIP	Waste-in-Place
WWTP	Waste Water Treatment Plant

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1.0 Executive Summary

Renewable gas (RG) is pipeline quality gas derived from biomass. It is a renewable fuel that is fully interchangeable with natural gas, and it has the potential to reduce greenhouse gas (GHG) emissions, create jobs and increase the diversity of domestic energy supply portfolio. Under two practical long term scenarios, renewable gas has the potential to meet between 4 to 10 percent of current (2010) natural gas usage in the U.S.[1] Reductions in GHG emissions in the U.S. may be up to 146 million tons of CO_2 per year. Developing renewable gas can create up to nearly 257,000 new jobs under scenarios of high biomass utilization. Renewable gas, derived from biomass and upgraded to natural gas quality, is carbon-neutral, interchangeable, fungible, and compatible with U.S. pipeline infrastructure. It can deliver a renewable option for homes and businesses, for manufacturing and heavy industries, and for transportation and electricity production.

Renewable gas can be produced from a variety of biomass sources including wastewater treatment plants, animal manure, landfills, woody biomass, crop residuals, and energy crops. Renewable gas can have the same physical composition as natural gas but is produced from renewable, biomass resources by utilizing technologies such as anaerobic digestion and thermal gasification. Under one scenario of high utilization considered in this study, the U.S. possesses a significant amount of biomass available for conversion to renewable gas. Roughly 721 million tons per year of livestock manure and 1,783 billion gallons per year of wastewater are available for conversion via anaerobic digestion. Another 3,799 million tons of municipal solid waste (MSW) in landfills are available for conversion to landfill gas via the natural processes of degradation that occurs within a landfill. Via thermal gasification, approximately 225 million tons per year of agricultural residue, energy crops, MSW, and wood residue are available for conversion. State-by-state biomass resource availabilities are available in section *6.0 Anaerobic Digestion Feedstocks*. Many European nations including Sweden, Germany, and Ireland are coming to the realization that carbonaceous renewable resources such as those listed above can be employed most effectively and efficiently to produce renewable gas.

Renewable gas offers numerous potential benefits for the United States:

- It is another source of domestically produced energy. Under the two practical long term scenarios that were considered for this study, the market potential of renewable gas is from 1.0 – 2.5 quadrillion Btu's per year. The technical potential, representing complete utilization of all available feedstocks, is approximately 9.5 quadrillion Btu's per year.
- The job creation potential of renewable biogas gas projects is significant. Direct jobs created range up to 83,000 depending on the depth of the market penetration. Using an average multiplier of 3.1[2,3,4,5,6] for indirect and induced jobs, total jobs created ranges up to 257,000.
- Depending on the model of deployment, renewable gas production could result in 146 million metric tons of CO_2 removed from the air annually. This is the equivalent of taking **29 million cars off the road**.[7]
- The California Air Resources Board (CARB), in a 2009 report, has determined that renewable gas is the **lowest carbon transportation fuel available today**.[8]

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[1] *This assumes a national usage of roughly 24 TCF of natural gas or 24 quadrillion BTU (for 2010). See http://www.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.*
[2] *http://www.reddi.gov.on.ca/guide_ecimpactassessment.htm#*
[3] *Congressional Research Service, http://assets.opencrs.com/rpts/R40080_20091002.pdf, p. 7*
[4] *Congressional Research Service, IBID, p. 11*
[5] *Iowa State, http://www.econ.iastate.edu/research/webpapers/paper_12864.pdf, p. 4*
[6] *State of Maryland, http://www.gov.state.md.us/statestat/documents/091029ARRA.pdf*
[7] *http://www.epa.gov/otaq/climate/420f05001.htm*
[8] *http://www.arb.ca.gov/regact/2009/lcfs09/lcfsfsor.pdf*

- Almost every state in the U.S. has the resources to participate in the production of renewable gas with the potential to create new green jobs.
- Renewable gas from renewable sources including animal manure, forest residues, and agricultural wastes can be produced at **efficiencies ranging from 60–70%**, thus, using our renewable resources in a responsible and efficient manner.[9]
- All of the technology components to produce renewable gas from this variety of biomass sources exist today.
- Renewable biogas production in digesters provides the agricultural sector additional environmental benefits by improving waste management, nutrient control, and dramatically reducing carbon emissions through the control of methane by placing manure in enclosed vessels instead of open lagoons.
- Renewable gas is an interchangeable fuel that can be delivered to customers via the existing U.S. pipeline infrastructure and can provide **a renewable energy option in the natural gas energy market, an energy market that overall represents 25% of U.S. energy use**.
- Renewable gas, in many instances, is the low-cost option among renewable products.[10]

Legislative and regulatory support for renewable fuels is understood to be crucial in realizing scale production for these resources. The same will be true for realizing the potential presented by renewable gas. Over the past several decades the U.S. Congress and the Executive Branch have endorsed a variety of incentives to further the advancement of renewable energy. Much of this effort has focused on creating incentives for the production of renewable electricity or renewable transportation fuels. These incentives have made a positive impact on the growth of renewable liquid transportation fuels produced from biomass resources and on renewable electricity produced from woody biomass, animal manure, and landfill gas. Currently, federal government policy gives disparate treatment to processes for producing renewable gas as compared to those which generate renewable electricity or transportation fuels.

Renewable gas production does not receive similar tax credits compared to other renewable energy products. In many instances, as set out in this report, biomass and other renewable resources may be more effectively and efficiently used to produce renewable gas directly. This potential is hindered by the existing tax incentive structure on renewable energy which drives these resources towards production of renewable electricity or liquid transportation fuels.

Importantly, renewable gas can be a supply source for all current users of natural gas. Prudent and well conceived changes in policy can expand its use across the country. These policy changes have to incorporate the following two principles:

- Parity – renewable gas being valued and incentivized similarly to renewable electricity or liquid transportation fuel.
- Accessibility and integration – the purchase and transfer of renewable gas through our nation's pipeline infrastructure to meet local, state, or federal goals for renewable fuels.

It is the mission of the American Gas Foundation (AGF) to conduct analysis of current and significant energy and environmental issues and to assess their intersection with alternative public policy approaches. Consistent with that mission, AGF and its trustees are hopeful that the analysis provided here will serve as a resource for dialogue among to explore further the benefits of leveraging our existing natural gas transmission and distribution infrastructure to deliver a renewable resource for generation to come.

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[9] *GTI, Vann Bush, "Biomass Gasification: State of the Art and Trends," presentation to GTI's Public Interest Advisory Committee, October 20, 2009.*
[10] *NREL, "Cost and Performance Assumptions for Modeling Electricity Generation Technologies," ICFI, NREL/SR-6A20-48595, November, 2010.*

2.0 Introduction

The overall objective of this work is to provide an estimate of the impact of RG. The impact is measured by considering the following metrics under defined market penetration scenarios:

- Annual biomass resource availability or abundance
- Annual energy production
- Annual reduction in new CO_2 emissions to the atmosphere
- Annual carbon credit values due to the reductions in CO_2 emissions
- Job creation, direct and indirect, associated with the production of energy
- Capital investment costs required to construct the facilities for RG production
- Annual costs needed to operate the facilities and support the debt incurred in the capital expenditures to construct the facilities
- Unit energy prices for RG

The U.S. biomass resource base includes crop residues, dedicated energy crops (e.g., switchgrass, willow, or hybrid poplar), landfill gas (LFG)[11], forest and wood wastes (urban wood waste, primary and secondary mill wastes), sludge from municipal water treatment, and animal (dairy cow, pig, and chicken) wastes. The study does not include displacement of primary food crops to energy production usage. Such usage creates an additional component of demand on food crops and can exert an upward pressure on food costs. Therefore, for the purposes of this study, food crops have been excluded. *Residues* from the following crops are included in this analysis: corn, wheat, soybeans, cotton, sorghum, barley, oats, rice, rye, canola, beans, peas, peanuts, potatoes, safflower, sunflower, sugarcane, and flaxseed. The annual biomass resource availabilities under a scenario of high biomass utilization are displayed in Table 15 and Table 18.

Two commercially available processes can convert biomass to RG: Anaerobic Digestion (AD) and Thermal Gasification (TG). In the first, biomass is partly converted to biogas under direct microbial action. The process is particularly suited for high-moisture biomass. In the second process, biomass is heated until it reacts to form methane or syngas, which is subsequently converted to methane. This process generally requires low-moisture biomass. Both routes ultimately convert the energy in the biomass to methane. Other options for using biomass, such as combustion or co-firing with fossil fuels to produce electricity have lower overall efficiency.

This analysis presents three potential degrees or scenarios of total biomass utilization or market penetration:

- *Non-aggressive.* This scenario assumes roughly 5% -25% (depending on resource) of biomass is processed into biogas. Total renewable gas (RG) production is 0.97 quads per year.
- *Aggressive.* This scenario assumes 15%-75% (depending on resource) of biomass is processed into renewable gas. The Aggressive scenario represents a concerted national effort to employ this renewable resource. Total RG production is 2.48 quads per year.
- *Maximum.* This scenario assumes 100% biomass utilization and conventional conversion efficiency. It provides a theoretical upper limit for renewable gas production. Total RG production is 9.5 quads per year.[12]

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[11] *Landfill gas is included in the analysis to be consistent with EIA and DOE definitions.*

[12] *Most of the results of this analysis are found in "Appendix: Results from the Maximum Utilization Scenario".*

The results of this study indicate a likely resource market penetration on the order of 4-10% of the natural gas currently (2010) used in this country, that is 1-2.5 quads for the Non-aggressive and Aggressive scenarios. Significant national results by scenario are summarized in Table 2.

Table 2: Summary Results by Scenario for the Entire United States.

Category of Assessment	Qty	Scenario		
		Non-aggressive	Aggressive	Maximum
Energy Potential	AD Renewable Gas [million dekatherm/yr]	334.8	871.4	2,123.3
	TG Renewable Gas [million dekatherm/yr]	631.8	1614.0	7,376.3
	AD+TG Renewable Gas [million dekatherm/yr]	966.6	2,485.4	9,499.6
	AD+TG Renewable Gas [% of U.S. National Usage][13]	4%	10%	40%
CO_2 Reduction	AD CO_2 Abatement [million tons CO_2/yr]	19.6	51.0	124.3
	TG CO_2 Abatement [million tons CO_2/yr]	37.0	94.5	431.8
	AD+TG CO_2 Abatement [million tons CO_2/yr]	56.6	145.5	556.1
Direct Jobs Created	AD Direct Jobs (low) [No.]	3,057	7,956	19,386
	AD Direct Jobs (High) [No.]	11,150	29,019	70,707
	TG Direct Jobs (low) [No.]	5,768	14,736	67,346
	TG Direct Jobs (High) [No.]	21,039	53,746	245,631
	AD+TG Direct Jobs (low) [No.]	8,825	22,692	86,732
	AD+TG Direct Jobs (High) [No.]	32,189	82,765	316,338

Job creation potential is reported as an estimated range of potential job numbers within each scenario. More detail is found in later sections of the report and in the appendices.

- Totaled over both technology sectors, direct jobs created range up to 32,200, 82,800 and 316,300 for the Non-aggressive, Aggressive, and Maximum scenarios, respectively.
- Using an average job multiplier of 3.1 for direct, indirect, and induced jobs, the totals are roughly 100,000, 258,000 and 987,000 for the three scenarios.

Under the Aggressive scenario, CO_2 abatement potentials over the states for TG and AD combined, span ranges of 0.18-12.68 million tons CO_2/yr and total over all states, 145.5 million tons CO_2/yr.

[13] *This assumes a national usage of roughly 24 TCF of natural gas or 24 quadrillion BTU (for 2010). See http://www.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.*

Table 3: Highlights of Major Results on Energy and CO_2 Abatement, Combined TG+AD, Aggressive Scenario.

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]
Alabama	38.1	2.23
Alaska	3.2	0.19
Arizona	17.9	1.05
Arkansas	59.1	3.46
California	132.7	7.77
Colorado	31.9	1.87
Connecticut	3.3	0.19
Delaware	6.5	0.38
Florida	59.3	3.47
Georgia	50.2	2.94
Hawaii	5.0	0.29
Idaho	25.3	1.48
Illinois	186.4	10.91
Indiana	95.4	5.58
Iowa	216.7	12.69
Kansas	88.2	5.16
Kentucky	41.0	2.40
Louisiana	51.2	3.00
Maine	9.0	0.53
Maryland	16.5	0.96
Massachusetts	9.3	0.54
Michigan	62.0	3.63
Minnesota	140.7	8.24
Mississippi	50.8	2.98
Missouri	97.4	5.70
Montana	22.2	1.30
Nebraska	103.8	6.07
Nevada	6.4	0.37
New Hampshire	5.2	0.30
New Jersey	20.7	1.21
New Mexico	10.7	0.63
New York	54.1	3.17
North Carolina	51.8	3.03
North Dakota	72.9	4.27
Ohio	80.2	4.69
Oklahoma	40.8	2.39
Oregon	16.9	0.99
Pennsylvania	60.4	3.54
Rhode Island	3.1	0.18
South Carolina	22.6	1.32
South Dakota	57.9	3.39

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]
Tennessee	40.1	2.35
Texas	147.5	8.63
Utah	8.8	0.52
Vermont	4.5	0.27
Virginia	37.2	2.18
Washington	32.4	1.90
West Virginia	8.7	0.51
Wisconsin	72.9	4.27
Wyoming	6.5	0.38
Total	**2,485.44**	**145.50**
Average	**49.71**	**2.91**
Maximum	**216.69**	**12.69**
Minimum	**3.10**	**0.18**
Std Dev	**48.21**	**2.82**
Relative Std Dev w/rt Avg	**96.98%**	**96.98%**

Table 4: Highlights of Major Results on Direct Job Creation, Combined TG + AD, by State and by Scenario.

State	Non Aggressive		Aggressive		Max Potential	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	130	474	348	1268	1297	4730
Alaska	12	42	29	105	129	472
Arizona	60	221	163	596	689	2512
Arkansas	203	739	540	1969	2035	7422
California	495	1806	1211	4419	4402	16057
Colorado	107	390	291	1063	1151	4200
Connecticut	13	46	30	109	105	384
Delaware	24	86	60	217	209	761
Florida	216	789	541	1975	2188	7980
Georgia	174	636	458	1672	1681	6130
Hawaii	19	68	46	167	174	635
Idaho	82	301	231	841	803	2929
Illinois	682	2486	1702	6207	7029	25638
Indiana	350	1275	871	3176	3473	12668
Iowa	762	2780	1978	7216	7735	28212
Kansas	304	1110	805	2938	3006	10964
Kentucky	142	519	375	1367	1409	5139
Louisiana	186	677	468	1705	1961	7151
Maine	32	116	82	299	339	1236
Maryland	60	217	150	548	580	2116
Massachusetts	36	130	85	308	329	1199
Michigan	227	828	566	2064	2219	8092
Minnesota	499	1820	1285	4687	5085	18547
Mississippi	179	651	464	1693	1797	6553
Missouri	345	1257	889	3242	3436	12531

State	Non Aggressive		Aggressive		Max Potential	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Montana	73	267	203	740	710	2588
Nebraska	358	1305	947	3455	3590	13096
Nevada	22	81	58	212	231	842
New Hampshire	20	73	47	172	183	667
New Jersey	82	298	189	689	759	2769
New Mexico	32	118	98	358	316	1153
New York	207	755	494	1802	1782	6498
North Carolina	178	650	473	1726	1667	6080
North Dakota	261	952	666	2429	2706	9870
Ohio	294	1074	732	2670	2911	10618
Oklahoma	130	474	372	1358	1227	4475
Oregon	58	213	154	563	568	2070
Pennsylvania	230	837	552	2013	1940	7076
Rhode Island	12	45	28	103	117	427
South Carolina	84	305	206	751	778	2838
South Dakota	199	727	529	1930	1992	7265
Tennessee	142	518	367	1337	1426	5200
Texas	501	1826	1347	4911	4873	17772
Utah	29	105	80	293	287	1047
Vermont	16	58	41	151	134	488
Virginia	137	501	340	1239	1225	4469
West Virginia	30	110	80	291	316	1151
Wisconsin	256	932	666	2429	2413	8803
Wyoming	19	71	59	217	173	631
Total	**8,825.4**	**32,189.0**	**22,692.1**	**82,765.3**	**86,731.7**	**316,337.9**
Average	**176.5**	**643.8**	**453.8**	**1655.3**	**1734.6**	**6,326.8**
Maximum	**762.3**	**2,780.3**	**1,978.4**	**7,215.9**	**7,735.0**	**28,211.8**
Minimum	**11.6**	**42.1**	**28.3**	**103.3**	**105.2**	**383.9**
Std Dev	**172.1**	**627.6**	**440.1**	**1,605.3**	**1,721.6**	**6,279.2**
Relative Std Dev w/rt Avg	**97.5%**	**97.5%**	**97.0%**	**97.0%**	**99.2%**	**99.2%**

Table 5: Highlights of Major Results on Energy and CO_2 Abatement, Anaerobic Digestion, Aggressive Scenario

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million tons/yr]
Alabama	17.4	1.0
Alaska	0.5	0.0
Arizona	8.7	0.5
Arkansas	16.8	1.0
California	86.6	5.1
Colorado	14.2	0.8
Connecticut	1.9	0.1
Delaware	4.0	0.2
Florida	20.7	1.2
Georgia	23.9	1.4
Hawaii	1.8	0.1
Idaho	10.5	0.6
Illinois	30.4	1.8

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million tons/yr]
Indiana	23.7	1.4
Iowa	36.6	2.1
Kansas	25.8	1.5
Kentucky	15.9	0.9
Louisiana	7.8	0.5
Maine	1.4	0.1
Maryland	7.4	0.4
Massachusetts	5.3	0.3
Michigan	22.2	1.3
Minnesota	21.1	1.2
Mississippi	12.9	0.8
Missouri	26.6	1.6
Montana	9.4	0.6
Nebraska	24.5	1.4
Nevada	3.9	0.2
New Hampshire	2.1	0.1
New Jersey	12.5	0.7
New Mexico	7.6	0.4
New York	34.5	2.0
North Carolina	27.2	1.6
North Dakota	6.1	0.4
Ohio	28.9	1.7
Oklahoma	24.1	1.4
Oregon	8.0	0.5
Pennsylvania	38.9	2.3
Rhode Island	1.9	0.1
South Carolina	10.2	0.6
South Dakota	13.9	0.8
Tennessee	16.6	1.0
Texas	77.9	4.6
Utah	5.8	0.3
Vermont	3.0	0.2
Virginia	21.2	1.2
Washington	13.1	0.8
West Virginia	3.4	0.2
Wisconsin	27.7	1.6
Wyoming	5.0	0.3
Total	**871.4**	**51.0**
Average	**17.4**	**1.0**
Maximum	**86.6**	**5.1**
Minimum	**0.5**	**0.03**
Std Dev	**16.7**	**1.0**
Relative Std Dev w/rt Avg	**96.0%**	**96.0%**

Table 6: Estimated Ranges of Job Creation, Anaerobic Digestion, by State and by Scenario.

State	Non Aggressive Low Estimate	Non Aggressive High Estimate	Aggressive Low Estimate	Aggressive High Estimate	Max Potential Low Estimate	Max Potential High Estimate
Alabama	57	209	159	579	378	1379
Alaska	2	8	5	16	12	45
Arizona	30	110	79	289	191	697
Arkansas	49	179	153	558	348	1270
California	341	1244	791	2884	2034	7417
Colorado	46	168	130	473	307	1118
Connecticut	8	28	17	63	45	166
Delaware	15	53	36	132	89	326
Florida	81	294	1	690	484	1767
Georgia	81	297	218	795	524	1912
Hawaii	7	26	16	60	41	149
Idaho	29	107	96	350	214	781
Illinois	120	437	278	1013	701	2556
Indiana	92	335	217	790	550	2007
Iowa	106	386	334	1218	755	2753
Kansas	78	285	236	860	542	1977
Kentucky	53	193	145	529	346	1262
Louisiana	30	108	71	259	180	658
Maine	5	18	12	46	31	113
Maryland	28	103	68	248	172	626
Massachusetts	23	83	49	178	125	456
Michigan	86	314	203	741	509	1856
Minnesota	63	230	192	702	441	1608
Mississippi	42	152	118	430	278	1015
Missouri	89	326	243	887	582	2122
Montana	27	98	86	313	194	706
Nebraska	69	253	224	815	501	1829
Nevada	14	53	36	131	89	324
New Hampshire	9	33	19	69	51	186
New Jersey	55	201	114	416	304	1110
New Mexico	22	79	69	251	155	565
New York	140	511	315	1148	818	2983
North Carolina	91	333	248	906	596	2172
North Dakota	17	63	55	202	124	453
Ohio	113	414	264	963	674	2459
Oklahoma	71	259	220	801	500	1825
Oregon	27	99	73	267	176	643
Pennsylvania	156	567	355	1296	920	3355
Rhode Island	9	31	17	64	48	174
South Carolina	40	146	93	341	240	875
South Dakota	39	142	127	464	284	1035
Tennessee	59	216	151	551	371	1355
Texas	259	943	712	2595	1694	6179
Utah	19	68	53	193	125	457
Vermont	10	38	27	99	66	242
Virginia	82	298	193	705	491	1791
Washington	50	181	120	437	303	1103
West Virginia	12	42	31	114	75	275
Wisconsin	92	336	253	923	604	2204

State	Non Aggressive		Aggressive		Max Potential	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Wyoming	14	52	45	166	102	373
Average	**61.1**	**223.0**	**159.1**	**580.4**	**387.7**	**1414.1**
Maximum	**341.1**	**1244.1**	**790.6**	**2883.6**	**2033.6**	**7417.0**
Minimum	**2.2**	**7.9**	**4.5**	**16.4**	**12.2**	**44.5**
Std Dev	**61.8**	**225.5**	**152.8**	**557.4**	**380.1**	**1386.5**
Relative Std Dev w/rt Avg	**101.1%**	**101.1%**	**96.0%**	**96.0%**	**98.0%**	**98.0%**

Table 7: Highlights of Major Results on Energy and CO_2 Abatement, Thermal Gasification, Aggressive Scenario.

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million tons/yr]
Alabama	20.7	1.2
Alaska	2.7	0.2
Arizona	9.2	0.5
Arkansas	42.4	2.5
California	46.1	2.7
Colorado	17.7	1.0
Connecticut	1.4	0.1
Delaware	2.6	0.2
Florida	38.6	2.3
Georgia	26.3	1.5
Hawaii	3.2	0.2
Idaho	14.7	0.9
Illinois	156.0	9.1
Indiana	71.6	4.2
Iowa	180.1	10.5
Kansas	62.4	3.7
Kentucky	25.1	1.5
Louisiana	43.4	2.5
Maine	7.6	0.4
Maryland	9.0	0.5
Massachusetts	3.9	0.2
Michigan	39.7	2.3
Minnesota	119.7	7.0
Mississippi	37.9	2.2
Missouri	70.7	4.1
Montana	12.8	0.7
Nebraska	79.3	4.6
Nevada	2.4	0.1
New Hampshire	3.1	0.2
New Jersey	8.2	0.5
New Mexico	3.2	0.2
New York	19.6	1.1
North Carolina	24.6	1.4
North Dakota	66.9	3.9
Ohio	51.3	3.0
Oklahoma	16.7	1.0
Oregon	8.9	0.5
Pennsylvania	21.5	1.3
Rhode Island	1.2	0.1

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million tons/yr]
South Carolina	12.3	0.7
South Dakota	44.0	2.6
Tennessee	23.6	1.4
Texas	69.6	4.1
Utah	3.0	0.2
Vermont	1.6	0.1
Virginia	16.0	0.9
Washington	19.3	1.1
West Virginia	5.3	0.3
Wisconsin	45.2	2.6
Wyoming	1.5	0.1
Total	**1614.0**	**94.5**
Average	**32.3**	**1.9**
Maximum	**180.1**	**10.5**
Minimum	**1.2**	**0.1**
Std Dev	**37.8**	**2.2**
Relative Std Dev w/rt Avg	**117.2%**	**117.2%**

Table 8: Estimated Ranges of Job Creation, Thermal Gasification, by State and by Scenario.

State	Non Aggressive		Aggressive		Max Potential	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	73	265	189	689	919	3351
Alaska	9	34	24	89	117	428
Arizona	30	110	84	307	498	1815
Arkansas	153	559	387	1411	1687	6152
California	154	562	421	1535	2369	8640
Colorado	61	222	162	590	845	3082
Connecticut	5	17	12	45	60	218
Delaware	9	33	23	86	119	435
Florida	136	495	352	1285	1704	6213
Georgia	93	339	241	877	1156	4218
Hawaii	12	42	29	107	133	487
Idaho	53	194	134	490	589	2148
Illinois	562	2049	1424	5195	6329	23083
Indiana	258	940	654	2386	2923	10662
Iowa	656	2394	1644	5998	6980	25459
Kansas	226	825	570	2078	2464	8987
Kentucky	90	327	230	837	1063	3877
Louisiana	156	569	397	1446	1780	6494
Maine	27	99	69	253	308	1123
Maryland	31	115	82	300	408	1489
Massachusetts	13	48	36	130	203	742
Michigan	141	514	363	1323	1710	6237
Minnesota	436	1590	1093	3985	4644	16940
Mississippi	137	500	346	1263	1518	5538
Missouri	255	931	646	2356	2854	10409
Montana	46	169	117	426	516	1882
Nebraska	288	1052	724	2640	3089	11267
Nevada	8	28	22	81	142	518

State	Non Aggressive		Aggressive		Max Potential	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
New Hampshire	11	40	28	103	132	481
New Jersey	27	97	75	273	455	1659
New Mexico	11	39	29	106	161	588
New York	67	243	179	653	964	3514
North Carolina	87	317	225	821	1071	3907
North Dakota	244	890	610	2227	2582	9417
Ohio	181	660	468	1707	2237	8159
Oklahoma	59	215	153	557	727	2651
Oregon	31	114	81	296	391	1427
Pennsylvania	74	270	197	717	1020	3722
Rhode Island	4	14	11	40	70	254
South Carolina	43	159	113	410	538	1964
South Dakota	160	585	402	1466	1708	6230
Tennessee	83	301	215	785	1054	3846
Texas	242	883	635	2316	3178	11593
Utah	10	36	28	100	162	590
Vermont	6	20	14	52	67	246
Virginia	56	203	146	533	734	2678
Washington	68	247	176	641	845	3083
West Virginia	19	68	48	177	240	876
Wisconsin	163	596	413	1506	1809	6598
Wyoming	5	19	14	51	71	259
Total	**5768**	**21039**	**14736**	**53746**	**67346**	**245631**
Average	**115.4**	**420.8**	**294.7**	**1074.9**	**1346.9**	**4912.6**
Maximum	**656**	**2394**	**1644**	**5998**	**6980**	**25459**
Minimum	**4**	**14**	**11**	**40**	**60**	**218**
Std Dev	**137.3**	**500.8**	**345.4**	**1259.6**	**1494.8**	**5452.0**
Relative Std Dev w/rt Avg	**119.0%**	**119.0%**	**117.2%**	**117.2%**	**111.0%**	**111.0%**

Under the defined scenarios, unit energy prices have been calculated for each of the feedstocks under consideration. The unit energy price is the ratio of the total annual operating expense, including financing costs, to the total amount of energy produced under the scenario. Detailed results by feedstock and by state are shown in section *9.0 Analysis Results.* Figure 1 shows, by feedstock, a summary of the distribution of unit prices across the United States under the Aggressive scenario. The 4 biomass sources on the left are TG feedstocks, and the 3 on the right are AD feedstocks. The maximum and minimum values belong to the states having the largest and smallest prices. The solid line shows the range between them. The vertical length of the box shows the range between the median and mean prices calculated over the states. The mean price is generally greater than the median because the distribution of unit prices over the states has a long tail toward higher prices that affects the mean price more than the median one.

For AD systems of production, RG prices by feedstock under the Aggressive scenario span the following ranges:

- For LFG systems, prices for RG range, by state, from $5-9/dekatherm, with a median price of $5.42/dekatherm. At the low end, this is competitive with today's prices for natural gas.
- For livestock manure, prices range from $5-52/dekatherm, with a median price of $7.41/dekatherm.
- For wastewater, prices span from $9-16/dekatherm, with a median price of $12.07/dekatherm.

For TG systems, prices over the feedstocks tend to be higher than in AD systems, due to the higher required investment in the gasification facility. The results for RG prices by feedstock under the Aggressive scenario are the following:

- For wood residues, prices by state ranges from about $10-$24/dekatherm, with a median price for renewable gas of about $12/dekatherm.
- For energy crops, prices are somewhat lower, ranging from about $8-$26/dekatherm, with a median RG price of $9.88/dekatherm.
- For agricultural residues, prices range from $10-$25/dekatherm, with a median price of $10.75/dekatherm.
- For municipal solid waste (MSW), RG prices fall in the range from $13-28/dekatherm, with a median price of $16.17/dekatherm.

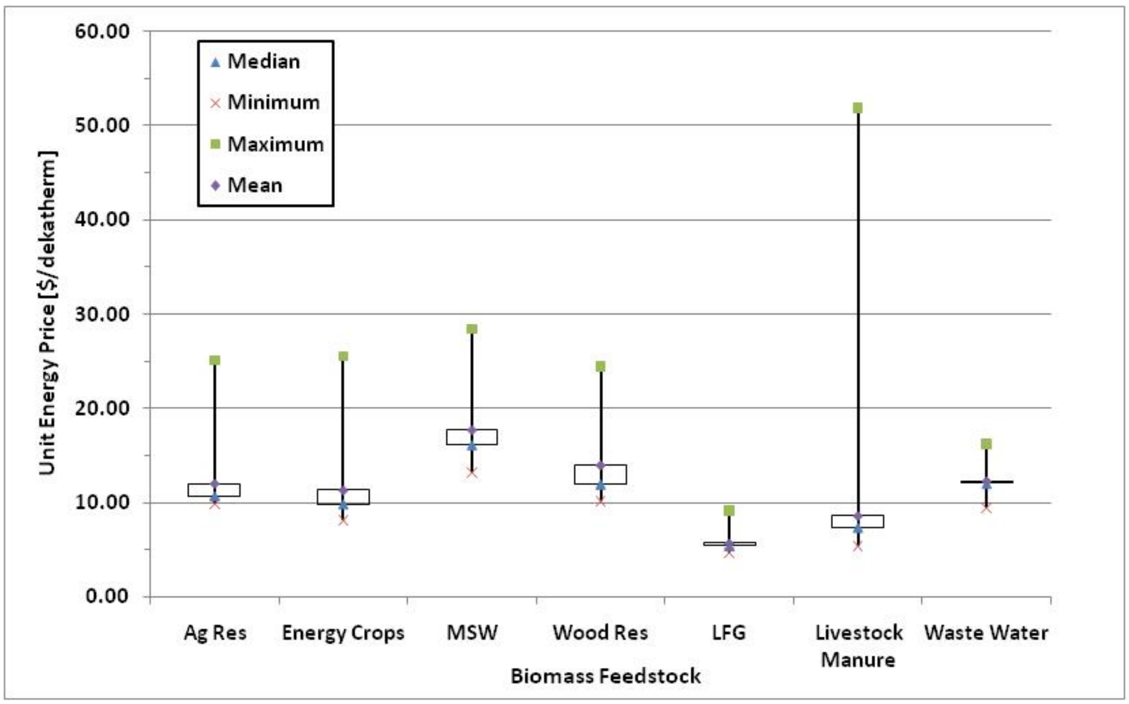

Figure 1: Ranges of Unit Energy Prices by Feedstock, Aggressive Scenario.

For both AD and TG, the computed RG energy prices are higher than current natural gas prices. The 2010 average wellhead price was $4.16/dekatherm, and the 2010 average citygate price was $6.16/dekatherm.[14] RG production prices, as evident in Figure 1, are generally higher than these prices. Bringing RG prices into a competitive range will require research, development, and deployment subsidies. However, compared to other renewable options such as solar or liquids from biomass, these RG prices may be more competitive.

[14] http://www.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm.

Current U.S. policies favor renewable electricity over renewable biogas production for distribution on the natural gas pipeline system. This drives the market to burn renewable gas to produce electricity instead of using it for other thermal and transportation applications of potentially higher value. If policies were encacted to equalize the incentives for producing renewable gas as a direct energy source, an increase in the capture, generation, and use of biogas would likely result.

Additional market and regulatory barriers, which vary[15] by state and region, include:

- Uncertainty in getting credits for using greenhouse gas (GHG) offsets for biogas-to-pipeline-gas projects,
- Prohibition in some locations (like California) of using LGF in natural gas pipelines or distribution systems,
- The lack of tax credits or other incentives, in comparison to other forms of renewable energy.

In particular, the Regional Greenhouse Gas Initiative (RGGI) cap and trade system in operation in ten states in the northeast and mid-Atlantic U.S. does not explicitly include biogas-to-pipeline gas in its criteria for offsets. Even with LFG, only methane "destruction" is included in the RGGI guidelines. Other regulatory challenges to gaining GHG or renewable portfolio standards (RPS) credits include additionality and regulatory surplus (that is, proving the renewable system or GHG reduction would not have taken place without these credits being issued or these regulations being in place), jurisdictional issues (e.g., is the biomass resource within the jurisdiction of the registry group), and offset project eligibility requirements. ***These barriers need to be addressed for biogas-to-pipeline gas to reach its true potential.***

There are some precedents. In terms of approval for RPS credit, the California Energy Commission (CEC) in its 2007 RPS Eligibility Guidebook determined biogas, derived from ***out-of-state*** digester gas, was a RPS eligible renewable energy resource. Also, the CEC indicated the gas distribution company's proposal complied with the CEC's delivery requirements:

- The gas must be injected into a natural gas pipeline system that is either within the Western Area Coordinating Council (WECC) region or interconnected to a natural gas pipeline system in the WECC region that delivers gas into California.
- The gas must be used at a facility that has been certified as RPS-eligible. As part of the application for certification, the applicant must attest that the RPS-eligible gas will be nominated to that facility or nominated to the load serving entity-owned pipeline serving the designated facility.
- When applying for RPS pre-certification, certification, or renewal, the application must include the following: 1) an attestation from the multi-fuel facility operator of its intent to procure biogas fuel that meets RPS eligibility criteria, and 2) an attestation from the fuel supplier that the fuel meets eligibility requirements.

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[15] The registry groups and protocols examined include the Regional Greenhouse Gas Initiative (RGGI), the Chicago Climate Exchange the Midwest Greenhouse Gas Accord, the Clean Development Mechanism the Western Climate Initiative, the U.S. EPA's Climate Leaders Program, and the Climate Action Reserve.

3.0 Statement of Work

Objectives

The overall objective of this work is to provide an estimate of the total potential impact that renewable energy resources could have. The impact will be estimated in terms of:

- The potential production of energy (in the form of renewable gas).
- The capital investment required.
- The on-going operating costs.
- The reduction of atmospheric CO_2 and potential CO_2/carbon credits.
- Regulatory issues to be confronted.

The specific objectives are to:

- Provide a listing, by state, of the types and potential quantities of renewable energy sources,
- Provide an estimate, by state, of the energy content of the potential renewable energy resources,
- Provide an estimate, by state, of the range of RG production by conversion technologies, specifically anaerobic digestion and thermal gasification,
- Provide an estimate, by state, of the capital expenses (capex) and operating expenses (opex) required to develop the infrastructure for the production of RG from the potential energy resources,
- Provide a factor to be used to calculate the potential impact of CO_2 trading, depending upon the cap-and-trade or other carbon reduction schemes,
- Provide an assessment of the technical, market, and regulatory barriers associated with RG development and operations.

Achieving these objectives required GTI to examine the renewable energy resources currently available across the U.S., along with their potential energy yields. The feedstocks that may populate the matrix of source materials includes food wastes, wastes from livestock operations and animal/poultry processing (dairy, swine, and chicken wastes), municipal sewage sludges, municipal solid wastes, landfills, on-purpose energy crops, forest and other wood wastes, and paper-making process wastes (trees, grasses, bark), mixed wastes, agricultural residues, and other industrial process wastes. Dedicated food crops will not be considered, given the recent negative ethanol/corn experience.

In addition to examining existing data on potential renewable resources, two general conversion processes will be examined: TG and AD.

In the area of thermo-chemical conversion technology, options include thermal gasification (fixed bed, updraft, downdraft), fluidized bed (atmospheric, pressurized), multi-stage, indirect gasification (including steam reforming), hydrogasification, catalytic gasification, and supercritical water gasification.

In the area of AD, process options include anaerobic lagoons, plug-flow digesters, completely mixed digesters (the 3 most common in current operation in the U.S.), landfills, and other suitable AD processes. In the investigation of conversion processes, both TG and AD will include consideration of feedstock gathering and preparation, reactor subsystems, gas cleanup requirements, methane production, and inter-changeability with pipeline-quality natural gas.

Utilizing suitable information on renewable energy resources and on appropriate technologies, GTI conducted an economic assessment of the production of pipeline-quality RG. The economic assessment is based on general capital and operating cost parameters found in the open literature and on previous work that it has performed in this area. GTI also made estimates of the job creation potential based on the renewable energy production potential. Known models for gas production, cleanup, capital expenses, and operating expenses were used in preparing the assessments and estimates.

Another major component of this work was the examination of the regulatory, market, and technical environment for renewable energy. Any move toward a portfolio that includes energy, both renewable and GHG-mitigating, required an understanding of how such benefits are valued under existing and proposed cap-and-trade scenarios such as the RGGI, a cooperative effort to limit GHG emissions by ten Northeastern and Mid-Atlantic states. GTI determined to what extent RG contributed to offsets within a given carbon trading scheme, which types of biomass/renewable energy sources were eligible for inclusion, what forms of energy are included, what modes of energy production are allowable, and how carbon offsets are allocated. In the absence of a specific regional trading scheme, GTI examined current trading schemes such as the Chicago Climate Exchange (CCX), RGGI, and others appropriate schemes. In examining the technical information and processing it through an economic model, GTI identified barriers to producing pipeline-quality RG via AD or TG.

4.0 Approach

GTI divided the assessment of biogas production from renewable resources into 2 sectors of technology: anaerobic digestion (AD) and thermal gasification (TG). In each of these sectors, a set of feedstocks were selected based on previous experience with those that are likely to have the largest impact. The assessment of impact in each sector contains 4 major components: annual resource availability, annual energy production from those resources, greenhouse gas reduction potential, and economic impact. The economic impact itself consists of capex requirements to begin production, opex requirements for ongoing operation, job creation expectations, and an estimate for the unit price of produced energy, based on the assumptions of the model.

In discussions with AGF, 3 scenarios for development were selected for examination. These are termed Non-aggressive, Aggressive, and Maximum. The objective of the Non-aggressive and Aggressive scenarios is to examine the production of energy in the form of renewable gas and under different levels of feedstock utilization or market penetration. The Non-aggressive scenario represents a low level of feedstock utilization. Utilization levels depend on feedstock and range from 15%-25% in the AD sector.

In the TG sector, they range from 5%-10%. The Aggressive scenario has higher levels of utilization which range from 40%-75% in the AD sector and 15%-25% in the TG sector. Within the assumptions of the model, the third scenario, the Maximum scenario, is intended to set an absolute upper bound on availabilities and energy production potential. Such a scenario is not realistically attainable; rather, it sets an upper boundary for expectations. A more detailed discussion of these utilization factors and of the assessment model is contained in *12.0 Appendix: Utilization Scenarios*.

Table 38 contains the utilization, conversion, and efficiency data employed.

Sections *6.0 Anaerobic Digestion Feedstocks* and *8.0 Thermal Gasification Feedstocks* contain details of the feedstocks chosen and the criteria by which selection of the data occurred. For the AD feedstocks, major assumptions within this study include:

- Animal Waste
  - Animal populations considered by state: dairy cows, beef cattle, hogs and pigs, sheep, broiler chickens, turkeys, and horses.
  - Global, weighted-average, specific CH_4 yield: 766.3 CF CH_4/wet-ton. (Within each state, however, a state-dependent, weighted-average specific CH_4 is calculated and used).
  - Energy density of methane: 1000 Btu/CF.

- Wastewater
  - Initial database of 436 wastewater facilities of capacity 5 MGD or greater.
  - Facilities accepted for biogas production with 17 MGD or greater capacity.
  - Specific energy yield: 7.9 dekatherm/MG
  - Energy density of methane: 1,000 Btu/CF

- Landfills
  - Landfill gas composition: 60% CH_4
  - 2,402 landfills in initial database.
  - Accepted landfills include those that are EPA-designated as *operational, potential, candidate, construction,* or *shutdown*, if the closure occurred in year 2000 or later.
  - Accepted landfills categorized as *small* or *large* and *arid* or *non-arid.* Landfill gas production depends on the categorization.

- Energy density of methane: 1,000 Btu/CF

For the TG feedstocks, the major assumptions include:

- Municipal Solid Waste
  - Only MSW considered that is currently directed to landfills.
  - Does not include MSW usually directed to energy projects.
  - Does not consider potential volume reduction via recycling.
  - Specific energy yield: 8.4 dekatherms/wet-ton

- Wood Residue
  - Resources include: forest residues, mill residues, urban wood residues
  - Specific energy yield: 11.2 dekatherms/wet-ton

- Energy Crops
  - Switch grass, willow, hybrid poplar considered.
  - Specific energy yield: 13.8 dekatherms/wet-ton.

- Agricultural Residues
  - Corn, wheat, soybeans, cotton, sorghum, barley, oats, rice, rye canola, beans, peas, peanuts, potatoes, safflower, sunflower, sugarcane, flaxseed are the agricultural products whose residues are considered.
  - Specific energy yield: 11.2 dekatherms/wet-ton.

Section *13.0 Appendix: Economic Inputs* contains important information on inputs to the economic calculations and to the CO_2 abatement calculations:

- Range of job creation factors:
  - Low: 9.13×10^{-6} jobs/dekatherm/yr
  - High: 33.3×10^{-6} jobs/dekatherm/yr
  - CO_2 abatement: 117 lbs CO_2/dekatherm of natural (primarily CH_4) combusted.
  - Financing and capital investment assumptions:
    - Debt-equity ratio: 50:50
    - Annual interest rate: 7%/yr
    - Loan term: 20 years
    - Return on equity: 10%/yr

5.0 Anaerobic Digestion Production Process Overview

The material in this section provides a *general and rudimentary* description of the processes involved in AD. Much technical literature has been written previously in conferences proceedings and text books, and the subject is still a topic of research today. The material is meant to convey background and context for the discussion of the model that is considered for evaluating energy production and economic factors.

Idiosyncrasies of source material, processing, and gas upgrading certainly exist for each feedstock which is considered. The processes applied in practice to each source feedstock reflect those details. However, the discussion below is kept rather general, those particulars are touched upon lightly, and they are incorporated to the degree that they impact the application of the model discussed in the section *4.0 Approach* and in section *12.0 Appendix: Utilization Scenarios*.

Anaerobic Digestion (AD)

AD is the process of degrading organic material through microbial action in an environment devoid of oxygen. The degradation process usually occurs in some form of tank, called a digester or reactor. Organic matter, perhaps first pretreated by grinding or by mechanical or chemical hydrolysis, enters the tank and is held there for a predefined, target duration. For systems that are animal manure-based, this duration ranges from a few days to a few weeks. For systems that are energy crop based, this residence time can range up to several tens?? of days. During that period, microbial activity breaks down the organic matter, and the resultant gaseous products contain a large fraction of methane and carbon dioxide along with trace amounts of other gases. Eventually, the material fed to the digester will be expelled from the digester to be replaced by newly entering feed matter to continue the digestion/degradation process. The new organic matter may replace the entirety of the resident matter in batch, or it may replace it semi-continuously; how this occurs depends on the reactor and on the collection and processing of the input source matter.

In the AD process, complex organic matter (source material) is broken down into simpler constituents, directly through the action of microorganisms and in the absence of oxygen. Figure 2 shows a typical process schematic for anaerobic digestion (Poulsen, 2003).[16] The AD process proceeds in 4 stages or sub processes. In the initial stage – hydrolysis – bacteria liquefy and break down organic matter comprised of complex organic polymers and cell structures. The end products of this first stage are organic molecules that consist primarily of sugars, amino acids, peptides, and fatty acids. The second stage of the AD process is acidogenesis. In this stage, acid-forming bacteria break down the products yielded from the hydrolytic stage. The resultant compounds formed primarily include volatile organic acids, CO_2, hydrogen, and ammonia. The penultimate step is acetogenesis. In this step, bacteria convert the volatile organic acids from the previous step into acetic acid (CH_3COOH) and acetate, CO_2, and hydrogen. In the final stage of the AD process, methanogenic (methane producing) bacteria transform the end results of the acidogenic and acetogenic stages, i.e. CO_2 and acetic acid, into methane (CH_4). The resultant gas yield consists primarily of CH_4, CO_2, and other trace gases such as hydrogen sulfide (H_2S).

[16] *This schematic is a simplified version of the original contained in the (Poulsen, 2003) reference. It has been slightly modified according to the discussion in the (Marty, 1986) reference.*

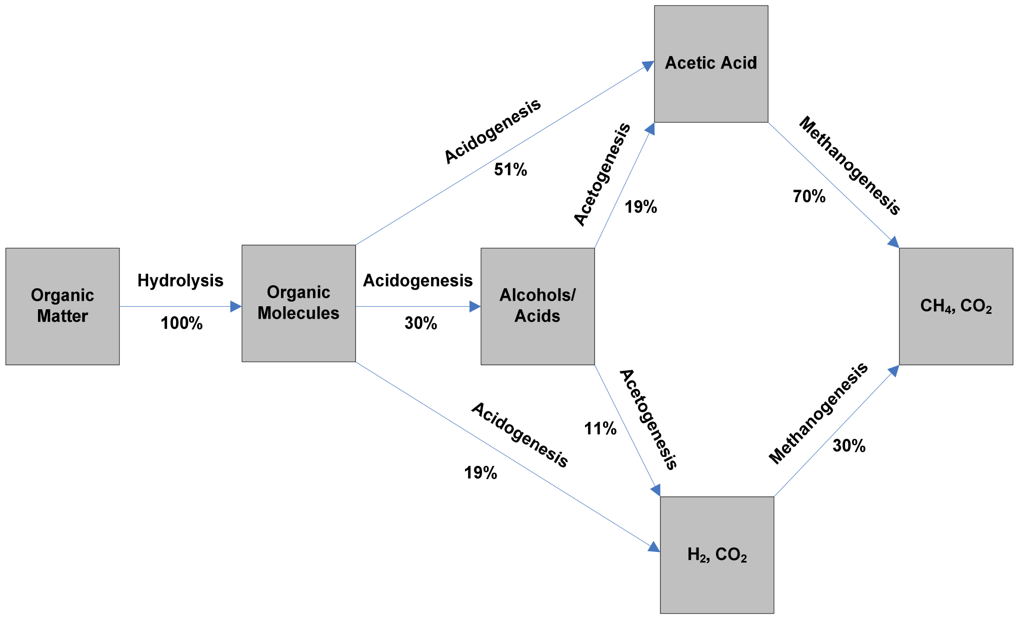

Figure 2: Process Schematic of Anaerobic Digestion

AD Raw Biogas Composition

The composition of raw biogas can vary depending on the materials being digested. Landfill biogas, for example, can contain significant amounts of H_2S as well as trace amounts of ammonia, mercury, chlorine, fluorine, siloxanes, and volatile metallic compounds (United Kingdom, 2002; Basic Information, 2008).

However, the composition of biogas generated from dairy manure tends to be more consistent since the dairy industry is regulated as a producer of milk for human consumption. Typical compounds and their reported concentration ranges are shown in Table 6. Methane concentration is shown as high as 74% but is generally reported as being around 60%. The values in Table 6 are typical for digester-based biogas. Landfill gas, unless the landfill is specifically designed for gas production, will have a typical methane fraction that is a bit lower, perhaps in the range of 55%. The addition of food wastes into a manure-based digester, so-called co-digestion, seems to improve biogas production and may increase methane concentration, but consideration of such co-digestion processes is beyond the scope of this work. CO_2, the other major biogas component, is often measured around 40%. Nitrogen, hydrogen, oxygen, and H_2S are found in smaller quantities. H_2S measured from gas samples taken at five dairy farms in New York State are reported to range from 600 ppm to more than 7000 ppm. Addition of other organic material into the digester, environmental aspects, and sulfur concentration in the water supply are thought to account for these variations (Scott, 2006).

AD Gas Cleanup

Natural gas produced from traditional wells requires processing in order to be suitable for injection into natural gas pipeline and transport to end users. Some processing, oil and condensate removal, can take place at the well head but gas is typically piped through low pressure gathering lines to a processing facility for removal of natural gas liquids (NGLs), hydrogen sulfide, and carbon dioxide down to pipeline specifications. Most NGLs are removed by absorption or cryogenic expansion. Amine processes account for more than 95% of U.S. hydrogen sulfide removal operations (Processing, 2004).

Similarly to natural gas, biogas derived from biomass feedstocks also needs to undergo one or more cleanup processes to remove unwanted components and to upgrade it suitably for natural gas pipelines. Some level of quality control needs to be in effect to prevent or minimize the entry of raw, unconditioned biogas, or less than pipeline quality biomethane, from entering the natural gas grid.

There are many methods and processes that can be used to remove contaminants from sub-quality gas streams. Saber & Takach (2008) reported an in depth, color-coded organizational chart of processes to remove hydrogen sulfide and/or carbon dioxide and water from sub-quality gas, included in that reference are named examples of products and processes. Some are well established; others are not as developed. Some are appropriate for use on farms, and others are only economical at gas flows measured in millions of standard cubic feet per day (MMSCFD) and where sulfur removal rates are measured in tons per day. The ability of a process to remove unwanted compounds is highly dependent on a number of factors and assessment of the true practicality of a method for a given application requires careful evaluation. Such a detailed analysis of a cleanup process is application dependent and is beyond the scope of this study.

Table 9: Typical Compounds and Concentrations Found in Biogas Derived from Anaerobic Digestion (Saber & Takach, 2008; VITA, 1980)

Compound	Typical Concentration Range, mol %
Methane, CH_4	54-70%
Carbon dioxide, CO_2	27-45%
Nitrogen, N_2	0.5-3%
Hydrogen, H_2	1-10%
Carbon monoxide, CO	0-0.1%
Oxygen, O_2	0-0.1%
Hydrogen sulfide, H_2S	600-7000+ ppm (Scott, 2006)
Trace elements, amines, sulfur compounds, non-methane volatile organic carbons (NMVOC), and halocarbons. (Scott, 2006)	

6.0 Anaerobic Digestion Feedstocks

Feedstocks suitable for AD include municipal wastewater and animal manure. LFG is a by-product of the AD of putrescible matter in a landfill. AD technology is generally applicable to waste streams that have high volatile solids and water contents.

Animal Waste Feedstocks

Types, Amounts and Availability of Animal Wastes

Large-scale, animal farm operations have a lot in common with industrial processing. Many significant sub-processes have to be addressed in maintaining an animal herd.[17] Among them are feeding, animal housing, medical care, breeding, and manure management. The quality and contents of the manure have an influence on the capacity for producing biomethane. Operational practices in the farm industry can impact both of these items. How the herd is housed and bedded, what the animals are fed, what contaminants enter the manure, and how the management of that manure is executed are all practices potentially affecting the manure itself and subsequently may influence the biogas produced from it.

In this assessment, manure from a variety of animal populations is considered. On a state-by-state basis, annual livestock manure amounts are determined from the manure production of the following animals: dairy cows, beef cattle, hogs and pigs, sheep, broiler chickens, turkeys, and horses. Animal population data are based on state inventories that generally span the years 2006-2009; for each animal, the most recent population data readily available in the references was selected (Agricultural Statistics Annual, 2009). For horses, the most recent data acquired was based on population inventories in 1999 (Equine, 2010).

Potential Impact of Resource

The annual availability of manure for each state is determined within each of the scenarios considered. For each animal, its specific manure production rate [lbs-manure/lbs-animal-day] was multiplied by the number of full-time-equivalent (FTE)[18] animal days per annum and by the typical weight of each animal. The resultant manure weight from each animal species is thus derived. In order to provide a convenient way to summarize the manure availability within an individual state, the total amount of manure produced by all animals is summed.

To deduce methane production in a given state, the total manure availability is multiplied by a weighted average specific methane production yield. Since each animal's manure has a different specific biogas yield, a single, weighted-average, specific yield is derived for each state to summarize energy production. Although the same set of animals is considered for each state, the distribution of animal populations differs from state to state, and, thus, so does the weighted-average specific yield. Over all the states, the global average of specific yields is 766.3 CF CH_4/wet-ton with a population standard deviation of 210.2 CF CH_4/wet-ton. Energy production for each state derives from the total methane production in each state multiplied by the energy density of methane, 1000 Btu/CF.

[17] The term herd is used loosely to mean a collection of animals, of whatever kind. Usually herd refers to a group of cows, cattle, sheep, or other, large, four-legged animals. Within this section, herd may additionally refer to a collection of chickens, turkeys, or other animals under consideration within this project as contributors of livestock manure.
[18] Not all animals remain alive to produce manure for an entire year, hence, the need to specify the number of FTE animals to calculate the annual manure production.

For livestock manure, two separate AD capex components are estimated. The first component covers the costs of the digester to produce raw biogas. The second component of AD capex is the cost for a cleanup facility to transform the raw biogas into renewable gas. Because the capex is broken into these pieces, AD opex is also comprised of 3 components: (a) the annual expense to operate a digester facility, (b) the annual expense to operate a cleanup facility, and (c) the financing payments. Details of the capex, opex, and financing payments for the digester facility are described more fully in *13.0 Appendix: Economic* .

Wastewater Treatment Plants

Types, Amounts, and Availability of Wastewater

Wastewater is created from residences and commercial or industrial facilities. It consists primarily of waste liquids and solids from household water usage, from commercial water usage, or from industrial processes. Depending on the architecture of the sewer system and local regulation, it may also contain storm water from roofs, streets, or other runoff areas. The contents of the wastewater may include anything which is expelled (legally or not) from a household and enters the drains. If storm water is included in the wastewater sewer flow, it may also contain components collected during runoff: soil, metals, organic compounds, animal waste, oils, solid debris such as leaves and branches, etc.

Processing of the influent to a large wastewater treatment plant (WWTP) is comprised typically of 3 stages: primary, secondary, and tertiary treatments. These stages consist of mechanical, biological, and sometimes chemical processing. The goal of such treatments is to prepare solids (treated sludge) and liquids (treated effluent) output from the WWTP that is environmentally safe and capable of being landfilled (treated solids) or returned to the environment (treated effluent). One step in the processing of the wastewater sludge may be anaerobic digestion, from which methane can be produced (Wastewater Treatment, 2006).

The reference (Opportunities, 2007) contains a list, by state, of 436 WWTPs that have influent rates above 5 million gallons/day MGD. This set was used to calculate the total available amount of wastewater in each state. In performing this calculation, a cut is made on WWTPs that have influent rates more than 17 MGD, which is the threshold above which energy projects become viable (Takach, 2010). Several states have zero inventory of WWTPs (Opportunities, 2007), and several additional states do not have WWTPs which pass the cut at 17 MGD. Hence, as a result of the content of the original data and of the cuts applied to it, some states show zero availability and consequently zero energy production from wastewater.

Potential Impact of Resource

The energy production from wastewater is calculated based on the annual availability of wastewater [million gals/year, MGY], with efficiency factors appropriate to the scenario under consideration, times the specific methane yield of wastewater [CF CH_4/million gals, CF/MG] times the energy density of methane, 1000 Btu/CF. Wastewater is similar to the case for livestock manure. A digester facility and a cleanup facility are required. Therefore, capex and opex for both facilities are estimated, along with the financing payments. Details of the capex, opex, and financing payments for the digester facility are described more fully in *13.0 Appendix: Economic Inputs*

Landfill Gas

Types, Amounts, and Availability of Landfills

Collecting and managing solid waste in a land area has a long history. Roman signposts have been found that advised: *Take your refuse farther or you will be fined* (American Public Works Association, 1970). In the U.S., the primary federal law currently controlling the disposal of solid and hazardous waste in the U.S. is the Resource Conservation and Recovery Act (RCRA, 1976). RCRA sets criteria under which landfills can accept municipal solid waste and nonhazardous industrial solid waste. Additionally, RCRA prohibits open dumping of waste and hazardous waste is managed from the time of its creation to the time of its disposal (USEPA, 2009).

For the production of energy, MSW can be utilized in either of two ways: it can be gasified directly through thermo-chemical processes (TG --- see the discussion in the section *7.0 Thermal Gasification Production Process Overview*), or it can be deposited into a landfill and undergo AD. Although most surveys (by the U.S. EPA, for example) indicate the material composition of all landfill constituents, the important components of MSW for the production of landfill gas are the organic fractions. They form the substrates undergoing decomposition within the landfill through the anaerobic processes. Typical or approximate contents of the organic fractions of MSW appear in Table 10.

Table 10: Components of the Organic Portion of Municipal Solid Waste (Cheremisinoff, et al., 1976)

Component	Composition wt %
Moisture	20.7
Cellulose, sugar, starch	46.6
Lipids	4.5
Protein	2.1
Other organics	1.2
Inert materials	24.9
Total	**100.0**

The production of landfill gas is the result of these anaerobic processes acting on the organic matter within a landfill. In a sense, the landfill itself serves as a substitute for an anaerobic digester tank – a closed volume, which contains putrescible matter and which becomes, after a time, devoid of oxygen. As described more generally in section *5.0 Anaerobic Digestion Production Process Overview*. Methane and carbon dioxide are the principal components of the resultant gas. The overall composition of raw LFG can vary depending on the materials residing within the landfill. Landfill biogas can, for example, contain significant amounts of hydrogen sulfide as well as trace amounts of ammonia, mercury, chlorine, fluorine, siloxanes, and volatile metallic compounds (United Kingdom Environment Agency, 2002), (Association, 2008). Typical compounds and their reported concentration ranges are shown in Table 11.[19] Methane concentration is generally reported as being around 55 mol %. Carbon dioxide is often measured at 40%. Nitrogen, hydrogen, oxygen, and hydrogen sulfide are found in smaller but significant quantities. Variation in source MSW, its organic contents, temperature conditions, moisture conditions, compaction densities, landfill operational procedures, and other landfill attributes account for the variation in LFG content.

[19] *See reference (Bagchi, 1994), which contains a slightly different list of fractional LFG content.*

Table 11: Landfill Gas Composition (Tchobanoglous, et al., 1993)

Compound	Concentration, mol %
Methane, CH_4	45 – 60
Carbon Dioxide, CO_2	40 – 60
Nitrogen, N_2	2 – 5
Hydrogen, H_2	0 – 0.2
Carbon Monoxide, CO	0 – 0.2
Oxygen, O_2	0.1 – 1
Sulfides, disulfides, mercaptans, etc.	0 – 1
Ammonia, NH_3	0.1 – 1
Trace elements, amines, sulfur compounds, non-methane volatile organic carbons halocarbons	0.01-0.6%

Landfill gas production is based on the amount of waste-in-place at a set of selected landfills. The selected set derives from an EPA database of 2402 unique landfills from across the country (Energy Projects, 2010). The landfills are categorized within the database as *candidate, potential, shutdown, construction,* or *operational*. *Candidate* landfills have been identified as promising for a waste-to-energy (W2E) project. *Potential* landfills are those for which data is missing but have the possibility of being good for a W2E project, if further data can be obtained to verify their suitability. Landfills designated *Construction* have a W2E project under construction. *Shutdown* landfills are those which are no longer receiving input waste. *Operational* landfills are, of course, still actively receiving MSW.

From the original EPA database, landfills were selected that fulfill the criteria in Table 12. Thus, if the landfill is identified as *operational*, *potential*, *construction,* or *candidate* and if it has nonzero waste-in-place, it is selected. If the landfill is identified as *shutdown* for less than 10 years and with nonzero waste-in-place, it is also selected. Twenty years is a typical lifetime for useful W2E gas production from a closed landfill. Having half of that lifetime remaining seems a reasonable criterion for incorporating a given landfill into the final data set for consideration of energy production.

Table 12: Selection Criteria for Landfills for Energy Production

Project Status	Waste-in-Place	Landfill Closure Year
Operational	> 0	--
Potential	> 0	--
Candidate	> 0	--
Construction	> 0	--
Shutdown	> 0	≥ 2000

Potential Impact of Resource

Gas production and energy production from landfills is determined on a state-by-state basis. The calculated rate of production of landfill gas depends on the size of the landfill --- the waste-in-place (WIP) --- and also on whether the state in which the landfill is located is categorized as *arid* or as *non-arid*. Table 13 contains a list of specified conditions and their associated rate production formulas (Geographic Perspective, 2005; State Workbook, 1995). From the CH_4 production rates, the biogas production rates are determined based on a 60% volume fraction of CH_4 within raw biogas. This is the common value chosen for the methane fraction for biogas derived via anaerobic digestion.

Table 13: Calculation of Landfill Gas Production Rates as a Function of Waste-in-Place, Landfill Size, and Climate Classification

Landfill Size	State Climate Designation	Rate of CH_4 Production [CF CH_4/day]
Small (< 1.1 x 10^6 tons WIP)	Arid	0.27*WIP
	Non-arid	0.35*WIP
Large (≥ 1.1 x 10^6 tons WIP)	Arid	0.16*WIP+419023
	Non-arid	0.26*WIP+419023

For the case of landfill gas, capex and opex are based solely on the necessity of a cleanup facility for conditioning the landfill gas to renewable. A digester is not required since the landfill itself functions as the digester to process the contained biomass into biogas. The capex and opex for the cleanup facility are calculated based on the discussion in *13.0 Appendix*: *Economic*

AD Feedstock Availabilities

Based on the discussion and selection of data described in section *6.0 Anaerobic Digestion Feedstocks*, Table 14 and Table 15 contain the annual availabilities, by state, for each of the 3 AD feedstocks under consideration in this study. Table 14 contains the availabilities under the Non-aggressive scenario, and Table 15 contains those for the Aggressive scenario. At the bottom of each table are a set of summary statistics of the distributions of the availabilities over the 50 states. The relative standard deviation is the ratio (in percent) of the standard deviation and the average value. It gives a measure of the relative spread in the distribution of available resources for each feedstock.

Table 14: Annual Availabilities of AD Feedstocks in the Non-aggressive Scenario

State	Landfill Gas [millions wet tons/yr]	Livestock Manure [millions wet tons/yr]	Wastewater [thousands MGY]
Alabama	22.6	3.4	4.8
Alaska	1.9	0.0	0.0
Arizona	22.1	2.4	12.6
Arkansas	7.3	4.4	0.0
California	451.5	14.2	37.0
Colorado	27.1	4.9	2.7
Connecticut	5.8	0.2	0.0
Delaware	9.4	0.3	5.9
Florida	61.5	3.4	7.3
Georgia	36.6	3.7	19.1
Hawaii	4.1	0.3	8.4
Idaho	1.0	5.1	0.0
Illinois	92.9	3.8	93.6
Indiana	66.0	3.4	27.2
Iowa	12.8	14.2	5.8
Kansas	19.0	10.9	5.2
Kentucky	20.0	4.5	8.1
Louisiana	20.1	1.6	1.4
Maine	2.4	0.3	0.0
Maryland	18.4	0.8	1.5
Massachusetts	16.6	0.2	30.8
Michigan	61.3	3.3	64.9
Minnesota	10.9	8.1	0.0
Mississippi	14.8	2.7	0.0
Missouri	43.2	8.3	16.5

State	Landfill Gas [millions wet tons/yr]	Livestock Manure [millions wet tons/yr]	Wastewater [thousands MGY]
Montana	3.1	4.4	0.0
Nebraska	6.9	11.4	1.7
Nevada	16.3	0.9	5.1
New Hampshire	8.0	0.1	0.0
New Jersey	56.2	0.2	36.2
New Mexico	3.7	3.5	3.9
New York	126.7	4.3	38.1
North Carolina	34.6	5.9	6.0
North Dakota	1.0	2.9	0.0
Ohio	90.9	4.0	34.2
Oklahoma	11.3	9.9	3.0
Oregon	12.5	2.5	1.7
Pennsylvania	131.8	5.0	18.1
Rhode Island	9.4	0.0	1.9
South Carolina	29.1	1.1	3.7
South Dakota	2.9	6.6	0.0
Tennessee	33.5	3.8	13.0
Texas	114.9	24.5	44.1
Utah	8.6	1.9	0.0
Vermont	5.5	0.9	0.0
Virginia	60.5	3.2	17.9
Washington	37.5	2.7	5.8
West Virginia	4.5	0.8	0.0
Wisconsin	38.9	9.3	7.3
Wyoming	1.5	2.3	0.0
Total	**1899.4**	**216.3**	**594.4**
Average	**38.0**	**4.3**	**11.9**
Maximum	**451.5**	**24.5**	**93.6**
Minimum	**1.0**	**0.0**	**0.0**
Std Dev	**67.6**	**4.6**	**18.4**
Relative Std Dev w/rt Avg	**177.9%**	**105.5%**	**155.0%**

Table 15: Annual Availabilities of AD Feedstocks in the Aggressive Scenario

State	Landfills [millions wet tons/yr]	Livestock Manure [millions wet tons/yr]	Wastewater [thousands MGY]
Alabama	45.3	11.2	14.5
Alaska	3.9	0.1	0.0
Arizona	44.3	8.0	37.9
Arkansas	14.6	14.7	0.0
California	903.0	47.4	110.9
Colorado	54.2	16.5	8.1
Connecticut	11.5	0.6	0.0
Delaware	18.8	1.1	17.6
Florida	123.0	11.2	21.9
Georgia	73.2	12.4	57.2
Hawaii	8.2	0.8	25.2
Idaho	2.0	17.2	0.0
Illinois	185.7	12.8	280.9
Indiana	132.0	11.4	81.7

State	Landfills [millions wet tons/yr]	Livestock Manure [millions wet tons/yr]	Wastewater [thousands MGY]
Iowa	25.6	47.3	17.5
Kansas	38.0	36.4	15.7
Kentucky	40.0	15.0	24.2
Louisiana	40.2	5.2	4.2
Maine	4.7	1.0	0.0
Maryland	36.8	2.8	4.4
Massachusetts	33.3	0.5	92.4
Michigan	122.6	11.0	194.8
Minnesota	21.7	27.0	0.0
Mississippi	29.6	8.9	0.0
Missouri	86.4	27.6	49.4
Montana	6.2	14.5	0.0
Nebraska	13.8	38.0	5.0
Nevada	32.7	2.9	15.3
New Hampshire	16.0	0.4	0.0
New Jersey	112.4	0.5	108.7
New Mexico	7.3	11.6	11.8
New York	253.3	14.2	114.4
North Carolina	69.2	19.8	17.9
North Dakota	2.1	9.7	0.0
Ohio	181.8	13.2	102.5
Oklahoma	22.7	33.0	8.9
Oregon	25.0	8.2	5.0
Pennsylvania	263.7	16.8	54.3
Rhode Island	18.8	0.0	5.8
South Carolina	58.2	3.7	11.0
South Dakota	5.8	22.2	0.0
Tennessee	67.0	12.6	39.1
Texas	229.9	81.5	132.4
Utah	17.3	6.4	0.0
Vermont	10.9	2.9	0.0
Virginia	121.0	10.6	53.7
Washington	75.1	8.8	17.3
West Virginia	8.9	2.8	0.0
Wisconsin	77.8	31.0	21.9
Wyoming	3.1	7.6	0.0
Total	**3798.8**	**721.2**	**1783.2**
Average	**76.0**	**14.4**	**35.7**
Maximum	**903.0**	**81.5**	**280.9**
Minimum	**2.0**	**0.0**	**0.0**
Std Dev	**135.2**	**15.2**	**55.3**
Relative Std Dev w/rt Avg	**177.9%**	**105.5%**	**155.0%**

7.0 Thermal Gasification Production Process Overview

As with discussion in the section *6.0 Anaerobic Digestion Feedstocks*, the material in this section also provides a *general and introductory* description of the processes in TG. TG is still a topic of research today. The intention is merely to communicate context for the discussion of the assessment and evaluation of energy production and economic factors.

Particulars of source material, pre-processing, and gas conditioning exist for each TG feedstock is considered. The processes applied in practice to each source feedstock would reflect those details. However, the discussion below is general, particular details are touched upon lightly, and they are incorporated to the degree that they impact the application of the model that is discussed in the section *4.0 Approach* and in the section *12.0 Appendix: Utilization Scenarios*.

Thermal Gasification (TG)

TG encompasses a fairly broad range of processes and reactions that convert carbonaceous feedstocks (coal, heavy oils, wood, biomass, sludge, etc.) into a mixture of gases, primarily hydrogen, carbon monoxide, steam, carbon dioxide, some methane, small amounts of ethane as well as higher hydrocarbons, small amounts of hydrogen sulfide, and nitrogen (if gasification is conducted with air). TG of biomass typically generates tars and oils that are undesirable by-products (depending upon the feedstock and operating conditions).

Thermal gasification is conducted in reducing (sub-stoichiometric or incompletely combusting) atmospheres. A portion of the process heat is typically provided by burning some of the carbon in the feedstock to generate heat for the endothermic gasification reactions. Process heating can be direct or indirect. Indirect heating of the gasifier is referred to as all thermal gasification. A typical range of syngas compositions from oxygen- or air-blown modes of operation is presented in Table 16.

This mixture of gases is known as synthesis gas or "syngas." For the purposes of this report, the syngas can be further catalytically converted into methane to generate RG. The syngas can also be converted into liquid products by Fischer-Tropsch synthesis for use as transportation fuel. The syngas can be transformed into a host of chemical products, among them are methanol, dimethyl ether, fuel gas/town gas, ethylene/propylene, acetic acid, liquids, and others. The syngas can also be combusted directly in a gas turbine to drive a generator for producing electric power. In some cases, a catalyst is included with the feedstock to accelerate the reactions and enable the reduction of operating temperature.

Table 16: Typical Compounds and Concentrations Found in Syngas from Thermal Gasification of Biomass (Hofbauer, 2007)

Compound	Typical Range		
	Air Blown Fixed Bed	Steam-Blown Fluidized Bed	Oxygen-Blown Entrained Flow
Calorific Value [Btu/ft^3]	107 – 161	322 – 376	268 – 322
Hydrogen, H_2 [mol%]	11 – 16	35 – 45	23 – 28
Carbon Monoxide, CO [mol%]	13 – 18	22 – 25	45 – 55
Carbon Dioxide, CO_2 [mol%]	12 – 16	20 – 23	10 – 15
Methane, CH_4 [mol%]	2 – 6	9 – 11	< 1
Nitrogen, N_2 [mol%]	45 – 60	< 1	< 5

TG can be carried out at temperatures in the range of 1200° to 2000°F and at pressures ranging from ambient to greater than 1000 psig. If the TG process is conducted at ambient or fairly low pressure, then the product RG must be compressed so it can then be injected into the transmission or distribution line at the appropriate pressure.
Many different types of TG technologies have been developed over the years. Among them are fixed bed (batch pyrolysis), moving bed (Lurgi type, upflow, downflow), fluidized bed gasification (GTI U-Gas®), fast-fluidized bed, and entrained flow gasifiers.

The nitrogen content of the syngas depends on the process employed in its production. If air is used in the gasification reactions, then nitrogen will be present in the syngas. If oxygen alone is used for the gasification reactions, the syngas will have very little nitrogen. In general, whatever process option is selected, the goal is to avoid high nitrogen in the resultant syngas, as nitrogen is difficult to remove.

The TG technology assumptions for the project include a generic gasification system. Neither fixed bed, fluidized bed, nor entrained flow gasifiers are specified. Unlike AD conversion, a processing stage identified as "cleanup" is not explicitly modeled in the TG process. Gas conditioning is subsumed within TG gasification system rather than being a system considered separately. TG conversion efficiencies for biomass feedstocks are typically reported in the range of 60% to 70%, depending upon the configuration and process conditions.

It is assumed the thermal conversion efficiency of any feedstock passing through the TG plant boundary limit is 65%; 65% of the net calorific value of the biomass entering the TG processing plant is converted to the equivalent renewable gas. The RG is assumed to have a calorific value of 1000 Btu/ft^3 and be at transmission pipeline pressure.

8.0 Thermal Gasification Feedstocks

For the current project, the feedstocks suitable for TG include agricultural residues, dedicated energy crops, municipal solid wastes, and, wood residues. TG technology is generally applicable to feedstocks that have low water (moisture) contents.

Conversion of feedstock to RG is based on as-received, net calorific value. For example, 100 tons of as-received (wet) feedstock entering the TG plant, and that its calorific value were to be 10.0 million Btu/wet ton. With energy conversion assumed to be 65% efficient, including upgrading and compression to pipeline specifications, the net production of RG in this example would be:

100 wet tons x 10.0 million Btu/wet ton x 0.65 = 650 million Btu (650 dekatherms)

The collection efficiency for each feedstock is assumed to be 95%. In other words, from an energy crop of 100 tons, 95 tons will be loaded onto trucks and conveyed to the TG plant. Energy output from TG is renewable gas upgraded and compressed to pipeline specifications. The plant capacity for thermal gasification is limited to no more than 3,000 tons per day or 985,500 tons per year (3,000 ton/day x 365 day/year x 90% stream factor).

Capex and annual opex are estimated based on publically available information. Capex is the expenses to construct the facility for feedstock processing. Opex is comprised of two major components: (a) annual expenses to process the feedstock into renewable gas and (b) annual financing costs. More details concerning the calculation are found in the appendices.

Municipal Solid Waste

Types, Amounts, and Availability of Specific Wastes

For the current report, the potential for utilizing municipal solid wastes as a feedstock for thermal gasification is based on MSW that is currently directed to landfills for disposal. MSW that is normally directed to waste-to-energy facilities or recycled is NOT included in the potential availability. MSW typically has water content associated with it. The typical calorific value of MSW used in this assessment is 8.4 million Btu/ton (wet basis). The quantities of MSW generated from domestic, commercial, and industrial activities are from the reference (State of Garbage, 2006).

Wood Residue

Types, Amounts, and Availability of Specific Wastes

For the current project, the potential, annual quantity of dedicated wood residues is based on the data presented in Geographic Perspective, 2005. Wood residues include forest residues, mill residues, and urban wood residues. Forest residue consists of a number of sources: unused portions of trees remaining after logging activity, trees killed by logging but remaining in the forest, other trees killed by other forestry operations. Mill residues consist of both primary and secondary residues. Primary residues are wood materials found at fabrication plants in which wood is converted into products. It also consists of both recycled byproducts and portions that are not used and usually considered waste. Secondary mill residues consist of scraps and sawdust from wood working shops that would manufacture end-user products from lumber. Urban wood residues consist of MSW wood, utility tree trimmings, and wood from construction and demolition. The reference (Geographic Perspective, 2005) reports wood residues by state in terms of dry metric tons (tonnes) per year. An allowance has been made to accommodate the typical moisture content of as-harvested wood residues.

Energy Crops

Types, Amounts, and Availability of Specific Wastes

The potential annual availability of dedicated energy crops is based on the data presented in Geographic Perspective, 2005. This reference reports energy crops by state in terms of dry metric tons (tonnes) per year. As with wood residues above, an allowance has been made to accommodate the typical moisture content of as-harvested energy crops.

Agricultural Residue

Types, Amounts, and Availability of Specific Wastes

Similarly to wood residues and energy crops, the potential quantity of agricultural residues is based on the data presented in Geographic Perspective, 2005. The crops that are included in this assessment are corn, wheat, soybeans, cotton, sorghum, barley, oats, rice, rye, canola, beans, peas, peanuts, potatoes, safflower, sunflower, sugarcane, and flaxseed. This reference reports agricultural residues by state in terms of dry metric tons (tonnes) per year. As with the wood residues above, an allowance has been made to accommodate the typical moisture content of as-harvested agricultural residues.

TG Feedstock Availabilities

Based on the discussion and selection of data described in section *8.0 Thermal Gasification Feedstocks*, Table 17 and Table 18 contain the annual availabilities, by state, for each of the 3 AD feedstocks under consideration in this study. Table 17 contains the availabilities under the Non-aggressive scenario, and Table 18 contains those for the Aggressive scenario. The bottom of each table contains a set of summary statistics of the distributions of the availabilities over the 50 states. The relative standard deviation is the ratio (in percent) of the standard deviation and the average value. It gives a measure of the relative spread in the distribution of available resources for each feedstock.

Table 17: TG Annual Feedstock Availabilities for the Non-aggressive Scenario

State	Ag Residues [millions wet tons/yr]	Energy Crops [millions wet tons/yr]	Municipal Solid Waste [millions wet tons/yr]	Wood Residues [millions wet tons/yr]
Alabama	0.14	0.29	0.30	0.38
Alaska	--	--	0.03	0.12
Arizona	0.12	--	0.34	0.08
Arkansas	1.68	0.10	0.14	0.40
California	0.58	--	1.42	0.67
Colorado	0.54	--	0.39	0.08
Connecticut	--	--	0.02	0.06
Delaware	0.09	--	0.04	0.02
Florida	1.14	0.05	0.53	0.44
Georgia	0.35	0.18	0.34	0.57
Hawaii	0.14	--	0.02	0.02
Idaho	0.63	--	0.05	0.13
Illinois	6.86	0.60	0.79	0.26
Indiana	3.14	0.18	0.40	0.21

State	Ag Residues [millions wet tons/yr]	Energy Crops [millions wet tons/yr]	Municipal Solid Waste [millions wet tons/yr]	Wood Residues [millions wet tons/yr]
Iowa	8.26	1.16	0.13	0.09
Kansas	2.67	0.46	0.16	0.06
Kentucky	0.60	0.20	0.23	0.33
Louisiana	1.52	0.12	0.26	0.48
Maine	--	--	0.04	0.38
Maryland	0.20	0.04	0.15	0.11
Massachusetts	--	--	0.13	0.10
Michigan	1.26	0.18	0.43	0.32
Minnesota	4.98	0.93	0.10	0.35
Mississippi	0.77	0.54	0.14	0.52
Missouri	2.10	0.95	0.32	0.33
Montana	0.55	--	0.06	0.11
Nebraska	3.83	0.33	0.10	0.03
Nevada	--	--	0.11	0.03
New Hampshire	--	--	0.03	0.14
New Jersey	0.03	--	0.33	0.12
New Mexico	0.06	--	0.09	0.03
New York	0.18	0.04	0.50	0.41
North Carolina	0.52	0.06	0.30	0.49
North Dakota	2.31	1.08	0.03	0.01
Ohio	1.75	0.18	0.63	0.27
Oklahoma	0.57	0.03	0.20	0.13
Oregon	0.20	--	0.11	0.19
Pennsylvania	0.28	0.08	0.46	0.39
Rhode Island	--	--	0.06	0.02
South Carolina	0.12	0.12	0.15	0.28
South Dakota	1.80	0.45	0.04	0.03
Tennessee	0.53	0.15	0.35	0.27
Texas	2.13	0.04	1.20	0.56
Utah	0.03	--	0.11	0.04
Vermont	--	--	0.02	0.07
Virginia	0.18	0.03	0.28	0.41
Washington	0.61	--	0.25	0.22
West Virginia	0.01	--	0.08	0.20
Wisconsin	1.55	0.37	0.17	0.33
Wyoming	0.04	--	0.03	0.02
Total	**55.1**	**8.9**	**12.6**	**11.3**
Average	**1.3**	**0.3**	**0.3**	**0.2**
Maximum	**8.3**	**1.2**	**1.4**	**0.7**
Minimum	**0.0**	**0.0**	**0.0**	**0.0**
Std Dev	**1.8**	**0.3**	**0.3**	**0.2**
Relative Std Dev w/rt Avg	**136.6%**	**103.8%**	**110.3%**	**78.5%**

Table 18: TG Annual Feedstock Availabilities for the Aggressive Scenario

State	Ag Residues [millions wet tons/yr]	Energy Crops [millions wet tons/yr]	Municipal Solid Waste [millions wet tons/yr]	Wood Residues [millions wet tons/yr]
Alabama	0.34	0.71	0.89	0.96
Alaska	--	--	0.10	0.29
Arizona	0.31	--	1.02	0.19
Arkansas	4.20	0.26	0.41	0.99
California	1.45	--	4.26	1.68
Colorado	1.36	--	1.17	0.20
Connecticut	--	--	0.05	0.15
Delaware	0.21	--	0.13	0.04
Florida	2.86	0.13	1.58	1.11
Georgia	0.87	0.44	1.03	1.43
Hawaii	0.35	--	0.07	0.04
Idaho	1.57	--	0.16	0.34
Illinois	17.16	1.50	2.37	0.65
Indiana	7.86	0.46	1.21	0.52
Iowa	20.66	2.89	0.40	0.22
Kansas	6.67	1.14	0.47	0.15
Kentucky	1.51	0.50	0.69	0.81
Louisiana	3.80	0.30	0.79	1.20
Maine	--	0.01	0.11	0.95
Maryland	0.51	0.09	0.44	0.28
Massachusetts	--	--	0.38	0.26
Michigan	3.14	0.44	1.30	0.80
Minnesota	12.46	2.32	0.31	0.88
Mississippi	1.92	1.34	0.43	1.31
Missouri	5.26	2.37	0.96	0.82
Montana	1.37	--	0.17	0.27
Nebraska	9.57	0.82	0.30	0.09
Nevada	--	--	0.34	0.08
New Hampshire	--	--	0.09	0.35
New Jersey	0.08	--	0.99	0.30
New Mexico	0.15	--	0.28	0.08
New York	0.44	0.09	1.50	1.01
North Carolina	1.31	0.16	0.89	1.22
North Dakota	5.78	2.69	0.08	0.03
Ohio	4.38	0.45	1.90	0.68
Oklahoma	1.44	0.07	0.60	0.32
Oregon	0.50	--	0.34	0.47
Pennsylvania	0.71	0.19	1.38	0.98
Rhode Island	--	--	0.17	0.04
South Carolina	0.29	0.30	0.46	0.69
South Dakota	4.50	1.14	0.11	0.07
Tennessee	1.31	0.38	1.06	0.67
Texas	5.33	0.10	3.61	1.39
Utah	0.08	--	0.33	0.09
Vermont	--	--	0.05	0.18
Virginia	0.44	0.08	0.85	1.03
Washington	1.53	--	0.75	0.55
West Virginia	0.03	--	0.25	0.51

State	Ag Residues [millions wet tons/yr]	Energy Crops [millions wet tons/yr]	Municipal Solid Waste [millions wet tons/yr]	Wood Residues [millions wet tons/yr]
Wisconsin	3.87	0.93	0.50	0.82
Wyoming	0.09	--	0.09	0.05
Total	**137.6**	**22.3**	**37.8**	**28.2**
Average	**3.3**	**0.8**	**0.8**	**0.6**
Maximum	**20.7**	**2.9**	**4.3**	**1.7**
Minimum	**0.0**	**0.0**	**0.1**	**0.0**
Std Dev	**4.5**	**0.8**	**0.8**	**0.4**
Relative Std Dev w/rt Avg	**136.6%**	**107.3%**	**110.3%**	**78.5%**

9.0 Analysis Results

Results for Anaerobic Digestion

Energy and Costs

Table 19 and Table 20 contain summaries of the AD assessment results for the Non-aggressive and Aggressive scenarios. For each state is given the total number of AD plants, the number of cleanup plants, the capex and opex associated with those AD and cleanup plants, and the total renewable gas annually expected from the state. In the Non-aggressive scenario, the cumulative energy production is some 335 million dekatherms/yr, with a range extending from Alaska at 0.2 million dekatherms/yr to California at 37.4 million dekatherms/yr. Capital investment amounts to approximately $8.3 billion in sum, spanning a range from roughly $10 million to slightly over $800 million dollars. Associated operating expenses range from $2.8 million/yr to $257.7 million/yr and total approximately $2.5 billion/yr.
In the Aggressive scenario, energy production totals roughly 871 million dekatherms/yr, ranging from roughly 0.5 million dekatherms/yr in Alaska to 86.6 million dekatherms/yr in California. Total capital expenditures amount to some $16.8 billion ($19.1 million – roughly $1.5 billion) with associated operating expenses at $5.5 billion/yr ($5.2 million/yr – roughly $513 million/yr).

Table 19: Summary of AD Assessment Results from the Non-aggressive Scenario

State	AD Plants [No.]	Cleanup Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Alabama	24	58	144.0	44.0	6.3
Alaska	3	6	10.5	2.8	0.2
Arizona	26	52	110.4	30.5	3.3
Arkansas	25	37	124.5	37.7	5.4
California	91	417	816.8	257.7	37.4
Colorado	36	61	153.2	43.2	5.0
Connecticut	2	16	25.4	7.0	0.8
Delaware	2	10	29.1	9.5	1.6
Florida	24	85	190.6	59.7	8.8
Georgia	30	85	195.6	61.2	8.9
Hawaii	4	18	29.6	7.8	0.8
Idaho	34	39	116.9	31.1	3.2
Illinois	30	120	272.0	87.8	13.1
Indiana	27	127	240.3	72.8	10.1
Iowa	56	83	276.8	82.9	11.6
Kansas	54	85	240.7	68.9	8.6
Kentucky	26	62	150.9	43.9	5.8
Louisiana	13	51	96.1	27.0	3.2
Maine	4	15	25.3	6.3	0.5
Maryland	6	43	77.1	22.6	3.1
Massachusetts	4	40	64.3	19.3	2.5
Michigan	26	97	213.3	66.6	9.4
Minnesota	45	73	199.0	56.6	6.9
Mississippi	18	42	107.7	32.3	4.6
Missouri	46	134	279.3	79.7	9.8
Montana	38	44	118.5	31.4	3.0
Nebraska	54	76	225.7	63.4	7.6

State	AD Plants [No.]	Cleanup Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Nevada	14	22	51.2	14.3	1.6
New Hampshire	1	13	23.5	7.0	1.0
New Jersey	9	45	99.4	35.3	6.0
New Mexico	32	36	97.9	25.7	2.4
New York	34	109	277.2	93.7	15.4
North Carolina	33	157	282.4	80.5	10.0
North Dakota	23	29	79.3	20.3	1.9
Ohio	27	99	239.1	78.5	12.4
Oklahoma	46	67	208.3	60.1	7.8
Oregon	24	40	96.3	26.7	3.0
Pennsylvania	31	119	302.7	102.4	17.0
Rhode Island	2	8	15.3	5.4	0.9
South Carolina	10	52	100.4	30.6	4.4
South Dakota	39	47	143.1	38.9	4.3
Tennessee	25	135	218.6	59.3	6.5
Texas	141	244	649.6	203.8	28.3
Utah	18	62	101.8	25.3	2.1
Vermont	5	13	33.9	9.1	1.1
Virginia	26	96	199.7	61.9	9.0
Washington	24	56	131.0	39.6	5.4
West Virginia	7	20	42.4	11.3	1.3
Wisconsin	44	114	266.3	77.4	10.1
Wyoming	22	25	67.7	17.4	1.5
Totals	**1385**	**3584**	**8260**	**2478**	**335**
Minimum	**1.0**	**6.0**	**10.5**	**2.8**	**0.2**
Maximum	**141.0**	**417.0**	**816.8**	**257.7**	**37.4**
Median	**25.5**	**54.0**	**127.7**	**38.3**	**5.2**
Average	**27.7**	**71.7**	**165.2**	**49.6**	**6.7**
Std Deviation	**23.9**	**67.3**	**144.7**	**45.9**	**6.8**
Relative Std Dev	**86.2%**	**93.9%**	**87.6%**	**92.6%**	**101.1%**

Table 20: Summary of AD Assessment Results from the Aggressive Scenario

State	AD Plants [No.]	Cleanup Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Alabama	46	80	306.4	103.4	17.4
Alaska	7	10	19.1	5.2	0.5
Arizona	51	77	223.5	66.8	8.7
Arkansas	52	64	302.1	100.4	16.8
California	181	507	1469.0	512.6	86.6
Colorado	74	99	333.4	101.8	14.2
Connecticut	3	17	41.1	12.5	1.9
Delaware	4	12	58.7	21.0	4.0
Florida	48	109	361.7	122.9	20.7
Georgia	55	110	400.0	138.9	23.9
Hawaii	7	21	49.3	14.2	1.8
Idaho	70	75	280.1	81.4	10.5
Illinois	56	146	515.6	181.1	30.4

State	AD Plants [No.]	Cleanup Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Indiana	47	147	426.2	143.5	23.7
Iowa	112	139	670.4	221.5	36.6
Kansas	110	141	551.8	173.1	25.8
Kentucky	50	86	317.0	101.1	15.9
Louisiana	27	65	174.2	53.3	7.8
Maine	9	20	45.1	12.1	1.4
Maryland	11	48	134.4	44.3	7.4
Massachusetts	5	41	101.7	34.5	5.3
Michigan	50	121	405.3	137.7	22.2
Minnesota	93	121	455.7	142.5	21.1
Mississippi	36	60	235.3	77.9	12.9
Missouri	89	177	555.2	175.9	26.6
Montana	79	85	276.1	79.2	9.4
Nebraska	110	132	536.4	166.3	24.5
Nevada	28	36	106.0	31.2	3.9
New Hampshire	3	15	38.0	12.5	2.1
New Jersey	10	46	167.8	65.8	12.5
New Mexico	65	69	227.8	64.7	7.6
New York	61	136	527.7	191.4	34.5
North Carolina	64	188	527.2	171.1	27.2
North Dakota	48	54	183.4	51.2	6.1
Ohio	50	122	458.3	163.1	28.9
Oklahoma	93	114	493.1	156.1	24.1
Oregon	49	65	204.5	60.8	8.0
Pennsylvania	60	148	579.4	211.5	38.9
Rhode Island	2	8	24.7	9.7	1.9
South Carolina	19	61	179.3	60.5	10.2
South Dakota	80	88	343.5	102.2	13.9
Tennessee	47	157	377.0	115.2	16.6
Texas	282	385	1432.9	488.0	77.9
Utah	38	82	185.9	51.2	5.8
Vermont	10	18	70.4	20.3	3.0
Virginia	45	115	369.1	125.6	21.2
Washington	46	78	260.6	84.4	13.1
West Virginia	14	27	84.6	24.6	3.4
Wisconsin	87	157	553.6	177.2	27.7
Wyoming	45	48	157.9	43.8	5.0
Totals	**2728**	**4927**	**16797**	**5507**	**871**
Minimum	**2.0**	**8.0**	**19.1**	**5.2**	**0.5**
Maximum	**282.0**	**507.0**	**1469.0**	**512.6**	**86.6**
Median	**48.5**	**81.0**	**291.1**	**92.4**	**13.5**
Average	**54.6**	**98.5**	**335.9**	**110.1**	**17.4**
Std Dev	**48.1**	**86.4**	**287.8**	**99.6**	**16.7**
Relative Std Dev	**88.2%**	**87.6%**	**85.7%**	**90.4%**	**96.0%**

Individual Feedstock Energy Production and Unit Prices

Table 21 and Table 22 summarize the AD energy production and consequent unit energy prices for the Non-aggressive and Aggressive scenarios, respectively. Near the bottom of each table are a set of statistics which summarize the distribution of findings across the states. The total energy production landfill gas is the feedstock with the largest, cumulative energy production potential in the Non-aggressive scenario. However, in the Aggressive scenario, livestock manure has the greatest, cumulative energy production potential. In both scenarios, wastewater is significantly behind the other two feedstocks in energy production potential. In the Non-aggressive scenario, the average unit energy price spans a range from just over $7/dekatherm (LFG) to about $19/dekatherm (wastewater). In the Aggressive scenario, that same range is just below $6/dekatherm (LFG) to just above $12/dekatherm (wastewater).

Table 21: AD Energy Production and Unit Prices by Feedstock and State in the Non-aggressive Scenario

	Renewable Gas [million dekatherm/yr]				RG Cost (Total Opex/dekatherm) [$/dekatherm]		
State	LFG	Livestock Manure	Waste Water	Total	LFG	Livestock Manure	Waste Water
Alabama	2.65	3.59	0.04	6.28	6.46	7.19	27.92
Alaska	0.22	0.02	0.00	0.24	6.61	79.24	--
Arizona	1.74	1.47	0.10	3.31	6.84	11.76	13.77
Arkansas	0.90	4.49	0.00	5.39	6.56	7.08	--
California	28.39	8.69	0.28	37.36	6.22	8.87	14.72
Colorado	1.96	3.07	0.02	5.04	6.45	9.83	20.28
Connecticut	0.70	0.15	0.00	0.85	7.76	10.35	--
Delaware	1.02	0.54	0.04	1.60	5.56	6.08	14.14
Florida	6.55	2.23	0.05	8.84	5.82	9.23	17.32
Georgia	4.37	4.41	0.14	8.92	6.41	6.91	18.55
Hawaii	0.55	0.15	0.06	0.77	8.75	12.52	16.19
Idaho	0.11	3.09	0.00	3.20	12.12	9.63	--
Illinois	9.85	2.58	0.71	13.13	5.79	9.03	10.57
Indiana	7.32	2.54	0.21	10.07	6.61	8.15	17.90
Iowa	1.54	10.01	0.04	11.59	7.31	7.05	24.67
Kansas	2.02	6.49	0.04	8.56	6.91	8.34	20.57
Kentucky	2.54	3.19	0.06	5.79	6.70	8.03	20.31
Louisiana	2.29	0.95	0.01	3.25	7.14	10.81	30.73
Maine	0.32	0.22	0.00	0.54	10.33	13.59	--
Maryland	2.12	0.95	0.01	3.08	7.30	7.16	29.89
Massachusetts	2.15	0.11	0.23	2.49	7.17	12.74	10.93
Michigan	6.80	2.15	0.49	9.44	6.03	9.42	10.82
Minnesota	1.44	5.46	0.00	6.90	7.66	8.35	--
Mississippi	1.69	2.86	0.00	4.55	6.71	7.34	--
Missouri	4.50	5.17	0.12	9.80	7.67	8.25	20.06
Montana	0.32	2.63	0.00	2.95	7.51	11.02	--
Nebraska	0.62	6.96	0.01	7.59	10.56	8.12	27.28
Nevada	1.00	0.55	0.04	1.58	5.59	14.93	14.92
New Hampshire	0.91	0.08	0.00	0.98	6.53	14.58	--
New Jersey	5.63	0.12	0.27	6.03	5.30	11.34	14.84
New Mexico	0.28	2.07	0.03	2.38	6.73	11.27	16.68
New York	12.47	2.61	0.29	15.36	5.23	9.23	15.34
North Carolina	4.57	5.38	0.04	9.99	9.05	7.08	24.31
North Dakota	0.14	1.73	0.00	1.88	11.74	10.76	--
Ohio	9.32	2.85	0.26	12.43	5.54	8.20	13.41

State	Renewable Gas [million dekatherm/yr]				RG Cost (Total Opex/dekatherm) [$/dekatherm]		
	LFG	Livestock Manure	Waste Water	Total	LFG	Livestock Manure	Waste Water
Oklahoma	1.39	6.36	0.02	7.77	6.87	7.88	19.20
Oregon	1.42	1.54	0.01	2.97	6.17	11.41	27.42
Pennsylvania	13.37	3.53	0.14	17.04	5.33	8.22	15.69
Rhode Island	0.92	0.01	0.01	0.94	5.33	16.82	24.64
South Carolina	3.28	1.08	0.03	4.39	6.46	8.33	17.25
South Dakota	0.22	4.05	0.00	4.26	10.74	9.03	--
Tennessee	3.78	2.61	0.10	6.49	9.39	8.40	18.32
Texas	12.26	15.72	0.33	28.32	5.66	8.24	14.47
Utah	0.80	1.26	0.00	2.06	14.14	11.17	--
Vermont	0.63	0.51	0.00	1.14	6.43	9.95	--
Virginia	6.46	2.36	0.14	8.95	6.10	8.33	20.86
Washington	3.72	1.67	0.04	5.43	5.70	10.51	19.53
West Virginia	0.61	0.66	0.00	1.27	7.97	9.75	--
Wisconsin	4.42	5.61	0.06	10.09	7.00	8.07	21.50
Wyoming	0.14	1.41	0.00	1.55	8.14	11.51	--
Totals	**182**	**148**	**4**	**335**	**--**	**--**	**--**
Minimum	**0.1**	**0.0**	**0.0**	**0.2**	**5.23**	**6.08**	**10.57**
Maximum	**28.4**	**15.7**	**0.7**	**37.4**	**14.14**	**79.24**	**30.73**
Median	**1.8**	**2.5**	**0.0**	**5.2**	**6.70**	**9.13**	**18.32**
Average	**3.6**	**3.0**	**0.1**	**6.7**	**7.28**	**11.02**	**19.00**
Std Deviation	**4.9**	**2.9**	**0.1**	**6.8**	**1.90**	**10.00**	**5.31**
Relative Std Dev [%]	**134.3%**	**99.3%**	**155.0%**	**101.1%**	**26.1%**	**90.7%**	**28.0%**

Table 22: AD Energy Production and Unit Prices by Feedstock and State in the Aggressive Scenario

State	Renewable Gas [million dekatherm/yr]				RG Cost (Total Opex/dekatherm) [$/dekatherm]		
	LFG	Livestock Manure	Waste Water	Total	LFG	Livestock Manure	Waste Water
Alabama	5.3	12.0	0.1	17.4	5.30	6.14	15.27
Alaska	0.4	0.1	0.0	0.5	5.38	51.86	--
Arizona	3.5	4.9	0.3	8.7	5.49	9.10	10.55
Arkansas	1.8	15.0	0.0	16.8	5.35	6.07	--
California	56.8	29.0	0.8	86.6	5.18	7.22	10.87
Colorado	3.9	10.2	0.1	14.2	5.30	7.85	12.72
Connecticut	1.4	0.5	0.0	1.9	5.95	8.26	--
Delaware	2.0	1.8	0.1	4.0	4.85	5.44	10.68
Florida	13.1	7.4	0.2	20.7	4.98	7.48	11.74
Georgia	8.7	14.7	0.4	23.9	5.28	5.96	12.15
Hawaii	1.1	0.5	0.2	1.8	6.45	9.67	11.36
Idaho	0.2	10.3	0.0	10.5	8.13	7.73	--
Illinois	19.7	8.6	2.1	30.4	4.97	7.34	9.49
Indiana	14.6	8.5	0.6	23.7	5.38	6.78	11.93
Iowa	3.1	33.4	0.1	36.6	5.73	6.05	14.19
Kansas	4.0	21.6	0.1	25.8	5.53	6.89	12.82
Kentucky	5.1	10.6	0.2	15.9	5.42	6.70	12.73
Louisiana	4.6	3.2	0.0	7.8	5.64	8.51	16.21

State	Renewable Gas [million dekatherm/yr]				RG Cost (Total Opex/dekatherm) [$/dekatherm]		
	LFG	Livestock Manure	Waste Water	Total	LFG	Livestock Manure	Waste Water
Maine	0.6	0.7	0.0	1.4	7.24	10.30	--
Maryland	4.2	3.2	0.0	7.4	5.72	6.15	15.93
Massachusetts	4.3	0.4	0.7	5.3	5.66	9.82	9.60
Michigan	13.6	7.2	1.5	22.2	5.09	7.60	9.57
Minnesota	2.9	18.2	0.0	21.1	5.90	6.90	--
Mississippi	3.4	9.5	0.0	12.9	5.42	6.24	--
Missouri	9.0	17.2	0.4	26.6	5.91	6.84	12.65
Montana	0.6	8.8	0.0	9.4	5.83	8.61	--
Nebraska	1.2	23.2	0.0	24.5	7.35	6.75	15.06
Nevada	2.0	1.8	0.1	3.9	4.87	11.14	10.94
New Hampshire	1.8	0.3	0.0	2.1	5.34	11.02	--
New Jersey	11.3	0.4	0.8	12.5	4.72	8.90	10.91
New Mexico	0.6	6.9	0.1	7.6	5.44	8.78	11.52
New York	24.9	8.7	0.9	34.5	4.69	7.48	11.08
North Carolina	9.1	17.9	0.1	27.2	6.59	6.07	14.07
North Dakota	0.3	5.8	0.0	6.1	7.94	8.46	--
Ohio	18.6	9.5	0.8	28.9	4.84	6.81	10.43
Oklahoma	2.8	21.2	0.1	24.1	5.51	6.60	12.36
Oregon	2.8	5.1	0.0	8.0	5.16	8.88	15.10
Pennsylvania	26.7	11.8	0.4	38.9	4.74	6.82	11.19
Rhode Island	1.8	0.0	0.0	1.9	4.73	12.62	14.18
South Carolina	6.6	3.6	0.1	10.2	5.30	6.89	11.71
South Dakota	0.4	13.5	0.0	13.9	7.44	7.34	--
Tennessee	7.6	8.7	0.3	16.6	6.77	6.94	12.07
Texas	24.5	52.4	1.0	77.9	4.90	6.81	10.79
Utah	1.6	4.2	0.0	5.8	9.14	8.73	--
Vermont	1.3	1.7	0.0	3.0	5.29	7.99	--
Virginia	12.9	7.9	0.4	21.2	5.12	6.90	12.92
Washington	7.4	5.6	0.1	13.1	4.92	8.30	12.47
West Virginia	1.2	2.2	0.0	3.4	6.05	7.83	--
Wisconsin	8.8	18.7	0.2	27.7	5.57	6.72	13.13
Wyoming	0.3	4.7	0.0	5.0	6.14	8.94	--
Totals	**365**	**493**	**13**	**871**	**--**	**--**	**--**
Minimum	**0.2**	**0.0**	**0.0**	**0.5**	**4.69**	**5.44**	**9.49**
Maximum	**56.8**	**52.4**	**2.1**	**86.6**	**9.14**	**51.86**	**16.21**
Median	**3.7**	**8.2**	**0.1**	**13.5**	**5.42**	**7.41**	**12.07**
Average	**7.3**	**9.9**	**0.3**	**17.4**	**5.71**	**8.63**	**12.30**
Std Deviation	**9.8**	**9.8**	**0.4**	**16.7**	**0.95**	**6.35**	**1.77**
Relative StdDev [%]	**134.3%**	**99.3%**	**155.0%**	**96.0%**	**16.6%**	**73.6%**	**14.4%**

Job Creation

The potential numbers of AD jobs created by state and by scenario is found in Table 23. Low and high estimates for each scenario are based on a range of job creation factors available in the literature. Further details on the calculation of these jobs numbers are found in *13.0 Appendix: Economic* At the low end of the Non-aggressive case, approximately 3,000 jobs may be created, and at the high end of the Aggressive case, that number rises to roughly 29,000 jobs.

Table 23: AD Job Creation by State and by Scenario

State	Non Aggressive		Aggressive		Max Potential	
	Low State Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	57	209	159	579	378	1379
Alaska	2	8	5	16	12	45
Arizona	30	110	79	289	191	697
Arkansas	49	179	153	558	348	1270
California	341	1244	791	2884	2034	7417
Colorado	46	168	130	473	307	1118
Connecticut	8	28	17	63	45	166
Delaware	15	53	36	132	89	326
Florida	81	294	189	690	484	1767
Georgia	81	297	218	795	524	1912
Hawaii	7	26	16	60	41	149
Idaho	29	107	96	350	214	781
Illinois	120	437	278	1013	701	2556
Indiana	92	335	217	790	550	2007
Iowa	106	386	334	1218	755	2753
Kansas	78	285	236	860	542	1977
Kentucky	53	193	145	529	346	1262
Louisiana	30	108	71	259	180	658
Maine	5	18	12	46	31	113
Maryland	28	103	68	248	172	626
Massachusetts	23	83	49	178	125	456
Michigan	86	314	203	741	509	1856
Minnesota	63	230	192	702	441	1608
Mississippi	42	152	118	430	278	1015
Missouri	89	326	243	887	582	2122
Montana	27	98	86	313	194	706
Nebraska	69	253	224	815	501	1829
Nevada	14	53	36	131	89	324
New Hampshire	9	33	19	69	51	186
New Jersey	55	201	114	416	304	1110
New Mexico	22	79	69	251	155	565
New York	140	511	315	1148	818	2983
North Carolina	91	333	248	906	596	2172
North Dakota	17	63	55	202	124	453
Ohio	113	414	264	963	674	2459
Oklahoma	71	259	220	801	500	1825
Oregon	27	99	73	267	176	643
Pennsylvania	156	567	355	1296	920	3355
South Carolina	40	146	93	341	240	875
South Dakota	39	142	127	464	284	1035

State	Non Aggressive		Aggressive		Max Potential	
	Low State Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Tennessee	59	216	151	551	371	1355
Texas	259	943	712	2595	1694	6179
Utah	19	68	53	193	125	457
Vermont	10	38	27	99	66	242
Virginia	82	298	193	705	491	1791
Washington	50	181	120	437	303	1103
West Virginia	12	42	31	114	75	275
Wisconsin	92	336	253	923	604	2204
Wyoming	14	52	45	166	102	373
Total	**3057.1**	**11150.3**	**7956.2**	**29018.8**	**19386.1**	**70707.1**
Average	**61.1**	**223.0**	**159.1**	**580.4**	**387.7**	**1414.1**
Maximum	**341.1**	**1244.1**	**790.6**	**2883.6**	**2033.6**	**7417.0**
Minimum	**2.2**	**7.9**	**4.5**	**16.4**	**12.2**	**44.5**
Std Dev	**61.8**	**225.5**	**152.8**	**557.4**	**380.1**	**1386.5**
Relative Std Dev w/rt Avg	**101.1%**	**101.1%**	**96.0%**	**96.0%**	**98.0%**	**98.0%**

CO_2 Abatement and Carbon Credit Values

CO_2 abatement and a range of carbon credit valuations within various markets are displayed in Table 24 and Table 25 for the Non-aggressive and Aggressive scenarios, respectively. Details of the computation of the abatements are found in *13.0 Appendix: Economic* In the Non-aggressive scenario, CO_2 abatement amounts to roughly 19.6 million tons/yr (ranging from 0.01 – 2.19 million tons/yr across the states). In the Aggressive scenario, approximately 51.01 million tons/yr is the cumulative amount across all the states with a range from roughly 0.03 – 5.07 million tons/yr across the states. The values of the carbon credits on 3 current carbon trading markets (CCX, RGGI, and European Climate Exchange or ECX) vary considerably with the market and with its participation or regulatory scheme. Calculated credit values span from $0.89 million/yr (CCX, Non-aggressive scenario) to $720 million/yr (ECX, Aggressive scenario).

Table 24: AD CO_2 Abatement and Sample Carbon Credit Values in the Non-aggressive Scenario

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton CO_2/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Alabama	6.3	0.37	0.02	0.68	5.19
Alaska	0.2	0.01	0.00	0.03	0.19
Arizona	3.3	0.19	0.01	0.36	2.73
Arkansas	5.4	0.32	0.01	0.59	4.45
California	37.4	2.19	0.10	4.07	30.88
Colorado	5.0	0.30	0.01	0.55	4.17
Connecticut	0.8	0.05	0.00	0.09	0.70
Delaware	1.6	0.09	0.00	0.17	1.32
Florida	8.8	0.52	0.02	0.96	7.31
Georgia	8.9	0.52	0.02	0.97	7.38
Hawaii	0.8	0.04	0.00	0.08	0.63
Idaho	3.2	0.19	0.01	0.35	2.65
Illinois	13.1	0.77	0.03	1.43	10.86
Indiana	10.1	0.59	0.03	1.10	8.33
Iowa	11.6	0.68	0.03	1.26	9.58

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton CO_2/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Kansas	8.6	0.50	0.02	0.93	7.08
Kentucky	5.8	0.34	0.02	0.63	4.79
Louisiana	3.2	0.19	0.01	0.35	2.69
Maine	0.5	0.03	0.00	0.06	0.45
Maryland	3.1	0.18	0.01	0.34	2.55
Massachusetts	2.5	0.15	0.01	0.27	2.05
Michigan	9.4	0.55	0.03	1.03	7.80
Minnesota	6.9	0.40	0.02	0.75	5.70
Mississippi	4.6	0.27	0.01	0.50	3.76
Missouri	9.8	0.57	0.03	1.07	8.10
Montana	3.0	0.17	0.01	0.32	2.44
Nebraska	7.6	0.44	0.02	0.83	6.28
Nevada	1.6	0.09	0.00	0.17	1.31
New Hampshire	1.0	0.06	0.00	0.11	0.81
New Jersey	6.0	0.35	0.02	0.66	4.98
New Mexico	2.4	0.14	0.01	0.26	1.97
New York	15.4	0.90	0.04	1.67	12.70
North Carolina	10.0	0.58	0.03	1.09	8.26
North Dakota	1.9	0.11	0.00	0.20	1.55
Ohio	12.4	0.73	0.03	1.35	10.27
Oklahoma	7.8	0.46	0.02	0.85	6.43
Oregon	3.0	0.17	0.01	0.32	2.46
Pennsylvania	17.0	1.00	0.05	1.86	14.08
Rhode Island	0.9	0.06	0.00	0.10	0.78
South Carolina	4.4	0.26	0.01	0.48	3.63
South Dakota	4.3	0.25	0.01	0.46	3.52
Tennessee	6.5	0.38	0.02	0.71	5.37
Texas	28.3	1.66	0.08	3.08	23.41
Utah	2.1	0.12	0.01	0.22	1.70
Vermont	1.1	0.07	0.00	0.12	0.94
Virginia	9.0	0.52	0.02	0.97	7.40
Washington	5.4	0.32	0.01	0.59	4.49
West Virginia	1.3	0.07	0.00	0.14	1.05
Wisconsin	10.1	0.59	0.03	1.10	8.34
Wyoming	1.5	0.09	0.00	0.17	1.28
Total	**334.84**	**19.60**	**0.89**	**36.46**	**276.80**
Average	**6.70**	**0.39**	**0.02**	**0.73**	**5.54**
Maximum	**37.36**	**2.19**	**0.10**	**4.07**	**30.88**
Minimum	**0.24**	**0.01**	**0.00**	**0.03**	**0.19**
Std Dev	**6.77**	**0.40**	**0.02**	**0.74**	**5.60**
Relative Std Dev w/rt Avg	**101.1%**	**101.1%**	**101.1%**	**101.1%**	**101.1%**

Table 25: AD CO_2 Abatement and Sample Carbon Credit Values in the Aggressive Scenario

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton CO_2/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Alabama	17.4	1.02	0.05	1.89	14.38
Alaska	0.5	0.03	0.00	0.05	0.41
Arizona	8.7	0.51	0.02	0.94	7.17
Arkansas	16.8	0.98	0.04	1.83	13.86
California	86.6	5.07	0.23	9.43	71.58
Colorado	14.2	0.83	0.04	1.55	11.73
Connecticut	1.9	0.11	0.01	0.21	1.57
Delaware	4.0	0.23	0.01	0.43	3.27
Florida	20.7	1.21	0.06	2.26	17.13
Georgia	23.9	1.40	0.06	2.60	19.73
Hawaii	1.8	0.11	0.00	0.20	1.49
Idaho	10.5	0.62	0.03	1.15	8.70
Illinois	30.4	1.78	0.08	3.31	25.14
Indiana	23.7	1.39	0.06	2.58	19.62
Iowa	36.6	2.14	0.10	3.98	30.24
Kansas	25.8	1.51	0.07	2.81	21.34
Kentucky	15.9	0.93	0.04	1.73	13.14
Louisiana	7.8	0.46	0.02	0.85	6.43
Maine	1.4	0.08	0.00	0.15	1.13
Maryland	7.4	0.44	0.02	0.81	6.15
Massachusetts	5.3	0.31	0.01	0.58	4.42
Michigan	22.2	1.30	0.06	2.42	18.38
Minnesota	21.1	1.23	0.06	2.29	17.42
Mississippi	12.9	0.76	0.03	1.41	10.67
Missouri	26.6	1.56	0.07	2.90	22.01
Montana	9.4	0.55	0.02	1.02	7.78
Nebraska	24.5	1.43	0.07	2.67	20.24
Nevada	3.9	0.23	0.01	0.43	3.25
New Hampshire	2.1	0.12	0.01	0.23	1.71
New Jersey	12.5	0.73	0.03	1.36	10.33
New Mexico	7.6	0.44	0.02	0.82	6.24
New York	34.5	2.02	0.09	3.75	28.51
North Carolina	27.2	1.59	0.07	2.96	22.49
North Dakota	6.1	0.36	0.02	0.66	5.02
Ohio	28.9	1.69	0.08	3.15	23.91
Oklahoma	24.1	1.41	0.06	2.62	19.88
Oregon	8.0	0.47	0.02	0.87	6.63
Pennsylvania	38.9	2.28	0.10	4.24	32.17
Rhode Island	1.9	0.11	0.01	0.21	1.58
South Carolina	10.2	0.60	0.03	1.11	8.46
South Dakota	13.9	0.81	0.04	1.52	11.51
Tennessee	16.6	0.97	0.04	1.80	13.69
Texas	77.9	4.56	0.21	8.49	64.43
Utah	5.8	0.34	0.02	0.63	4.79
Vermont	3.0	0.17	0.01	0.32	2.45
Virginia	21.2	1.24	0.06	2.31	17.51

Washington	13.1	0.77	0.03	1.43	10.86
West Virginia	3.4	0.20	0.01	0.37	2.83
Wisconsin	27.7	1.62	0.07	3.02	22.91
Wyoming	5.0	0.29	0.01	0.54	4.12
Total	**871.44**	**51.01**	**2.31**	**94.89**	**720.38**
Average	**17.43**	**1.02**	**0.05**	**1.90**	**14.41**
Maximum	**86.59**	**5.07**	**0.23**	**9.43**	**71.58**
Minimum	**0.49**	**0.03**	**0.00**	**0.05**	**0.41**
Std Dev	**16.74**	**0.98**	**0.04**	**1.82**	**13.84**
Relative Std Dev w/rt Avg	**96.03%**	**96.03%**	**96.03%**	**96.03%**	**96.03%**

Results for Thermal Gasification

Table 26 through Table 32 are the main analysis results for the TG sector and are analogous to those for the AD sector. As with the AD tables, each of the TG tables contains a set of summary statistics near the bottom; these identify the totals, averages, maxima, minima, and spread (standard deviation) of the distributions of values over the states.

Energy and Costs

Table 26: Summary of TG Assessment Results in the Non-aggressive Scenario

State	TG Plants [No.]	Average Plant Capacity [Thousand ton/year]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Alabama	4	274.9	440.5	109.3	7.9
Alaska	2	75.1	93.3	20.6	1.0
Arizona	3	180.3	243.9	58.5	3.3
Arkansas	5	369.5	730.9	192.3	16.8
California	4	654.8	791.1	213.0	16.9
Colorado	3	337.6	363.3	92.5	6.7
Connecticut	2	38.3	60.5	12.5	0.5
Delaware	3	48.5	105.2	22.3	1.0
Florida	5	397.3	716.1	186.6	14.9
Georgia	4	360.2	521.9	132.9	10.2
Hawaii	3	59.8	113.4	24.7	1.3
Idaho	3	271.6	299.3	75.4	5.8
Illinois	11	626.7	2371.2	648.0	61.5
Indiana	7	394.2	1199.6	319.4	28.2
Iowa	13	429.6	2668.8	729.6	71.9
Kansas	6	390.1	987.2	264.5	24.8
Kentucky	4	339.5	500.0	126.7	9.8
Louisiana	5	406.4	764.4	200.7	17.1
Maine	2	207.8	167.9	41.3	3.0
Maryland	4	125.4	260.4	60.2	3.4
Massachusetts	2	113.9	126.5	28.8	1.4
Michigan	5	389.5	736.9	191.2	15.4
Minnesota	10	438.1	1869.5	503.3	47.8
Mississippi	5	397.3	691.6	177.7	15.0
Missouri	7	455.5	1177.3	310.5	27.9

State	TG Plants [No.]	Average Plant Capacity [Thousand ton/year]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Montana	3	236.4	274.7	68.2	5.1
Nebraska	7	354.6	1209.7	328.1	31.6
Nevada	2	72.4	90.7	19.9	0.8
New Hampshire	2	86.4	100.3	22.5	1.2
New Jersey	3	161.1	219.4	52.4	2.9
New Mexico	3	61.5	125.5	27.1	1.2
New York	4	279.8	422.2	106.0	7.3
North Carolina	4	342.2	490.5	125.1	9.5
North Dakota	7	337.0	1035.0	276.0	26.7
Ohio	5	490.6	858.2	228.9	19.8
Oklahoma	4	233.0	364.5	90.4	6.5
Oregon	3	166.6	241.1	57.0	3.4
Pennsylvania	4	302.8	458.4	115.3	8.1
Rhode Island	2	35.7	57.4	11.8	0.4
South Carolina	4	166.3	317.9	75.2	4.8
South Dakota	5	354.3	688.8	183.8	17.6
Tennessee	4	323.9	486.0	122.6	9.0
Texas	7	477.4	1195.6	318.9	26.5
Utah	3	58.9	119.3	25.7	1.1
Vermont	2	43.8	65.3	13.7	0.6
Virginia	4	225.3	369.6	90.8	6.1
Washington	3	361.1	389.1	99.2	7.4
West Virginia	3	100.0	158.6	36.4	2.0
Wisconsin	5	410.4	776.8	203.9	17.9
Wyoming	3	29.0	78.1	15.7	0.6
Total	**218**	**13492**	**28593.3**	**7457.1**	**631.8**
Average	**4.4**	**269.8**	**571.9**	**149.1**	**12.6**
Maximum	**13**	**655**	**2669**	**730**	**72**
Minimum	**2**	**29**	**57**	**12**	**0**
Std Dev	**2.3**	**159.2**	**557.6**	**153.2**	**15.0**
Relative Std Dev w/rt Avg	**52.5%**	**59.0%**	**97.5%**	**102.7%**	**119.0%**

Table 27: Summary of TG Assessment Results in the Aggressive Scenario

State	TG Plants [No.]	Average Plant Capacity [Thousand ton/year]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Alabama	5	604.6	890.8	237.0	20.7
Alaska	2	196.4	175.0	42.2	2.7
Arizona	4	337.1	541.7	138.6	9.2
Arkansas	9	502.0	1725.1	464.4	42.4
California	9	806.6	2033.6	558.1	46.1
Colorado	5	487.8	853.6	226.0	17.7
Connecticut	2	100.1	113.4	25.6	1.4
Delaware	3	128.3	197.3	45.8	2.6
Florida	9	545.1	1683.4	452.0	38.6
Georgia	6	636.2	1133.9	303.7	26.3
Hawaii	3	153.2	209.7	49.9	3.2
Idaho	4	427.0	644.7	170.5	14.7

State	TG Plants [No.]	Average Plant Capacity [Thousand ton/year]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Illinois	24	785.5	5757.0	1594.2	156.0
Indiana	13	612.0	2807.8	766.7	71.6
Iowa	28	570.8	6489.5	1791.2	180.1
Kansas	11	534.8	2329.5	637.3	62.4
Kentucky	5	688.9	1017.9	275.4	25.1
Louisiana	9	613.9	1783.2	481.1	43.4
Maine	4	198.8	393.9	99.4	7.6
Maryland	4	331.9	486.7	123.4	9.0
Massachusetts	2	316.3	243.4	61.1	3.9
Michigan	8	669.1	1640.2	444.2	39.7
Minnesota	18	731.9	4254.8	1177.1	119.7
Mississippi	8	600.0	1514.1	405.1	37.9
Missouri	11	860.8	2549.8	702.4	70.7
Montana	4	372.9	592.3	154.5	12.8
Nebraska	13	539.9	2889.5	797.1	79.3
Nevada	2	209.3	177.8	43.3	2.4
New Hampshire	2	223.7	187.1	45.8	3.1
New Jersey	4	292.6	495.4	126.1	8.2
New Mexico	3	169.1	238.7	56.7	3.2
New York	6	447.9	964.2	254.4	19.6
North Carolina	6	576.6	1078.1	288.1	24.6
North Dakota	11	493.2	2298.0	633.7	66.9
Ohio	9	739.6	2027.7	557.0	51.3
Oklahoma	5	428.1	768.8	202.6	16.7
Oregon	3	435.5	449.2	116.2	8.9
Pennsylvania	6	519.5	1021.1	270.3	21.5
Rhode Island	2	103.2	112.6	25.7	1.2
South Carolina	4	434.9	590.8	153.1	12.3
South Dakota	9	411.0	1660.9	449.8	44.0
Tennessee	6	557.6	1066.1	282.8	23.6
Texas	13	646.9	2850.7	782.9	69.6
Utah	3	165.4	229.1	54.5	3.0
Vermont	2	113.9	122.0	28.0	1.6
Virginia	5	469.7	765.6	201.2	16.0
Washington	4	689.6	819.9	221.9	19.3
West Virginia	3	264.0	297.9	74.8	5.3
Wisconsin	8	756.7	1722.4	469.7	45.2
Wyoming	3	77.2	146.8	32.3	1.5
Total	**342**	**22576.9**	**65042.91**	**17594.81**	**1614.01**
Average	**6.8**	**451.5**	**1300.86**	**351.90**	**32.28**
Maximum	**28**	**860.8**	**6489.47**	**1791.22**	**180.11**
Minimum	**2**	**77.2**	**112.61**	**25.64**	**1.20**
Std Dev	**5.3**	**213.3**	**1348.88**	**374.83**	**37.83**
Relative Std Dev w/rt Avg	**77.8%**	**47.2%**	**103.7%**	**106.5%**	**117.2%**

Individual Feedstock Energy Production and Unit Prices

Table 28: TG Energy Production and Unit Prices by Feedstock and by State in the Non-aggressive Scenario

State	Renewable Gas [million dekatherm/yr]					RG Cost (Total Opex/dekatherm) [$/dekatherm]			
	Ag Res	Energy Crops	MSW	Wood Res	Total	Ag Res	Energy Crops	MSW	Wood Res
Alabama	1.00	2.56	1.61	2.78	7.9	16.57	11.10	18.08	12.67
Alaska	--	--	0.19	0.84	1.0	--	--	31.62	17.34
Arizona	0.89	--	1.86	0.56	3.3	17.05	--	17.41	19.26
Arkansas	12.23	0.93	0.75	2.89	16.8	10.31	14.48	22.06	12.54
California	4.23	--	7.76	4.90	16.9	11.35	--	14.36	10.93
Colorado	3.95	--	2.13	0.58	6.7	11.56	--	16.80	19.08
Connecticut	--	--	0.10	0.43	0.5	--	--	37.76	20.67
Delaware	0.62	--	0.23	0.13	1.0	18.73	--	30.10	28.30
Florida	8.32	0.45	2.87	3.22	14.9	11.40	17.50	15.54	12.19
Georgia	2.54	1.59	1.87	4.16	10.2	12.97	12.56	17.39	11.40
Hawaii	1.01	--	0.13	0.13	1.3	16.52	--	35.28	28.35
Idaho	4.56	--	0.30	0.98	5.8	11.13	--	28.18	16.65
Illinois	49.96	5.37	4.32	1.89	61.5	10.25	9.14	13.96	14.01
Indiana	22.89	1.63	2.20	1.50	28.2	10.49	12.48	16.67	14.89
Iowa	60.15	10.38	0.73	0.64	71.9	10.07	9.22	22.22	18.64
Kansas	19.41	4.09	0.85	0.44	24.8	10.16	9.82	21.38	20.54
Kentucky	4.39	1.80	1.25	2.37	9.8	11.24	12.17	19.31	13.22
Louisiana	11.05	1.09	1.44	3.50	17.1	10.58	13.87	18.61	11.93
Maine	--	--	0.20	2.76	3.0	--	--	31.11	12.70
Maryland	1.49	0.33	0.80	0.83	3.4	14.92	19.04	21.68	17.41
Massachusetts	--	--	0.69	0.74	1.4	--	--	22.59	17.90
Michigan	9.14	1.58	2.37	2.33	15.4	11.12	12.59	16.34	13.27
Minnesota	36.29	8.33	0.57	2.57	47.8	10.34	9.77	23.72	12.94
Mississippi	5.59	4.82	0.79	3.81	15.0	12.66	9.40	21.78	11.67
Missouri	15.32	8.51	1.75	2.38	27.9	10.81	9.72	17.70	13.20
Montana	3.98	--	0.31	0.77	5.1	11.54	--	27.86	17.70
Nebraska	27.87	2.93	0.54	0.25	31.6	9.96	10.71	24.01	23.71
Nevada	--	--	0.62	0.23	0.8	--	--	23.21	24.39
New Hampshire	--	--	0.17	1.03	1.2	--	--	32.56	16.43
New Jersey	0.23	--	1.80	0.88	2.9	24.28	--	17.55	17.12
New Mexico	0.43	--	0.50	0.25	1.2	20.68	--	24.53	23.89

State	Renewable Gas [million dekatherm/yr]					RG Cost (Total Opex/dekatherm) [$/dekatherm]			
	Ag Res	Energy Crops	MSW	Wood Res	Total	Ag Res	Energy Crops	MSW	Wood Res
New York	1.29	0.33	2.72	2.96	7.3	15.48	18.96	15.75	12.47
North Carolina	3.81	0.56	1.61	3.55	9.5	11.67	16.51	18.07	11.89
North Dakota	16.83	9.64	0.15	0.09	26.7	10.54	9.40	33.67	31.04
Ohio	12.75	1.62	3.46	1.98	19.8	10.20	12.52	14.79	13.84
Oklahoma	4.18	0.24	1.10	0.95	6.5	11.38	20.62	19.99	16.80
Oregon	1.45	--	0.62	1.36	3.4	15.04	--	23.18	15.27
Pennsylvania	2.07	0.68	2.51	2.86	8.1	13.70	15.71	16.10	12.58
Rhode Island	--	--	0.31	0.11	0.4	--	--	27.90	29.49
South Carolina	0.84	1.06	0.84	2.02	4.8	17.31	13.97	21.43	13.78
South Dakota	13.11	4.07	0.20	0.19	17.6	10.12	9.83	31.14	25.57
Tennessee	3.83	1.36	1.92	1.94	9.0	11.65	13.09	17.26	13.93
Texas	15.53	0.36	6.56	4.06	26.5	10.77	18.54	15.00	11.48
Utah	0.22	--	0.60	0.27	1.1	24.49	--	23.44	23.43
Vermont	--	--	0.10	0.51	0.6	--	--	37.91	19.74
Virginia	1.28	0.28	1.54	3.00	6.1	15.52	19.79	18.29	12.42
Washington	4.45	--	1.36	1.61	7.4	11.20	--	18.88	14.61
West Virginia	0.08	--	0.46	1.49	2.0	31.92	--	25.10	14.92
Wisconsin	11.27	3.34	0.92	2.38	17.9	10.53	10.35	20.94	13.19
Wyoming	0.27	--	0.16	0.15	0.6	23.33	--	33.16	27.18
Totals	**401**	**80**	**69**	**82**	**632**	**--**	**--**	**--**	**--**
Minimum	**0.1**	**0.2**	**0.1**	**0.1**	**0.4**	**9.96**	**9.14**	**13.96**	**10.93**
Maximum	**60.1**	**10.4**	**7.8**	**4.9**	**71.9**	**31.92**	**20.62**	**37.91**	**31.04**
Median	**4.2**	**1.6**	**0.8**	**1.4**	**7.4**	**11.47**	**12.54**	**21.56**	**15.10**
Average	**9.5**	**2.9**	**1.4**	**1.6**	**12.6**	**13.85**	**13.32**	**22.67**	**17.17**
Std Deviation	**13.0**	**3.0**	**1.5**	**1.3**	**15.0**	**4.86**	**3.59**	**6.48**	**5.43**
Relative Std Dev [%]	**136.6%**	**103.8%**	**110.3%**	**78.5%**	**119.0%**	**35.1%**	**27.0%**	**28.6%**	**31.6%**

Table 29: TG Energy Production and Unit Prices by Feedstock and by State in the Aggressive Scenario

State	Renewable Gas [million dekatherm/yr]					RG Cost (Total Opex/dekatherm) [$/dekatherm]			
	Ag Res	Energy Crops	MSW	Wood Res	Total	Ag Res	Energy Crops	MSW	Wood Res
Alabama	2.49	6.39	4.83	6.96	20.7	13.04	8.73	13.56	11.95
Alaska	--	--	0.57	2.10	2.7	--	--	23.72	13.64
Arizona	2.24	--	5.58	1.40	9.2	13.41	--	15.65	15.15
Arkansas	30.57	2.32	2.26	7.22	42.4	10.31	11.39	16.55	11.83
California	10.57	--	23.28	12.24	46.1	10.71	--	13.69	10.31
Colorado	9.88	--	6.39	1.46	17.7	10.90	--	15.11	15.01
Connecticut	--	--	0.29	1.07	1.4	--	--	28.32	16.26
Delaware	1.56	--	0.69	0.32	2.6	14.74	--	22.58	22.26
Florida	20.80	1.12	8.61	8.05	38.6	10.75	13.77	13.98	11.50
Georgia	6.36	3.98	5.60	10.41	26.3	10.20	9.88	15.64	10.75
Hawaii	2.52	--	0.38	0.32	3.2	13.00	--	26.46	22.30
Idaho	11.40	--	0.89	2.45	14.7	10.50	--	21.14	13.10
Illinois	124.89	13.42	12.95	4.73	156.0	9.97	8.62	13.96	11.02
Indiana	57.22	4.08	6.59	3.76	71.6	10.20	9.82	14.99	11.71
Iowa	150.37	25.95	2.20	1.59	180.1	10.01	8.70	16.67	14.66
Kansas	48.53	10.22	2.55	1.10	62.4	9.97	9.26	16.03	16.16
Kentucky	10.98	4.50	3.76	5.92	25.1	10.60	9.58	14.48	10.40
Louisiana	27.63	2.73	4.32	8.76	43.4	10.58	10.91	13.96	11.25
Maine	--	0.11	0.61	6.89	7.6	--	25.52	23.33	11.98
Maryland	3.72	0.82	2.41	2.06	9.0	11.74	14.98	16.26	13.70
Massachusetts	--	--	2.06	1.86	3.9	--	--	16.94	14.08
Michigan	22.86	3.95	7.11	5.83	39.7	10.49	9.91	14.69	10.44
Minnesota	90.71	20.83	1.71	6.42	119.7	9.96	8.55	17.79	10.18
Mississippi	13.97	12.06	2.37	9.52	37.9	11.07	8.87	16.33	11.01
Missouri	38.29	21.27	5.24	5.95	70.7	10.19	8.50	13.27	10.38
Montana	9.94	--	0.93	1.94	12.8	10.88	--	20.90	13.93
Nebraska	69.68	7.32	1.63	0.63	79.3	9.96	8.43	18.01	18.65
Nevada	--	--	1.86	0.57	2.4	--	--	17.41	19.19
New Hampshire	--	--	0.51	2.58	3.1	--	--	24.42	12.93
New Jersey	0.58	--	5.41	2.20	8.2	19.10	--	15.78	13.47
New Mexico	1.07	--	1.50	0.62	3.2	16.27	--	18.40	18.79
New York	3.23	0.83	8.17	7.39	19.6	12.18	14.92	14.17	11.76
North Carolina	9.52	1.40	4.84	8.87	24.6	11.01	12.99	13.55	11.21

State	Renewable Gas [million dekatherm/yr]					RG Cost (Total Opex/dekatherm) [$/dekatherm]			
	Ag Res	Energy Crops	MSW	Wood Res	Total	Ag Res	Energy Crops	MSW	Wood Res
North Dakota	42.08	24.11	0.45	0.23	66.9	9.94	8.23	25.25	24.42
Ohio	31.88	4.04	10.39	4.96	51.3	10.20	9.85	13.30	10.89
Oklahoma	10.46	0.60	3.29	2.37	16.7	10.74	16.22	15.00	13.22
Oregon	3.61	--	1.87	3.40	8.9	11.83	--	17.38	12.02
Pennsylvania	5.16	1.70	7.52	7.15	21.5	10.77	12.36	14.48	11.86
Rhode Island	--	--	0.92	0.28	1.2	--	--	20.93	23.20
South Carolina	2.11	2.66	2.52	5.04	12.3	13.62	10.99	16.08	10.84
South Dakota	32.76	10.18	0.61	0.48	44.0	10.12	9.27	23.35	20.12
Tennessee	9.57	3.40	5.77	4.85	23.6	10.99	10.30	15.52	10.96
Texas	38.81	0.90	19.69	10.14	69.6	10.16	14.58	13.49	10.83
Utah	0.56	--	1.79	0.66	3.0	19.27	--	17.58	18.44
Vermont	--	--	0.29	1.28	1.6	--	--	28.43	15.53
Virginia	3.20	0.70	4.62	7.50	16.0	12.21	15.57	13.72	11.72
Washington	11.13	--	4.09	4.04	19.3	10.57	--	14.16	11.49
West Virginia	0.20	--	1.38	3.72	5.3	25.11	--	18.82	11.74
Wisconsin	28.17	8.34	2.75	5.96	45.2	10.53	8.15	15.71	10.38
Wyoming	0.68	--	0.48	0.38	1.5	18.35	--	24.87	21.38
Totals	**1002**	**200**	**207**	**206**	**1614**	**--**	**--**	**--**	**--**
Minimum	**0.2**	**0.1**	**0.3**	**0.2**	**1.2**	**9.94**	**8.15**	**13.27**	**10.18**
Maximum	**150.4**	**26.0**	**23.3**	**12.2**	**180.1**	**25.11**	**25.52**	**28.43**	**24.42**
Median	**10.5**	**4.0**	**2.5**	**3.6**	**19.4**	**10.75**	**9.88**	**16.17**	**12.00**
Average	**23.9**	**6.9**	**4.1**	**4.1**	**32.3**	**12.05**	**11.34**	**17.72**	**14.00**
Std Deviation	**32.6**	**7.4**	**4.6**	**3.2**	**37.8**	**3.16**	**3.63**	**4.22**	**3.87**
Relative StdDev [%]	**136.6%**	**107.3%**	**110.3%**	**78.5%**	**117.2%**	**26.2%**	**32.0%**	**23.8%**	**27.6%**

Job Creation

Table 30: TG Job Creation by State and by Scenario

State	Non Aggressive		Aggressive		Max Potential	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	73	265	189	689	919	3351
Alaska	9	34	24	89	117	428
Arizona	30	110	84	307	498	1815
Arkansas	153	559	387	1411	1687	6152
California	154	562	421	1535	2369	8640
Colorado	61	222	162	590	845	3082
Connecticut	5	17	12	45	60	218
Delaware	9	33	23	86	119	435
Florida	136	495	352	1285	1704	6213
Georgia	93	339	241	877	1156	4218
Hawaii	12	42	29	107	133	487
Idaho	53	194	134	490	589	2148
Illinois	562	2049	1424	5195	6329	23083
Indiana	258	940	654	2386	2923	10662
Iowa	656	2394	1644	5998	6980	25459
Kansas	226	825	570	2078	2464	8987
Kentucky	90	327	230	837	1063	3877
Louisiana	156	569	397	1446	1780	6494
Maine	27	99	69	253	308	1123
Maryland	31	115	82	300	408	1489
Massachusetts	13	48	36	130	203	742
Michigan	141	514	363	1323	1710	6237
Minnesota	436	1590	1093	3985	4644	16940
Mississippi	137	500	346	1263	1518	5538
Missouri	255	931	646	2356	2854	10409
Montana	46	169	117	426	516	1882
Nebraska	288	1052	724	2640	3089	11267
Nevada	8	28	22	81	142	518
New Hampshire	11	40	28	103	132	481
New Jersey	27	97	75	273	455	1659
New Mexico	11	39	29	106	161	588
New York	67	243	179	653	964	3514
North Carolina	87	317	225	821	1071	3907
North Dakota	244	890	610	2227	2582	9417
Ohio	181	660	468	1707	2237	8159
Oklahoma	59	215	153	557	727	2651
Oregon	31	114	81	296	391	1427
Pennsylvania	74	270	197	717	1020	3722
Rhode Island	4	14	11	40	70	254
South Carolina	43	159	113	410	538	1964
South Dakota	160	585	402	1466	1708	6230
Tennessee	83	301	215	785	1054	3846
Texas	242	883	635	2316	3178	11593
Utah	10	36	28	100	162	590
Vermont	6	20	14	52	67	246
Virginia	56	203	146	533	734	2678
Washington	68	247	176	641	845	3083

State	Non Aggressive		Aggressive		Max Potential	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
West Virginia	19	68	48	177	240	876
Wisconsin	163	596	413	1506	1809	6598
Wyoming	5	19	14	51	71	259
Total	**5768**	**21039**	**14736**	**53746**	**67346**	**245631**
Average	**115.4**	**420.8**	**294.7**	**1074.9**	**1346.9**	**4912.6**
Maximum	**656**	**2394**	**1644**	**5998**	**6980**	**25459**
Minimum	**4**	**14**	**11**	**40**	**60**	**218**
Std Dev	**137.3**	**500.8**	**345.4**	**1259.6**	**1494.8**	**5452.0**
Relative Std Dev w/rt Avg	**119.0%**	**119.0%**	**117.2%**	**117.2%**	**111.0%**	**111.0%**

CO2 Abatement and Carbon Credit Values

Table 31: TG CO_2 Abatement and Sample Carbon Credit Values in the Non-aggressive Scenario

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Alabama	7.9	0.47	0.02	0.87	6.6
Alaska	1.0	0.06	0.00	0.11	0.9
Arizona	3.3	0.19	0.01	0.36	2.7
Arkansas	16.8	0.98	0.04	1.83	13.9
California	16.9	0.99	0.04	1.84	14.0
Colorado	6.7	0.39	0.02	0.73	5.5
Connecticut	0.5	0.03	0.00	0.06	0.4
Delaware	1.0	0.06	0.00	0.11	0.8
Florida	14.9	0.87	0.04	1.62	12.3
Georgia	10.2	0.60	0.03	1.11	8.4
Hawaii	1.3	0.07	0.00	0.14	1.0
Idaho	5.8	0.34	0.02	0.64	4.8
Illinois	61.5	3.60	0.16	6.70	50.9
Indiana	28.2	1.65	0.07	3.07	23.3
Iowa	71.9	4.21	0.19	7.83	59.4
Kansas	24.8	1.45	0.07	2.70	20.5
Kentucky	9.8	0.57	0.03	1.07	8.1
Louisiana	17.1	1.00	0.05	1.86	14.1
Maine	3.0	0.17	0.01	0.32	2.4
Maryland	3.4	0.20	0.01	0.38	2.8
Massachusetts	1.4	0.08	0.00	0.16	1.2
Michigan	15.4	0.90	0.04	1.68	12.7
Minnesota	47.8	2.80	0.13	5.20	39.5
Mississippi	15.0	0.88	0.04	1.63	12.4
Missouri	27.9	1.64	0.07	3.04	23.1

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Montana	5.1	0.30	0.01	0.55	4.2
Nebraska	31.6	1.85	0.08	3.44	26.1
Nevada	0.8	0.05	0.00	0.09	0.7
New Hampshire	1.2	0.07	0.00	0.13	1.0
New Jersey	2.9	0.17	0.01	0.32	2.4
New Mexico	1.2	0.07	0.00	0.13	1.0
New York	7.3	0.43	0.02	0.80	6.0
North Carolina	9.5	0.56	0.03	1.04	7.9
North Dakota	26.7	1.56	0.07	2.91	22.1
Ohio	19.8	1.16	0.05	2.16	16.4
Oklahoma	6.5	0.38	0.02	0.70	5.3
Oregon	3.4	0.20	0.01	0.37	2.8
Pennsylvania	8.1	0.47	0.02	0.88	6.7
Rhode Island	0.4	0.02	0.00	0.05	0.3
South Carolina	4.8	0.28	0.01	0.52	3.9
South Dakota	17.6	1.03	0.05	1.91	14.5
Tennessee	9.0	0.53	0.02	0.99	7.5
Texas	26.5	1.55	0.07	2.89	21.9
Utah	1.1	0.06	0.00	0.12	0.9
Vermont	0.6	0.04	0.00	0.07	0.5
Virginia	6.1	0.36	0.02	0.66	5.0
Washington	7.4	0.44	0.02	0.81	6.1
West Virginia	2.0	0.12	0.01	0.22	1.7
Wisconsin	17.9	1.05	0.05	1.95	14.8
Wyoming	0.6	0.03	0.00	0.06	0.5
Total	**631.79**	**36.99**	**1.68**	**68.79**	**522.28**
Average	**12.64**	**0.74**	**0.03**	**1.38**	**10.45**
Maximum	**71.90**	**4.21**	**0.19**	**7.83**	**59.44**
Minimum	**0.42**	**0.02**	**0.00**	**0.05**	**0.34**
Std Dev	**15.04**	**0.88**	**0.04**	**1.64**	**12.43**
Relative Std Dev w/rt Avg	**119.02%**	**119.02%**	**119.02%**	**119.02%**	**119.02%**

Table 32: TG CO_2 Abatement and Sample Carbon Credit Values in the Aggressive Scenario

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Alabama	20.7	1.2	0.05	2.25	17.1
Alaska	2.7	0.2	0.01	0.29	2.2
Arizona	9.2	0.5	0.02	1.00	7.6
Arkansas	42.4	2.5	0.11	4.61	35.0
California	46.1	2.7	0.12	5.02	38.1
Colorado	17.7	1.0	0.05	1.93	14.7
Connecticut	1.4	0.1	0.00	0.15	1.1
Delaware	2.6	0.2	0.01	0.28	2.1
Florida	38.6	2.3	0.10	4.20	31.9
Georgia	26.3	1.5	0.07	2.87	21.8
Hawaii	3.2	0.2	0.01	0.35	2.7
Idaho	14.7	0.9	0.04	1.60	12.2
Illinois	156.0	9.1	0.41	16.99	129.0
Indiana	71.6	4.2	0.19	7.80	59.2
Iowa	180.1	10.5	0.48	19.61	148.9
Kansas	62.4	3.7	0.17	6.79	51.6
Kentucky	25.1	1.5	0.07	2.74	20.8
Louisiana	43.4	2.5	0.12	4.73	35.9
Maine	7.6	0.4	0.02	0.83	6.3
Maryland	9.0	0.5	0.02	0.98	7.5
Massachusetts	3.9	0.2	0.01	0.43	3.2
Michigan	39.7	2.3	0.11	4.33	32.9
Minnesota	119.7	7.0	0.32	13.03	98.9
Mississippi	37.9	2.2	0.10	4.13	31.3
Missouri	70.7	4.1	0.19	7.70	58.5
Montana	12.8	0.7	0.03	1.39	10.6
Nebraska	79.3	4.6	0.21	8.63	65.5
Nevada	2.4	0.1	0.01	0.26	2.0
New Hampshire	3.1	0.2	0.01	0.34	2.6
New Jersey	8.2	0.5	0.02	0.89	6.8
New Mexico	3.2	0.2	0.01	0.35	2.6
New York	19.6	1.1	0.05	2.14	16.2
North Carolina	24.6	1.4	0.07	2.68	20.4
North Dakota	66.9	3.9	0.18	7.28	55.3
Ohio	51.3	3.0	0.14	5.58	42.4
Oklahoma	16.7	1.0	0.04	1.82	13.8
Oregon	8.9	0.5	0.02	0.97	7.3
Pennsylvania	21.5	1.3	0.06	2.34	17.8
Rhode Island	1.2	0.1	0.00	0.13	1.0
South Carolina	12.3	0.7	0.03	1.34	10.2
South Dakota	44.0	2.6	0.12	4.79	36.4
Tennessee	23.6	1.4	0.06	2.57	19.5
Texas	69.6	4.1	0.18	7.57	57.5
Utah	3.0	0.2	0.01	0.33	2.5
Vermont	1.6	0.1	0.00	0.17	1.3
Virginia	16.0	0.9	0.04	1.74	13.2
Washington	19.3	1.1	0.05	2.10	15.9
West Virginia	5.3	0.3	0.01	0.58	4.4

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Wyoming	1.5	0.1	0.00	0.17	1.3
Total	**1614.01**	**94.48**	**4.29**	**175.74**	**1334.24**
Average	**32.28**	**1.89**	**0.09**	**3.51**	**26.68**
Maximum	**180.11**	**10.54**	**0.48**	**19.61**	**148.89**
Minimum	**1.20**	**0.07**	**0.00**	**0.13**	**0.99**
Std Dev	**37.83**	**2.21**	**0.10**	**4.12**	**31.27**
Relative Std Dev w/rt Avg	**117.18%**	**117.18%**	**117.18%**	**117.18%**	**117.18%**

Joint Results

Table 33 through Table 37 contains the combined results by state for energy production, costs, job creation, and CO_2 abatement.

Energy and Costs

Table 33: Summary of Combined Results for AD and TG in the Non-aggressive Scenario

State	Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Alabama	86	584.5	153.3	14.2
Alaska	11	103.8	23.3	1.3
Arizona	81	354.3	89.0	6.6
Arkansas	67	855.4	230.0	22.2
California	512	1608.0	470.7	54.2
Colorado	100	516.5	135.7	11.7
Connecticut	20	85.8	19.5	1.4
Delaware	15	134.2	31.8	2.6
Florida	114	906.7	246.3	23.7
Georgia	119	717.6	194.1	19.1
Hawaii	25	143.0	32.5	2.0
Idaho	76	416.3	106.5	9.0
Illinois	161	2643.2	735.8	74.7
Indiana	161	1439.9	392.2	38.3
Iowa	152	2945.6	812.5	83.5
Kansas	145	1227.9	333.4	33.3
Kentucky	92	650.9	170.6	15.6
Louisiana	69	860.4	227.7	20.3
Maine	21	193.2	47.6	3.5
Maryland	53	337.5	82.8	6.5
Massachusetts	46	190.7	48.1	3.9
Michigan	128	950.2	257.8	24.9
Minnesota	128	2068.5	559.9	54.7
Mississippi	65	799.3	210.0	19.6
Missouri	187	1456.6	390.2	37.8
Montana	85	393.1	99.6	8.0
Nebraska	137	1435.4	391.5	39.2
Nevada	38	141.9	34.2	2.4
New Hampshire	16	123.8	29.5	2.2

State	Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
New Jersey	57	318.7	87.7	8.9
New Mexico	71	223.4	52.8	3.6
New York	147	699.4	199.7	22.7
North Carolina	194	772.9	205.6	19.5
North Dakota	59	1114.3	296.3	28.6
Ohio	131	1097.3	307.4	32.2
Oklahoma	117	572.8	150.5	14.2
Oregon	67	337.3	83.7	6.4
Pennsylvania	154	761.2	217.7	25.1
Rhode Island	12	72.7	17.2	1.4
South Carolina	66	418.3	105.9	9.1
South Dakota	91	831.9	222.7	21.8
Tennessee	164	704.5	181.9	15.5
Texas	392	1845.1	522.7	54.8
Utah	83	221.1	51.0	3.1
Vermont	20	99.2	22.8	1.7
Virginia	126	569.4	152.7	15.0
Washington	83	520.0	138.8	12.9
West Virginia	30	201.0	47.7	3.3
Wisconsin	163	1043.1	281.3	28.0
Wyoming	50	145.8	33.0	2.1
Total	**5187**	**36854**	**9935.1**	**966.6**
Average	**103.7**	**737.1**	**198.7**	**19.3**
Maximum	**512**	**2946**	**813**	**83**
Minimum	**11**	**73**	**17**	**1**
Std Dev	**87.7**	**640.7**	**179.5**	**18.8**
Relative Std Dev w/rt Avg	**84.5%**	**86.9%**	**90.3%**	**97.5%**

Table 34: Summary of Combined Results of AD and TG in the Aggressive Scenario

State	Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Alabama	131	1197.2	340.4	38.1
Alaska	19	194.1	47.4	3.2
Arizona	132	765.2	205.4	17.9
Arkansas	125	2027.2	564.8	59.1
California	697	3502.6	1070.7	132.7
Colorado	178	1187.0	327.8	31.9
Connecticut	22	154.4	38.1	3.3
Delaware	19	256.0	66.8	6.5
Florida	166	2045.2	574.9	59.3
Georgia	171	1533.9	442.6	50.2
Hawaii	31	259.1	64.1	5.0
Idaho	149	924.8	251.9	25.3
Illinois	226	6272.6	1775.4	186.4
Indiana	207	3234.0	910.2	95.4
Iowa	279	7159.8	2012.8	216.7
Kansas	262	2881.4	810.4	88.2
Kentucky	141	1335.0	376.5	41.0
Louisiana	101	1957.4	534.4	51.2

State	Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Maine	33	439.0	111.6	9.0
Maryland	63	621.1	167.7	16.5
Massachusetts	48	345.1	95.5	9.3
Michigan	179	2045.4	581.9	62.0
Minnesota	232	4710.5	1319.6	140.7
Mississippi	104	1749.4	482.9	50.8
Missouri	277	3105.0	878.3	97.4
Montana	168	868.4	233.8	22.2
Nebraska	255	3426.0	963.4	103.8
Nevada	66	283.8	74.5	6.4
New Hampshire	20	225.1	58.2	5.2
New Jersey	60	663.2	191.9	20.7
New Mexico	137	466.6	121.4	10.7
New York	203	1491.8	445.8	54.1
North Carolina	258	1605.2	459.2	51.8
North Dakota	113	2481.3	684.9	72.9
Ohio	181	2486.1	720.1	80.2
Oklahoma	212	1261.9	358.8	40.8
Oregon	117	653.6	177.0	16.9
Pennsylvania	214	1600.6	481.8	60.4
Rhode Island	12	137.3	35.3	3.1
South Carolina	84	770.2	213.6	22.6
South Dakota	177	2004.5	552.0	57.9
Tennessee	210	1443.1	398.0	40.1
Texas	680	4283.5	1270.9	147.5
Utah	123	415.1	105.7	8.8
Vermont	30	192.4	48.2	4.5
Virginia	165	1134.7	326.8	37.2
Washington	128	1080.5	306.4	32.4
West Virginia	44	382.5	99.4	8.7
Wisconsin	252	2276.1	646.9	72.9
Wyoming	96	304.7	76.1	6.5
Total	**7997**	**81840**	**23102.2**	**2485.4**
Average	**159.9**	**1636.8**	**462.0**	**49.7**
Maximum	**697**	**7160**	**2013**	**217**
Minimum	**12**	**137**	**35**	**3**
Std Dev	**132.6**	**1525.3**	**436.2**	**48.2**
Relative Std Dev w/rt Avg	**82.9%**	**93.2%**	**94.4%**	**97.0%**

Job Creation

Table 35: Summary of Combined Results for AD and TG by State and by Scenario

State	Non Aggressive		Aggressive		Max Potential	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
Alabama	130	474	348	1268	1297	4730
Alaska	12	42	29	105	129	472
Arizona	60	221	163	596	689	2512
Arkansas	203	739	540	1969	2035	7422
California	495	1806	1211	4419	4402	16057
Colorado	107	390	291	1063	1151	4200
Connecticut	13	46	30	109	105	384
Delaware	24	86	60	217	209	761
Florida	216	789	541	1975	2188	7980
Georgia	174	636	458	1672	1681	6130
Hawaii	19	68	46	167	174	635
Idaho	82	301	231	841	803	2929
Illinois	682	2486	1702	6207	7029	25638
Indiana	350	1275	871	3176	3473	12668
Iowa	762	2780	1978	7216	7735	28212
Kansas	304	1110	805	2938	3006	10964
Kentucky	142	519	375	1367	1409	5139
Louisiana	186	677	468	1705	1961	7151
Maine	32	116	82	299	339	1236
Maryland	60	217	150	548	580	2116
Massachusetts	36	130	85	308	329	1199
Michigan	227	828	566	2064	2219	8092
Minnesota	499	1820	1285	4687	5085	18547
Mississippi	179	651	464	1693	1797	6553
Missouri	345	1257	889	3242	3436	12531
Montana	73	267	203	740	710	2588
Nebraska	358	1305	947	3455	3590	13096
Nevada	22	81	58	212	231	842
New Hampshire	20	73	47	172	183	667
New Jersey	82	298	189	689	759	2769
New Mexico	32	118	98	358	316	1153
New York	207	755	494	1802	1782	6498
North Carolina	178	650	473	1726	1667	6080
North Dakota	261	952	666	2429	2706	9870
Ohio	294	1074	732	2670	2911	10618
Oklahoma	130	474	372	1358	1227	4475
Oregon	58	213	154	563	568	2070
Pennsylvania	230	837	552	2013	1940	7076
Rhode Island	12	45	28	103	117	427
South Carolina	84	305	206	751	778	2838
South Dakota	199	727	529	1930	1992	7265
Tennessee	142	518	367	1337	1426	5200
Texas	501	1826	1347	4911	4873	17772
Utah	29	105	80	293	287	1047
Vermont	16	58	41	151	134	488
Virginia	137	501	340	1239	1225	4469

State	Non Aggressive		Aggressive		Max Potential	
	Low Estimate	High Estimate	Low Estimate	High Estimate	Low Estimate	High Estimate
West Virginia	30	110	80	291	316	1151
Wisconsin	256	932	666	2429	2413	8803
Wyoming	19	71	59	217	173	631
Total	**8825.4**	**32189.0**	**22692.1**	**82765.3**	**86731.7**	**316337.9**
Average	**176.5**	**643.8**	**453.8**	**1655.3**	**1734.6**	**6326.8**
Maximum	**762.3**	**2780.3**	**1978.4**	**7215.9**	**7735.0**	**28211.8**
Minimum	**11.6**	**42.1**	**28.3**	**103.3**	**105.2**	**383.9**
Std Dev	**172.1**	**627.6**	**440.1**	**1605.3**	**1721.6**	**6279.2**
Relative Std Dev w/rt Avg	**97.5%**	**97.5%**	**97.0%**	**97.0%**	**99.2%**	**99.2%**

CO_2 Abatement and Carbon Credit Values

Table 36: Combined CO_2 Abatement and Sample Carbon Credit Values in the Non-aggressive Scenario

State	Renewable Gas (RG) [million dekatherm/yr]	CO2 Abatement [million ton/yr]	CCX CFI CO2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Alabama	14.2	0.83	0.04	1.55	11.77
Alaska	1.3	0.07	0.00	0.14	1.05
Arizona	6.6	0.39	0.02	0.72	5.48
Arkansas	22.2	1.30	0.06	2.42	18.34
California	54.2	3.18	0.14	5.91	44.84
Colorado	11.7	0.69	0.03	1.27	9.68
Connecticut	1.4	0.08	0.00	0.15	1.14
Delaware	2.6	0.15	0.01	0.28	2.13
Florida	23.7	1.39	0.06	2.58	19.59
Georgia	19.1	1.12	0.05	2.08	15.78
Hawaii	2.0	0.12	0.01	0.22	1.68
Idaho	9.0	0.53	0.02	0.98	7.47
Illinois	74.7	4.37	0.20	8.13	61.72
Indiana	38.3	2.24	0.10	4.17	31.65
Iowa	83.5	4.89	0.22	9.09	69.02
Kansas	33.3	1.95	0.09	3.63	27.57
Kentucky	15.6	0.91	0.04	1.70	12.89
Louisiana	20.3	1.19	0.05	2.21	16.81
Maine	3.5	0.20	0.01	0.38	2.89
Maryland	6.5	0.38	0.02	0.71	5.39
Massachusetts	3.9	0.23	0.01	0.43	3.24
Michigan	24.9	1.46	0.07	2.71	20.55
Minnesota	54.7	3.20	0.15	5.95	45.18
Mississippi	19.6	1.14	0.05	2.13	16.17
Missouri	37.8	2.21	0.10	4.11	31.21
Montana	8.0	0.47	0.02	0.87	6.62
Nebraska	39.2	2.29	0.10	4.27	32.40
Nevada	2.4	0.14	0.01	0.26	2.01
New Hampshire	2.2	0.13	0.01	0.24	1.81
New Jersey	8.9	0.52	0.02	0.97	7.40

State	Renewable Gas (RG) [million dekatherm/yr]	CO2 Abatement [million ton/yr]	CCX CFI CO2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
New Mexico	3.6	0.21	0.01	0.39	2.94
New York	22.7	1.33	0.06	2.47	18.73
North Carolina	19.5	1.14	0.05	2.13	16.14
North Dakota	28.6	1.67	0.08	3.11	23.64
Ohio	32.2	1.89	0.09	3.51	26.65
Oklahoma	14.2	0.83	0.04	1.55	11.77
Oregon	6.4	0.37	0.02	0.70	5.29
Pennsylvania	25.1	1.47	0.07	2.74	20.79
Rhode Island	1.4	0.08	0.00	0.15	1.12
South Carolina	9.1	0.54	0.02	1.00	7.56
South Dakota	21.8	1.28	0.06	2.38	18.05
Tennessee	15.5	0.91	0.04	1.69	12.85
Texas	54.8	3.21	0.15	5.97	45.32
Utah	3.1	0.18	0.01	0.34	2.60
Vermont	1.7	0.10	0.00	0.19	1.45
Virginia	15.0	0.88	0.04	1.64	12.44
Washington	12.9	0.75	0.03	1.40	10.63
West Virginia	3.3	0.19	0.01	0.36	2.73
Wisconsin	28.0	1.64	0.07	3.05	23.14
Wyoming	2.1	0.12	0.01	0.23	1.76
Total	**966.64**	**56.59**	**2.57**	**105.25**	**799.08**
Average	**19.33**	**1.13**	**0.05**	**2.11**	**15.98**
Maximum	**83.49**	**4.89**	**0.22**	**9.09**	**69.02**
Minimum	**1.27**	**0.07**	**0.00**	**0.14**	**1.05**
Std Dev	**18.85**	**1.10**	**0.05**	**2.05**	**15.58**
Relative Std Dev w/rt Avg	**97.49%**	**97.49%**	**97.49%**	**97.49%**	**97.49%**

Table 37: Combined CO_2 Abatement and Sample Carbon Credit Values in the Aggressive Scenario

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Alabama	38.1	2.23	0.10	4.15	31.47
Alaska	3.2	0.19	0.01	0.34	2.61
Arizona	17.9	1.05	0.05	1.95	14.80
Arkansas	59.1	3.46	0.16	6.44	48.88
California	132.7	7.77	0.35	14.45	109.69
Colorado	31.9	1.87	0.08	3.48	26.38
Connecticut	3.3	0.19	0.01	0.35	2.70
Delaware	6.5	0.38	0.02	0.71	5.40
Florida	59.3	3.47	0.16	6.46	49.02
Georgia	50.2	2.94	0.13	5.47	41.51
Hawaii	5.0	0.29	0.01	0.55	4.15

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Idaho	25.3	1.48	0.07	2.75	20.87
Illinois	186.4	10.91	0.49	20.30	154.10
Indiana	95.4	5.58	0.25	10.39	78.85
Iowa	216.7	12.69	0.58	23.59	179.13
Kansas	88.2	5.16	0.23	9.61	72.92
Kentucky	41.0	2.40	0.11	4.47	33.92
Louisiana	51.2	3.00	0.14	5.58	42.34
Maine	9.0	0.53	0.02	0.98	7.42
Maryland	16.5	0.96	0.04	1.79	13.60
Massachusetts	9.3	0.54	0.02	1.01	7.66
Michigan	62.0	3.63	0.16	6.75	51.24
Minnesota	140.7	8.24	0.37	15.32	116.35
Mississippi	50.8	2.98	0.13	5.53	42.02
Missouri	97.4	5.70	0.26	10.60	80.49
Montana	22.2	1.30	0.06	2.42	18.36
Nebraska	103.8	6.07	0.28	11.30	85.77
Nevada	6.4	0.37	0.02	0.69	5.26
New Hampshire	5.2	0.30	0.01	0.56	4.26
New Jersey	20.7	1.21	0.05	2.25	17.11
New Mexico	10.7	0.63	0.03	1.17	8.88
New York	54.1	3.17	0.14	5.89	44.72
North Carolina	51.8	3.03	0.14	5.64	42.85
North Dakota	72.9	4.27	0.19	7.94	60.29
Ohio	80.2	4.69	0.21	8.73	66.29
Oklahoma	40.8	2.39	0.11	4.44	33.70
Oregon	16.9	0.99	0.04	1.84	13.97
Pennsylvania	60.4	3.54	0.16	6.58	49.96
Rhode Island	3.1	0.18	0.01	0.34	2.57
South Carolina	22.6	1.32	0.06	2.46	18.65
South Dakota	57.9	3.39	0.15	6.31	47.90
Tennessee	40.1	2.35	0.11	4.37	33.19
Texas	147.5	8.63	0.39	16.06	121.92
Utah	8.8	0.52	0.02	0.96	7.28
Vermont	4.5	0.27	0.01	0.49	3.74
Virginia	37.2	2.18	0.10	4.05	30.75
Washington	32.4	1.90	0.09	3.53	26.78
West Virginia	8.7	0.51	0.02	0.95	7.22
Wisconsin	72.9	4.27	0.19	7.94	60.29
Wyoming	6.5	0.38	0.02	0.71	5.38
Total	**2485.44**	**145.50**	**6.60**	**270.63**	**2054.62**
Average	**49.71**	**2.91**	**0.13**	**5.41**	**41.09**
Maximum	**216.69**	**12.69**	**0.58**	**23.59**	**179.13**
Minimum	**3.10**	**0.18**	**0.01**	**0.34**	**2.57**
Std Dev	**48.21**	**2.82**	**0.13**	**5.25**	**39.85**
Relative Std Dev w/rt Avg	**96.98%**	**96.98%**	**96.98%**	**96.98%**	**96.98%**

10.0 Regulatory Issues

Introduction

For RG from biogas to be cost competitive, it is important that producers, distributors, and users of the RG be able to take advantage of the potential for monetization of environmental benefits offered by this renewable resource. There are two primary pathways for this monetization of benefits to occur, CO_2 credits and offsets and RPS credits. This section will examine regulatory barriers to both pathways. Regulatory issues dealing with cleanup of biogas to RG are not the subject of this section and have been covered by other GTI documents (see for instance Saber, 2009). A full description of all regulatory issues and barriers for various non-voluntary and voluntary GHG trading regimes is presented in the Appendix (section 15.0).

The European Union institutions – the Commission, Parliament and Council – already have legislative mandates and related opinions and communications stating biogas and biomethane can and should be used for a variety of purposes, including electric generation, directly as a vehicle fuel, and to be ‘mainstreamed’ into the existing natural gas grid. Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas had outlined in the obligations of member states to allow access to the natural gas grid and, importantly, specifies biogas should be given non-discriminatory access to the natural gas system, as long as it is brought up to pipeline quality (which still is under national authority until the Committee for European Normalization finalizes a biogas quality standard). European regulatory authorities that do not allow ‘grid-injection’ of biogas that are not in compliance with European law.[20]

In Germany a carbon tax, carbon cap and trade system, and a renewable energy feed-in tariff have created the incentives for the biogas industry to flourish, creating tens of thousands of jobs in the biomass energy industry. Germany now has more than 5,000 biogas production plants of various sizes in both rural and urban areas.[21]

Sweden has fifteen cities relying on biomethane for its natural gas vehicles (NGV), providing over 50% of the methane used for vehicles in Sweden. Subsidies are available for biogas production facilities and NGV fueling stations.

In Canada, Terasen Gas has received approval in December 2010 from the British Columbia Utilities Commission for a new renewable gas program for an initial two-year period. In 2011, up to 24,000 residential customers will be able to subscribe to the program on a first-come, first-served basis. The equivalent of 10% of customers’ natural gas requirements will be assigned from local renewable energy projects feeding gas supply into the Terasen Gas network. As part of the biogas program, Terasen Gas has also received approval to activate two projects to upgrade raw biogas into pipeline-quality biogas, known as biomethane or renewable gas, which will then be added to Terasen Gas distribution system.[22]

[20] http://eggfuel.ie/?p=409
[21] http://www.eesi.org/renewable-biogas-too-valuable-waste-16-jun-2010
[22] http://iscleaner.com/section/biogas/

Current U.S. policies favor renewable electricity over renewable biogas production for distribution on the natural gas pipeline system. This drives the market to burn biogas to produce electricity instead of using it for other potentially higher value thermal and transportation applications. If policies were to be enacted to equalize the incentives for producing biogas to those provided for producing wind and solar electricity, very likely an increase in the capture, generation, and use of biogas would result.

CO_2 Credits

The primary regulatory barriers in the U.S. to obtaining CO_2 credits for RG are additionality, regulatory surplus, process requirements, geographic eligibility limitations, offset project eligibility requirements, and specific regulatory prohibitions and uncertainties. It should be noted the first and only actively traded non-voluntary CO_2 credit cap and trade system in the U.S. is occurring under the RGGI, first discussed in 2003, and implemented in 2009, with three auctions having occurred with CO_2 credits ranging from about $3.05-3.51 per ton of CO_2. RGGI, applying mainly to power plants over 25 MW but allowing offsets in other applications, is in force in ten Northeast and Mid-Atlantic States (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, New Hampshire, New York, Rhode Island and Vermont) and much of the U.S. trading experience comes from there. *However, these auctions have not as yet given GHG credits or offsets to biogas to RG projects.*[23]

The additionality criterion is designed to avoid giving credits to projects that would have happened anyway, and to ensure the project reduces emissions more than would have occurred in the absence of the project. There are standardized tests for additionality in RGGI and some other trading regimes, but as a RG project has not been tested under this criterion, it is a potential barrier to the success of these projects.

The regulatory surplus requirement is designed to avoid "double counting," and means the credit will not be given for projects required under RPS or other regulations. This leads to the dilemma that projects credited with RPS benefits cannot simultaneously receive GHG credits, a barrier to project implementation. The process requirements for each CO_2 trading regime are standardized, but take time and effort to ensure compliance with all data requests.

Even though climate change is a worldwide issue, specific trading schemes like RGGI require projects and offsets must occur within the geographic boundaries of its member states. Other jurisdictions, including California, allow offsets to occur from renewables outside the geographic boundaries of the trading zone, if firm contracts linking the source of renewable electrons or RG to the end user or power plant within the jurisdiction can be shown. Climate Action Registry (CAR) allows for projects only within the U.S.

A carbon offset is a reduction in emissions of carbon or GHG made in order to compensate for or to offset, an emission made elsewhere. RG is not explicitly covered under the offset requirements of RGGI or elsewhere, and this may present a major barrier to its acceptance. Some discussions of prevention of manure-related methane emissions as being acceptable occurs, but mostly related to methane "destruction" (presumably flaring) or onsite use of methane particularly for power generation, not usefully using the methane so captured offsite. RGGI has not established formal guidelines for giving

[23] On 26 May 2011, New Jersey Governor Chris Christie announced that New Jersey intends to terminate its membership in RGGI. See "Christie Pulls New Jersey From 10-State Climate Initiative" by Mireya Navarro, New York Times, 26 May 2011 (http://www.nytimes.com/2011/05/27/nyregion/christie-pulls-nj-from-greenhouse-gas-coalition.html?_r=1) and "New Jersey Gov. Chris Christie pulls out of greenhouse gas effort" by Juliet Eilperin, Washington Post, 26 May 2011 (http://www.washingtonpost.com/national/new-jersey-gov-chris-christie-pulls-out-of-greenhouse-gas-effort/2011/05/26/AGoQUGC).

offset credits for RG being used in residential, commercial, or industrial establishments to displace natural gas. This is a critical barrier to gaining offset credits for RG.

In terms of regulatory prohibitions and uncertainties, one of the most troubling is the explicit California prohibition of LFG, the so-called Hayden amendment, from entering the natural gas pipeline. This barrier to implementation would need to be removed to allow full use of LFG, with all due consideration of pipeline quality requirements.

RPS Credits

Credits for RG under the RPS requirements now in force in over half the states are critical to the success of RG projects where the biogas is destined for power plant applications. An excellent precedent in California has occurred, where RG from renewable projects in Texas, with firm contracts for transportation to California, was given RPS credits in California.
The RPS credits for RGGI and other trading regimes have not been so certain, and test cases need to be established in their areas to ensure that RG gets appropriate credits.

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12.0 Appendix: Utilization Scenarios

For analyzing the processing and economics of converting biomass into renewable gas, GTI used a block process model. The model is intended to be a general framework that has two positive features: (1) it captures enough reality associated with feedstock processing to be quantifiable, and (2) it is general enough to be a convenient organization to enable the analysis work across all feedstocks. It is not intended to capture all the details and idiosyncrasies associated with all the feedstocks considered within this project, whether they be processed via anaerobic digestion or via thermal gasification.

Figure 3 contains the block processing diagram. For feedstock processed via thermal gasification, the processing path consists of 3-stages: *Utilization* → *Collection* → *Conversion/TG* → **PQG/RG**.
For feedstock that is processed via anaerobic digestion, the processing path is comprised of 4-stages: *Utilization* → *Collection* → *Conversion/AD* → *Cleanup* → **PQG/RG**.

Prima facie, the AD path appears to have an additional processing step, the *Cleanup* block. In fact, the transformation into RG of the syngas produced via TG is an integrated part of the TG conversion process. For the purposes of the analysis performed within this project, it is conveniently modeled as being subsumed within the *Conversion* block. However, for the AD processing path, it is more convenient to explicitly model the *Cleanup* process separately from the conversion process. Each one of these steps along a process path (TG or AD) has an associated efficiency, which is modeled in the analysis.

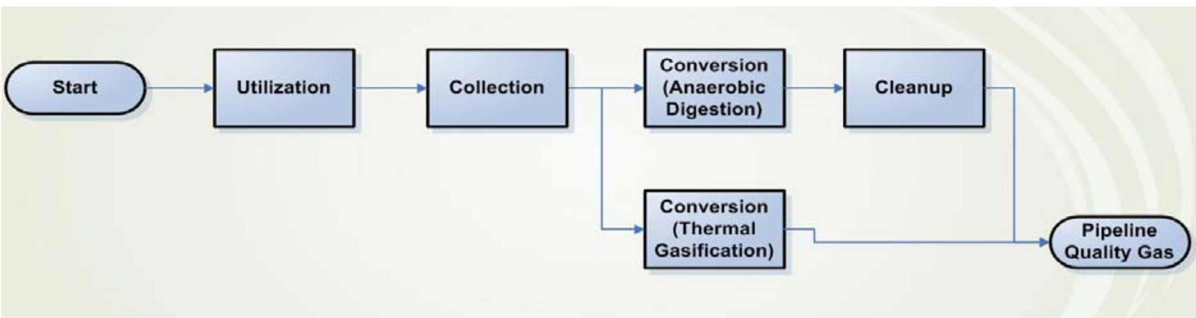

Figure 3: Block Diagram of Feedstock Processing into Pipeline Quality/Renewable Gas

Scenarios and Efficiency Values

Based on discussions with AGF, GTI and AGF developed tables of *Utilization*, *Collection*, *Conversion*, and *Cleanup* efficiency values for each of the potential feedstocks in the study. Based upon the block diagram in Figure 3, these factors are input parameters to the calculations and analysis performed in the study. In fact, the selection of their values defines the study under consideration. The term *Utilization* refers to the potential application or market penetration of each considered feedstock. AGF and GTI selected for consideration three separate utilization scenarios for each feedstock: Non-Aggressive, Aggressive, and Maximum Potential.

The objective of these scenarios was to examine to what extent each feedstock could possibly be utilized for generating renewable gas. The 3 scenarios are firstly distinguished by their *Utilization* efficiencies. The Non-aggressive scenario represents a low level of *Utilization* efficiency. The Aggressive scenario has overall a higher level, and Maximum Potential has the highest possible at 100%. The Maximum Potential scenario has its *Utilization* and *Collection* values set to 100%. Although the Maximum Potential scenario has such high overall efficiencies at all stages is patently unattainable in reality, examination of this scenario does set the overall scale — within the context of this model, the input data, and the assumptions — for the maximum conceivable energy production and expenses.

In the Non-aggressive scenario, a fairly low level of *Utilization*/market penetration is envisioned, ranging from 5% for MSW to 25% for wastewater. In the Aggressive scenario is considered generally higher levels of market penetration in the event economic incentives would or could be implemented to spur renewable energy. *Utilization* fractions range from 15% to 75% over the selected feedstocks under this Aggressive scenario.

Collection refers to the efficiency of the harvesting or gathering procedure. It is assumed 5% of the feedstock would be lost, wasted, or, for example, left on the ground. Collection efficiency is 95% for the Non-aggressive and Aggressive scenarios. It is set to 100% for the Maximum Potential scenario. GTI recognizes that an alternative method of modeling could be used to implement the overall *Utilization* and

Collection efficiencies as a single efficiency, rather than as individual efficiencies. For some references it may be useful to compare the product of *Utilization* x *Collection* efficiencies in this model with the overall, generic utilization factors considered in other models.

Conversion refers to the process of converting feedstock into gas, either via TG or via AD. In the case of TG, the conversion efficiency is modeled at 65% for all scenarios. For AD, the available data provide energy yield factors that already include the conversion efficiency. Therefore, within the context of this model, the AD conversion efficiencies are set at 100% because the real efficiencies already are implicitly contained in the energy yield factors.

Cleanup refers to the typical efficiency of biogas collection from AD or from landfill during the process of upgrading the biogas to pipeline quality. *Cleanup* is assumed to be 95% efficient (5% loss of biogas) within the Non-aggressive and Aggressive scenarios. As discussed earlier, the TG *Cleanup* process step is subsumed in this model into the TG *Conversion* process step. Hence, for the TG *Cleanup* efficiencies to reflect this fact consistently, they are set to 1.0 or 100%. This is similar to the AD *Conversion* efficiencies which are set to 1.0 to reflect that the efficiencies are implicitly included in the energy yield factors available in the AD data.

Table 38: Summary of Utilization Scenarios, Associated Collection, Conversion, and Biogas Cleanup Efficiency Factors.

Global Efficiencies Table

Non-aggressive							
Technology	**TG**	**TG**	**TG**	**TG**	**AD**	**AD**	**AD**
Efficiency	**Ag Residues**	**Energy Crops**	**Municipal Solid Waste**	**Wood Residues**	**Landfill Gas**	**Livestock Manure**	**Waste Water**
Utilization	0.10	0.10	0.05	0.10	0.20	0.15	0.25
Collection	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Conversion	0.65	0.65	0.65	0.65	1.00	1.00	1.00
Cleanup	1.00	1.00	1.00	1.00	0.95	0.95	0.95
Total	**0.06**	**0.06**	**0.03**	**0.06**	**0.18**	**0.14**	**0.23**

Global Efficiencies Table

Aggressive							
Technology	TG	TG	TG	TG	AD	AD	AD
Efficiency	**Ag Residues**	**Energy Crops**	**Municipal Solid Waste**	**Wood Residues**	**Landfill Gas**	**Livestock Manure**	**Waste Water**
Utilization	0.25	0.25	0.15	0.25	0.40	0.50	0.75
Collection	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Conversion	0.65	0.65	0.65	0.65	1.00	1.00	1.00
Cleanup	1.00	1.00	1.00	1.00	0.95	0.95	0.95
Total	**0.15**	**0.15**	**0.09**	**0.15**	**0.36**	**0.45**	**0.68**

Global Efficiencies Table

Max Potential							
Technology	**TG**	**TG**	**TG**	**TG**	**AD**	**AD**	**AD**
Efficiency	**Ag Residues**	**Energy Crops**	**Municipal Solid Waste**	**Wood Residues**	**Landfill Gas**	**Livestock Manure**	**Waste Water**
Utilization	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Collection	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Conversion	0.65	0.65	0.65	0.65	1.00	1.00	1.00
Cleanup	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Total	**0.65**	**0.65**	**0.65**	**0.65**	**1.00**	**1.00**	**1.00**

Included in Table 39 is a summary of the modeled efficiency factors for *Utilization*, *Collection*, *Conversion*, and *Cleanup*, as a function of feedstock and technology. Under each scenario, the estimated, annual availabilities of each feedstock will reflect the *Utilization* and *Collection* efficiencies. The energy production from the annual availability will reflect all 4 efficiencies: *Utilization, Collection, Conversion,* and *Cleanup*. Additionally, a summary of the energy yield factors for each feedstock as well as the modeled water (moisture) content of each is presented in Table 39.

Table 39: Specific Energy Yields and Other Feedstock Data

Specific Energy Yields							
	Ag Residues	**Energy Crops**	**Municipal Solid Waste**	**Wood Residues**	**Landfill Gas**	**Livestock Manure**	**Waste Water**
Technology	**TG**	**TG**	**TG**	**TG**	**AD**	**AD**	**AD**
Specific Energy Yield [MMBtu/wet ton] {[MMBtu/MG] if WWTP}	11.2	13.8	8.4	11.2	*	0.77**	7.9
Specific Energy Yield [MMBtu/dry ton]	13.2	16.2	9.9	13.2	‡	‡	‡
Moisture Content [%]	15%	15%	15%	15%	‡	‡	‡

*The specific energy yield of landfill gas is based on the methane production of the waste in place within the landfill *x* the energy content of the methane. This is described more fully in following sections.

**The specific energy yield of livestock manure is specified as a state-dependent, weighted-average yield. The number in this table is a global, weighted average over all states and animals considered. This circumstance is described more fully in following sections.

‡ This data is subsumed within the energy yield factors and is not needed to compute the AD energy yield.

13.0 Appendix: Economic Inputs

Specific Expenses for Anaerobic Digestion

The following power law functions, derived from publically available data, provide specific capex and opex as a function of annual plant capacity for the AD:

$$\text{Specific Capex [\$/wet ton manure]} = 501.099\ Wa^{-0.2786}$$
$$\text{Specific Opex [\$/wet ton manure]} = 5610.97 Wa^{-0.7568}$$

In the above expressions, W_a is the annual wet tonnage of biomass processed.

Specific Expenses for Wastewater Treatment Plants

The specific capex and opex estimates for the digester facility at wastewater treatment plants are based on the following expressions:

$$\text{Specific Capex [\$/MG]} = 31{,}824.34 + 133{,}869.00/V_a.$$
$$\text{Specific Opex [\$/MG]} = 6772.9 + 36{,}846.48/V_a.$$

In the above expressions, V_a [millions of gallons, MG] is the annual volume of sludge processed, based on a ratio of sludge volume to wastewater volume of 0.369% @ 4% solids.

Specific Expenses for Cleanup

Both the specific capital cost and the specific operating cost of the cleanup facility are functions of the annual throughput of raw biogas (Takach, 2010):

$$\text{Specific Capex [\$/MCF]} = 4.72 + 908{,}142.72/V_a.$$
$$\text{Specific Opex [\$/MCF]} = 1.91 + 93{,}604/V_a.$$

In the above expressions, V_a is the annual volume of biogas in thousands of cubic feet (MCF).

Expenses for Thermal Gasification

Capex and opex are estimated based on published cost estimates for pressurized biomass gasification to generate renewable gas. For TG, the capex is the cost to construct the facility to process feedstock into renewable gas. Opex consists of the annual expenses in operating such a facility, including financing. Based on the different scales of operation and converting to $US and standard short tons, the capex and opex are estimated from the following formulae, respectively:

$$\text{Capex (\$millions)} = \$256.47079 \times (\text{Plant Capacity, ton/year})^{0.64405}$$
$$\text{Opex (\$millions)} = \$71.69318 \times (\text{Plant Capacity, ton/year})^{0.738195}$$

The plant capacity is measured in annual wet tons of feedstock. See (Takach, 2010) and references therein. Contrary to the AD expenses, these functions parameterize the total capex and opex as functions of the plant capacity, not the specific capex and opex.

Jobs Creation

Calculations of potential jobs creation is based on a study done by Kammen and colleagues at the University of California, Berkeley (Kammen, 2004). In this study, early phase, manufacturing and construction jobs are set on the same footing as ongoing operations and maintenance jobs. After this equalization, specific employment estimates range from 0.78-2.84 jobs/MW_a of biomass-based electrical energy production, in which 1 MW_a is the average, biomass-based electrical power generated. Converting this into jobs/MMBtu or jobs/dekatherm and folding in a typical 35% efficiency for electrical generation, this yields a job creation factor ranging from (9.13-33.3) x 10^{-6} jobs/MMBtu/yr. This range of factors defines the low and high estimates in the potential jobs creation tables.

CO_2 Abatement and Carbon Credit Values

The value of carbon credits for the utilization of renewable fuel is also estimated. From the energy production rates, the amount of new CO_2 not released into the environment is calculated based on a rate of 117 lbs CO_2/MMBtu of energy. An extended discussion of carbon-trading and regulatory considerations for the production of renewable gas is contained in the section *10.0 Regulatory Issues* and in *15.0 Appendix: Regulatory Issues*. The annual value of those credits is calculated based on 3 credit factors, one from the CCX, one from the RGGI, and one from the ECX. Recent rates on each of the exchanges are shown in Table 40 (Chicago Climate, 2010; Auction Results, 2010; Intercontinental Exchange, 2010).

Table 40: Carbon Credit Values

Exchange	Value [$/ton CO_2]
CCX	0.0454
RGGI	1.86
ECX	14.12

The large disparity of rates is evidence of the significant differences in the regulatory environments regionally within the U.S. and nationally between the U.S. and Europe. Because the differences are so large, and because in some circumstances the ownership of the carbon credits associated with the renewable energy production would be in question or negotiable, the estimated carbon credit values for each state are not included as a reduction in the operating expenses.

Financing Assumptions

A component of the operating costs that enter the calculation for the unit price of RG is the financing cost for renewable energy projects. For both TG and AD in each state, the financing parameters are shown in Table 41. The annual interest rate is designated as r. The monthly interest rate is *i*. The debt-equity ratio is ρ and in this study is 50:50 by assumption. For a general debt-equity ratio of ρ, the fractional amount of debt is $\frac{\rho}{1+\rho}$ and the fractional equity is $\frac{1}{1+\rho}$. Hence, for a total capital expense *P*, the principal of a loan is $\frac{\rho}{1+\rho}P$, and the amount of equity is $\frac{1}{1+\rho}P$. The annual financing cost (C_F), therefore, contains two terms. The first is the annual sum of monthly loan payments, and the second is the annual return on investment, based on a return rate of f_R = 10%:

$$C_F = \frac{12i(\frac{\rho}{1+\rho})P}{(1-(1+i)^{-N})} + f_R\left(\frac{1}{1+\rho}\right)P$$

Table 41: Financing Parameters for Renewable Energy Projects

Name	Variable	Definition	Value
Interest Rate	r	Annual interest rate for financing.	7%
Monthly interest Rate	i	Rate interest accrued on a monthly basis on remaining loan principal.	$(1+r)^{1/12}-1$
Debt/Equity Ratio	ρ	Ratio of amount of debt incurred in the capital expense of constructing the processing facilities to produce RG to the amount of equity provided.	50%:50%
Term	N	Loan repayment time period	20 years or 240 months
Return on Equity	f_R	Annual amount of return made on the original equity provided.	10%

14.0 Appendix: Results from the Maximum Utilization Scenario

The following set of tables constitutes a summary of the main results from the analysis of the Maximum scenario. The Maximum scenario (see *12.0 Appendix: Utilization Scenarios*) is the scenario in which (almost) all efficiencies are set to their highest possible values (100%). It is an unrealistic scenario, but it sets important upper limits to the amount of energy, number of jobs, etc., *within the context and assumptions of the model*. The following set of tables display the same information that was included in the main body of results for the Non-aggressive and Aggressive scenarios.

Results for Anaerobic Digestion

Availabilities

Table 42: AD Annual Feedstock Availabilities for the Maximum Scenario

State	Landfills [millions wet tons/yr]	Livestock Manure [millions wet tons/yr]	Wastewater [thousands MGY]
Alabama	119.1	23.6	20.3
Alaska	10.2	0.2	0.0
Arizona	116.5	16.8	53.3
Arkansas	38.4	30.8	0.0
California	2376.4	99.8	155.6
Colorado	142.7	34.7	11.3
Connecticut	30.4	1.3	0.0
Delaware	49.6	2.2	24.7
Florida	323.7	23.6	30.7
Georgia	192.7	26.0	80.2
Hawaii	21.7	1.8	35.4
Idaho	5.3	36.1	0.0
Illinois	488.7	27.0	394.2
Indiana	347.5	24.1	114.7
Iowa	67.4	99.6	24.5
Kansas	99.9	76.5	22.1
Kentucky	105.3	31.6	33.9
Louisiana	105.7	10.9	5.9
Maine	12.4	2.0	0.0
Maryland	97.0	5.9	6.1
Massachusetts	87.5	1.1	129.6
Michigan	322.7	23.3	273.4
Minnesota	57.2	56.8	0.0
Mississippi	77.9	18.8	0.0
Missouri	227.5	58.1	69.3
Montana	16.4	30.5	0.0
Nebraska	36.4	80.0	7.0
Nevada	86.0	6.2	21.5
New Hampshire	42.0	0.8	0.0
New Jersey	295.9	1.1	152.6
New Mexico	19.3	24.5	16.6
New York	666.6	30.0	160.5
North Carolina	182.2	41.6	25.1
North Dakota	5.5	20.4	0.0
Ohio	478.5	27.8	143.9

State	Landfills [millions wet tons/yr]	Livestock Manure [millions wet tons/yr]	Wastewater [thousands MGY]
Oklahoma	59.7	69.6	12.5
Oregon	65.9	17.3	7.0
Pennsylvania	693.8	35.4	76.2
Rhode Island	49.4	0.1	8.2
South Carolina	153.1	7.7	15.5
South Dakota	15.2	46.7	0.0
Tennessee	176.3	26.6	54.8
Texas	604.9	171.7	185.9
Utah	45.5	13.5	0.0
Vermont	28.7	6.0	0.0
Virginia	318.5	22.3	75.4
Washington	197.6	18.6	24.3
West Virginia	23.5	5.9	0.0
Wisconsin	204.7	65.3	30.7
Wyoming	8.0	16.0	0.0
Total	**9996.8**	**1518.2**	**2502.8**
Average	**199.9**	**30.4**	**50.1**
Maximum	**2376.4**	**171.7**	**394.2**
Minimum	**5.3**	**0.1**	**0.0**
Std Dev	**355.7**	**32.0**	**77.6**
Relative Std Dev w/rt Avg	**177.9%**	**105.5%**	**155.0%**

Energy and Costs

Table 43: Summary of AD Assessment Results from the Maximum Scenario

State	AD Plants [No.]	Cleanup Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Alabama	71	105	569.3	209.5	41.4
Alaska	11	14	32.7	10.0	1.3
Arizona	78	104	393.9	128.9	20.9
Arkansas	81	93	560.3	199.2	38.1
California	279	605	2780.8	1087.5	222.7
Colorado	115	140	600.2	198.8	33.6
Connecticut	5	19	72.8	25.5	5.0
Delaware	6	14	114.3	45.0	9.8
Florida	73	134	691.0	261.7	53.0
Georgia	82	137	745.1	283.5	57.4
Hawaii	9	23	81.5	26.5	4.5
Idaho	109	114	496.0	153.1	23.4
Illinois	84	174	971.9	378.5	76.7
Indiana	69	169	784.9	297.6	60.3
Iowa	174	201	1234.8	435.8	82.7
Kansas	171	202	999.6	337.3	59.4
Kentucky	77	113	578.7	201.9	37.9
Louisiana	41	79	312.1	107.5	19.7
Maine	14	25	75.3	22.6	3.4
Maryland	17	54	245.5	91.6	18.8
Massachusetts	7	43	177.4	68.9	13.7

State	AD Plants [No.]	Cleanup Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Michigan	76	147	750.8	283.2	55.7
Minnesota	146	174	822.5	276.5	48.3
Mississippi	57	81	436.0	156.9	30.5
Missouri	136	224	992.6	346.2	63.7
Montana	123	129	484.6	147.9	21.2
Nebraska	172	194	963.8	319.0	54.9
Nevada	43	51	190.0	61.3	9.7
New Hampshire	5	17	71.3	27.0	5.6
New Jersey	12	48	339.2	148.0	33.3
New Mexico	101	105	398.6	120.2	17.0
New York	90	165	1049.0	421.0	89.6
North Carolina	98	222	933.4	337.2	65.2
North Dakota	75	81	320.3	95.1	13.6
Ohio	75	147	891.6	351.3	73.8
Oklahoma	145	166	899.0	305.0	54.8
Oregon	77	93	366.3	118.7	19.3
Pennsylvania	92	180	1158.5	467.4	100.7
Rhode Island	2	8	51.3	22.5	5.2
South Carolina	29	71	336.2	127.9	26.3
South Dakota	125	133	612.3	193.8	31.1
Tennessee	71	181	645.5	222.5	40.7
Texas	437	540	2669.6	984.0	185.6
Utah	59	103	307.2	93.1	13.7
Vermont	16	24	128.2	40.8	7.3
Virginia	67	137	693.8	264.0	53.8
Washington	72	104	487.9	175.1	33.1
West Virginia	23	36	149.7	48.1	8.3
Wisconsin	135	205	1008.6	353.6	66.2
Wyoming	70	73	275.8	81.2	11.2
Totals	**4202**	**6401**	**30952**	**11159**	**2123**
Minimum	**2.0**	**8.0**	**32.7**	**10.0**	**1.3**
Maximum	**437.0**	**605.0**	**2780.8**	**1087.5**	**222.7**
Median	**75.0**	**109.0**	**528.2**	**184.4**	**33.2**
Average	**84.0**	**128.0**	**619.0**	**223.2**	**42.5**
Std Deviation	**74.7**	**109.6**	**541.7**	**206.9**	**41.6**
Relative Std Dev	**88.9%**	**85.6%**	**87.5%**	**92.7%**	**98.0%**

Individual Feedstock Energy Production and Unit Prices

Table 44: AD Energy Production and Unit Prices by Feedstock and State in the Maximum Scenario

State	Renewable Gas [million dekatherm/yr]				RG Cost (Total Opex/dekatherm) [$/dekatherm]		
	LFG	Livestock Manure	Waste Water	Total	LFG	Livestock Manure	Waste Water
Alabama	14.7	26.5	0.2	41.4	4.35	5.40	12.78
Alaska	1.2	0.1	0.0	1.3	4.38	38.23	--
Arizona	9.6	10.9	0.4	20.9	4.42	7.55	9.59
Arkansas	5.0	33.2	0.0	38.1	4.37	5.35	--
California	157.3	64.2	1.2	222.7	4.31	6.19	9.80
Colorado	10.8	22.6	0.1	33.6	4.35	6.65	11.05
Connecticut	3.9	1.1	0.0	5.0	4.59	6.98	--
Delaware	5.6	4.0	0.2	9.8	4.19	4.90	9.67
Florida	36.3	16.5	0.2	53.0	4.24	6.38	10.39
Georgia	24.2	32.6	0.6	57.4	4.35	5.27	10.66
Hawaii	3.0	1.1	0.3	4.5	4.77	8.01	10.13
Idaho	0.6	22.8	0.0	23.4	5.38	6.56	--
Illinois	54.5	19.1	3.1	76.7	4.23	6.28	8.86
Indiana	40.6	18.8	0.9	60.3	4.38	5.87	10.52
Iowa	8.5	74.0	0.2	82.7	4.51	5.34	12.04
Kansas	11.2	48.0	0.2	59.4	4.44	5.95	11.12
Kentucky	14.1	23.6	0.3	37.9	4.40	5.82	11.06
Louisiana	12.7	7.0	0.0	19.7	4.48	7.14	13.41
Maine	1.8	1.6	0.0	3.4	5.05	8.44	--
Maryland	11.7	7.0	0.0	18.8	4.51	5.42	13.22
Massachusetts	11.9	0.8	1.0	13.7	4.48	8.12	8.94
Michigan	37.7	15.9	2.2	55.7	4.28	6.47	8.92
Minnesota	8.0	40.3	0.0	48.3	4.57	5.96	--
Mississippi	9.4	21.1	0.0	30.5	4.40	5.48	--
Missouri	25.0	38.2	0.6	63.7	4.57	5.92	11.01
Montana	1.8	19.4	0.0	21.2	4.54	7.20	--
Nebraska	3.4	51.4	0.1	54.9	5.09	5.85	12.63
Nevada	5.5	4.0	0.2	9.7	4.20	9.03	9.84
New Hampshire	5.0	0.6	0.0	5.6	4.37	8.99	--
New Jersey	31.2	0.9	1.2	33.3	4.14	7.44	9.83
New Mexico	1.5	15.3	0.1	17.0	4.40	7.32	10.24
New York	69.1	19.3	1.3	89.6	4.13	6.38	9.94
North Carolina	25.3	39.7	0.2	65.2	4.82	5.35	11.96
North Dakota	0.8	12.8	0.0	13.6	5.31	7.10	--
Ohio	51.6	21.1	1.1	73.8	4.19	5.90	9.50
Oklahoma	7.7	47.0	0.1	54.8	4.43	5.74	10.81
Oregon	7.9	11.4	0.1	19.3	4.30	7.39	12.66
Pennsylvania	74.1	26.1	0.6	100.7	4.15	5.90	10.02
Rhode Island	5.1	0.1	0.1	5.2	4.15	10.23	12.04
South Carolina	18.2	8.0	0.1	26.3	4.35	5.96	10.37
South Dakota	1.2	29.9	0.0	31.1	5.13	6.28	--
Tennessee	21.0	19.3	0.4	40.7	4.88	5.99	10.61
Texas	67.9	116.2	1.5	185.6	4.21	5.89	9.74
Utah	4.4	9.3	0.0	13.7	5.74	7.28	--

State	Renewable Gas [million dekatherm/yr]				RG Cost (Total Opex/dekatherm) [$/dekatherm]		
	LFG	Livestock Manure	Waste Water	Total	LFG	Livestock Manure	Waste Water
Vermont	3.5	3.8	0.0	7.3	4.35	6.78	--
Virginia	35.8	17.4	0.6	53.8	4.29	5.96	11.19
Washington	20.6	12.3	0.2	33.1	4.22	6.98	10.88
West Virginia	3.4	4.9	0.0	8.3	4.63	6.64	--
Wisconsin	24.5	41.4	0.2	66.2	4.45	5.83	11.33
Wyoming	0.8	10.4	0.0	11.2	4.66	7.44	--
Totals	**1011**	**1093**	**20**	**2123**	**--**	**--**	**--**
Minimum	**0.6**	**0.1**	**0.0**	**1.3**	**4.13**	**4.90**	**8.86**
Maximum	**157.3**	**116.2**	**3.1**	**222.7**	**5.74**	**38.23**	**13.41**
Median	**10.2**	**18.1**	**0.2**	**33.2**	**4.40**	**6.33**	**10.61**
Average	**20.2**	**21.9**	**0.4**	**42.5**	**4.50**	**7.21**	**10.77**
Std Deviation	**27.2**	**21.7**	**0.6**	**41.6**	**0.34**	**4.56**	**1.20**
Relative StdDev [%]	**134.3%**	**99.3%**	**155.0%**	**98.0%**	**7.6%**	**63.3%**	**11.1%**

Job Creation

Estimates of the numbers of AD jobs created in the maximum scenario are displayed in the job creation tables in section *9.0 Analysis Results*.

CO_2 Abatement and Carbon Credit Values

Table 45: AD CO_2 Abatement and Sample Carbon Credit Values in the Maximum Scenario

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton CO_2/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Alabama	41.4	2.42	0.11	4.51	34.22
Alaska	1.3	0.08	0.00	0.15	1.11
Arizona	20.9	1.23	0.06	2.28	17.31
Arkansas	38.1	2.23	0.10	4.15	31.53
California	222.7	13.04	0.59	24.25	184.12
Colorado	33.6	1.97	0.09	3.66	27.76
Connecticut	5.0	0.29	0.01	0.54	4.12
Delaware	9.8	0.57	0.03	1.07	8.09
Florida	53.0	3.11	0.14	5.78	43.85
Georgia	57.4	3.36	0.15	6.25	47.47
Hawaii	4.5	0.26	0.01	0.49	3.69
Idaho	23.4	1.37	0.06	2.55	19.38
Illinois	76.7	4.49	0.20	8.36	63.44
Indiana	60.3	3.53	0.16	6.56	49.82
Iowa	82.7	4.84	0.22	9.00	68.35
Kansas	59.4	3.48	0.16	6.46	49.08
Kentucky	37.9	2.22	0.10	4.13	31.33
Louisiana	19.7	1.16	0.05	2.15	16.32
Maine	3.4	0.20	0.01	0.37	2.80
Maryland	18.8	1.10	0.05	2.05	15.55

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton CO_2/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Massachusetts	13.7	0.80	0.04	1.49	11.33
Michigan	55.7	3.26	0.15	6.07	46.07
Minnesota	48.3	2.83	0.13	5.26	39.91
Mississippi	30.5	1.78	0.08	3.32	25.20
Missouri	63.7	3.73	0.17	6.94	52.67
Montana	21.2	1.24	0.06	2.31	17.53
Nebraska	54.9	3.21	0.15	5.98	45.40
Nevada	9.7	0.57	0.03	1.06	8.05
New Hampshire	5.6	0.33	0.01	0.61	4.62
New Jersey	33.3	1.95	0.09	3.63	27.55
New Mexico	17.0	0.99	0.05	1.85	14.03
New York	89.6	5.24	0.24	9.76	74.06
North Carolina	65.2	3.82	0.17	7.10	53.93
North Dakota	13.6	0.80	0.04	1.48	11.24
Ohio	73.8	4.32	0.20	8.04	61.04
Oklahoma	54.8	3.21	0.15	5.97	45.29
Oregon	19.3	1.13	0.05	2.10	15.96
Pennsylvania	100.7	5.90	0.27	10.97	83.28
Rhode Island	5.2	0.31	0.01	0.57	4.31
South Carolina	26.3	1.54	0.07	2.86	21.71
South Dakota	31.1	1.82	0.08	3.39	25.70
Tennessee	40.7	2.38	0.11	4.43	33.63
Texas	185.6	10.86	0.49	20.20	153.39
Utah	13.7	0.80	0.04	1.49	11.34
Vermont	7.3	0.43	0.02	0.79	6.01
Virginia	53.8	3.15	0.14	5.86	44.47
Washington	33.1	1.94	0.09	3.61	27.39
West Virginia	8.3	0.48	0.02	0.90	6.83
Wisconsin	66.2	3.88	0.18	7.21	54.72
Wyoming	11.2	0.65	0.03	1.22	9.25
Total	**2123.34**	**124.30**	**5.64**	**231.20**	**1755.28**
Average	**42.47**	**2.49**	**0.11**	**4.62**	**35.11**
Maximum	**222.73**	**13.04**	**0.59**	**24.25**	**184.12**
Minimum	**1.34**	**0.08**	**0.00**	**0.15**	**1.11**
Std Dev	**41.64**	**2.44**	**0.11**	**4.53**	**34.42**
Relative Std Dev w/rt Avg	**98.04%**	**98.04%**	**98.04%**	**98.04%**	**98.04%**

Results for Thermal Gasification

Availabilities

Table 46: TG Annual Feedstock Availabilities for the Maximum Scenario

State	Ag Residues [millions wet tons/yr]	Energy Crops [millions wet tons/yr]	Municipal Solid Waste [millions wet tons/yr]	Wood Residues [millions wet tons/yr]
Alabama	1.4	3.0	6.2	4.0
Alaska	--	--	0.7	1.2
Arizona	1.3	--	7.2	0.8
Arkansas	17.7	1.1	2.9	4.2
California	6.1	--	29.9	7.1
Colorado	5.7	--	8.2	0.8
Connecticut	--	0.0	0.4	0.6
Delaware	0.9	0.0	0.9	0.2
Florida	12.0	0.5	11.1	4.7
Georgia	3.7	1.9	7.2	6.0
Hawaii	1.5	--	0.5	0.2
Idaho	6.6	--	1.1	1.4
Illinois	72.2	6.3	16.6	2.7
Indiana	33.1	1.9	8.5	2.2
Iowa	87.0	12.2	2.8	0.9
Kansas	28.1	4.8	3.3	0.6
Kentucky	6.3	2.1	4.8	3.4
Louisiana	16.0	1.3	5.6	5.1
Maine	--	0.0	0.8	4.0
Maryland	2.2	0.4	3.1	1.2
Massachusetts	--	0.0	2.7	1.1
Michigan	13.2	1.9	9.1	3.4
Minnesota	52.5	9.8	2.2	3.7
Mississippi	8.1	5.7	3.0	5.5
Missouri	22.1	10.0	6.7	3.4
Montana	5.8	--	1.2	1.1
Nebraska	40.3	3.4	2.1	0.4
Nevada	0.0	--	2.4	0.3
New Hampshire	--	0.0	0.7	1.5
New Jersey	0.3	0.0	7.0	1.3
New Mexico	0.6	--	1.9	0.4
New York	1.9	0.4	10.5	4.3
North Carolina	5.5	0.7	6.2	5.1
North Dakota	24.3	11.3	0.6	0.1
Ohio	18.4	1.9	13.4	2.9
Oklahoma	6.0	0.3	4.2	1.4
Oregon	2.1	0.0	2.4	2.0
Pennsylvania	3.0	0.8	9.7	4.1
Rhode Island	--	--	1.2	0.2
South Carolina	1.2	1.2	3.2	2.9
South Dakota	18.9	4.8	0.8	0.3
Tennessee	5.5	1.6	7.4	2.8
Texas	22.4	0.4	25.3	5.9
Utah	0.3	--	2.3	0.4

State	Ag Residues [millions wet tons/yr]	Energy Crops [millions wet tons/yr]	Municipal Solid Waste [millions wet tons/yr]	Wood Residues [millions wet tons/yr]
Vermont	--	0.0	0.4	0.7
Virginia	1.9	0.3	5.9	4.3
Washington	6.4	0.0	5.3	2.3
West Virginia	0.1	0.0	1.8	2.2
Wisconsin	16.3	3.9	3.5	3.4
Wyoming	0.4	--	0.6	0.2
Total	**579.5**	**93.9**	**265.4**	**118.9**
Average	**13.5**	**2.5**	**5.3**	**2.4**
Maximum	**87.0**	**12.2**	**29.9**	**7.1**
Minimum	**0.0**	**0.0**	**0.4**	**0.1**
Std Dev	**18.7**	**3.3**	**5.9**	**1.9**
Relative Std Dev w/rt Avg	**139.1%**	**134.6%**	**110.3%**	**78.5%**

Energy and Costs

Table 47: Summary of TG Assessment Results from the Maximum Scenario

State	TG Plants [No.]	Average Plant Capacity [Thousand ton/year]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Alabama	18	790.9	4045.6	1109.5	100.6
Alaska	3	670.3	582.0	156.2	12.8
Arizona	11	785.2	2524.2	694.6	54.5
Arkansas	28	832.2	6805.5	1888.8	184.7
California	46	908.0	11314.3	3143.7	259.5
Colorado	16	902.0	3896.1	1080.9	92.5
Connecticut	2	496.1	324.2	84.9	6.5
Delaware	4	502.3	593.3	158.7	13.1
Florida	31	826.3	7486.4	2075.0	186.6
Georgia	21	903.4	5008.4	1385.3	126.7
Hawaii	4	466.1	666.0	176.2	14.6
Idaho	11	739.5	2494.5	685.8	64.5
Illinois	101	941.9	25389.7	7076.8	693.2
Indiana	48	899.3	11913.1	3314.8	320.2
Iowa	106	944.0	26669.6	7434.3	764.5
Kansas	39	845.2	9624.7	2675.9	269.9
Kentucky	19	857.8	4480.6	1237.7	116.4
Louisiana	31	837.4	7418.2	2053.4	195.0
Maine	7	542.6	1364.0	370.8	33.7
Maryland	10	618.1	1998.1	539.2	44.7
Massachusetts	5	710.1	1054.0	286.9	22.3
Michigan	30	906.9	7287.1	2021.0	187.3
Minnesota	71	902.7	17730.4	4937.5	508.7
Mississippi	25	880.2	5952.4	1646.2	166.3
Missouri	45	923.0	11088.9	3081.9	312.6
Montana	10	704.5	2217.7	608.1	56.5
Nebraska	49	727.3	12075.6	3358.1	338.3

State	TG Plants [No.]	Average Plant Capacity [Thousand ton/year]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Nevada	5	380.0	806.7	216.5	15.5
New Hampshire	3	700.6	619.9	167.9	14.4
New Jersey	12	463.8	2402.0	655.2	49.8
New Mexico	4	647.6	822.3	223.7	17.7
New York	19	783.0	4527.5	1253.3	105.5
North Carolina	20	830.3	4707.7	1299.8	117.3
North Dakota	39	656.2	9515.0	2644.9	282.8
Ohio	38	956.9	9505.4	2647.4	245.0
Oklahoma	15	668.8	3299.9	903.6	79.6
Oregon	9	625.7	1805.6	493.2	42.9
Pennsylvania	20	834.1	4715.2	1302.5	111.8
Rhode Island	3	375.4	444.3	115.8	7.6
South Carolina	11	753.6	2402.2	656.7	59.0
South Dakota	27	739.1	6529.9	1811.9	187.1
Tennessee	19	895.4	4594.4	1273.4	115.5
Texas	56	837.7	14025.5	3908.2	348.1
Utah	5	491.8	911.3	243.5	17.7
Vermont	2	553.1	345.6	91.6	7.4
Virginia	15	742.7	3397.8	934.0	80.4
Washington	16	858.3	3769.7	1040.9	92.6
West Virginia	7	433.1	1174.2	316.8	26.3
Wisconsin	29	921.0	7134.3	1982.3	198.1
Wyoming	3	406.7	423.0	109.0	7.8
Total	**1168**	**36618**	**279883.7**	**77574.0**	**7376.3**
Average	**23.4**	**732.4**	**5597.7**	**1551.5**	**147.5**
Maximum	**106**	**957**	**26670**	**7434**	**765**
Minimum	**2**	**375**	**324**	**85**	**7**
Std Dev	**22.9**	**168.7**	**5824.6**	**1625.4**	**163.7**
Relative Std Dev w/rt Avg	**97.9%**	**23.0%**	**104.1%**	**104.8%**	**111.0%**

Individual Feedstock Energy Production and Unit Prices

Table 48: TG Energy Production and Unit Prices by Feedstock and State in the Maximum Scenario

State	Renewable Gas [million dekatherm/yr]					RG Cost (Total Opex/dekatherm) [$/dekatherm]			
	Ag Res	Energy Crops	MSW	Wood Res	Total	Ag Res	Energy Crops	MSW	Wood Res
Alabama	10.49	26.92	33.91	29.31	100.6	10.73	8.62	13.55	10.42
Alaska	--	--	4.01	8.84	12.8	--	--	14.24	11.22
Arizona	9.42	--	39.16	5.91	54.5	11.04	--	13.51	10.40
Arkansas	128.72	9.76	15.84	30.42	184.7	9.89	9.37	13.25	10.32
California	44.53	--	163.40	51.54	259.5	10.20	--	13.25	10.17
Colorado	41.60	--	44.82	6.13	92.5	9.97	--	13.45	10.30
Connecticut	--	--	2.03	4.51	6.5	--	--	17.01	11.16
Delaware	6.58	0.30	4.83	1.36	13.1	10.11	19.41	13.56	15.28
Florida	87.58	4.73	60.39	33.89	186.6	10.05	9.45	13.41	10.03
Georgia	26.76	16.77	39.29	43.83	126.7	10.07	8.13	13.50	10.24
Hawaii	10.63	--	2.64	1.35	14.6	10.69	--	15.89	15.31
Idaho	47.99	--	6.22	10.30	64.5	10.00	--	15.22	10.78
Illinois	525.86	56.49	90.89	19.93	693.2	9.91	8.22	13.20	10.09
Indiana	240.91	17.20	46.25	15.81	320.2	9.92	8.08	13.34	10.72
Iowa	633.14	109.28	15.41	6.70	764.5	9.91	8.13	13.34	10.06
Kansas	204.35	43.03	17.86	4.63	269.9	9.93	8.08	13.84	11.09
Kentucky	46.22	18.93	26.36	24.91	116.4	10.10	8.76	13.25	10.26
Louisiana	116.35	11.49	30.31	36.87	195.0	10.01	8.98	13.40	10.30
Maine	--	0.45	4.26	29.01	33.7	--	17.52	14.01	10.45
Maryland	15.67	3.43	16.93	8.69	44.7	10.74	10.28	14.04	11.27
Massachusetts	--	--	14.47	7.82	22.3	--	--	13.56	11.59
Michigan	96.25	16.64	49.87	24.53	187.3	10.00	8.15	13.45	10.30
Minnesota	381.95	87.72	12.01	27.02	508.7	9.92	8.04	14.24	10.04
Mississippi	58.80	50.79	16.65	40.07	166.3	10.13	8.11	14.10	10.07
Missouri	161.22	89.57	36.76	25.04	312.6	9.95	8.20	13.27	10.25
Montana	41.87	--	6.49	8.16	56.5	9.96	--	15.04	11.46
Nebraska	293.38	30.83	11.47	2.67	338.3	9.89	8.32	14.42	12.80
Nevada	0.11	--	13.04	2.40	15.5	29.70	--	13.94	13.17
New Hampshire	--	--	3.58	10.85	14.4	--	--	14.66	10.64
New Jersey	2.44	0.12	38.00	9.26	49.8	13.11	24.62	13.62	11.09
New Mexico	4.51	--	10.56	2.60	17.7	11.16	--	13.25	12.90

State	Renewable Gas [million dekatherm/yr]					RG Cost (Total Opex/dekatherm) [$/dekatherm]			
	Ag Res	Energy Crops	MSW	Wood Res	Total	Ag Res	Energy Crops	MSW	Wood Res
New York	13.61	3.48	57.33	31.11	105.5	10.02	10.24	13.29	10.26
North Carolina	40.10	5.92	33.96	37.36	117.3	10.07	8.91	13.54	10.26
North Dakota	177.19	101.51	3.15	0.96	282.8	9.92	8.12	15.16	16.76
Ohio	134.22	17.01	72.92	20.86	245.0	9.93	8.11	13.29	9.97
Oklahoma	44.04	2.53	23.07	9.96	79.6	10.23	11.13	13.72	10.88
Oregon	15.22	0.19	13.12	14.33	42.9	10.82	22.05	13.92	9.89
Pennsylvania	21.74	7.14	52.78	30.10	111.8	10.63	8.48	13.25	10.35
Rhode Island	--	--	6.46	1.16	7.6	--	--	15.07	15.92
South Carolina	8.88	11.18	17.69	21.21	59.0	11.21	9.05	13.88	9.92
South Dakota	137.95	42.88	4.25	2.00	187.1	9.99	8.09	14.02	13.81
Tennessee	40.29	14.33	40.48	20.40	115.5	10.06	8.48	13.40	10.03
Texas	163.42	3.80	138.21	42.70	348.1	9.91	10.01	13.22	9.91
Utah	2.36	--	12.57	2.79	17.7	13.22	--	14.07	12.65
Vermont	--	--	2.00	5.38	7.4	--	--	17.07	10.66
Virginia	13.47	2.96	32.41	31.57	80.4	10.05	10.68	13.71	10.22
Washington	46.86	--	28.73	16.99	92.6	10.07	--	13.59	10.52
West Virginia	0.86	0.09	9.68	15.67	26.3	17.23	26.43	13.55	10.74
Wisconsin	118.60	35.12	19.33	25.09	198.1	9.96	8.04	13.56	10.24
Wyoming	2.84	--	3.34	1.59	7.8	12.59	--	14.94	14.68
Totals	**4219**	**843**	**1449**	**866**	**7376**	**--**	**--**	**--**	**--**
Minimum	**0.1**	**0.1**	**2.0**	**1.0**	**6.5**	**9.89**	**8.04**	**13.20**	**9.89**
Maximum	**633.1**	**109.3**	**163.4**	**51.5**	**764.5**	**29.70**	**26.43**	**17.07**	**16.76**
Median	**44.0**	**14.3**	**17.3**	**15.0**	**96.6**	**10.06**	**8.62**	**13.58**	**10.44**
Average	**98.1**	**25.5**	**29.0**	**17.3**	**147.5**	**11.00**	**10.80**	**13.96**	**11.24**
Std Deviation	**136.5**	**30.7**	**32.0**	**13.6**	**163.7**	**3.17**	**4.97**	**0.88**	**1.71**
Relative StdDev [%]	**139.1%**	**120.1%**	**110.3%**	**78.5%**	**111.0%**	**28.8%**	**46.1%**	**6.3%**	**15.2%**

Job Creation

Estimates of the numbers of TG jobs created in the maximum scenario are displayed in the job creation tables in section *9.0 Analysis Results*.

CO_2 Abatement and Carbon Credit Values

Table 49: TG CO_2 Abatement and Sample Carbon Credit Values in the Maximum Scenario

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Alabama	100.6	5.89	0.27	10.96	83.2
Alaska	12.8	0.75	0.03	1.40	10.6
Arizona	54.5	3.19	0.14	5.93	45.0
Arkansas	184.7	10.81	0.49	20.11	152.7
California	259.5	15.19	0.69	28.25	214.5
Colorado	92.5	5.42	0.25	10.08	76.5
Connecticut	6.5	0.38	0.02	0.71	5.4
Delaware	13.1	0.77	0.03	1.42	10.8
Florida	186.6	10.92	0.50	20.32	154.2
Georgia	126.7	7.41	0.34	13.79	104.7
Hawaii	14.6	0.86	0.04	1.59	12.1
Idaho	64.5	3.78	0.17	7.02	53.3
Illinois	693.2	40.58	1.84	75.48	573.0
Indiana	320.2	18.74	0.85	34.86	264.7
Iowa	764.5	44.76	2.03	83.24	632.0
Kansas	269.9	15.80	0.72	29.38	223.1
Kentucky	116.4	6.81	0.31	12.68	96.2
Louisiana	195.0	11.42	0.52	21.23	161.2
Maine	33.7	1.97	0.09	3.67	27.9
Maryland	44.7	2.62	0.12	4.87	37.0
Massachusetts	22.3	1.30	0.06	2.43	18.4
Michigan	187.3	10.96	0.50	20.39	154.8
Minnesota	508.7	29.78	1.35	55.39	420.5
Mississippi	166.3	9.74	0.44	18.11	137.5
Missouri	312.6	18.30	0.83	34.04	258.4
Montana	56.5	3.31	0.15	6.15	46.7
Nebraska	338.3	19.81	0.90	36.84	279.7
Nevada	15.5	0.91	0.04	1.69	12.8
New Hampshire	14.4	0.84	0.04	1.57	11.9
New Jersey	49.8	2.92	0.13	5.43	41.2
New Mexico	17.7	1.03	0.05	1.92	14.6
New York	105.5	6.18	0.28	11.49	87.2
North Carolina	117.3	6.87	0.31	12.78	97.0
North Dakota	282.8	16.56	0.75	30.79	233.8
Ohio	245.0	14.34	0.65	26.68	202.5
Oklahoma	79.6	4.66	0.21	8.67	65.8
Oregon	42.9	2.51	0.11	4.67	35.4
Pennsylvania	111.8	6.54	0.30	12.17	92.4
Rhode Island	7.6	0.45	0.02	0.83	6.3
South Carolina	59.0	3.45	0.16	6.42	48.7

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
South Dakota	187.1	10.95	0.50	20.37	154.7
Tennessee	115.5	6.76	0.31	12.58	95.5
Texas	348.1	20.38	0.92	37.91	287.8
Utah	17.7	1.04	0.05	1.93	14.7
Vermont	7.4	0.43	0.02	0.80	6.1
Virginia	80.4	4.71	0.21	8.76	66.5
Washington	92.6	5.42	0.25	10.08	76.5
West Virginia	26.3	1.54	0.07	2.86	21.7
Wisconsin	198.1	11.60	0.53	21.57	163.8
Wyoming	7.8	0.45	0.02	0.85	6.4
Total	**7376.30**	**431.81**	**19.59**	**803.16**	**6097.71**
Average	**147.53**	**8.64**	**0.39**	**16.06**	**121.95**
Maximum	**764.53**	**44.76**	**2.03**	**83.24**	**632.00**
Minimum	**6.55**	**0.38**	**0.02**	**0.71**	**5.41**
Std Dev	**163.72**	**9.58**	**0.43**	**17.83**	**135.34**
Relative Std Dev w/rt Avg	**110.98%**	**110.98%**	**110.98%**	**110.98%**	**110.98%**

Joint Results

Energy and Costs

Table 50: Summary of Combined Results for AD and TG in the Maximum Scenario

State	Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Alabama	194	4614.8	1319.0	142.0
Alaska	28	614.7	166.2	14.2
Arizona	193	2918.1	823.4	75.4
Arkansas	202	7365.8	2088.0	222.9
California	930	14095.2	4231.2	482.2
Colorado	271	4496.3	1279.7	126.1
Connecticut	26	397.0	110.5	11.5
Delaware	24	707.5	203.6	22.9
Florida	238	8177.4	2336.7	239.6
Georgia	240	5753.4	1668.8	184.1
Hawaii	36	747.5	202.7	19.1
Idaho	234	2990.5	838.8	87.9
Illinois	359	26361.6	7455.3	769.9
Indiana	286	12698.1	3612.4	380.4
Iowa	481	27904.3	7870.2	847.2
Kansas	412	10624.3	3013.2	329.2
Kentucky	209	5059.3	1439.5	154.3
Louisiana	151	7730.3	2160.9	214.8
Maine	46	1439.3	393.4	37.1
Maryland	81	2243.7	630.8	63.5
Massachusetts	55	1231.3	355.8	36.0
Michigan	253	8037.9	2304.2	243.0
Minnesota	391	18552.9	5214.1	557.0
Mississippi	163	6388.3	1803.1	196.8

State	Plants [No.]	CAPEX [$ million]	OPEX [$ million/yr]	Renewable Gas [million dekatherm/yr]
Missouri	405	12081.5	3428.1	376.3
Montana	262	2702.3	756.0	77.7
Nebraska	415	13039.4	3677.1	393.3
Nevada	99	996.6	277.8	25.3
New Hampshire	25	691.2	194.9	20.0
New Jersey	72	2741.2	803.2	83.2
New Mexico	210	1220.9	343.8	34.6
New York	274	5576.5	1674.3	195.1
North Carolina	340	5641.1	1636.9	182.6
North Dakota	195	9835.4	2740.0	296.4
Ohio	260	10397.0	2998.8	318.9
Oklahoma	326	4198.9	1208.6	134.4
Oregon	179	2171.9	611.8	62.2
Pennsylvania	292	5873.7	1769.9	212.5
Rhode Island	13	495.6	138.3	12.8
South Carolina	111	2738.4	784.5	85.2
South Dakota	285	7142.2	2005.7	218.2
Tennessee	271	5239.9	1495.9	156.2
Texas	1033	16695.1	4892.2	533.7
Utah	167	1218.5	336.6	31.4
Vermont	42	473.7	132.3	14.7
Virginia	219	4091.7	1198.0	134.2
Washington	192	4257.6	1216.0	125.7
West Virginia	66	1323.9	364.8	34.6
Wisconsin	369	8142.9	2335.9	264.3
Wyoming	146	698.8	190.1	19.0
Total	**11771**	**310836**	**88733.1**	**9499.6**
Average	**235.4**	**6216.7**	**1774.7**	**190.0**
Maximum	**1033**	**27904**	**7870**	**847**
Minimum	**13**	**397**	**110**	**12**
Std Dev	**194.1**	**6165.8**	**1754.5**	**188.6**
Relative Std Dev w/rt Avg	**82.4%**	**99.2%**	**98.9%**	**99.2%**

Job Creation

Estimates of the numbers of the combined numbers of jobs created in the maximum scenario are displayed in the table of joint results of job creation in section *9.0 Analysis Results*.

CO_2 Abatement and Carbon Credit Values

Table 51: Combined CO_2 Abatement and Sample Carbon Credit Values in the Maximum Scenario

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Alabama	142.0	8.3	0.4	15.5	117.4
Alaska	14.2	0.8	0.0	1.5	11.7
Arizona	75.4	4.4	0.2	8.2	62.4
Arkansas	222.9	13.0	0.6	24.3	184.2
California	482.2	28.2	1.3	52.5	398.6
Colorado	126.1	7.4	0.3	13.7	104.3
Connecticut	11.5	0.7	0.0	1.3	9.5
Delaware	22.9	1.3	0.1	2.5	18.9
Florida	239.6	14.0	0.6	26.1	198.1
Georgia	184.1	10.8	0.5	20.0	152.2
Idaho	87.9	5.1	0.2	9.6	72.7
Illinois	769.9	45.1	2.0	83.8	636.5
Indiana	380.4	22.3	1.0	41.4	314.5
Iowa	847.2	49.6	2.2	92.2	700.4
Kansas	329.2	19.3	0.9	35.8	272.2
Kentucky	154.3	9.0	0.4	16.8	127.6
Louisiana	214.8	12.6	0.6	23.4	177.5
Maine	37.1	2.2	0.1	4.0	30.7
Maryland	63.5	3.7	0.2	6.9	52.5
Massachusetts	36.0	2.1	0.1	3.9	29.8
Michigan	243.0	14.2	0.6	26.5	200.9
Minnesota	557.0	32.6	1.5	60.6	460.4
Mississippi	196.8	11.5	0.5	21.4	162.7
Missouri	376.3	22.0	1.0	41.0	311.1
Montana	77.7	4.5	0.2	8.5	64.2
Nebraska	393.3	23.0	1.0	42.8	325.1
Nevada	25.3	1.5	0.1	2.8	20.9
New Hampshire	20.0	1.2	0.1	2.2	16.5
New Jersey	83.2	4.9	0.2	9.1	68.7
New Mexico	34.6	2.0	0.1	3.8	28.6
New York	195.1	11.4	0.5	21.2	161.3
North Carolina	182.6	10.7	0.5	19.9	150.9
North Dakota	296.4	17.4	0.8	32.3	245.0
Ohio	318.9	18.7	0.8	34.7	263.6
Oklahoma	134.4	7.9	0.4	14.6	111.1
Oregon	62.2	3.6	0.2	6.8	51.4
Pennsylvania	212.5	12.4	0.6	23.1	175.7
Rhode Island	12.8	0.8	0.0	1.4	10.6
South Carolina	85.2	5.0	0.2	9.3	70.5
South Dakota	218.2	12.8	0.6	23.8	180.4

State	Renewable Gas [million dekatherm/yr]	CO_2 Abatement [million ton/yr]	CCX CFI CO_2 Potential Value [$ million/yr]	RGGI Potential Value [$ million/yr]	ECX ERU Potential Value [$ million/yr]
Tennessee	156.2	9.1	0.4	17.0	129.1
Texas	533.7	31.2	1.4	58.1	441.2
Utah	31.4	1.8	0.1	3.4	26.0
Vermont	14.7	0.9	0.0	1.6	12.1
Virginia	134.2	7.9	0.4	14.6	110.9
Washington	125.7	7.4	0.3	13.7	103.9
West Virginia	34.6	2.0	0.1	3.8	28.6
Wisconsin	264.3	15.5	0.7	28.8	218.5
Wyoming	19.0	1.1	0.1	2.1	15.7
Total	**9499.6**	**556.1**	**25.2**	**1034.4**	**7853.0**
Average	**190.0**	**11.1**	**0.5**	**20.7**	**157.1**
Maximum	**847.2**	**49.6**	**2.2**	**92.2**	**700.4**
Minimum	**11.5**	**0.7**	**0.0**	**1.3**	**9.5**
Std Dev	**188.6**	**11.0**	**0.5**	**20.5**	**155.9**
Relative Std Dev w/rt Avg	**99.2%**	**99.2%**	**99.2%**	**99.2%**	**99.2%**

15.0 Appendix: Regulatory Issues

Introduction

The registry groups and protocols examined include the RGGI, the CCX, the Midwest Greenhouse Gas Accord (MGGRA), the CDM, the Western Climate Initiative (WCI), the U.S. EPA's Climate Leaders Program, and the CAR. Both the CDM and RGGI offset programs are specifically designed to serve as compliance mechanisms under the respective international and regional regulations. CAR and Climate Leaders programs are voluntary GHG reduction programs. CCX serves as a voluntary program for emission reductions through cap and trade system among CCX members. CCX does not have a regulatory affiliation, but emissions reductions targets are legally binding. EPA's Climate Leaders program has thus far developed offset protocols across seven categories of offset activities: commercial boilers, industrial boilers, transit bus efficiency, captured methane end use, landfill methane, manure management, and afforestation. The regional accords MGGRA and WCI are in the early stages of development, with detailed protocols to follow. However, California has some specific protocols already in place. Individual state protocols, notably California and Michigan, are covered as necessary.

The protocols developed for accruing regulatory credit for GHG emissions reductions across various administrative agencies, voluntary registration groups, and regional associations have some features in common. Biogas projects proposed need to meet these screens even to be considered for GHG credits. Much of the information in this section is taken from a Swedish study (Lazarus, 2010).

Much of the credits cover AD systems, but not TG systems. The one notable exception to TG system mention is under Michigan regulations, covered under the final section of this report. One is specifically mentioned, under the CDM protocols, for inclusion of upgraded biogas that is injected into the natural gas distribution system.

Additionality and Regulatory Surplus

To avoid giving credits to projects that would have happened anyway, rules have been specified (Clean Development, 2010) to ensure additionality of the project, that is, to ensure the project reduces emissions more than would have occurred in the absence of the project. This is also a "regulatory surplus" test to ensure, in order for a project to be accepted under any of the offset programs, it must be validated that it would not have been required otherwise by regulations. The emissions reductions must also be beyond "business as usual" and "beyond common practice." The methods used by the RGGI, the CCX, and others to test for additionality tend to be standardized, to allow a potential project developer some level of certainty as to whether or not his project would pass the additionality screen. The MGGRA has not yet standardized its additionality test. RGGI has the added requirement for offset eligibility that no project funds are received from system benefits charges (SBC's) or other (retail gas or electric) ratepayer-funded subsidies or from the auction or sale of CO_2 allowances. Further, RGGI requires no credits or allowances awarded under any other mandatory or voluntary GHG program be eligible for offset credits. There is a direct implication under RGGI guidelines (discussed under voluntary renewable credits) for plants that would have been built for RPS requirements will not be eligible for offset credits. While this seems confusing, it is designed to prevent "double counting" of GHG emissions reductions which may have occurred anyway due to RPS regulations.

So if a project developer has arranged for funds from SBC sources, say through the New York State Energy Research and Development Authority, the project will probably not be eligible for additional offset credits under RGGI guidelines. The developers need to take this into account in arranging for financing of GHG reduction projects.

For LFG, for RGGI, CAR, and Climate Leaders: LFG projects required by any local, state or federal law, regulation, or administrative or judicial order are ineligible under regulatory surplus screening. Under four U.S-based protocols (RGGI, CAR, Climate Leaders, and CCX) all new LFG collection and destruction systems not required by regulation and at sites without a pre-existing destruction system are considered additional. Both Climate Leaders and CAR use a somewhat different performance standard approach to arrive at the same conclusion; both are based on the observation only slightly over 20% of unregulated landfills currently combust landfill gas. AS MGGRA and WCI are in draft form, additionality requirements for LFG sites are not yet specified in detail.

For manure management and AD, the specificity of regulatory surplus requirements differs across protocols. Under RGGI, CAR, CDM, and CCX projects are ineligible if the project activity is required by regulation. Under Climate Leaders, the requirements appear to permit project activities that go beyond what is required by regulation, to reduce GHG emissions to a level beyond what is required. The Climate Leaders protocol does not provide further guidance on how this would be demonstrated. The CDM allows project inclusion if compliance mechanisms for specific regulations are not being enforced. For additionality for CCX and RGGI, projects must be beyond "business as usual" for manure management, and for RGGI the projects must not include SBC or other ratepayer subsidies. Emissions ***reductions from fossil fuel displacement through end use of the collected methane*** can be credited under three programs: CDM, which includes fossil fuel displacement emissions reductions in its manure methodology; Climate Leaders, which considers end use of methane in a separate protocol which is not addressed in this study; and RGGI, if the project transfers rights to attribute credits to a RPS or other regulatory requirement to the regulatory agency.

The latter point is confusing, as it seems to violate the regulatory surplus screening requirement. However, it does offer an opening for digester gas used for combustion rather than "destroyed." Whether or not offsite combustion via pipeline transport and eventual end-use is included is not certain. And how the verification of offsite end-use combustion can be accomplished is not specified. Nevertheless, the opening is there. ***On-site energy use,*** under baseline and project conditions, is included within the project boundary under Climate Leaders, CAR, and CDM protocols. Project-related energy use, but not baseline energy use, is considered by the CCX protocol.

Process Requirements

Each of the programs has established process requirements for third party or government verification and for registering the GHG emissions. For all projects, credits are issued after the projects emissions have been reported and verified. So a developer cannot count on offset credits being granted before both reporting and verification have occurred.

Offset Project Eligibility Requirements

Eligible project locations and start dates differ across programs. The CAR permits projects only with the US. The RGGI permits projects only within the 10 RGGI states or other approved jurisdictions, with intent to expand the boundaries if certain emission triggers are reached. CCX projects are heavily U.S. dominated, but credits from other countries are accepted. The MGGRA requires the offsets be taken from facilities located in the participating six U.S. states and participating Canadian province. The CDM is international in scope and allows inclusion of projects from over 100 developing countries.

Project start dates vary from the date the prospective program is announced up to 12 months prior to the program announcement. The intent is to encourage early developers and yet to screen out non-additional projects. With CAR, projects operational up to 12 months before publication are eligible only if they list with CAR prior to publication.

The protocols GTI examined are applicable to most landfill capture and combustion technologies and project conditions. However CCX and CAR exclude specific landfill management technologies such as geomembranes, bio-covers, and bioreactors. The CDM landfill protocol is also applicable to the end use of landfill gas, while under Climate Leaders, a separate methane end use project protocol must be used. ***None of the other programs considered here provide offset credits for the emission benefits for substitution of LFG for higher GHG fuels or electricity.***

RGGI Summary

RGGI is the first operational U.S. regional GHG cap-and-trade group. The accord has been signed by the Governors of ten Northeastern and Mid-Atlantic States (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont).[24]

In a review of RGGI model rule guidelines, methane from renewable sources ("RG") turned into pipeline gas and displacing natural gas in the system is not explicitly included under the guidelines at this time. This gives rise to at least ten issues which are discussed in more detail below. While there is a possibility some RG, for example from anaerobic digesters from large farms or via regional collection may be included, even this is not a certainty. Most of the guidelines are for electricity generation, energy conservation or efficiency, or for GHG (e.g., methane, SF6) destruction (not GHG use). So an action plan needs to be developed so gas utilities or others can approach appropriate regulators and ensure RG is included under the RGGI guidelines, either directly or as an offset credit.

1. Will RGGI allow RG to count for offsets under its carbon trading system?

According to RGGI guidelines on Categories of Offsets (Offsets, 2010):

Categories of Offsets

- RGGI has developed prescriptive standards for specific project categories, to ensure that offsets are real, additional, verifiable, enforceable, and permanent. At this time, five project categories for CO_2 offset allowances are eligible under the participating states' regulations.
- Landfill methane capture and destruction
- Reduction in emissions of sulfur hexafluoride (SF6) in the electric power sector
- Sequestration of carbon due to forestation;
- Reduction or avoidance of CO_2 emissions from natural gas, oil, or propane end-use combustion due to end-use energy efficiency in the building sector
- Avoided methane emissions from agricultural manure management operations

Despite the mention of "reduction or avoidance of CO_2 emissions from natural gas" above, it applies only to combustion due to end-use energy efficiency in the building sector. ***Thus, groundwork needs to be done to get RG included under the offset allowances of RGGI.*** More discussion follows on the offsets later in this section.

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[24] *See footnote 23 regarding new Jersey's intent to terminate its membership in RGGI.*

The groundwork will involve developing a plan for scientific data gathering and advocacy of such before RGGI and other state and regional officials to gain inclusion of RG under the acceptable offset categories. As stated (Offsets, 2010):

> Offset project data will be incorporated into the RGGI emissions and allowance tracking system. The RGGI participating states are developing model application and submittal materials and guidance documents for use in administering the offset component of RGGI. These materials are expected to be available in early 2009.

It is likely "avoided methane emissions from agricultural manure management operations" offer at least an option for RG CO_2 offset credits *if* the methane comes from "agricultural" animal manure sources.

2. Eligible Biomass Issue

Under RGGI guidelines (Model Rule, 2007, p.12):

> *Eligible biomass.* Eligible biomass includes sustainably harvested woody and herbaceous fuel sources that are available on a renewable or recurring basis (excluding old growth timber), including dedicated energy crops and trees, agricultural food and feed crop residues, aquatic plants, unadulterated wood and wood residues, animal wastes, other clean organic wastes not mixed with other solid wastes, biogas, and other neat liquid biofuels derived from such fuel sources. Sustainably harvested will be determined by the regulatory agency.

Many of the candidate crops being evaluated, including miscanthus, kelp, and wood wastes are included under the "eligible biomass" category. However, "not mixed with biogas … derived from such fuel sources" is not in support of having biomass as an acceptable biogas. This requires further investigation to determine eligibility, or what needs to be changed in the rules to make our candidate crops eligible.

3. Renewable Energy Issue and Voluntary Retail Purchasing

Under RGGI guidelines (Model Rule, 2007, p.20), for purposes of "voluntary renewable energy purchase by retail electricity customers," the following definition is provided:

> Renewable energy includes electricity generated from biomass, wind, solar thermal, photovoltaic, geothermal, hydroelectric facilities certified by the Low Impact Hydropower Institute, wave and tidal action, and fuel cells powered by renewable fuels. The renewable energy generation or renewable energy attribute credits related to such purchases may not be used by the generator or purchaser to meet any regulatory mandate, such as a renewable portfolio standard.

Renewable gas into pipeline gas is not covered under the "renewable energy" reference in this section unless the gas is used for electricity generation or possibly by fuel cells. The non-inclusion of renewables so defined to meet such regulatory mandates as renewable portfolio standards is confusing. Perhaps it is only in reference to retail purchase of credits, but it certainly works against widespread deployment of renewables.

4. Voluntary Renewable Energy Market Set Aside

Under RGGI guidelines (Model Rule, 2007, p. 47):

> Voluntary renewable energy market set-aside allocation. For each control period, the regulatory agency shall allocate to the voluntary renewable energy market set-aside account a certain number of tons.

Further,

> Any person may submit data to the regulatory agency documenting purchases of voluntary renewable energy that meet the requirements of this subdivision by no later than the July 30 prior to the beginning of a control period. Such data must be from reputable sources, which may include retail electricity providers, organizations that certify renewable energy products, and other parties as determined by the regulatory agency. To be considered, data must be verifiable and document the following for voluntary renewable energy purchases.

And in addition (Model Rule, 2007, p. 48):

> Subject to the timely receipt of adequate data pursuant to subparagraph (i) of this paragraph, and based on such data, the regulatory agency shall project the voluntary renewable energy purchases in the State during a control period that represents renewable energy generation in one or more participating states. The megawatt hours (MWh) of projected voluntary renewable energy purchases in a control period shall be multiplied by the marginal CO_2 emissions rate (lbs. CO_2/MWh) in the control area where the generation occurred, as determined by the regulatory agency. If data to determine the marginal emissions rate is unavailable, the average emissions rate shall be used, as determined by the regulatory agency.

Thus, while it initially appears the renewable energy voluntary credit might apply to RG into RG, it appears the guidelines currently narrowly define these in terms of MWh and not therms. Developing a strategy to convince the regulatory agency to allow therm credits as well as MWh credits is needed to be able to use this section of the regulations.

5. Strategic Energy Purpose Allocation

Under the guidelines (Model rule, 2007, p. 44):

> Consumer benefit or strategic energy purpose allocation. The regulatory agency will allocate a minimum of twenty-five percent of the NAME OF RELEVANT RGGI STATE CO_2 Budget Trading Program base budget to the consumer benefit or strategic energy purpose set-aside account. [The reference to the consumer benefit or strategic energy purpose account illustrates how this account could be labeled and does not necessarily represent what an individual RGGI state will propose.]

The strategic energy purpose allocation is referred to later in the guidelines (Model Rule, 2007, p. 62) as follows:

> The CO_2 allowances allocated for the consumer benefit or strategic energy purpose account under subdivision XX5.3 (b). [Should states wish to establish other set-aside allocations (for new sources, for example), they would be referred to (at least generically) in the above subdivision.]

6. Offset Guidelines

The emissions offset provisions (Overview, 2007) of the Model Rule provide compliance flexibility by awarding CO_2 offset allowances to projects outside the capped sector that reduce and/or sequester emissions of GHG's. CO_2 offset allowances may be used to satisfy a limited fraction of a source's compliance obligation. Initially, the use of CO_2 offset allowances is constrained to 3.3% of a unit's total compliance obligation during a control period, though this may be expanded to 5% and 10% if a stage one or stage two trigger events occurs, respectively.

The offset guidelines include (Model Rule, 2007, p. 97-104) the following relevant definitions:

(a) Anaerobic digester. A device that promotes the decomposition of organic material to simple organics and gaseous biogas products, usually accomplished by means of controlling temperature and volume, and including a methane recovery system.
(b) Anaerobic digestion. The degradation of organic material including manure brought about through the action of microorganisms in the absence of elemental oxygen.
(f) Biogas. Gas resulting from the decomposition of organic matter under anaerobic conditions. The principle constituents are methane and carbon dioxide.
…………………………….
(ae) Regional-type anaerobic digester. An anaerobic digester using feedstock from more than one agricultural operation, or importing feedstock from more than one agricultural operation. Also commonly referred to as a 'community digester' or 'centralized digester.'
…………………………….
(ak) Total solids. Total solids are the total of all solids in a sample. They include the total suspended solids, total dissolved solids, and volatile suspended solids.
…………………………….
(an) Volatile solids. The fraction of total solids that is comprised primarily of organic matter.

General requirements for these offsets are as follows (Model Rule, 2007, p. 104-105):

Eligible CO_2 emissions offset projects. The regulatory agency may award CO_2 offset allowances to the sponsor of any of the following offset projects that have satisfied all the applicable requirements of this Subpart.

(1) *Offset project types*. The following types of offset projects are eligible for the award of CO_2 offset allowances.
- (i) Landfill methane capture and destruction;
- (ii) Reduction in emissions of sulfur hexafluoride (SF6);
- (iii) Sequestration of carbon due to forestation;
- (iv) Reduction or avoidance of CO_2 emissions from natural gas, oil, or propane end use combustion due to end use energy efficiency; and
- (v) Avoided methane emissions from agricultural manure management operations.

(2) *Offset project locations*. Eligible offset projects may be located in any of the following locations:
- (i) in any participating state; and
- (ii) in any state or other United States jurisdiction in which a cooperating regulatory agency has entered into a memorandum of understanding with the regulatory agency to carry out certain obligations relative to CO_2 emissions offset projects in that state or U.S. jurisdiction, including but not limited to the obligation to perform audits of offset project sites, and report violations of this Subpart.

It appears that landfill methane capture and avoided methane emissions from agricultural manure operations can be included in the offsets. AD is defined, but TG is not included explicitly.

Avoidance of CO_2 emissions from natural gas is mentioned, but only as related to end-use combustion. Another way to avoid these emissions from natural gas is to produce the CO_2 emissions from RG, but this may be difficult to defend unless tied to RG purchases by end-use consumers. As these purchases, particularly from residential and commercial customers that are unlikely to claim the CO_2 credits, are accrued, it may be possible to include them under the offsets.

It is also noteworthy projects in any participating state can be included, so gas utilities may want to look at resource assessments to include at least the 10 RGGI states.

In reference to offset allowances, RGGI requirements state (Model Rule, 2007, p. 106):

> CO_2 offset allowances shall not be awarded to an offset project that includes an electric generation component, unless the project sponsor transfers legal rights to any and all attribute credits (other than the CO_2 offset allowances awarded under section XX10.7) generated from the operation of the offset project that may be used for compliance with a renewable portfolio standard or other regulatory requirement, to the regulatory agency or its agent.

This opens up the possibility projects that have an electricity generation component can use such CO_2 reductions as offsets *if* the project sponsors transfer the legal rights of such credits.

Regulatory additionality requirements (Sherry, 2009) mean eligible projects be limited to non-NSPS landfills. Non-NSPS limits to small landfills (less than 2.5 million tons WIP design capacity). These small landfills typically face institutional and financial barriers (capital rationing) to development of LFG projects.

7. Energy Conservation Measures as Eligible Offset Projects

The potential for RG in relationship to *non-electricity* applications is discussed (Model Rule, 2007, p. 133) in the guidelines, including the following:

> (i) Eligible offset projects shall reduce CO_2 emissions through one or more of the following energy conservation measures:
> *(g)* Fuel switching to a less carbon-intensive fuel for use in combustion systems, including the use of liquid or gaseous renewable fuels, provided that conversions to electricity are not eligible.

The explicit inclusion of fuel switching to a less carbon-intensive fuel gives us a possible opening. RG gas may be viewed as less *carbon-intensive* than natural gas, however, there still is 117 lbs of CO_2 produced per MMBtu, so this argument may not be valid and needs to be investigated further. And as this discussion devolves to a building-by-building discussion, this section may not be applicable at all.

8. Anaerobic Digestion Issue

The RGGI guidelines refer (Model Rule, 2007, p. 147) to the *destruction* of methane from AD projects, as follows:

> (i) Eligible offset projects shall consist of the destruction of that portion of methane generated by an anaerobic digester that would have been generated in the absence of the offset project through the uncontrolled anaerobic storage of manure or organic food waste.
> (ii) Eligible offset projects shall employ only manure-based anaerobic digester systems using livestock manure as the majority of digester feedstock, defined as more than 50% of the mass input into the digester on an annual basis. Organic food waste used by an anaerobic digester shall only be that which would have been stored in anaerobic conditions in the absence of the offset project.
> (iii) The provisions of paragraphs XX10.3 (d)(2) and (3) shall not apply to agricultural manure management offset projects provided either of the following requirements are met.
> (a) The offset project is located in a state that has a market penetration rate for anaerobic digester projects of 5% or less.

> (b) The offset project is located at a farm with 4,000 or less head of dairy cows, or a farm with equivalent animal units, assuming an average live weight for dairy cows (lbs./cow) of 1,400 lbs., or, if the project is a regional type digester, total annual manure input to the digester is designed to be less than the average annual manure produced by a farm with 4,000 or less head of dairy cows, or a farm with equivalent animal units, assuming an average live weight for dairy cows (lbs./cow) of 1,400 lbs.

It appears the guidelines focus on of the "destruction" of the methane produced from AD, rather than using it productively.

9. Reduction of Natural Gas Combustion

RGGI guidelines (Model Rule, 2007, p. 132) define the following

> *Reduction or avoidance of CO_2 emissions from natural gas, oil, or propane end-use combustion due to end-use energy efficiency.* Offset projects that reduce CO_2 emissions by reducing onsite combustion of natural gas, oil, or propane for end-use in an existing or new commercial or residential building by improving the energy efficiency of fuel usage and/or the energy efficient delivery of energy services may qualify for the award of CO_2 emissions offset allowances under this Subpart, provided they meet the requirements of this subdivision.
> Eligibility:
>
> (i) Eligible offset projects shall reduce CO_2 emissions through one or more of the following energy conservation measures:
>
> *(a)* improvements in the energy efficiency of combustion equipment that provide space heating and hot water, including a reduction in fossil fuel consumption through the use of renewable energy;
> **…**
> *(f)* measures that improve the passive solar performance of buildings and utilization of active heating systems *using renewable energy*; and
> *(g)* fuel switching to a less carbon intensive fuel for use in combustion systems, including the use of liquid or gaseous renewable fuels, provided that conversions to electricity are not eligible**.**

It is possible to claim credit for biogas to pipeline gas under this eligibility provision. The difficulty will be proving the RG molecules are made to the appliance, which is impossible, unless the combustion devices are "on farm." There is no discussion of renewables credit by displacement, i.e., generating renewable methane in one place and transferring credit downstream to another locale even if the molecules of RG do not reach that locale. This needs to be firmed up in the regulatory arena. While we can point to a reduction in fossil fuel use at the site, it is difficult to have a causative path back to the biogas, because the apparent natural gas use at the home or business will remain the same. Perhaps if the retail customer purchased the renewable credits, then this is the proof of use.

The California Experience

In a petition (Energy Division, 2008) to the California Public Utility Commission (CPUC), PG&E asked to be granted RPS credit for renewable biogas transported through the natural gas pipeline system from out of state. The petition was granted by the CPUC. This was an important precedent as it allowed biogas generation outside of the state, transport via the gas pipeline system, and in-state RPS credits for use of that biogas in an electricity generation facility.

The CEC, in its RPS Eligibility Guidebook adopted December 19, 2007, determined biogas, derived from digester gas, is an RPS eligible renewable energy resource (Renewables Portfolio, 2008). Also, PG&E's proposal complies with the CEC's delivery requirements (Renewables, 2008, p. 20):

- The gas must be injected into a natural gas pipeline system that is either within the WECC region or interconnected to a natural gas pipeline system in the WECC region that delivers gas into California.

- The gas must be used at a facility that has been certified as RPS-eligible. As part of the application for certification, the applicant must attest that the RPS-eligible gas will be nominated to that facility or nominated to the LSE-owned pipeline serving the designated facility.

- When applying for RPS pre-certification, certification, or renewal, the application must include the following: 1) an attestation from the multi-fuel facility operator of its intent to procure biogas fuel that meets RPS eligibility criteria, and 2) an attestation from the fuel supplier that the fuel meets eligibility requirements.

The CEC is responsible for determining RPS eligibility and compliance with RPS delivery requirements. Based on the information provided in AL 3132-E, it appears PG&E's amended contract with Microgy would comply with the CEC's requirements. Specifically, the Huckabay Ridge facility [in Texas] is connected by a gas distribution pipeline to the El Paso natural gas pipeline system, which is located in the WECC. PG&E has received certification from the CEC that its Humboldt Bay Power Plant is an RPS eligible facility for the purposes of generating electricity with biogas.

However, the CEC RPS guidelines noted (Renewables Portfolio, 2008, p. 21) for out-of-state biogas facilities that:

> This section applies to renewable facilities that are located out-of-state and have their first point of interconnection to the WECC transmission system outside the state, as defined in the *Overall Program Guidebook*. Facilities that have their first point of interconnection to the WECC transmission system within the state are considered to be in-state facilities and are not subject to the requirements of this section for RPS eligibility. Out-of-state facilities that are not or will not be interconnected to the WECC transmission system are not eligible for the RPS."

The CEC guidelines (Renewables Portfolio, 2008, p. 22) also noted that:

> Generation from renewable facilities located out-of-state is potentially eligible for the RPS. To qualify for the RPS, generation from an out-of-state facility must meet the RPS eligibility requirements described above and must satisfy all of the following criteria.
> a) Facility is located so that it is or will be connected to the WECC transmission system.
> b) Facility commences initial commercial operations on or after January 1, 2005.
> c) Retail seller or procurement entity of the procured generation demonstrates delivery of its generation to an in-state market hub or in-state location, as specified in the delivery requirements below.
> d) Facility does not cause or contribute to any violation of a California environmental quality standard or requirement within California.
> e) If located outside the United States, the facility is developed and operated in a manner that is as protective of the environment as would a similar facility be if it were located in California.
> f) Facility and retail seller participate in an RPS tracking and verification system approved by the CEC.

The key for acceptance is two-fold: (1) connection to the WECC transmission system and (2) demonstrated delivery of its generation to an in-state market hub or in-state location. It appears the WECC transmission system referred to in this section is the electricity transmission system, and not the natural gas pipeline system.

California and Landfill Gas as Pipeline Gas

CPUC Rule 30 (Rule 30, 2009) does not allow the use of landfill gas as pipeline gas. As part of the Gas Delivery Specifications, the following is stated:

> o. Landfill Gas: Gas from landfills will not be accepted or transported.
> p. Biogas: Biogas refers to a gas derived from renewable organic sources. The gas is primarily a mixture of methane and carbon dioxide. Biogas must be free from bacteria, pathogens and any other substances injurious to utility facilities or that would cause the gas to be unmarketable and it shall confirm to all gas quality specifications identified in this Rule.

While the origins of this rule are not clear (e.g., concerns over bacteria or siloxanes), the intent is to prevent landfill gas from entering the gas delivery system and being delivered to customers' end-use appliances and devices. The ruling has of course prevented landfill gas from entering the gas distribution system in California. Presumably, this would also impact out-of-state gas contracted for in California, even if the actual molecules did not reach the California border.

The Chicago Climate Exchange (CCX)

The CCX guidelines (General Offset, 2009) indicate eligibility for:

> Currently, the following mitigation activities have prescriptive eligibility, evaluation and verification requirements:
>
> - Landfill Methane Collection and Combustion
> - Avoided Emissions from Organic Waste Disposal
> - Agriculture Methane Collection and Combustion
> - Coal Mine Methane Collection and Combustion
> - Agricultural Best Management Practices
> - Continuous Conservation Tillage
> - Grassland Conversion Soil Carbon Sequestration
> - Sustainable Rangeland Soil Carbon Sequestration
> - Forest Carbon Sequestration
> - Afforestation and Reforestation
> - Sustainable Forest Management
> - Small-Scale Renewable Biogas
> - Renewable Energy Systems
> - Ozone-Depleting Substance Destruction

There is no indication biogas-to-pipeline projects would not be eligible under this program, however, there are no specific examples of such indicated either. Also no mention is made of thermal gasification.

Western Climate Initiative (Bushnell, 2008)

At the end of February 2007, California Governor Schwarzenegger together with the Governors from Arizona, New Mexico, Oregon and Washington, announced a plan to establish a regional cap-and-trade system. With the recent addition of Utah, Montana, British Columbia, Manitoba, Ontario, and Quebec the WCI (seven states and four Canadian provinces as of September 2008) has agreed to reduce regional emissions (across all sectors and GHG, not just electricity and CO_2) to 15% below 2005 levels (WCI, 2007). The WCI regional cap-and-trade is scheduled to start January 2012 and the overall target is based on the aggregation of existing state emissions and emissions goals. California has reiterated its commitment to this initiative and plans to link its cap-and-trade program with other WCI partner programs to create a regional market system. Member states' emission reductions will need to meet their state specific targets as well as the regional goal.

Because the WCI involves cap-and-trade across all sectors and GHG, this is a major opportunity for biogas as pipeline gas to get into the equation. It is critical gas companies within this region work to see that biogas into pipeline gas is included, and does not run into the uncertainties found in the RGGI guidelines.

The WCI's offset program, which is still in development, will likely be more expansive than RGGI's. Analysis (Till, 2010) indicates WCI offset credits may account for up to 49% of the total emission reductions from 2012 to 2020, although participating jurisdictions will retain the discretion to adopt more stringent limits. Authorized project types include: (1) agricultural (soil sequestration and manure management); (2) forestry (afforestation/reforestation, forest management and preservation, and forest products); and (3) waste management (landfill gas and wastewater management). The WCI is currently developing standardized protocols for offset project types. Offset projects may be located in participating jurisdictions or elsewhere in the United States, Canada, or Mexico subject to comparably rigorous oversight, validation, verification, and enforcement requirements. The WCI will not accept offset credits for projects in developed countries from sources that, if located within the WCI, would be regulated entities. But WCI will accept CDM offset credits from developing countries.

Sample Project Studies

There was analysis (Lazarus, 2010) of sample projects across protocols, and recommendations for improvements in the protocols and the project descriptors to ensure compliance and acceptance. Four protocols were examined, including RGGI, CCX, CAR, and CDM. For the Stockholm Environmental Institute study referenced, the recommendations included:

> Based on our review and road test, we suggest the following areas for further consideration and potential improvements in landfill gas protocols:
>
> - More effective accounting for pre-existing LFG control systems to minimize the risks of over-crediting (where they are not accounted for), while not being so conservative as to eliminate the opportunity for additional methane capture and destruction. The CDM methodology provides a reasonable model to consider.
>
> - Eligibility of LFG projects to generate offsets up to, but not beyond, the date that a control system is required by regulation. Protocols respond quite differently where changes in regulation or landfill conditions *after initial project verification or registration* trigger legal requirements for the landfill gas control system. Responses range from immediate cessation of eligibility (Climate Leaders) to crediting up to the date the system is required (CCX, CAR) or until the end of the crediting period (RGGI,

CDM). Given the regulation is already widely in place for landfills and it is relatively easy to predict when a particular landfill will be required to control its emissions, we recommend adopting the approach used by CCX and CAR, i.e. project eligibility until the date an LFG control system is required by regulation.

- Development and adoption of common default factors for the efficiency of combustion devices (flares, engines, boilers, etc.). The variation among methodologies can lead to differences in crediting that, while small (5-10%), can be readily resolved.

- Adoption of the requirement that project developers submit a public attestation of regulatory additionality. This requirement is included in CAR and RGGI protocols, as verifiers can otherwise find it difficult to execute their responsibilities. A similar requirement was recently adopted by CCX.

- The requirement that LFG flow must be measured continuously. This is common practice, and significantly reduces error compared with monthly measurement.

- Adoption of an uncertainty discount for less accurate measurement methods, specifically in the case of less-than-continuous methane concentration measurement.

Further recommendations for manure management protocols:

Based on our review and road test of these protocols, we suggest the following areas for further consideration and potential improvements in manure management protocols:

- Adoption of the requirement that project developers submit a public attestation of regulatory additionality, as with landfill methane protocols.

- Additional research to validate the methods commonly used to quantify baseline methane emissions from manure management activities, and, if appropriate, develop alternative methods. Our assessment of sample projects in this report provides no clear indication of a preferred approach between the two predominant methods (the use of default annual methane conversion factors (MCFs) and application of the van't Hoff-Arrhenius factor).

- Additional research to validate the consideration of default values for maximum methane production per kg of volatile solids (often symbolized as B_o) to reflect variations in livestock diet and solids separation. Climate Leaders is currently the only protocol, of those reviewed, to provide default B_o values to reflect livestock diet and solids separation variations.

- Where the default B_o values may vary due to diet or other factors, inclusion of a provision that does not allow B_o values to increase over time. Since, for a given operation, more offset credits would be awarded to facilities with a livestock diet that produces more GHG emissions (e.g. low roughage diets in the case of dairy cows), we suggest protocols should avoid the perverse incentive of allowing facilities that switch to higher-emitting diets to also generate more offset credits. One way to limit such an incentive would be to not allow B_o values to increase above levels associated with historic diet practices.

- Inclusion of the full suite of potentially significant project emissions. For example, only CAR and CDM protocols include project emissions from digester effluent, which can be large as in the case of the sample projects considered here. CCX and RGGI assume 100% collection efficiency of biogas, which could overstate emission reductions. Climate Leaders include nitrous oxide but not methane emissions from non-digester manure management.

- Further assessment of baseline (and project) nitrous oxide emissions from field spreading of manure (and digester effluent), which could be quite significant but is subject to considerable uncertainty. In some project circumstances, e.g. where field spreading is the baseline management method, nitrous oxide from field spreading can be the single largest source of baseline emissions. Counting this source can mean the difference between generating offset credits and not doing so.

- Inclusion of provisions that baseline CH_4 emissions cannot exceed the quantity of CH_4 captured and destroyed by the project digester. Digesters, which are typically engineered and operated to maximize methane production, will tend to produce more methane than pre-project management systems, such as lagoons. Currently, RGGI, CAR, and CDM all include such a provision, which guards against over-crediting. CCX addresses this concern by requiring the use of the lesser of these values.

- Further specification of monitoring requirements. In order to verify CH_4 captured by the digester is being destroyed and flared as CO_2, protocols could consistently include monitoring requirements, similar to those of CAR, for the operation of the manure digester/flare and inspection of biogas instruments.

Clean Development Mechanism (CDM), (Clean Development, 2010)

The CDM is one of the "flexibility" mechanisms defined in the Kyoto Protocol. It is defined in Article 12 of the Protocol, and is intended to meet two objectives: (1) to assist parties not included in Annex I in achieving sustainable development and in contributing to the ultimate objective of the United Nations Framework Convention on Climate Change (UNFCCC), which is to prevent dangerous climate change; and (2) to assist parties included in Annex I in achieving compliance with their quantified emission limitation and reduction commitments (GHG emission caps). "Annex I" parties are those countries listed in Annex I of the treaty, and are the industrialized countries. Non-Annex I parties are developing countries.

Objective (2) is achieved by allowing the Annex I countries to meet part of their caps using “Certified Emission Reductions” from CDM emission reduction projects in developing countries. This is subject to oversight to ensure these emission reductions are real and "additional." The CDM is supervised by the CDM Executive Board and is under the guidance of the Conference of the Parties of the United Nations Framework Convention on Climate Change.

The CDM allows industrialized countries to invest in emission reductions wherever it is cheapest globally. Between 2001, which was the first year CDM projects could be registered, and 2012, the end of the Kyoto commitment period, the CDM is expected to produce some 1.5 billion tons of carbon dioxide equivalents (CO_2e) in emission reductions. Most of these reductions are through renewable energy, energy efficiency, and fuel switching.

CDM protocols specifically mention (Indicative simplified, 2010, p. 1-2) alternatives to methane destruction for AD biogas projects:

> The recovered methane from the above measures may also be utilized for the following applications instead of flaring or combustion:
>
> (a) Thermal or electrical energy generation directly; or
> (b) Thermal or electrical energy generation after bottling of upgraded biogas; or
> (c) Thermal or electrical energy generation after upgrading and distribution:
> (i) Upgrading and injection of biogas into a natural gas distribution grid with no significant transmission constraints; or
> (ii) Upgrading and transportation of biogas via a dedicated piped network to a group of end users.

While only in reference to manure and AD, the specific mention of upgrading and injection into a natural gas distribution system is very helpful and may set a precedent for other protocols.

Midwestern Greenhouse Gas Reduction Accord (MMGRA)

The MGGRA (Till, 2010) commits six Midwestern States and one Canadian province to establish greenhouse gas reduction targets and develop a multi-sector GHG cap-and-trade program. On November 15, 2007, the Governors of Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin and the Premier of Manitoba entered into the Midwestern Greenhouse Gas Reduction Accord. In June 2009, the MGGRA Advisory Group released its draft recommendations for the program's cap-and-trade program. The draft recommendations call for reducing participating jurisdictions' greenhouse gas emissions 20% below 2005 levels by 2020. Similarly to the WCI, regulated emissions would include electricity generation, industrial processes, transportation fuels, and residential, commercial, and industrial fuel combustion.

Given its early stage of development, many details about MGGRA's offset program are unknown. Twenty percent of a regulated entity's compliance obligation may be satisfied via offset credits, and MGGRA may increase that amount if prices rise above certain price thresholds (to be determined). Offset projects may be located in participating jurisdictions, or other jurisdictions that enter into a Memorandum of Understanding with MGGRA, and that have a GHG regulatory program of equal or greater stringency. MGGRA will consider whether international offsets (beyond Canada), including credits generated by CDM and JI projects, will be available for compliance. MGGRA has not yet defined the types of projects that would qualify for inclusion in the offset program.

Thermal gasification is mentioned in at least one state RECS document pertaining to credits, as follows:

Under Michigan's Advanced Cleaner Energy Credits (ACEC) program (Michigan Energy, 2010),

> **Advanced Cleaner Energy Credit (ACEC) Definition:** PA 295 allows that one ACEC is granted for every MWh of electricity generated from an advanced cleaner energy system. There is no requirement to generate or obtain ACECs, but they may be used to help meet the renewable energy and energy optimization standards.
>
> - An ACEC may be traded, sold, or otherwise transferred.
> - An ACEC expires when substituted for a REC or EOC.
> - An ACEC expires 3 years after generation.

ACEC System Requirements

- ACECs generated by facilities in existence on January 1, 2008 cannot make up more than 7% of the electric provider's required RECs
- ACECs are produced by a gasification facility, an industrial cogeneration facility, a coal fired electric generating facility that captures and sequesters 85% of the carbon dioxide, or an electric generating facility using technology not in operation on October 6, 2008.
- If a facility uses advanced cleaner energy technology and another technology that doesn't qualify, the ACECs earned shall be on a percentage basis.
- If a facility qualifies for both ACECs and RECs, only one type will be granted at the owner's option.

Under the program a gasification system is defined as:

> Gasification facility uses a thermo-chemical process that does not use direct combustion to produce synthesis gas from carbon-based fuel or a combined synthesis gas and with or without methane to generate electricity for commercial use.

Description of Project Tasks

The above narrative describes in general terms the scope of work performed in the proposed project. The detailed task plan was followed below:

Task 1. Define Data Handling and Analysis Framework
Task 2. Data Assembly and Analysis
Task 3. Assess Technical, Market, Regulatory Barriers
Task 4. Prepare Report
Task 5. Project Management

Task 1. Define Data Handling and Analysis Framework

The objectives of this task defined the analytical framework for handling the different types of technical data that were assembled and analyzed. The types of data collected included feedstock materials, current production/generation rates, water (moisture) contents, calorific values, potential yields of synthesis gas (syngas) and/or pipeline-quality RG from processing either by anaerobic digestion or by thermal gasification, cleanup technologies applicable, to AD or TG, capital and operating cost information for AD and TG as well as other data. The goals of this task were to plan and prepare the tools for encapsulating the data and analyzing it. These tools were contained in Microsoft Excel spreadsheets.

Task 2. Data Assembly and Analysis

The goals of this task were to collect and review relevant technical and economic information on existing potential renewable energy resources within the 50 United States. On a state-by-state basis, a determination was made on suitable feedstock resources, appropriate technological applications (AD or TG), and estimates of the total potential for pipeline-quality RG production from each renewable resource. Energy yield and efficiency data was from previous studies GTI has conducted.

A state-by-state, high-level estimate was created of the potential capex and opex associated with pipeline-quality RG production. Cost information was obtained from studies available in the open literature and from previous studies GTI has conducted. Consideration of a typical debt/equity ratio for capex and opex costs allowed the appropriate generation of costs to produce pipeline-quality RG for injection into the pipeline. Such costs were compared to current natural gas costs. GTI also estimated the potential job creation associated with the energy production potential in each state.

GTI worked interactively with American Gas Foundation (AGF) to define the selection of the data and the parameters of this study. Working with AGF, GTI formulated a feedstock utilization model capturing market penetration scenarios of interest to AGF. This embodied setting the assumptions for the fractional utilization of the feedstocks under consideration.

Task 3. Assess Technical, Market, Regulatory Barriers

The main objectives of this task determined what technical, market, and regulatory barriers to the development of a RG market currently exist. Any move toward a portfolio that includes energy, both renewable and GHG-mitigating, required an understanding of how such benefits valued under existing and proposed cap-and-trade scenarios such as the RGGI, a cooperative effort to limit GHG emissions by ten Northeastern and Mid-Atlantic states. GTI determined to what extent RG contributes to offsets within a given carbon trading scheme, which types of biomass/renewable energy sources are eligible for inclusion, what forms of energy are included, what modes of energy production are allowable, and how carbon offsets are allocated. In the absence of a specific regional trading scheme, GTI examined current trading schemes such as the CCX and RGGI.

Task 4. Prepare Report

This task entailed preparing a report to document the findings of the project. A draft outline of the report was prepared shortly after project initiation. It was reviewed and approved by AGF. Preparation of a bibliography will begin after the task work and analysis in Tasks 1 through 3 are completed. All findings of the project will be included in a report after the data and analysis work is completed.

GTI anticipates that AGF will require about 2 weeks to review the draft final report and to return comments. GTI will then incorporate AGF's comments into the report and submit it to AGF as the final deliverable. GTI anticipates that finalizing the report will take approximately 1 week, but the duration is dependent on how extensive the comments are.

Task 5. Project Management

The objectives of this task managed all aspects of the project including technical, contractual, financial, and personnel-related issues, and to ensure AGF is kept informed as to all developments that occur during the performance of the work scope.

The GTI project manager, Dr. Stephen F. Takach, Senior Scientist, kept the AGF project manager apprised of all project-related developments and progress on a timely basis. Communications were made by e-mail, fax, phone, and as needed, Webex-based presentations.

Project Deliverable

The deliverable for the project is a final report addressing the objectives stated at the beginning of Section 2.0. This final report contains a section discussing the assumptions and parameters involved in the study. It contains a set of tables highlighting the results of the data assembly and analysis. It also contains a discussion of the current barriers to RG production and usage.