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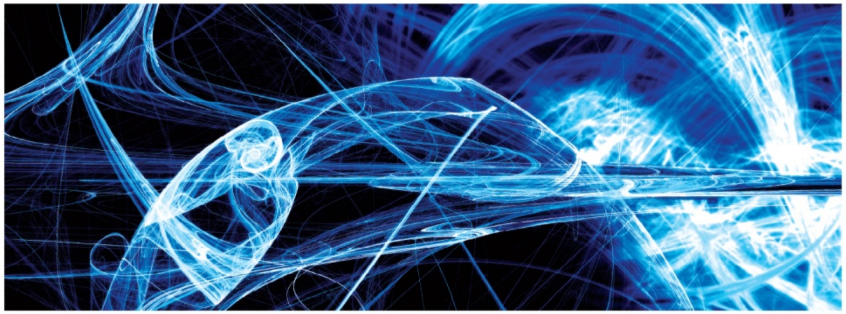
New Jersey Agricultural
Experiment Station

ASSESSMENT OF BIOMASS ENERGY POTENTIAL IN NEW JERSEY



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Prepared by: The New Jersey Agricultural Experiment Station

NJAES Report 2007-1

Study Team

- **Project Director –** Margaret Brennan
- **Waste Stream/Biomass Assessment**
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- **Waste Stream/Biomass Mapping**
  - *Team Members:* David Tulloch (Team Leader), Caroline Phillipuk
- **Policy Recommendations**
  - *Team Members:* Margaret Brennan (Team Leader), all members of project teams
- **Navigant Consulting**
  - Provided technology cost and performance data; developed interactive database with information and functionality specifications provided by NJAES.

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Full Report and Bioenergy Calculator are available on-line at:
njaes.rutgers.edu/bioenergy

Please use the following reference for this report:

- Brennan, Margaret, David Specca, Brian Schilling, David Tulloch, Steven Paul, Kevin Sullivan, Zane Helsel, Priscilla Hayes, Jacqueline Melillo, Bob Simkins, Caroline Phillipuk, A.J. Both, Donna Fennell, Stacy Bonos, Mike Westendorf and Rhea Brekke. "*Assessment of Biomass Energy Potential in New Jersey*." New Jersey Agricultural Experiment Station Publication No. 2007-1. Rutgers, the State University of New Jersey, New Brunswick, NJ. July, 2007.

Glossary of Acronyms Used

AD	Anaerobic Digestion
BIGCC	Biomass Integrated Gasification Combined Cycle
BTL	Biomass to Liquids
C&D	Construction & Demolition
CAPEX	Capital Expenditure
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
DDG	Distiller Dry Grain
FT	Fischer-Tropsch
GGE	Gallons of Gasoline Equivalent
HHV	Higher Heating Value
ICE	Internal Combustion Engine
kW(h)	kilowatt(hour)
LFG	Landfill Gas
LNG	Liquid Natural Gas
LCOE	Levelized Cost of Energy (for power)
M/Mm/MM	Million
Mmscf	Million square cubic feet
MDT	Million Dry Tons
MeTHF	Methyltetrahydrofuran
MGPY	Million Gallon per Year
MMBtu	Million British Thermal Units
MSW	Municipal Solid Waste
MW	Megawatt
MWh	Megawatt-hour
NJAES	New Jersey Agricultural Experiment Station
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SCF	Standard Cubic Foot
TPD	Ton Per Day
WWTP	Wastewater Treatment Plant

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In September 2006, the New Jersey Board of Public Utilities retained the New Jersey Agricultural Experiment Station to evaluate the state's bioenergy potential.

- The four major goals of this project were to:
  - Assess the characteristics and quantity of New Jersey's biomass resources;
  - Assess technologies (commercially or near commercially available) that are capable of producing bioenergy, in the form of electric power and transportation fuels from New Jersey's biomass resources;
  - Develop the first statewide mapping of waste/biomass resources and bioenergy potential;
  - Develop policy recommendations for moving New Jersey into the forefront of bioenergy innovation.
- These deliverables will result in the establishment of an outstanding foundation upon which to develop the bioenergy potential for New Jersey.

Research yielded six major findings about New Jersey's biomass resources:

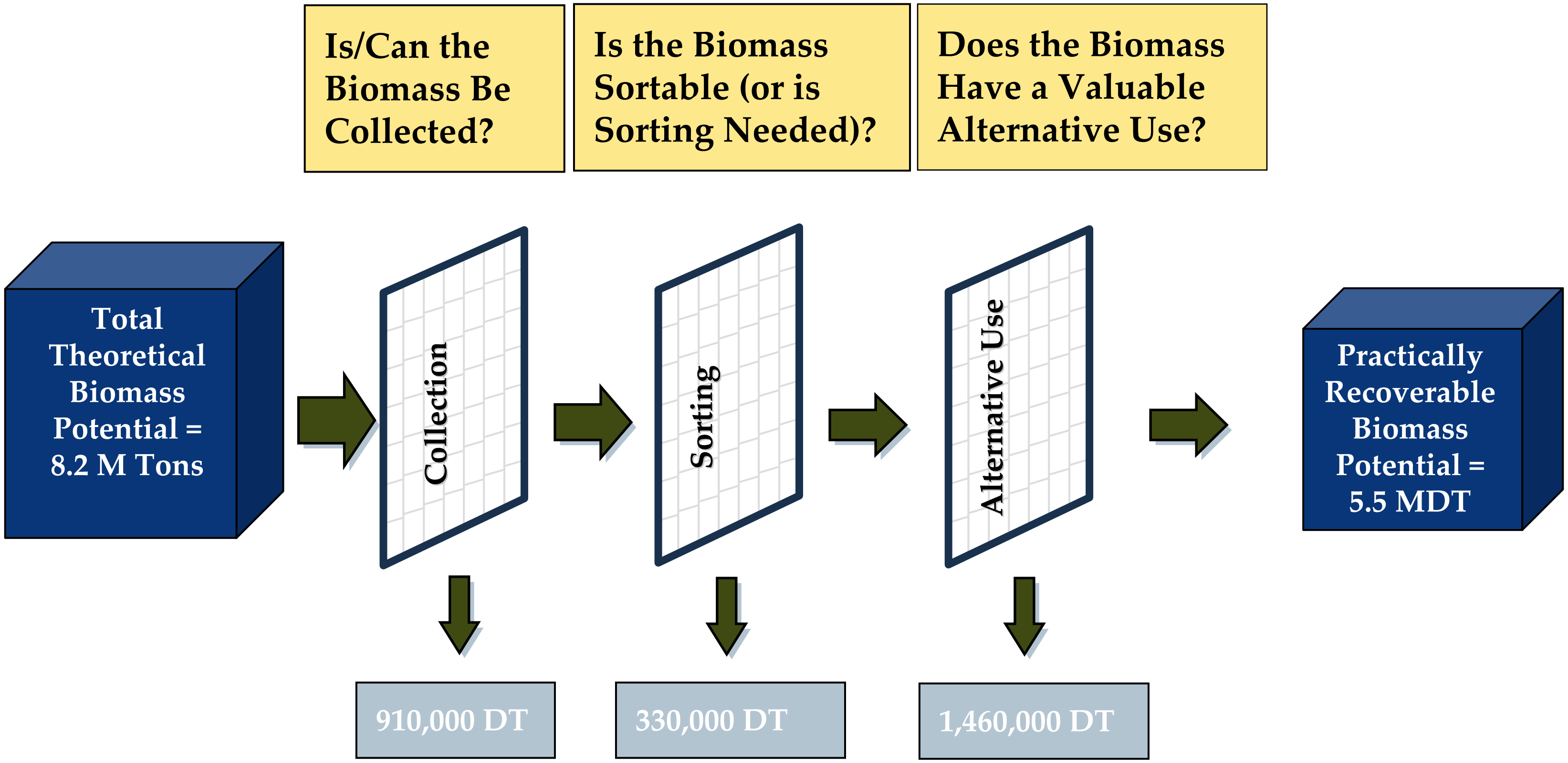
1. New Jersey produces an estimated 8.2 million dry tons (MDT) of biomass[1] annually.
2. A screening process was developed to estimate practically recoverable biomass. Approximately 5.5 MDT (~65%) of New Jersey's biomass could ultimately be available to produce bioenergy.
3. New Jersey's estimated practically recoverable biomass resource of 5.5 MDT could deliver up to 1,124 MW of power, (~9% of New Jersey's electricity consumption) or 311 million gallons of gasoline equivalent (~5% of transportation fuel consumed) if appropriate technologies and infrastructure were in place.
4. Almost 75% of New Jersey's biomass resources are produced directly by the state's population, the majority in solid waste (e.g., municipal waste). Biomass is concentrated in central and northeastern counties.
5. The large proportion of waste-based biomass in the state supports the recommendation that New Jersey pursue development of an energy-from-waste industry.
6. Agriculture and forestry management are also important potential sources of biomass and account for the majority of the remaining amount of biomass.

[1] This total includes biogas and landfill gas quantities converted to dry ton equivalents on an energy basis. This does NOT include biomass that is currently used for incineration or sewage sludge because these are not classified as Class I renewable feedstocks in NJ.

A range of biomass resources were examined; these were divided into 5 categories based on physical characteristics.

Feedstock Type	Definitions	Resources
Sugars/Starches	Traditional agricultural crops suitable for fermentation using 1st generation technologies Some food processing residues are sugar and starch materials	• Agricultural crops (sugars/starches) • Food processing residues (w/residual sugars)
Lignocellulosic Biomass	Clean woody and herbaceous materials from a variety of sources Includes clean urban biomass that is generally collected separately from the municipal waste stream (wood from the urban forest, yard waste, used pallets)	• Agricultural residues • Cellulosic energy crops • Food processing residues • Forest residues, mill residues • Urban wood wastes • Yard wastes
Bio-oils	Traditional edible oil crops and waste oils suitable for conversion to biodiesel	• Agricultural crops (beans/oils) • Waste oils/fats/grease
Solid Wastes	Primarily lignocellulosic biomass, but that may be contaminated (e.g., C&D wood) or co-mingled with other biomass types	• Municipal solid waste (biomass component) • Construction & Demolition (C&D) wood • Food wastes • Non-recycled paper • Recycled materials
Other Wastes	Other biomass wastes that are generally separate from the solid waste stream Includes biogas and landfill gas	• Animal waste (farm) • Wastewater treatment biogas • Landfill gas

A screening process was developed to estimate how much of New Jersey's theoretically available biomass might be recoverable. The results indicate that approximately 5.5 MDT (~65%) of New Jersey's biomass could ultimately be available to produce energy, in the form of power, heat, or fuels.



Is/Can the Biomass Be Collected?

Is the Biomass Sortable (or is Sorting Needed)?

Does the Biomass Have a Valuable Alternative Use?

Total Theoretical Biomass Potential = 8.2 M Tons

Collection

Sorting

Alternative Use

Practically Recoverable Biomass Potential = 5.5 MDT

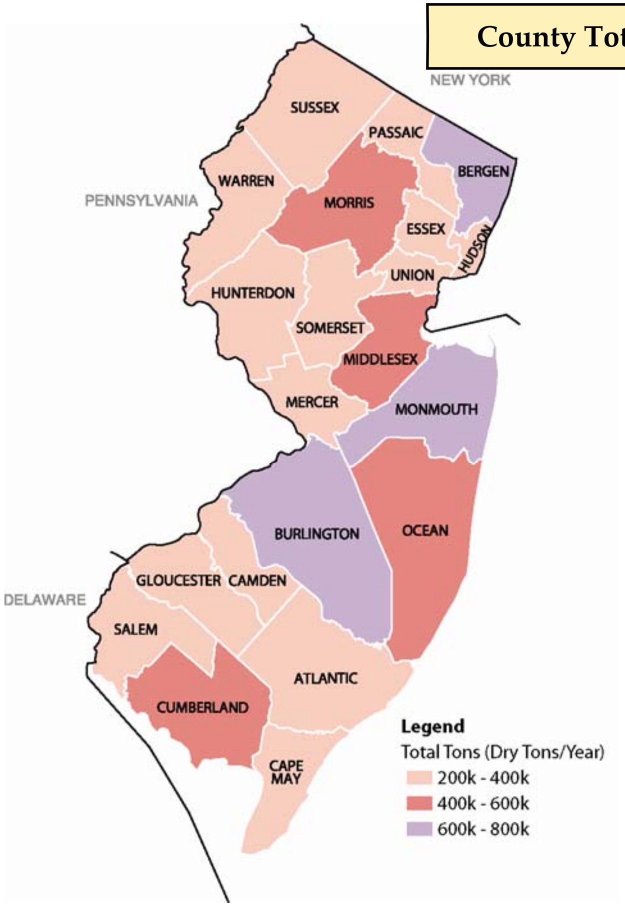
910,000 DT

330,000 DT

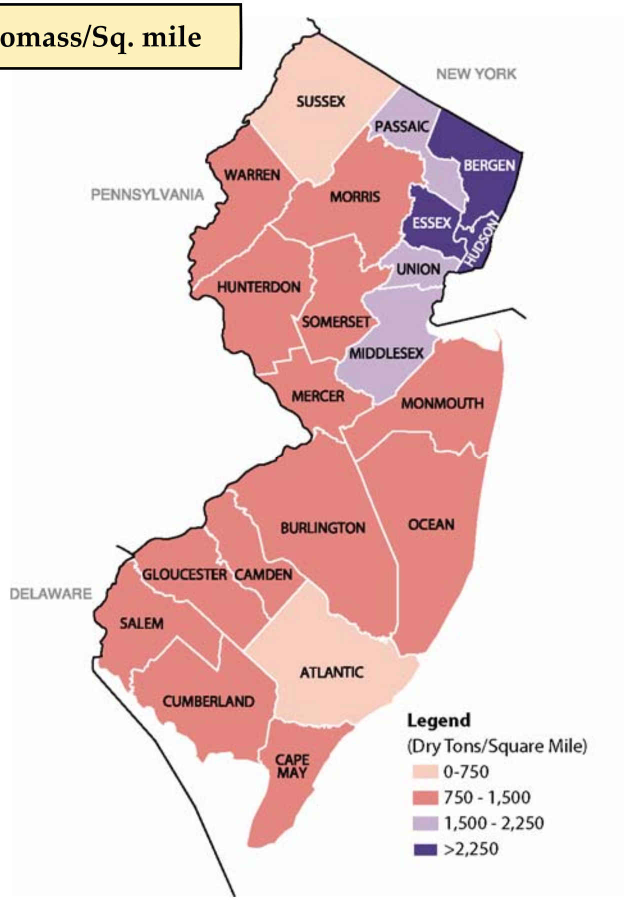
1,460,000 DT

Note: This screening process is preliminary and would require considerably more analysis to reach any final conclusions. The screening analysis has been incorporated into the database, and provide flexible "scenario analysis" capabilities for the user.

Biomass is concentrated in the counties of central and northeastern New Jersey.

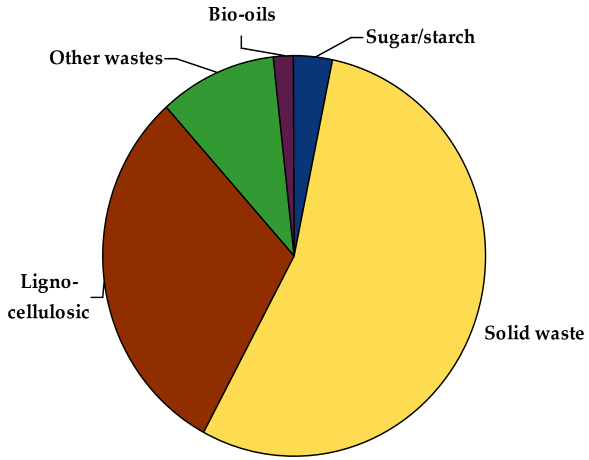

County Totals

The energy contained in each ton of biomass is lower than for conventional fuels; thus, transportation distances between a source and an energy conversion facility can be a key factor in determining the economics of a bioenergy project .


Biomass/Sq. mile

Almost 75% of New Jersey’s biomass resource is produced directly by the state’s population, much of it in the form of municipal solid waste.

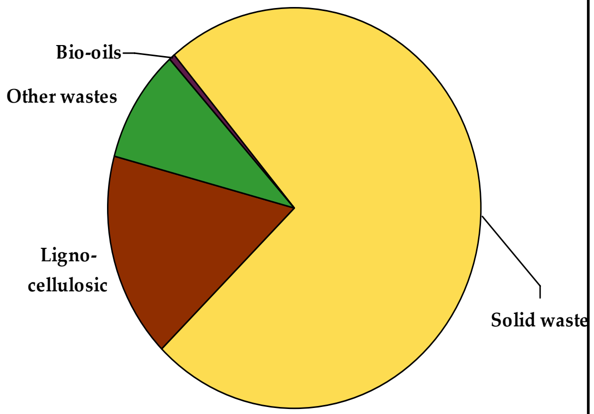
Total Available Biomass Resources by Type (dry tons/yr)



Total = 8.2 million dry tons/yr[1]

The chart on the left shows NJ’s total biomass. The chart on the right shows just the population-related biomass waste stream.

Biomass Resources Associated with Population (dry tons/yr)



Total = 6.1 million dry tons/yr[1]

In the past, generating energy from solid waste typically involved incineration. Several new technologies described in Section III are becoming capable of converting solid waste into energy without incineration.

1. This total includes biogas and landfill gas quantities converted to dry ton equivalents on an energy basis. Note that these are gross quantities, not taking into account differences in heat content per ton.

Executive Summary » County Population Growth » 2007-2020

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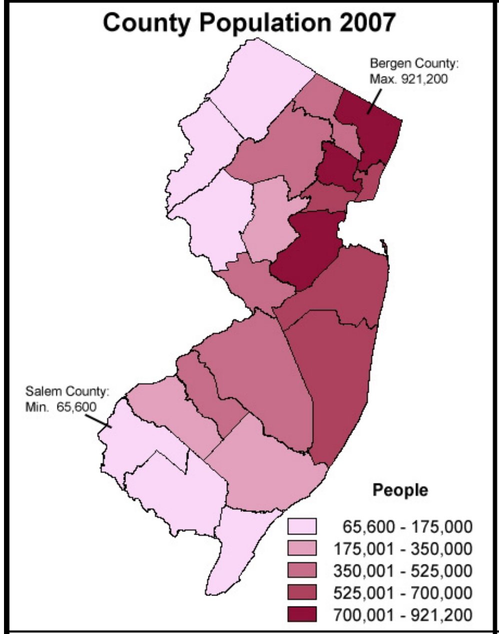
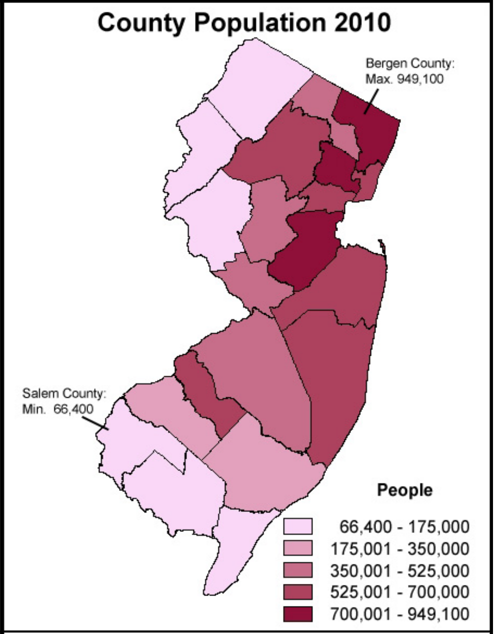
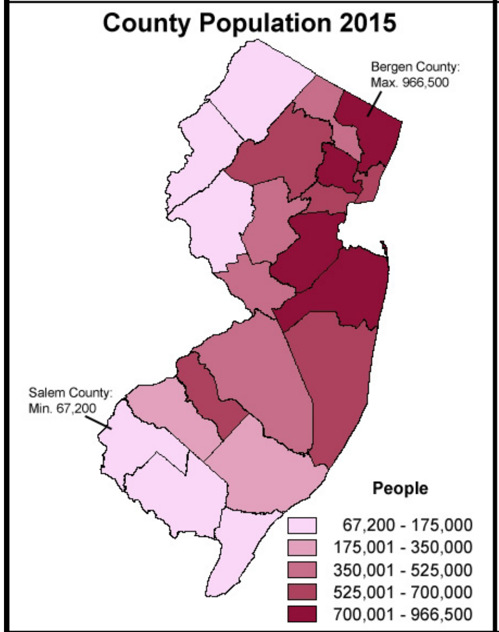
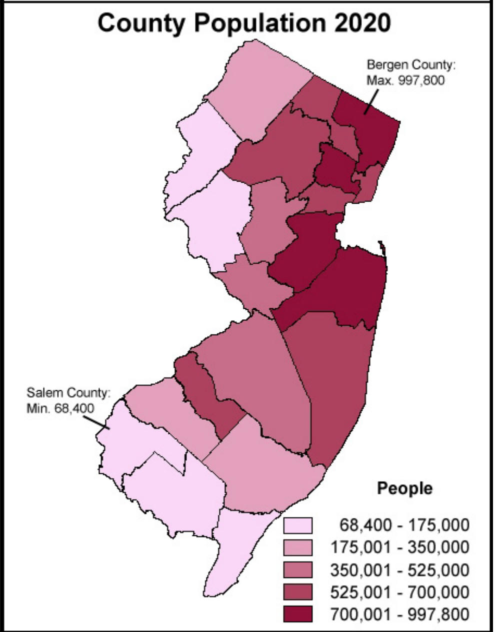
New Jersey Population Projections by County

Between 2007 and 2020, New Jersey's population is expected to grow by about 10% adding about 1,000,000 more people.


County Population 2007


County Population 2010

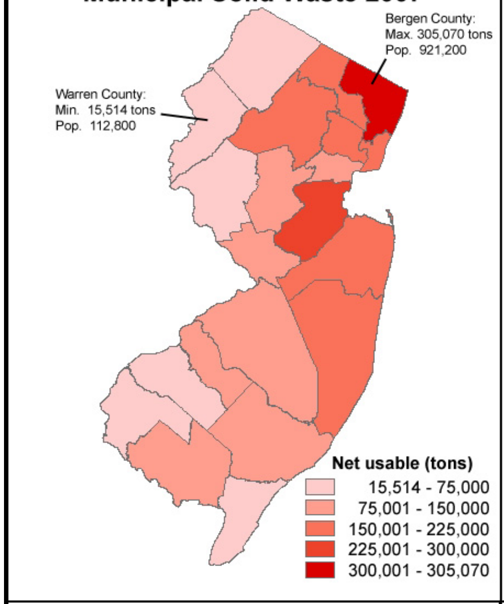

County Population 2015

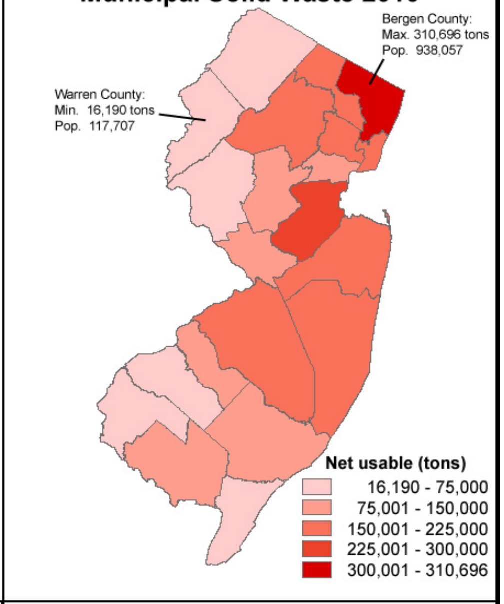

County Population 2020

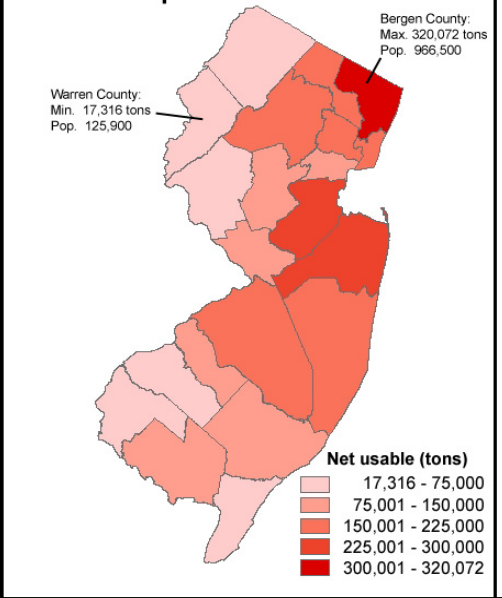
Municipal Solid Waste Projections by County

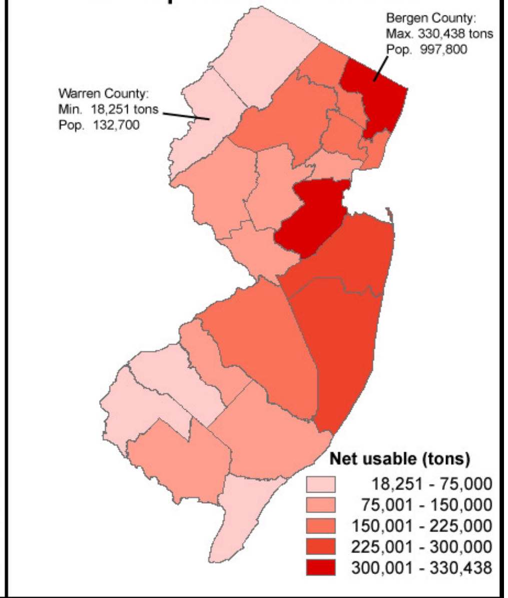
Almost 75% of New Jersey's biomass resource is produced directly by the state's population, much of it in the form of municipal solid waste

With increases in population comes increases in the amount of solid waste generated in the state. MSW is expected to increase by 10.55% by 2020.

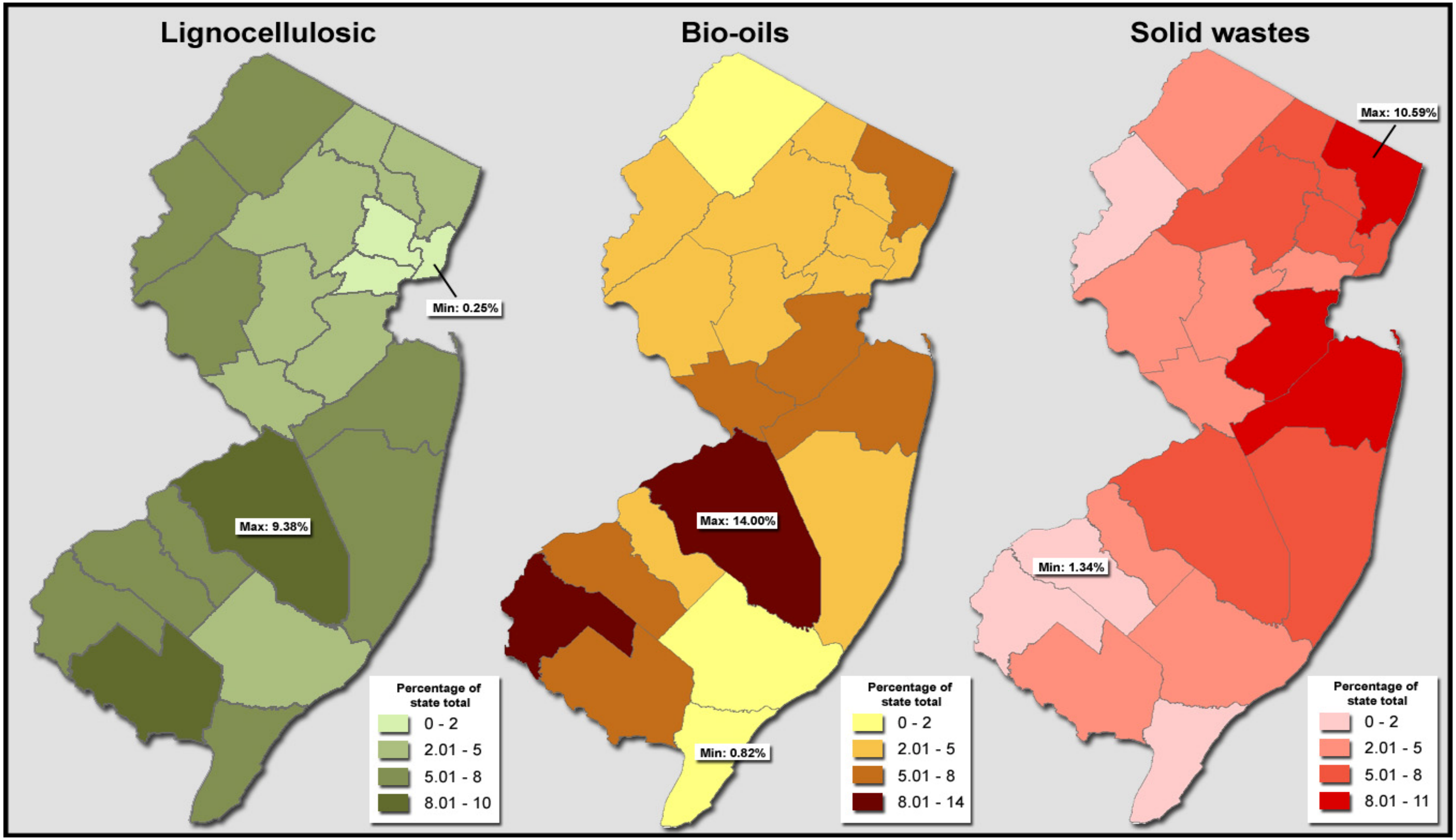

Municipal Solid Waste 2007


Municipal Solid Waste 2010


Municipal Solid Waste 2015


Municipal Solid Waste 2020

Biomass Resources by Feedstock Category 2007



Mapping out a strategy for effective biomass resource utilization is a valuable next step for New Jersey to understand the actual potential.

Biomass Resource Utilization Strategy

Biomass Locational Mapping	**Understand Quality Characteristics**	**Determine Infrastructure Requirements**	**Determine Most Appropriate Use**	**Develop Collection Plan**	**Develop Separation Plan**
Use GIS mapping to determine location of resources, including central nodes that might make good plant locations	Compile quality characteristics of proximal resources to determine compatibility with prospective facility	Evaluate collection, delivery, and handling infrastructure needed to process resources at each facility or node	For those resources that have an alternative use, decide whether the alternative use is preferred to energy production	For resources not currently collected, develop a viable collection plan	For resources not currently separated from the waste stream, develop separation plan

An early part of the project design was to identify the leading biomass to energy conversion technologies that should be evaluated

Section III describes the biomass conversion technologies that were determined to be the most important for the analysis. Considerations for this analysis included:

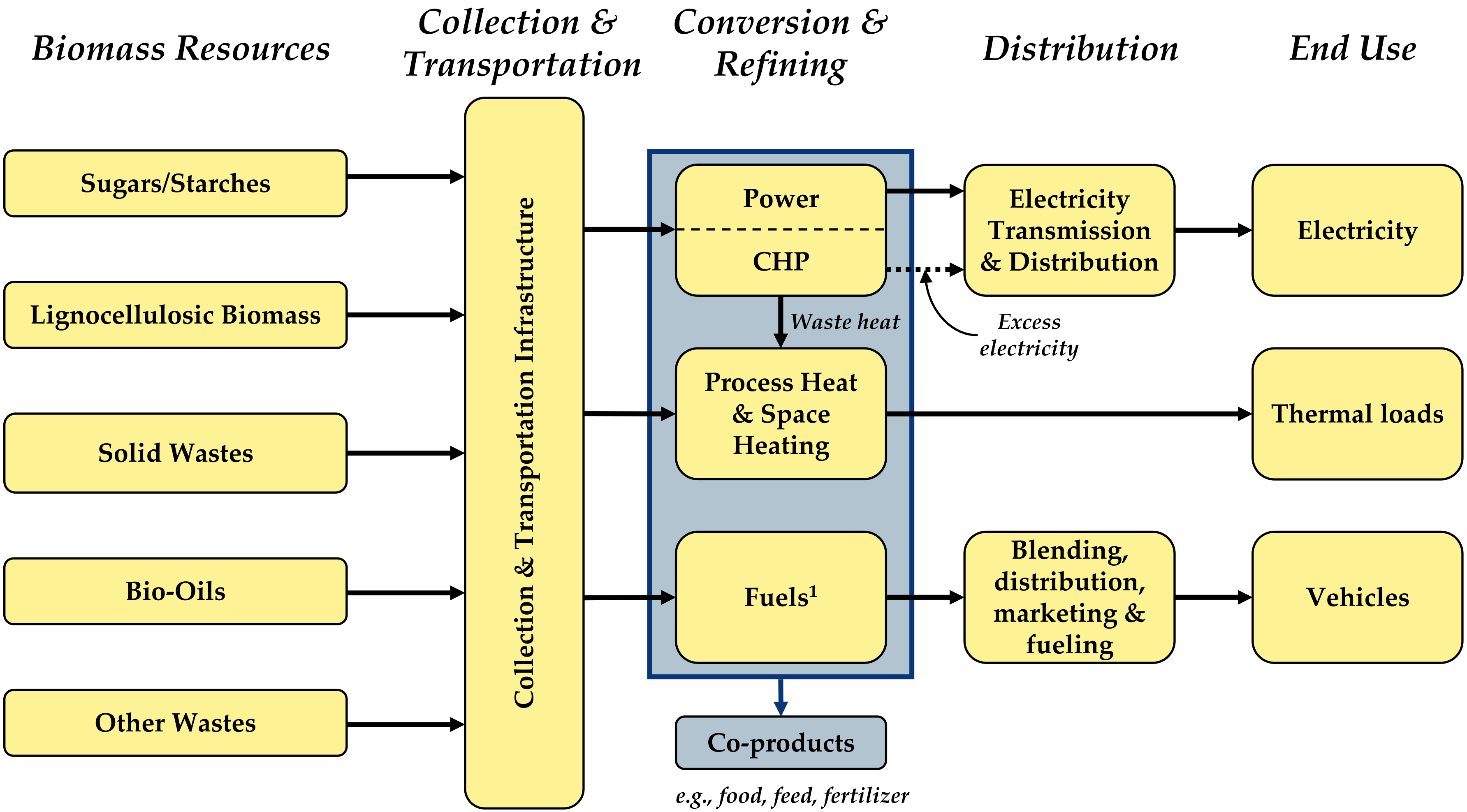
- There are numerous *technically feasible* bioenergy conversion technologies. However, certain technologies that are not well developed yet and/or are likely to be applicable mainly to niche applications were generally excluded from detailed analysis.
- Although there are many biomass feedstocks that *could* be used with a particular conversion technology, in practice, certain feedstocks are better suited to certain conversion processes.
- Given the wide range of technologies within a particular "platform" (e.g., types of biomass gasification reactors), the analysis focuses on broad technology platforms with similar characteristics. Representative feedstock-conversion-end use pathways were selected for the economic analysis.
- The decision to screen out specific technologies *for the current analysis* does not mean that it will not find some application in New Jersey in the future.

Technology development and commercialization proceeds through a number of basic stages.

R&D	**Demonstration**			**Market Entry**	**Market Penetration**	**Market Maturity**
	Initial System Prototypes	**Refined Prototypes**	**Commercial Prototypes**			
• Research on component technologies • General assessment of market needs • Assess general magnitude of economics	• Integrate component technologies • Initial system prototype for debugging	• Ongoing development to reduce costs or for other needed improvements • "Technology" (systems) demonstrations • Some small-scale "commercial" demonstrations	• Commercial demonstration • Full size system in commercial operating environment • Communicate program results to early adopters/ selected niches	• Commercial orders • Early movers or niche segments • Product reputation is initially established • Business concept implemented • Market support usually needed to address high cost production	• Follow-up orders based on need and product reputation • Broad(er) market penetration • Infrastructure developed • Full-scale manufacturing	• Roll-out of new models, upgrades • Increased scale drives down costs and results in learning
10+ years	4 - 8 years			1 - 3 years	10 - 20 years	Ongoing

The time required to pass through any given stage can vary considerably. The values shown here are representative of a technology that passes successfully from one stage to the next without setbacks.

The analysis covered power, fuels and heat applications.



1. Mainly liquid transportation fuels. Can also be used for power and heat applications (e.g., biodiesel blends for home heating oil).

Thirteen bioenergy applications were included in the analysis

Application	**Core technology platforms and applications**				
	Direct Combustion	**Thermo-chemical Conversion**	**Fermentation**	**Anaerobic Digestion**	**Physio-chemical Conversion**
Power/CHP	**1.**Stand-alone rankine (steam) cycle plant **2.**Small-scale rankine cycle CHP plant **3.**Biomass co-firing with coal	**4.** Stand-alone BIGCC plant **5.** Small-scale gasification-IC engine CHP plant **6.** Stand-alone pyrolysis plant		**11.**Food waste anaerobic digester with IC engine CHP plant/ Landfill gas with microturbine	
Heat Only	• Discussed qualitatively and shown in context of CHP applications above.				
Transportation Fuels		**7.** .Biomass-to-liquids plant (Fischer-Tropsch) **8.**.Dilute acid hydrolysis for biofuels production[1]	**9.** Corn-ethanol dry mill **10.**Cellulosic ethanol plant	**12.** CNG or LNG from landfill gas/AD gas	**13.**Transesterfication Biodiesel

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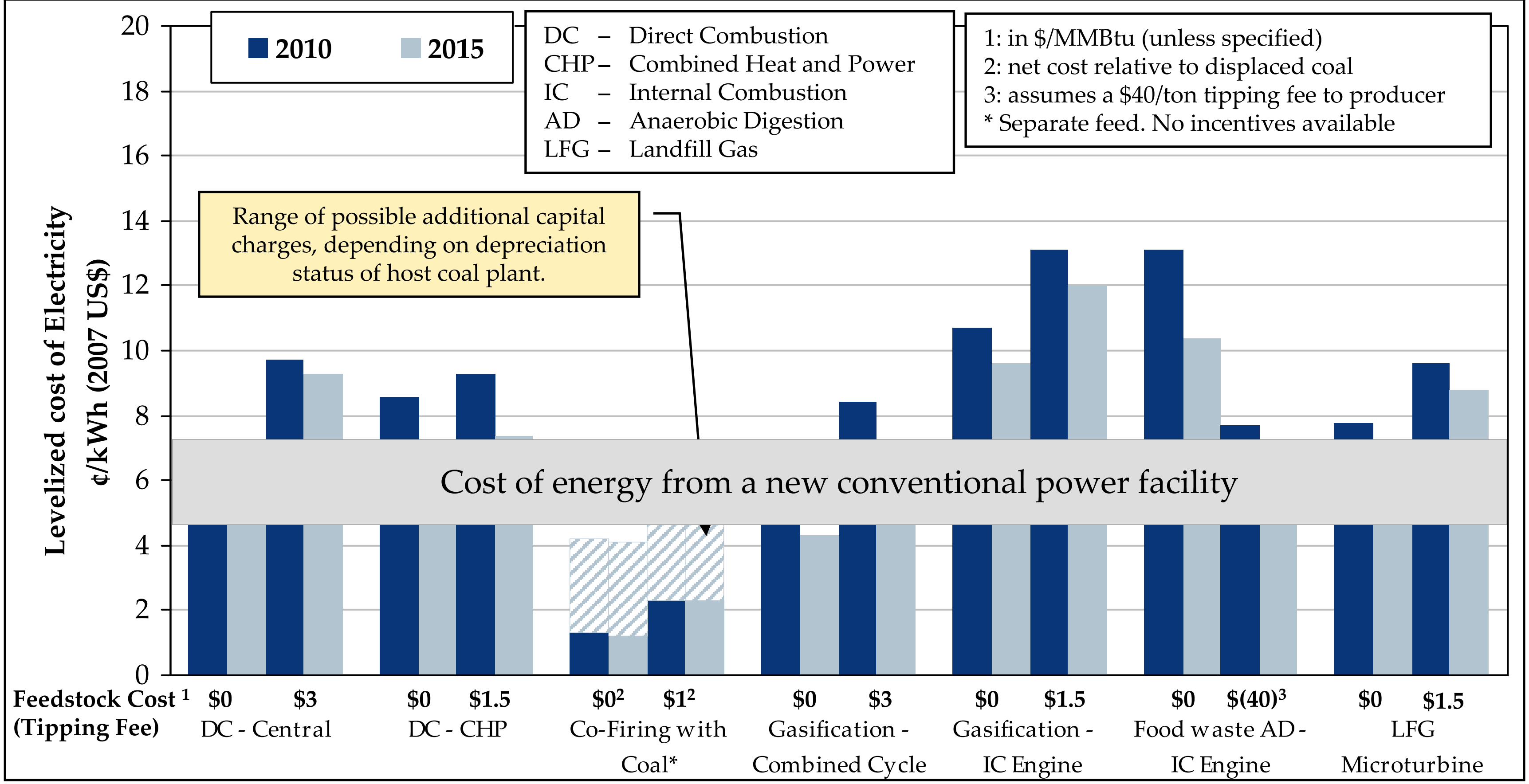
1. Involves the production of ethers (gasoline blendstock) and esters (diesel blendstock).

By 2010 and 2015, cost reduction potential should bring additional biopower technologies into the realm of commercial application.

LCOE Comparison for Biomass Power Options: 2010 & 2015 without incentives



DC – Direct Combustion
CHP – Combined Heat and Power
IC – Internal Combustion
AD – Anaerobic Digestion
LFG – Landfill Gas

1: in $/MMBtu (unless specified)
2: net cost relative to displaced coal
3: assumes a $40/ton tipping fee to producer
* Separate feed. No incentives available

Range of possible additional capital charges, depending on depreciation status of host coal plant.

- Both combustion and gasification technologies are opportunities for New Jersey

✓ Biomass co-firing offers environmental benefits to existing coal fired power production.

✓ Gasification technology is relatively well developed and can be deployed at a range of scales for power generation, which makes it suitable to New Jersey's biomass resources. Gasification is also suitable for municipal wastes, and could offer lower emissions than conventional incineration.

- Anaerobic digestion is a commercialized and well developed technology option

✓ High population density ensures a concentrated stream of food wastes, landfill gas, MSW

✓ There also remain untapped opportunities for landfill gas and for installing cogeneration at wastewater treatment plants, and these projects are likely to have very attractive economics.

- Feedstock availability for 1st generation biofuels are limited.

✓ Any plants of this type would require importation of feedstock (except for biodiesel from yellow grease.)

- New Jersey's petroleum and petrochemical industry in ideal position to capitalize on technological innovation, such as direct conversion of vegetable oils and fats into renewable diesel at oil refineries

- New Jersey's import / export infrastructure, makes the state an ideal center for biofuels trading activities as a global trade emerges.

The biomass supply data described in Section II was integrated with the conversion technology data developed in Section III to estimate the energy potential of New Jersey's biomass resources.

- "Typical" moisture and energy content and/or yield assumptions for each resource to calculate total estimated energy potential was developed.

- Estimated energy potential included energy produced using current or near-term technologies appropriate for each resource .

- This was a *high-level* examination of potential energy from biomass, such that the quantitative estimates described in this presentation should be considered indicative only. In particular, the results of the screening analysis to estimate recoverable potential should be considered preliminary.

A unique Bioenergy Calculator and interactive biomass resource database was developed to aggregate all biomass and technology information. This database contains a number of important features:

- Detailed biomass resource data, by county, for more than **40 biomass resources**.
- Energy generation data for **13 bioenergy technologies** that takes into consideration advances in energy output and efficiency over time.
- The database was designed to analyze the biomass resource data and technology assessment data in an interactive fashion. The database is:
  - Structured by county and resource type
  - Contains technology performance estimates to convert biomass quantities into energy (electricity and fuel) potential.
- The **Bioenergy Calculator** yields projected biopower and biofuel estimates for 2007, 2010, 2015, 2020.
- The database allows for continual updating as additional data is collected and refined.
- A screening tool is imbedded in the database to conduct sensitivity analyses on the estimate of recoverable biomass.

Bioenergy Potential by County

TYPE	POWER (MWh) TOTAL				FUELS (GGE)			
County	**2007**	**2010**	**2015**	**2020**	**2007**	**2010**	**2015**	**2020**
Atlantic	314,881.11	328,749.72	355,478.29	367,122.70	11,823,683	12,082,097	12,528,498	12,970,734
Bergen	664,828.98	693,861.18	749,852.80	774,451.06	23,661,464	24,115,715	24,892,782	25,730,144
Burlington	710,094.49	739,098.42	794,775.95	820,201.33	31,727,019	32,330,126	33,371,647	34,435,818
Camden	342,322.04	354,458.01	378,166.63	385,925.63	10,598,947	10,695,522	10,858,657	11,079,685
Cape May	314,374.07	325,265.09	346,641.55	352,843.81	8,941,315	9,027,148	9,174,121	9,370,800
Cumberland	485,905.53	501,315.20	531,507.22	536,380.39	18,621,363	18,733,853	18,923,595	19,078,796
Essex	338,982.74	349,505.05	370,045.75	374,828.95	13,245,096	13,344,433	13,511,658	13,686,640
Gloucester	410,326.59	432,814.74	476,320.72	501,635.35	15,365,062	15,791,440	16,540,332	17,356,599
Hudson	286,466.01	297,010.58	317,552.06	324,466.44	9,748,537	9,853,621	10,031,318	10,250,743
Hunterdon	324,248.50	337,117.35	362,372.39	369,735.23	11,433,543	11,559,243	11,778,999	11,975,681
Mercer	330,997.01	345,948.13	374,927.40	386,724.06	11,469,646	11,664,408	11,998,315	12,345,934
Middlesex	661,582.44	693,385.53	754,409.91	787,056.71	26,645,402	27,289,741	28,402,093	29,603,575
Monmouth	656,519.07	688,537.02	750,438.38	781,031.71	22,555,350	23,078,199	23,983,715	24,940,502
Morris	433,595.14	454,727.55	495,558.15	513,734.70	17,302,975	17,740,519	18,498,309	19,247,212
Ocean	496,042.96	524,558.96	579,944.01	610,054.42	15,646,435	16,138,561	17,001,555	17,911,546
Passaic	335,791.32	346,499.44	367,541.42	372,010.62	11,172,986	11,240,097	11,352,900	11,493,522
Salem	267,545.73	274,758.43	289,070.87	290,342.49	14,373,720	14,394,895	14,430,614	14,473,284
Somerset	221,650.91	233,174.94	255,604.33	266,081.30	7,968,678	8,169,713	8,522,937	8,865,053
Sussex	292,933.04	303,039.45	322,872.59	329,104.34	9,463,309	9,576,391	9,774,154	10,004,845
Union	216,722.59	224,103.36	238,557.79	242,293.28	6,845,042	6,898,498	6,988,562	7,099,243
Warren	264,582.84	272,332.91	287,628.24	289,927.67	12,607,823	12,675,699	12,795,245	12,892,537
TOTAL	8,370,393.10	8,720,261.07	9,399,266.46	9,675,952.18	311,217,394	316,399,920	325,360,004	334,812,894
Total (MW)	1,124	1,171	1,262	1,299				

Technologies Used:

Power	Gasification BIGGC Anaerobic Digestion	**Fuels**	Gasification Fermentation Transesterification Anaerobic Digestion

New Jersey's estimated practically recoverable biomass resource of 5.5 MDT would produce its power or fuel potential utilizing a slightly different composition of the biomass available.

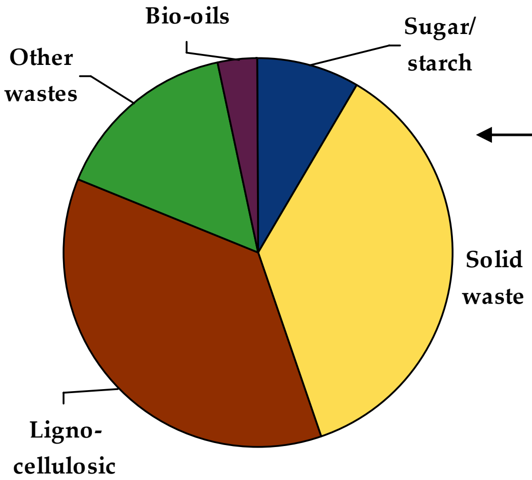
5.5MDT per year

=

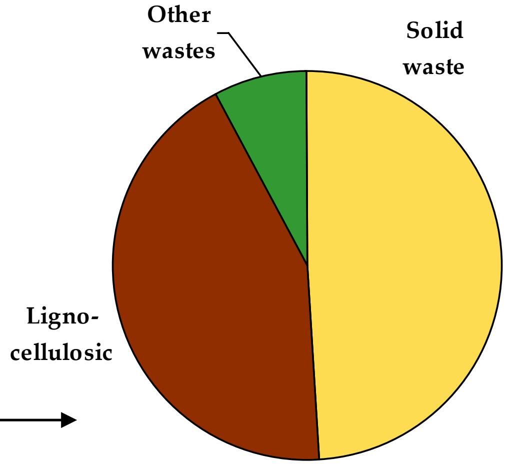
311 M GGE of biofuel/year

OR

1,124 MW of electricity



Resource base for fuels



Resource base for electricity

The energy that could be created if New Jersey's recoverable biomass was utilized suggests substantial benefits could be achieved.

1. New Jersey's estimated practically recoverable biomass resource of 5.5 MDT could deliver up to 1,124 MW of New Jersey's electricity power demand or 311 million gallons of gasoline equivalent of transportation fuel consumed.
2. This practically recoverable energy potential equals approximately 9% of New Jersey's electricity consumption or 5% of its transportation fuel consumed.
3. Establishing a commercially competitive bioenergy industry will require moderately high fuel prices, technological advances, development of feedstock infrastructure, financial incentives and significant commitment by the state.
4. New Jersey's large municipal waste biomass resource, combined with its proximity to a petrochemical infrastructure, makes it a good location to utilize advanced power and fuels technologies
5. Based on assumptions about population growth and efficiency improvements, the potential exists for bioenergy to grow to over 1,299 MW or 335 M GGE of biofuel by 2020.

1. One gallon of gasoline contains approximately 125,000 Btu of energy. Biofuels have different volumetric energy densities (some lower, some higher). Estimates of biofuel yields have been converted to "gallons of gasoline equivalent" based on the ratio of volumetric energy densities, to allow for consistent comparisons among the various fuels.
2. The total energy potential from feedstock that could classify as Class II Renewables could potentially add up to 500 MW or 85 M GGE biofuels if it were included in these totals (it is not).

Policy Recommendations » Summary

Capturing New Jersey's Biomass Energy Potential – Possible Policy Considerations

Develop Policies to Provide Better Access to Biomass Resources	Make NJ a Leader in Support of New Technologies	Integrate with Existing NJ Petrochemical/ Refining Infrastructure	Capitalize on Existing Policies and Practices	Address Regulatory Roadblocks and Inconsistencies
• Create incentives to develop biomass "nodes" as possible plant sites, and to increase waste diversion practices • Establish Bioenergy Enterprise Zones • Create incentives to support development of feedstock infrastructure • Create educational programming to encourage more rigorous recycling efforts	• Establish/appoint a state agency with primary responsibility for developing bioenergy industry • Create Bioenergy Innovation Fund to support ongoing R&D • Promote NJ as premier location for biomass technology companies • Leverage expertise in academia & pharma/ biotech industries	• Further evaluate technologies (e.g., FT, biodiesel) that may benefit from proximity to petrochemical infrastructure • Engage industry experts in efforts to develop workable solutions	• Integrate new efforts (i.e. biofuels) with existing policies (e.g. RPS, Clean Energy Program, & MSW recycling reqs.) • Should not undermine the viability of RPS projects such as waste incineration • Analyze highest and best use of feedstocks by measuring the value of tradeoffs of alternative uses	• Biomass feedstocks and end products may be subject to different regulatory oversight; need to identify and address incongruous policies and regulations • Streamline regulatory process

The purpose of the supply analysis was to look comprehensively at New Jersey's biomass* that could potentially be available to produce energy

- Biomass is a broad definition for biologically-derived renewable materials that can be used to produce heat, electric power, transportation fuels, and other products and chemicals.
- NJAES conducted research and collected public data on biomass resources for each New Jersey county to determine an estimated available biomass quantity in tons/yr.
- A Bioenergy Calculator and interactive biomass resource database was developed to analyze and aggregate the data collected by NJAES. This was integrated with other information (e.g. process efficiencies and yields) provided by Navigant Consulting in order to make reasonable estimates of the energy production potential.
- A screening process was created within the database to determine how much of the total biomass created was "practically" recoverable.
- **The quantitative results are illustrative only**; capturing even the practically recoverable biomass estimate of 5.5 MDT will require an intense examination of public policies, economic incentives, and regulatory practices.

Importantly, this was New Jersey's first comprehensive look at its biomass resources that could be used to produce energy.

* Industrial biomass waste was not included

Executive Summary » Biomass Supply Conclusions

Research yielded six major findings about New Jersey's biomass resources:

1. New Jersey produces an estimated 8.2 million dry tons (MDT) of biomass[1] annually.
2. Screening process developed to estimate practically recoverable biomass. Approximately 5.5 MDT (~65%) of New Jersey's biomass could ultimately be available to produce bioenergy.
3. Almost 75% of New Jersey's biomass resources produced directly by state's population, majority in solid waste (e.g., municipal waste). Biomass concentrated in central and northeastern counties.
4. Agriculture and forestry management also important potential sources of biomass, account for majority of remaining amount.
5. New Jersey's estimated practically recoverable biomass resource of 5.5 MDT could deliver up to 1,124 MW of power, (~9% of New Jersey's electricity consumption) or 311 million gallons of gasoline equivalent (~5% of transportation fuel consumed) if appropriate technologies and infrastructure were in place.
6. Large proportion of waste-based biomass supports recommendation that New Jersey pursue development of a energy from waste industry.

[1] This total includes biogas and landfill gas quantities converted to dry ton equivalents on an energy basis. This does NOT include biomass that is currently used for incineration or sewage sludge because these are not classified as Class I renewable feedstocks in NJ.

A range of biomass resources were examined; these can be divided into 5 categories based on their physical characteristics.

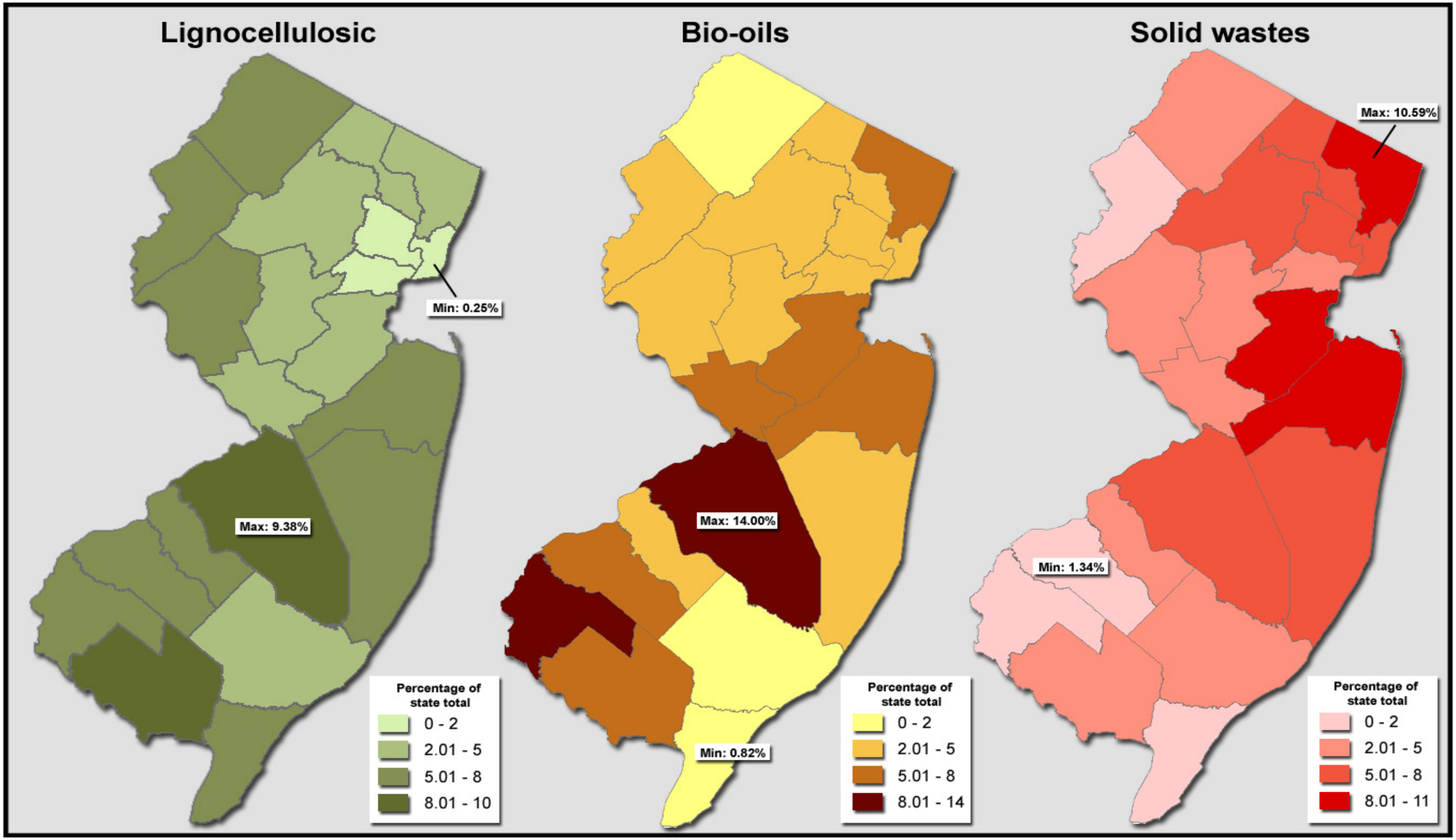
Feedstock Type	Definitions	Resources
Sugars/Starches	Traditional agricultural crops suitable for fermentation using 1st generation technologies Some food processing residues are sugar and starch materials	• Agricultural crops (sugars/starches) • Food processing residues (w/residual sugars)
Lignocellulosic Biomass	Clean woody and herbaceous materials from a variety of sources Includes clean urban biomass that is generally collected separately from the municipal waste stream (wood from the urban forest, yard waste, used pallets)	• Agricultural residues • Cellulosic energy crops • Food processing residues • Forest residues, mill residues • Urban wood wastes • Yard wastes
Bio-oils	Traditional edible oil crops and waste oils suitable for conversion to biodiesel	• Agricultural crops (beans/oils) • Waste oils/fats/grease
Solid Wastes	Primarily lignocellulosic biomass, but that may be contaminated (e.g., C&D wood) or co-mingled with other biomass types	• Municipal solid waste (biomass portion) • C&D wood • Food wastes • Non-recycled paper • Recycled materials
Other Wastes	Other biomass wastes that are generally separate from the solid waste stream Includes biogas and landfill gas	• Animal waste (farm) • Wastewater treatment biogas • Landfill gas

1. New Jersey produces an estimated 8.2 million dry tons (MDT) of biomass annually. Individual county amounts range from 210,000-740,000 DT.

County	Sugar/ Starch	Ligno	Bio-Oils	Solid Waste			Other Wastes	Totals (Tons)
				Recycled	Landfilled Biomass	C&D non-recycled		
Atlantic	3,170	108,957	1,179	31,919	115,217	25,602	30,315	316,358
Bergen	4	87,455	3,779	169,401	294,436	69,209	115,775	740,060
Burlington	29,787	255,697	23,040	60,576	149,554	32,570	130,609	681,833
Camden	2,477	118,822	2,550	29,799	39,659	41,743	34,565	269,615
Cape May	831	145,752	851	24,249	42,421	24,471	8,925	247,500
Cumberland	26,681	216,226	10,823	54,495	56,829	13,574	42,461	421,088
Essex	-	37,392	3,313	76,587	87,559	71,750	40,251	316,851
Gloucester	15,206	173,089	11,462	27,420	15,704	20,022	58,327	321,229
Hudson	-	7,949	2,527	109,051	191,915	41,639	19,328	372,410
Hunterdon	25,370	138,574	5,985	11,304	42,090	56,986	31,986	312,295
Mercer	9,306	80,835	8,101	75,089	113,978	25,883	12,200	325,393
Middlesex	11,212	95,451	8,216	169,437	260,179	81,044	52,927	678,466
Monmouth	11,537	151,043	8,639	92,865	199,296	49,677	54,940	567,996
Morris	4,429	114,985	2,431	71,636	165,620	38,695	33,375	431,170
Ocean	2,239	156,619	2,833	85,768	221,097	43,008	17,981	529,543
Passaic	6	52,724	2,090	94,517	177,172	38,164	3,308	367,980
Salem	59,560	135,424	18,675	5,396	17,035	14,625	37,777	288,492
Somerset	9,267	67,465	2,282	40,404	104,843	1,482	14,546	240,289
Sussex	6,796	160,795	653	17,667	40,322	11,216	35,978	273,427
Union	5	42,242	2,225	46,261	60,536	48,164	10,022	209,455
Warren	48,006	135,236	5,014	10,588	11,150	7,822	53,302	271,117
TOTALS	265,887	2,482,731	126,666	1,304,429	2,406,613	757,346	838,899	8,182,570

- Biogas (in Other Wastes) is based in Tons Equivalent biomass, assuming 500 Btu/scf and 8000 Btu/lb

Biomass Resources by Feedstock Category 2007



Although the theoretical potential is large, there are several reasons why it will not be practical to recover all of New Jersey's biomass.

1. *Lack of collection and transport infrastructure for certain feedstocks*

   New Jersey's municipal solid waste and agricultural crops maintain a well established collection and delivery infrastructure. For agricultural and forestry residues, such a system may have to be created or revamped. Economic incentives may be needed to incentivize the owners of collection operations to add to or divert a portion of their fleet for these purposes.

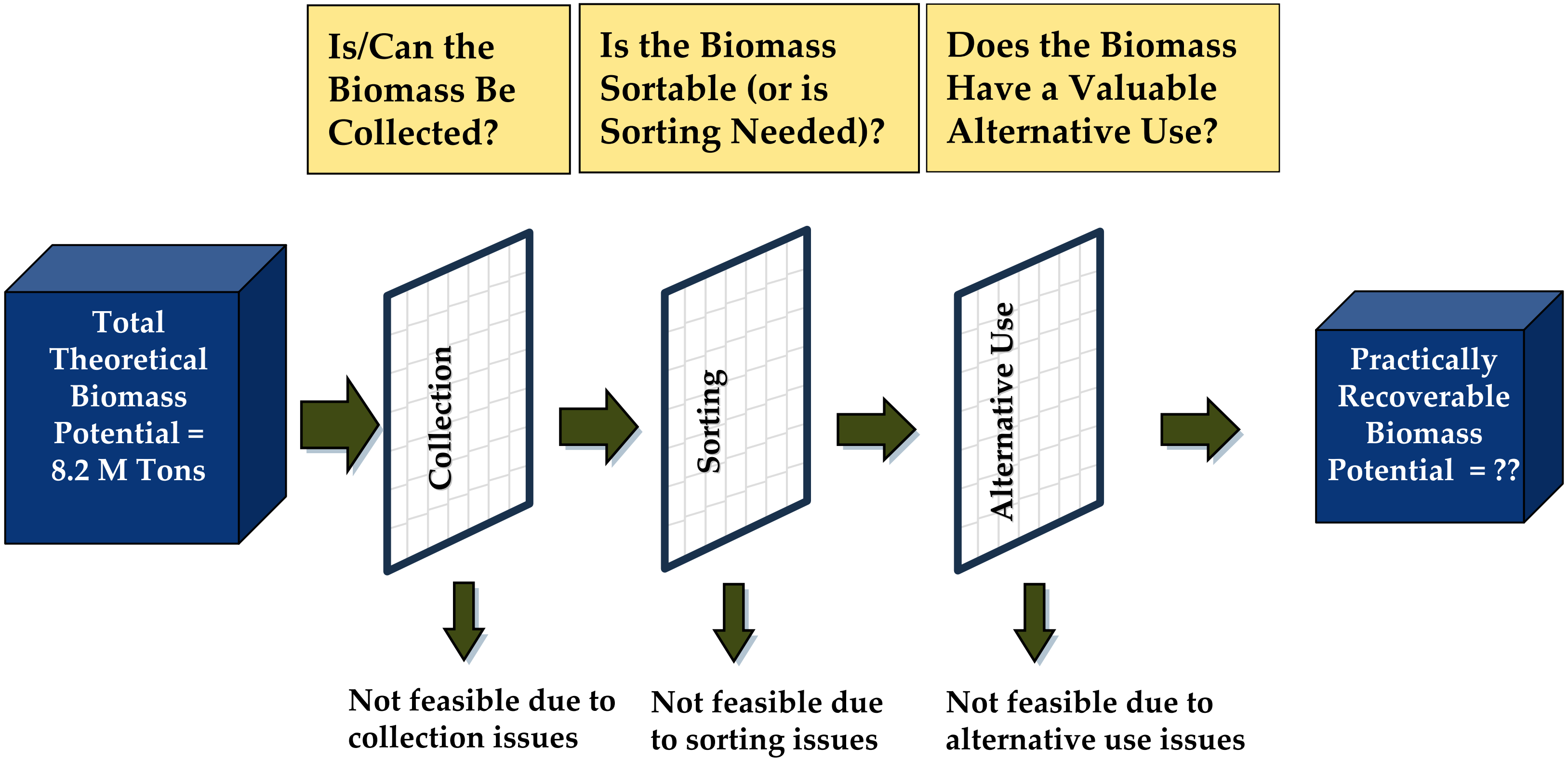
2. ***Co-mingling of significant quantities of biomass with other wastes***

   Further source separation practices will be needed if New Jersey is to take advantage of wastes that are now not fully separated, such as food waste and C&D wood. This will require a change in behavior for businesses and residents which may be difficult to achieve.

3. *Competition from existing uses*

   Much of New Jersey's urban waste biomass is currently recycled and used in alternative markets. These markets are well established, and may offer a higher value than (today's) energy cost (especially given the technology costs for converting that resource to energy).

2. A screening process was developed to help estimate how much of New Jersey's theoretically available biomass might be recoverable.



Is/Can the Biomass Be Collected?

Is the Biomass Sortable (or is Sorting Needed)?

Does the Biomass Have a Valuable Alternative Use?

Total Theoretical Biomass Potential = 8.2 M Tons

Collection

Sorting

Alternative Use

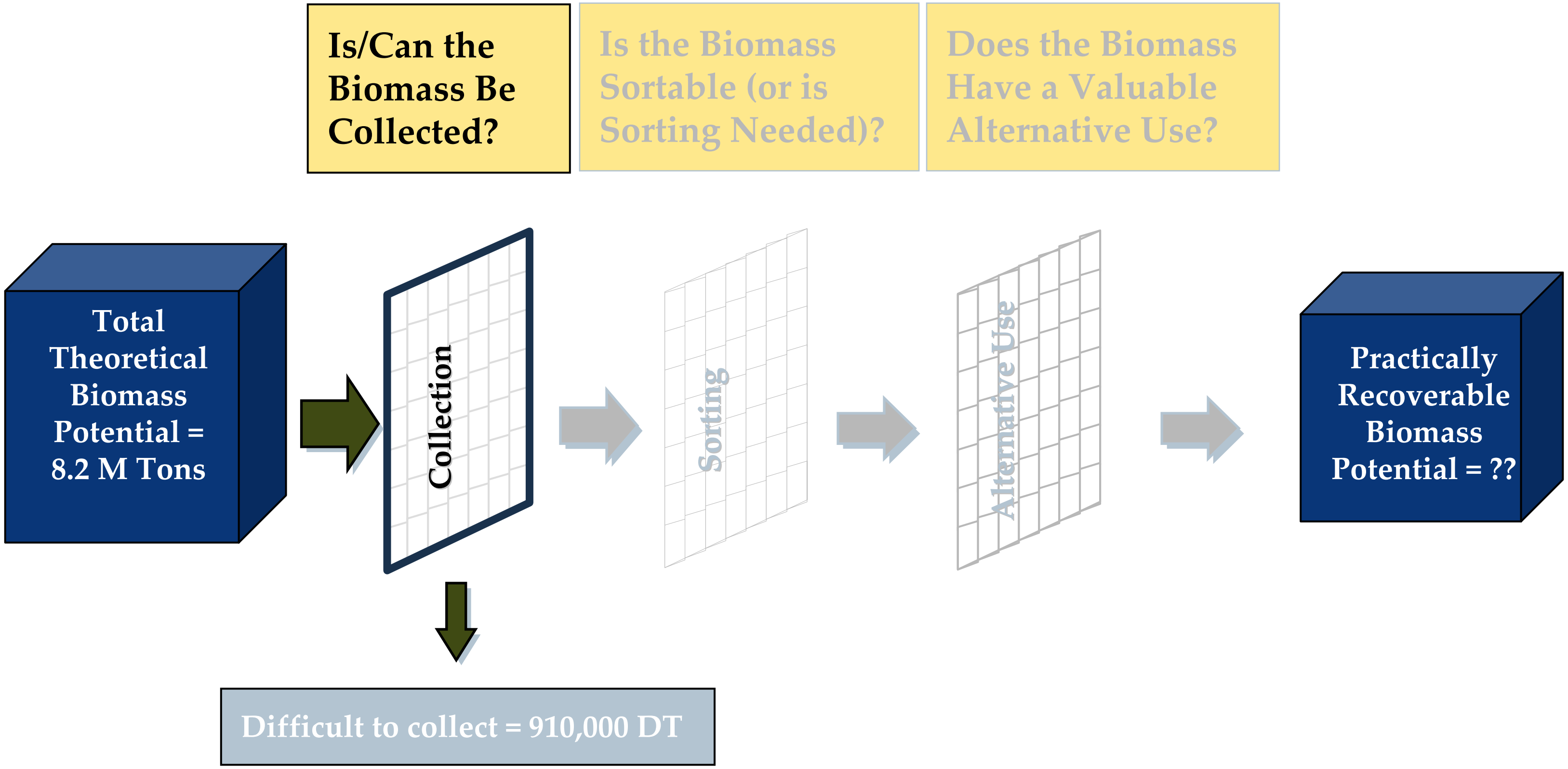
Practically Recoverable Biomass Potential = ??

Not feasible due to collection issues

Not feasible due to sorting issues

Not feasible due to alternative use issues

If a resource was either now collected, easy to collect, or produced onsite such as landfill gas, it passed the Collection screen.



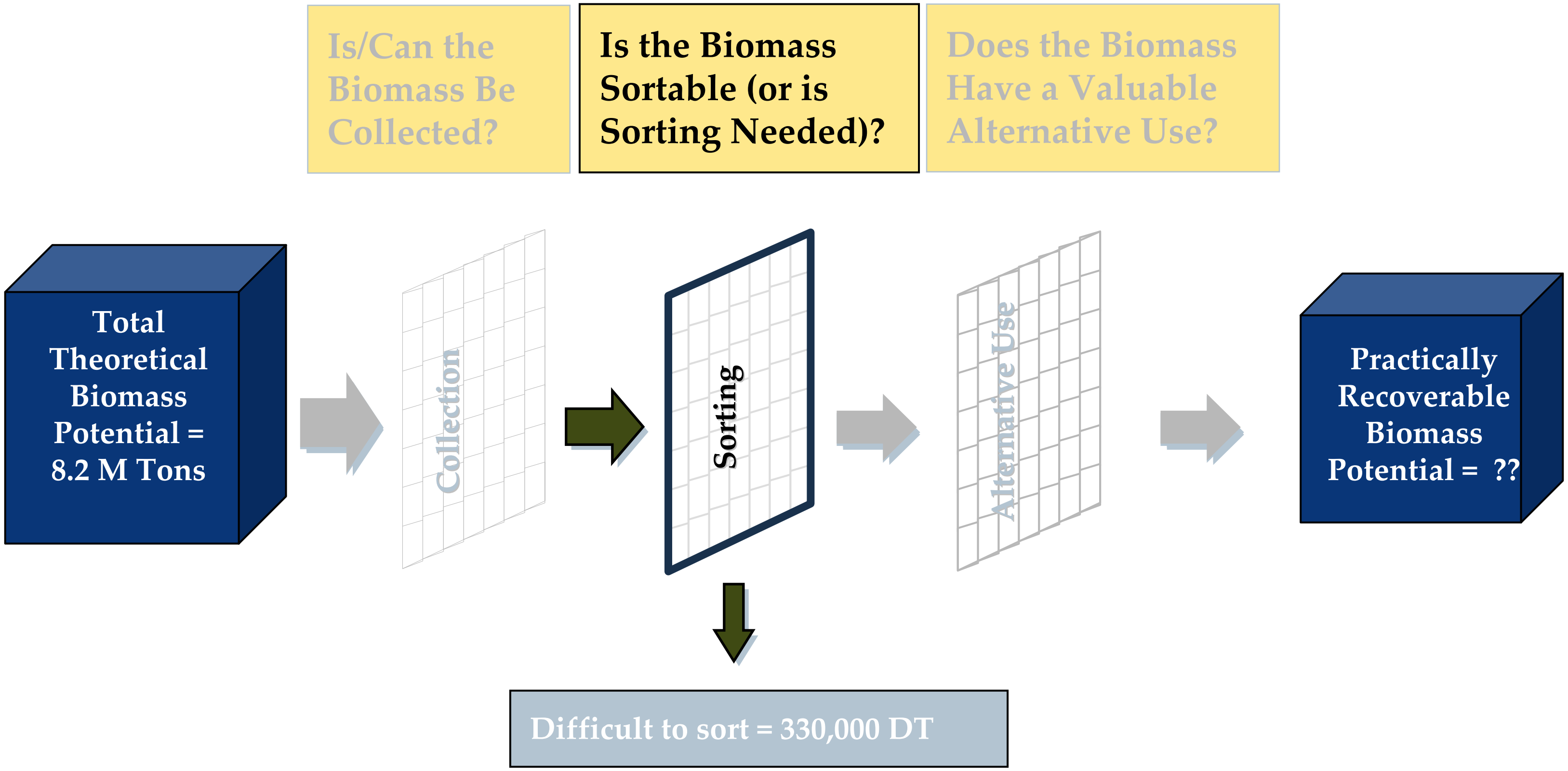
Is/Can the Biomass Be Collected?

Is the Biomass Sortable (or is Sorting Needed)?

Does the Biomass Have a Valuable Alternative Use?

Note: This screening process is preliminary and would require considerably more analysis to reach any final conclusions. The screening analysis has been incorporated into the database, and provide flexible “scenario analysis” capabilities for the user.

The Sorting Screen filtered out the resources that were difficult to sort.



Is/Can the Biomass Be Collected?

Is the Biomass Sortable (or is Sorting Needed)?

Does the Biomass Have a Valuable Alternative Use?

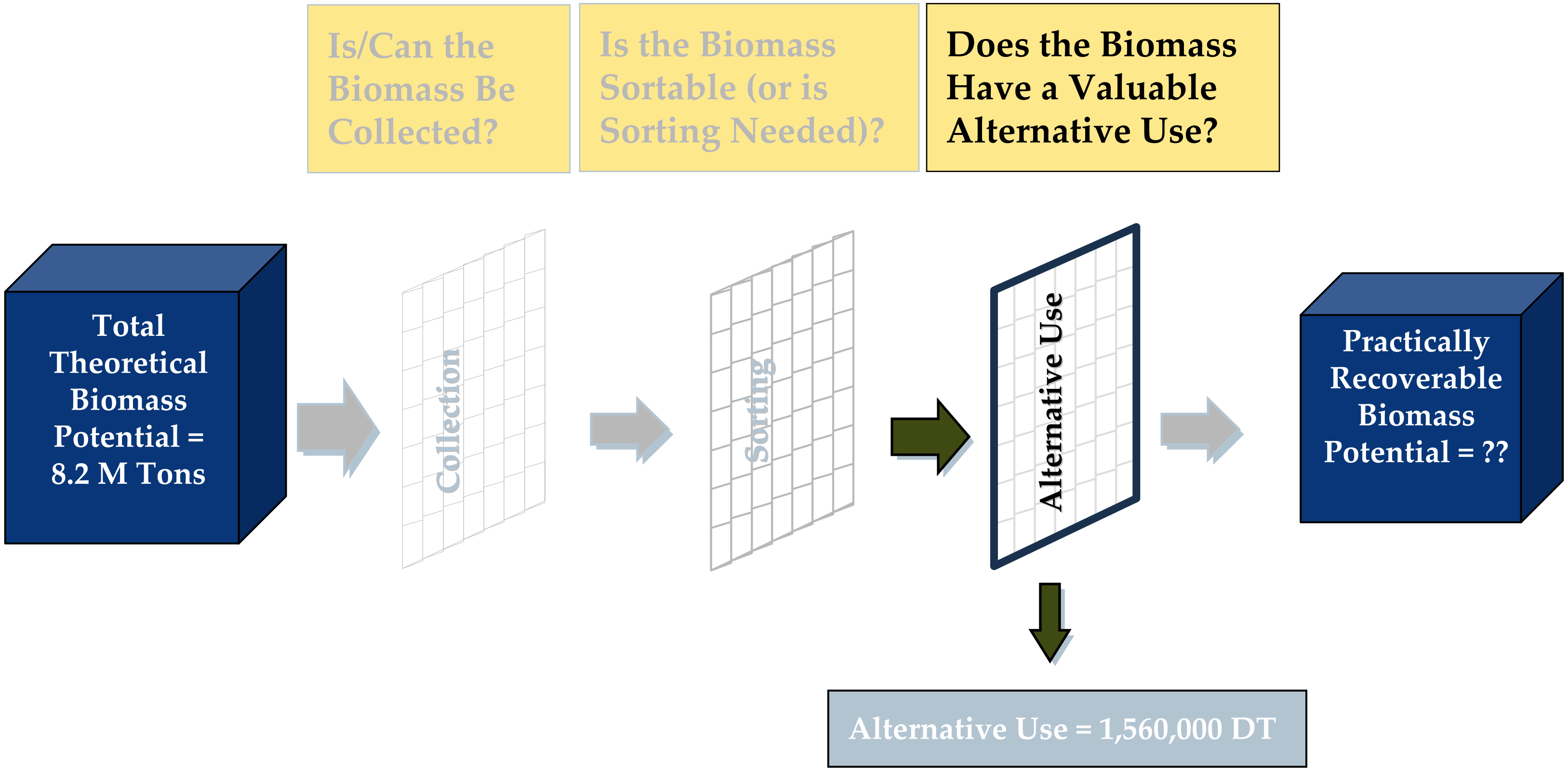
Total Theoretical Biomass Potential = 8.2 M Tons

Practically Recoverable Biomass Potential = ??

Difficult to sort = 330,000 DT

Note: This screening process is preliminary and would require considerably more analysis to reach any final conclusions. The screening analysis has been incorporated into the database, and provide flexible "scenario analysis" capabilities for the user.

The Alternative Use screen filtered out the resources with a current alternative use and would likely not be converted to energy. This includes municipal waste currently incinerated.



Is/Can the Biomass Be Collected?

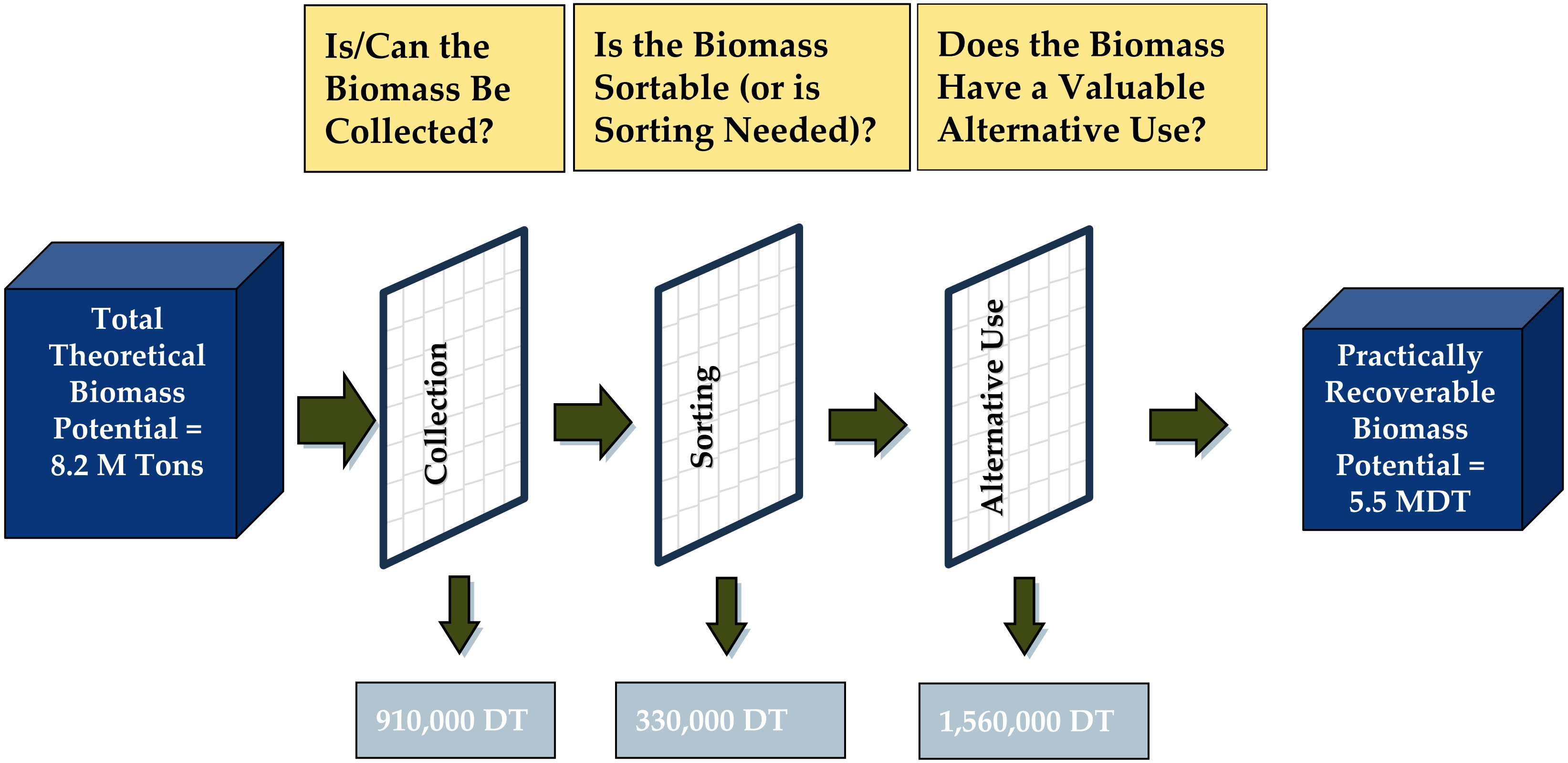
Is the Biomass Sortable (or is Sorting Needed)?

Does the Biomass Have a Valuable Alternative Use?

Alternative Use = 1,560,000 DT

Note: This screening process is preliminary and would require considerably more analysis to reach any final conclusions. The screening analysis has been incorporated into the database, and provide flexible "scenario analysis" capabilities for the user.

The results of this process indicate that approximately 5.5 MDT (~65%) of New Jersey’s biomass could ultimately be available to produce energy, in the form of power, heat, or transportation fuels.



Is/Can the Biomass Be Collected?

Is the Biomass Sortable (or is Sorting Needed)?

Does the Biomass Have a Valuable Alternative Use?

Total Theoretical Biomass Potential = 8.2 M Tons

Collection

Sorting

Alternative Use

Practically Recoverable Biomass Potential = 5.5 MDT

910,000 DT

330,000 DT

1,560,000 DT

Note: This screening process is preliminary and would require considerably more analysis to reach any final conclusions. The screening analysis has been incorporated into the database, and provide flexible “scenario analysis” capabilities for the user.

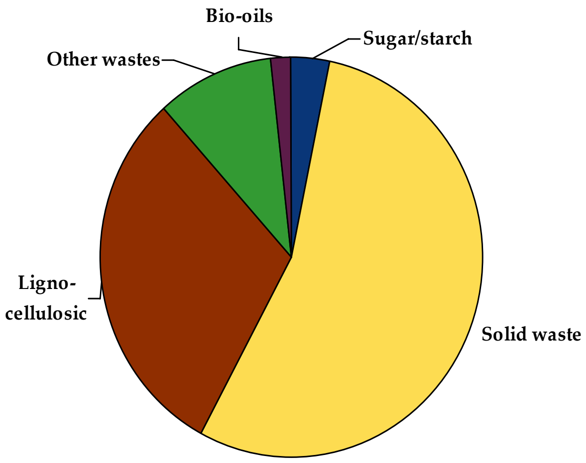
3. **New Jersey's estimated biomass resource of 5.5 MDT could deliver up to 1,124 MW of power in 2007, and 1,299 MW of power in 2020 (16% increase), if all biomass is utilized by electricity generating technologies.**

- If all biomass is utilized by fuel production technologies, 311 million gallons of gasoline equivalent in 2007 and 335 million GGE by 2020 (8% increase) could be produced.

- In other words, the current biomass resource base in New Jersey would be capable of delivering, either ~9% of New Jersey's current electricity demand or ~5% of New Jersey's current transportation fuel demand, if the appropriate technologies and infrastructure were in place to produce the bioenergy.

4. Almost 75% of New Jersey's biomass resource is produced directly by the state's population, much of it in the form of municipal solid waste.

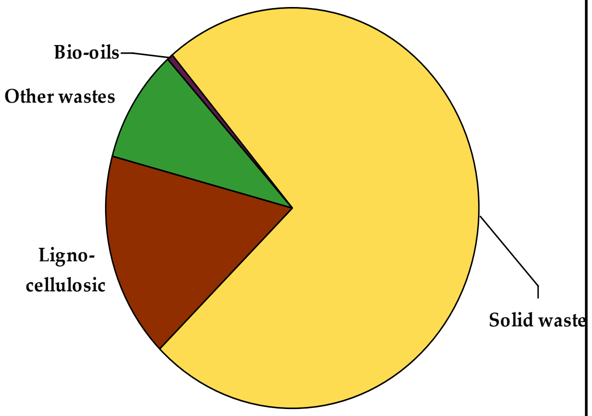
Total Available Biomass Resources by Type (dry tons/yr)



Total = 8.2 million dry tons/yr[1]

The chart on the left shows NJ's total biomass. The chart on the right shows just the population-related biomass waste stream.

Biomass Resources Associated with Population (dry tons/yr)

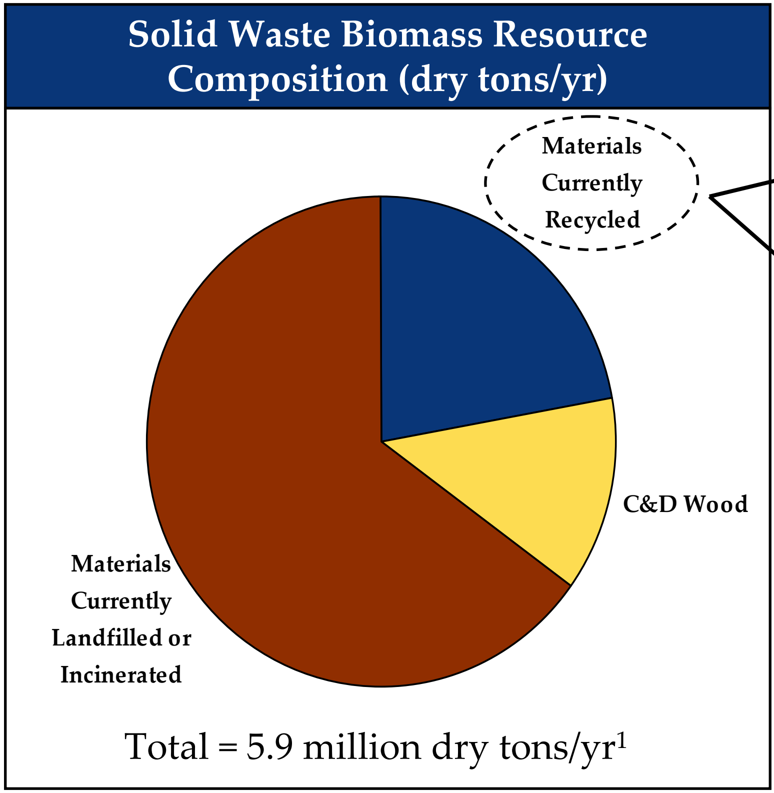


Total = 6.1 million dry tons/yr[1]

In the past, generating energy from solid waste typically involved incineration. Several new technologies described in Section III are becoming capable of converting solid waste into energy without incineration.

1. This total includes biogas and landfill gas quantities converted to dry ton equivalents on an energy basis. Note that these are gross quantities, not taking into account differences in heat content per ton.

This chart provides one example of how the solid waste resource potential can be impacted when considering possible alternative uses.



Solid Waste Biomass Resource Composition (dry tons/yr)

Total = 5.9 million dry tons/yr[1]

Recycled Materials	DT/YR ('000)
Newspaper	320,000
Corrugated	487,000
Mixed Office Paper	130,000
Other Paper	153,000
Food Waste	49,000
Wood Scraps	119,000
TOTAL	1,258,000

Many recycled materials have an alternative market that may be more lucrative than energy production.

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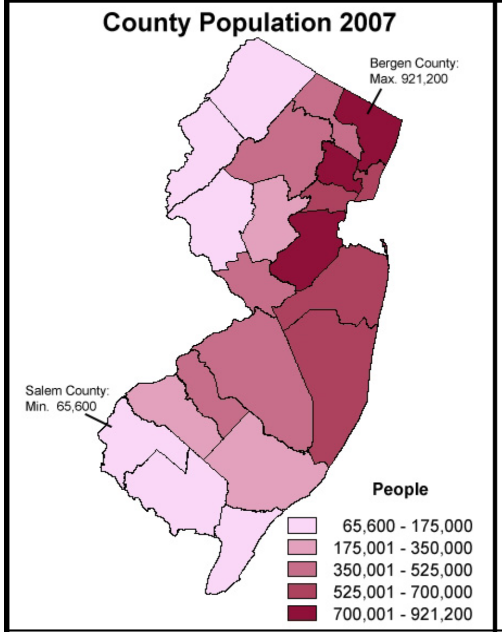
1. Includes amounts currently incinerated. Note that these are gross quantities, not taking into account differences in heat content per ton

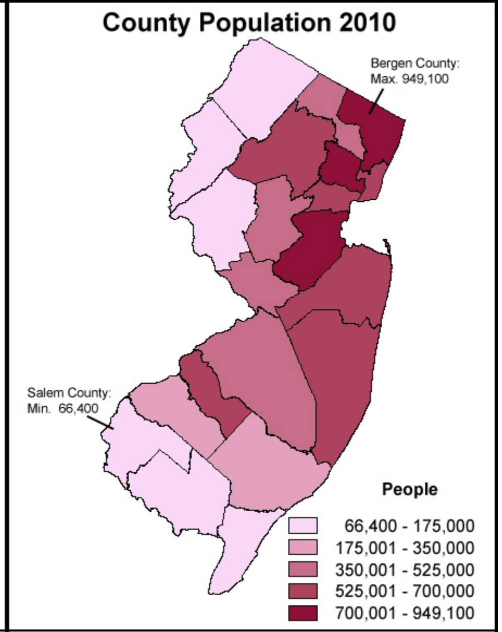
Biomass Supply Analysis» County Population Growth » 2007-2020

New Jersey Population Projections by County

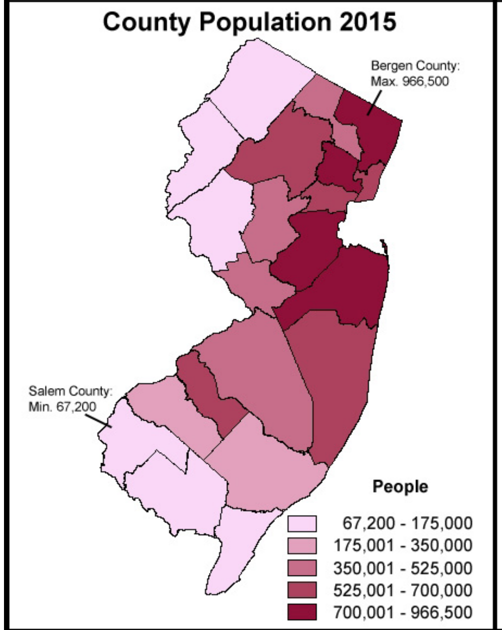
Between 2007 and 2020, New Jersey’s population is expected to grow by about 10% adding about 1,000,000 more people.



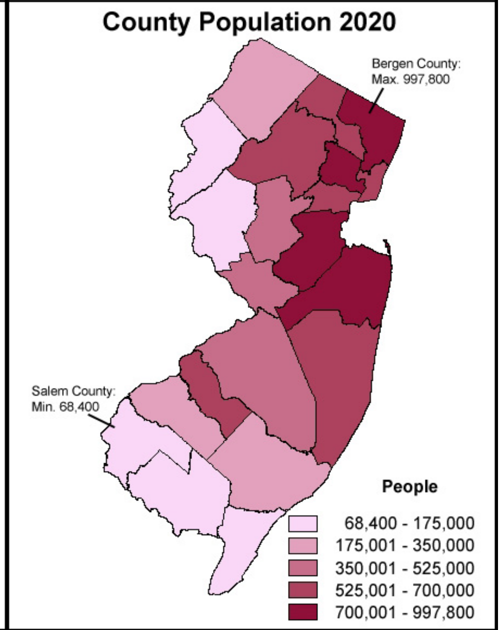
County Population 2007



County Population 2010



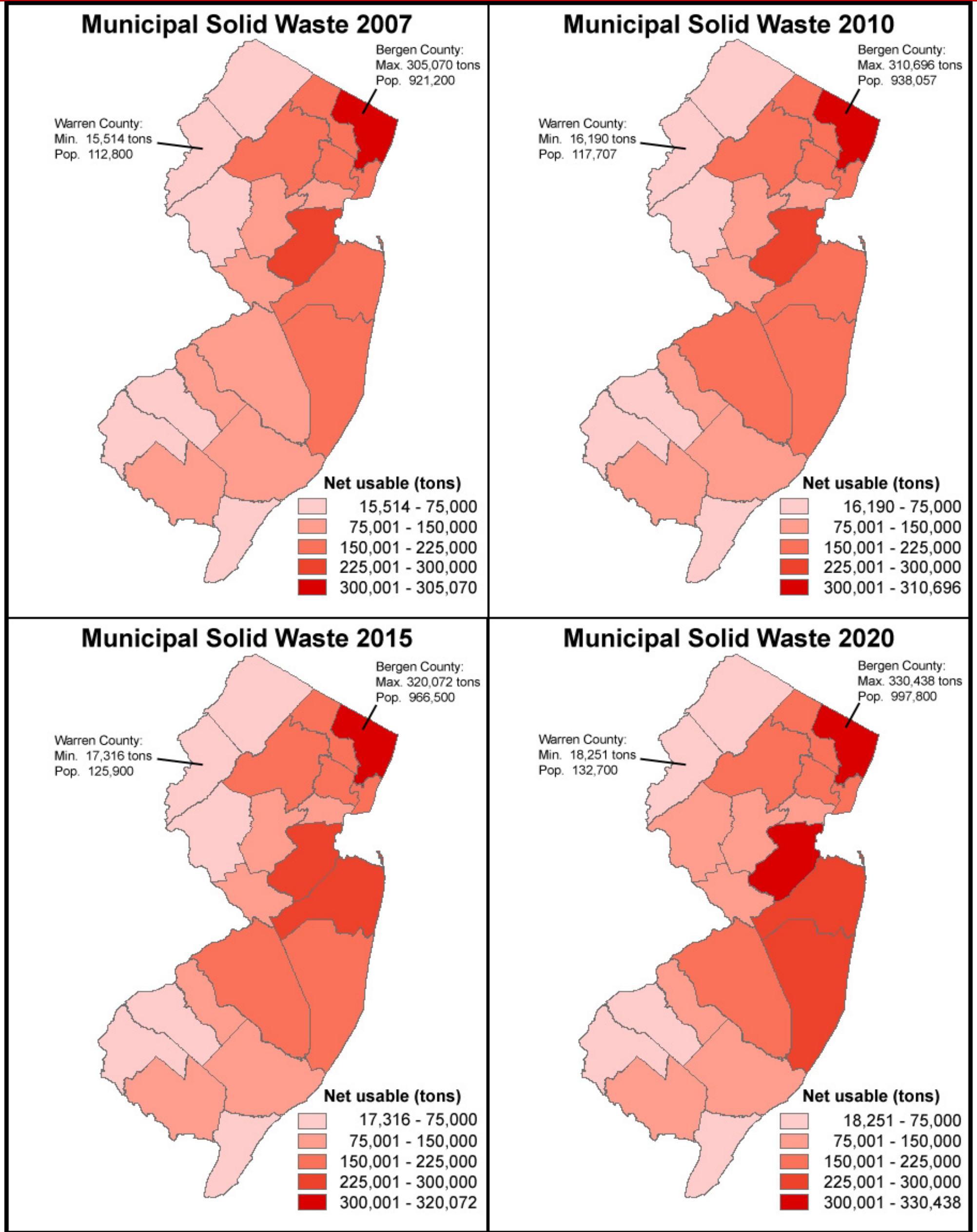
County Population 2015



County Population 2020

Municipal Solid Waste Projections by County

With increases in population comes increases in the amount of solid waste generated in the state. MSW is expected to increase by 10.55% by 2020.

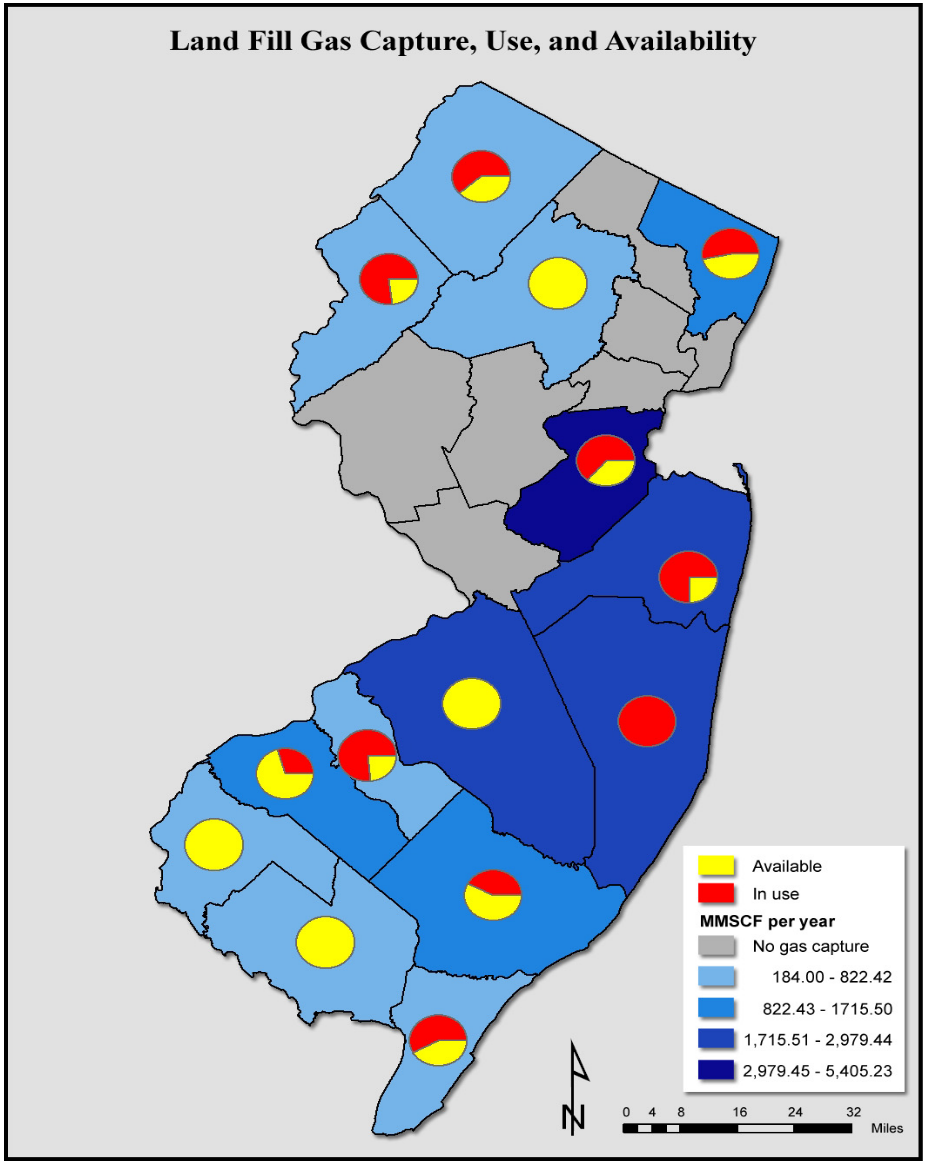

Municipal Solid Waste 2007

Municipal Solid Waste 2010

Municipal Solid Waste 2015

Municipal Solid Waste 2020

Biomass Supply Analysis » Landfill Gas Generation and Use » *2007*

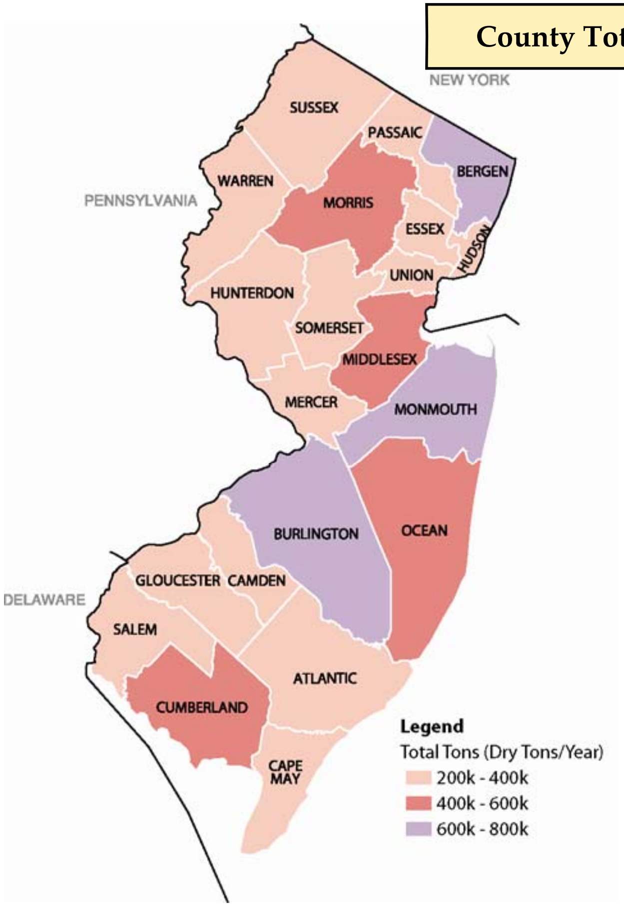

Land Fill Gas Capture, Use, and Availability

Landfill Gas Totals by County in 2007 (mmscf/yr)			
County	Total Captured	Currently Used	Net Available
Atlantic	1,426.43	602.79	823.64
Bergen	1,715.50	912.50	803.00
Burlington	2,979.44	0.00	2,979.44
Camden	684.35	525.60	158.75
Cape May	474.50	273.75	200.75
Cumberland	788.40	0.00	788.40
Gloucester	1,402.04	413.34	988.69
Middlesex	5,405.23	3,444.52	1,960.71
Monmouth	2,372.50	1,788.50	584.00
Morris	503.84	0.00	503.84
Ocean	2,471.05	2,471.05	0.00
Salem	184.00	0.00	184.00
Sussex	616.40	378.90	237.50
Warren	822.42	631.45	190.97
Total	21,846.09	11,442.40	10,403.69

- A cogen station will be built on the Burlington County Landfill site in 2008, initially producing 7.2 MW of a possible 14.7 MW.
- All of the LFG currently flared in Salem and Cumberland will be converted to electricity in 2008.

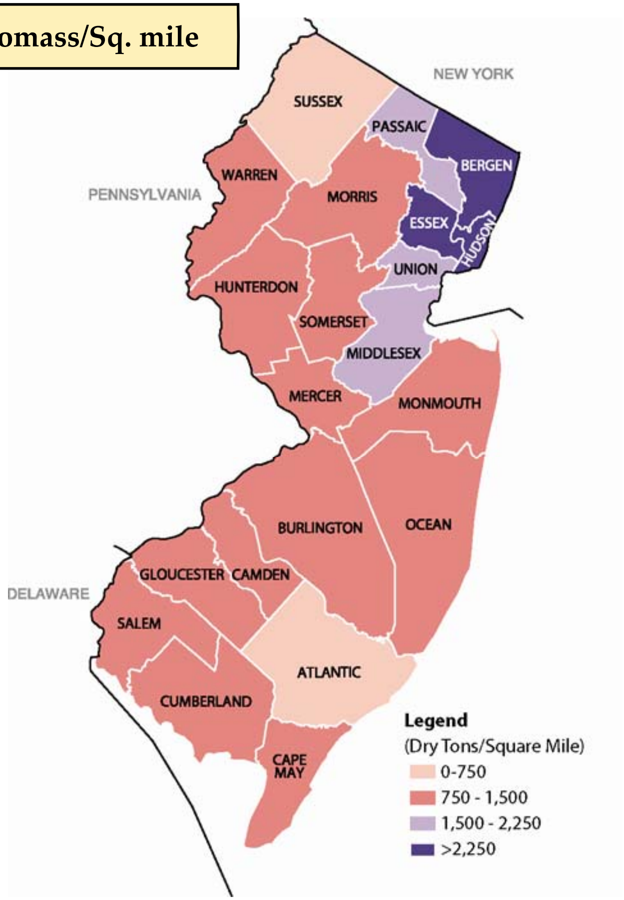
Biomass is concentrated in the counties of central and northeastern New Jersey.

County Totals



The energy contained in each ton of biomass is lower than for conventional fuels; thus, transportation distances between a source and an energy conversion facility can be a key factor in determining the economics of a bioenergy project .

Biomass/Sq. mile



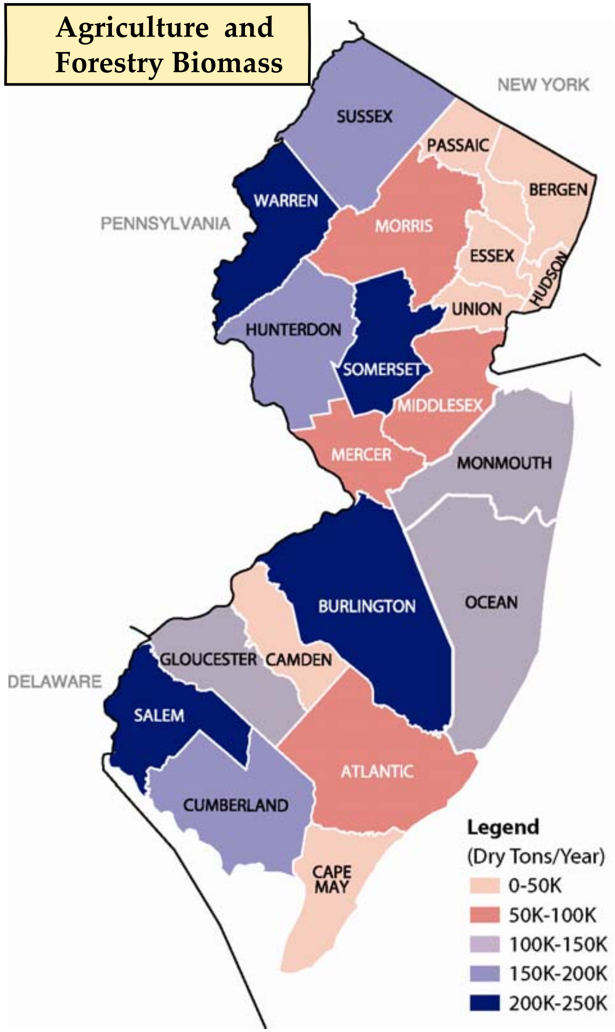
5. Large proportion of waste-based biomass supports recommendation that New Jersey pursue development of a energy from waste industry.

- Conversion of solid waste to clean energy could become *the* major source of renewable energy to help NJ meet its goal of 20% renewable energy by 2020.
- Energy from waste in New Jersey is particularly attractive because waste disposal costs are high and the waste collection and consolidation infrastructure is already in place.
- Conversion of solid waste to clean energy would also provide economic development and new jobs, improved quality of life through reduced air and water pollution and improved energy security through domestic production.
- Vegetative and animal waste from farms can also be utilized by these technologies to produce even more renewable energy and bolster the local farm economy.

6. Agriculture and forestry management are also important potential sources of biomass, and account for the majority of the remaining amount.

- Biomass from agricultural sources include both crops and crop residues. The use of agricultural crops for energy production would require the decision to convert the current food supply chain into energy production, which could have other major policy implications. Crop residues, on the other hand, are generally underutilized and undervalued, which should allow for an easier decision to use these resources.
- In the case of energy crops, New Jersey would also need to decide whether to maintain the current crop varieties, or introduce new crops that may be better suited to energy production (eg. poplar or switchgrass).

Agriculture and Forestry Biomass



Mapping out a strategy for effective biomass resource utilization is a valuable next step for New Jersey to understand the actual potential.

Biomass Resource Utilization Strategy

Biomass Locational Mapping	**Understand Quality Characteristics**	**Determine Infrastructure Requirements**	**Determine Most Appropriate Use**	**Develop Collection Plan**	**Develop Separation Plan**
Use GIS mapping to determine location of resources, including central nodes that might make good plant locations	Compile quality characteristics of proximal resources to determine compatibility with prospective facility	Evaluate collection, delivery, and handling infrastructure needed to process resources at each facility or node	For those resources that have an alternative use, decide whether the alternative use is preferred to energy production	For resources not currently collected, develop a viable collection plan	For resources not currently separated from the waste stream, develop separation plan

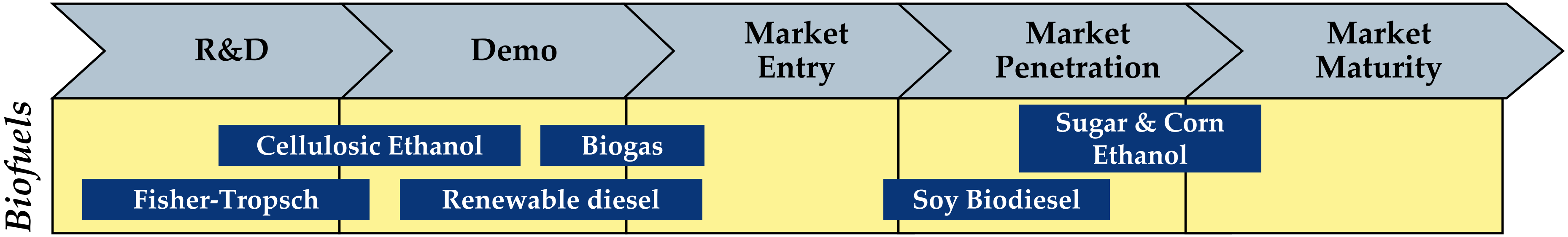
- I. Executive Summary
- II. Biomass Supply Analysis
- **III. Technology Assessment**
- IV. Economic Analysis
- V. Policy Recommendations/Next Steps
- VI. Appendix

Technology development and commercialization proceeds through a number of basic stages.

R&D	Demonstration			Market Entry	Market Penetration	Market Maturity
	Initial System Prototypes	Refined Prototypes	Commercial Prototypes			
• Research on component technologies • General assessment of market needs • Assess general magnitude of economics	• Integrate component technologies • Initial system prototype for debugging	• Ongoing development to reduce costs or for other needed improvements • “Technology” (systems) demonstrations • Some small-scale “commercial” demonstrations	• Commercial demonstration • Full size system in commercial operating environment • Communicate program results to early adopters/ selected niches	• Commercial orders • Early movers or niche segments • Product reputation is initially established • Business concept implemented • Market support usually needed to address high cost production	• Follow-up orders based on need and product reputation • Broad(er) market penetration • Infrastructure developed • Full-scale manufacturing	• Roll-out of new models, upgrades • Increased scale drives down costs and results in learning
10+ years	4 - 8 years			1 - 3 years	10 - 20 years	Ongoing

The time required to pass through any given stage can vary considerably. The values shown here are representative of a technology that passes successfully from one stage to the next without setbacks.

Biofuels technologies are sometimes referred to as “1st Generation” or “2nd Generation”. Here is one way to categorize these technologies.



R&D
Demo
Market Entry
Market Penetration
Market Maturity

Biofuels

Cellulosic Ethanol
Biogas
Fisher-Tropsch
Renewable diesel
Sugar & Corn Ethanol
Soy Biodiesel

2nd Generation Biofuels

- **R&D efforts are focused on**:
  - Increasing the range of feedstock from which to produce biofuels
  - Reducing the biomass to liquid conversion costs

- **Three technology platforms under development:**
  - Biochemical pathway: conversion of the cellulose to fermentable sugars to multiple alcohol fuels
  - Thermochemical pathway: conversion of biomass to syngas and synthesis to multiple fuels
  - Purification of biogas (landfill gas and anaerobic digester gas) into biomethane for transportation fuels (as a compressed or liquefied gas)

- Significant private and public money invested in R&D
- High potential for oil displacement

1st Generation Biofuels

- ***Ethanol*** is a clean burning, high-octane alcohol fuel used as a replacement and extender for gasoline
  - Has been commercially produced since the 70’s in the US and Brazil, still the market leaders
  - Corn ethanol is cost competitive (with no subsidies) with gasoline when crude oil is above $50/barrel ($30/brl from sugar cane)

- ***Biodiesel*** is a high-cetane, sulfur-free alternative to (or extender of) diesel fuel and heating oil
  - Commercialized in Europe in the 90’s
  - Worst economics (and smaller market) than ethanol

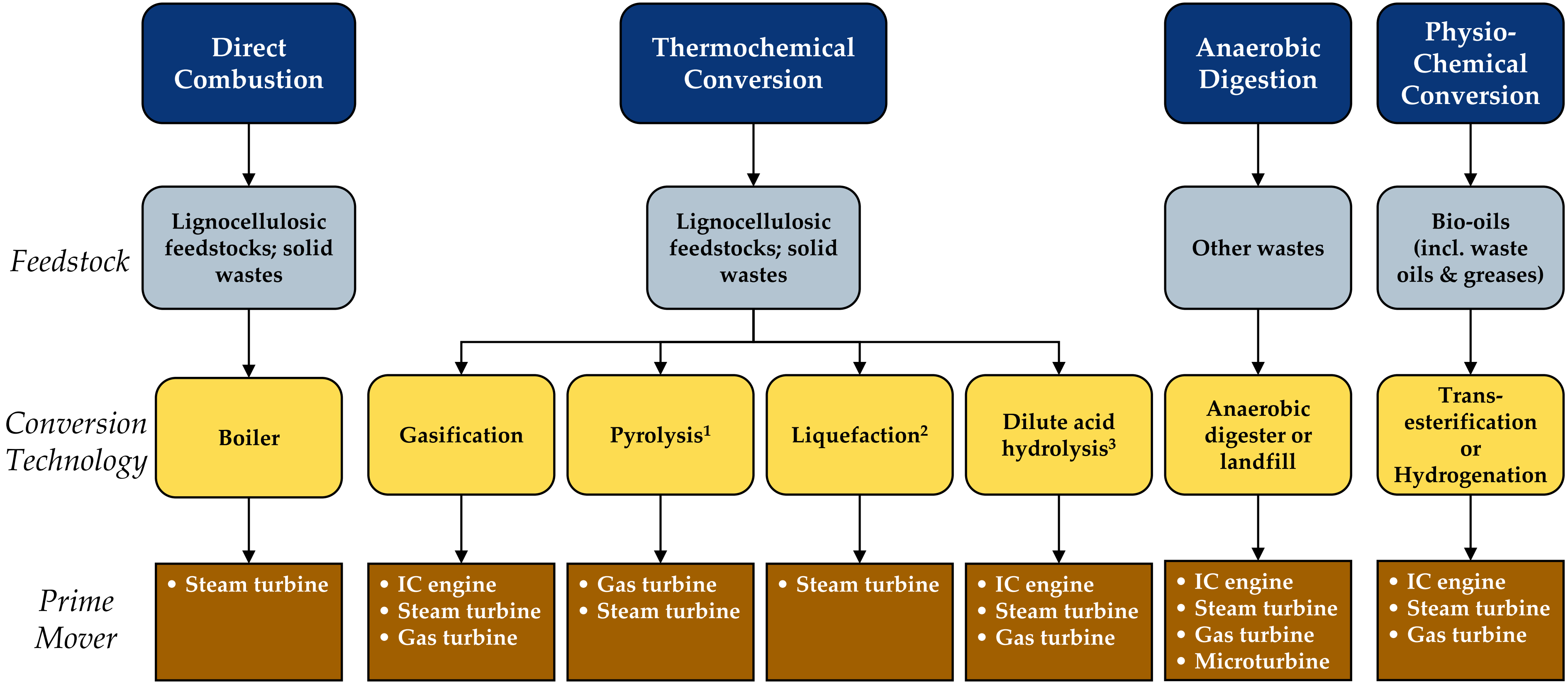
- **Pros**: ease of use in the petroleum infrastructure; today’s only renewable option for liquid transport fuels
- **Cons**: limited scalability; impact on grain for food prices

Thirteen bioenergy applications were included in the analysis

Application	**Core technology platforms and applications**				
	Direct Combustion	**Thermo-chemical Conversion**	**Fermentation**	**Anaerobic Digestion**	**Physio-chemical Conversion**
Power/CHP	**1.**Stand-alone rankine (steam) cycle plant **2.**Small-scale rankine cycle CHP plant **3.**Biomass co-firing with coal	**4.** Stand-alone BIGCC plant **5.** Small-scale gasification-IC engine CHP plant **6.** Stand-alone pyrolysis plant		**11.**Food waste anaerobic digester with IC engine CHP plant/ Landfill gas with microturbine	
Heat Only	• Discussed qualitatively and shown in context of CHP applications above.				
Transportation Fuels		**7.** .Biomass-to-liquids plant (Fischer-Tropsch) **8.**.Dilute acid hydrolysis for biofuels production[1]	**9.** Corn-ethanol dry mill **10.**Cellulosic ethanol plant	**12.** CNG or LNG from landfill gas/AD gas	**13.**Transesterfication Biodiesel

1. Involves the production of ethers (gasoline blendstock) and esters (diesel blendstock).

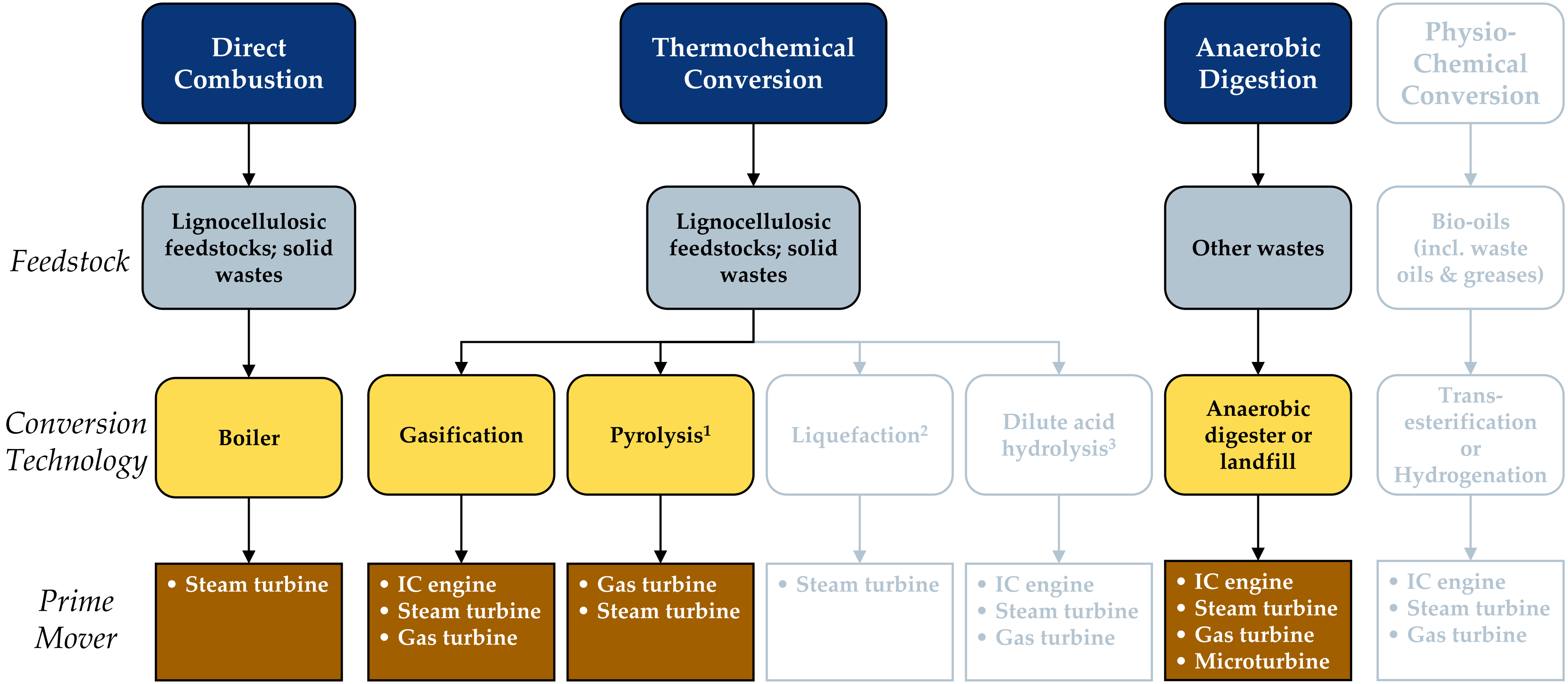
Biomass power generation is possible with multiple technology platforms.



	Direct Combustion	Thermochemical Conversion	Thermochemical Conversion	Thermochemical Conversion	Thermochemical Conversion	Anaerobic Digestion	Physio-Chemical Conversion
Feedstock	Lignocellulosic feedstocks; solid wastes	Lignocellulosic feedstocks; solid wastes				Other wastes	Bio-oils (incl. waste oils & greases)
Conversion Technology	Boiler	Gasification	Pyrolysis[1]	Liquefaction[2]	Dilute acid hydrolysis[3]	Anaerobic digester or landfill	Trans-esterification or Hydrogenation
Prime Mover	• Steam turbine	• IC engine • Steam turbine • Gas turbine	• Gas turbine • Steam turbine	• Steam turbine	• IC engine • Steam turbine • Gas turbine	• IC engine • Steam turbine • Gas turbine • Microturbine	• IC engine • Steam turbine • Gas turbine

1. Pyrolysis produces non-condensable gases, pyrolysis oils and char. The gases and some char are burned to run the process. Some char can be sold and the pyrolysis oils are used in power generation. Alternatively, char can be crushed and mixed with the pyrolysis oils to be burned in a boiler.
2. Includes aqueous and non-aqueous liquefaction. Like pyrolysis, these processes generally produce a mixture of gases liquids and solids. It is assumed that the liquids are best suited to boiler applications.
3. Produces a range of chemicals (e.g., furfural) that can be upgraded to fuels (so-called "P-series" fuels).

Four conversion technologies are generally considered the most appropriate for biomass power applications.



	Direct Combustion	Thermochemical Conversion				Anaerobic Digestion	Physio-Chemical Conversion
Feedstock	Lignocellulosic feedstocks; solid wastes	Lignocellulosic feedstocks; solid wastes				Other wastes	Bio-oils (incl. waste oils & greases)
Conversion Technology	Boiler	Gasification	Pyrolysis[1]	Liquefaction[2]	Dilute acid hydrolysis[3]	Anaerobic digester or landfill	Trans-esterification or Hydrogenation
Prime Mover	• Steam turbine	• IC engine • Steam turbine • Gas turbine	• Gas turbine • Steam turbine	• Steam turbine	• IC engine • Steam turbine • Gas turbine	• IC engine • Steam turbine • Gas turbine • Microturbine	• IC engine • Steam turbine • Gas turbine

1. Pyrolysis produces non-condensable gases, pyrolysis oils and char. The gases and some char are burned to run the process. Some char can be sold and the pyrolysis oils are used in power generation. Alternatively, char can be crushed and mixed with the pyrolysis oils to be burned in a boiler.
2. Includes aqueous and non-aqueous liquefaction. Like pyrolysis, these processes generally produce a mixture of gases liquids and solids. It is assumed that the liquids are best suited to boiler applications.
3. Produces a range of chemicals (e.g., furfural) that can be upgraded to fuels (so-called "P-series" fuels).

The rationale for selecting the biopower options is as follows:

Options Retained for Analysis

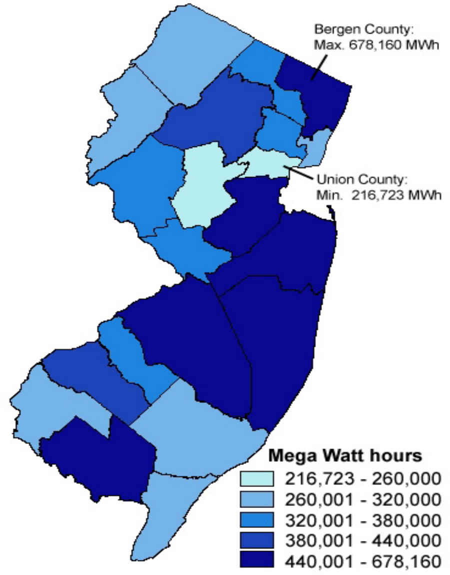
- **Direct combustion** is the primary form of biomass utilization for power generation. It is mature technology that is applied broadly in industrial CHP and stand-alone grid power applications
- **Gasification** has received significant public and private sector investment and numerous technologies are commercially available. Although this technology is much less widely deployed relative to direct combustion, it is considered a major technology platform for future biomass power development
- **Pyrolysis** is less developed than either direct combustion or gasification, but is the subject of moderate technology development and commercialization activities. One company (DynaMotive) is constructing a 200 tpd power plant in Canada.
- **Anaerobic Digestion** is commonly practiced in wastewater treatment plants and increasingly on animal farms. Landfill gas is also a product of natural anaerobic digestion in landfills. Power and CHP are the most common applications.

Options Not Retained for Analysis

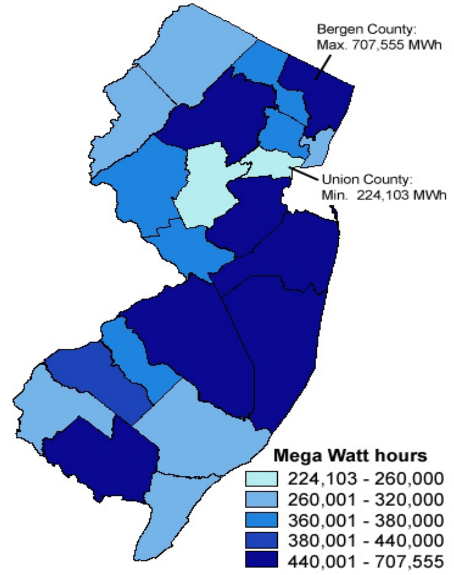
- **Liquefaction** has received limited development efforts to date and is not yet commercially available. One company (Changing World Technologies) is attempting to commercialize the technology, with a focus on animal renderings as feedstock. In addition, this technology is generally not considered for power generation as the primary application.
- **Dilute acid hydrolysis** is relatively well developed technology for producing various chemicals, but is generally not considered for power generation as the primary application.
- **Physio-chemical conversion** is mature technology for producing biodiesel. While biodiesel can be used in power generation, the dominant application is in transportation.

Biopower Production Projections

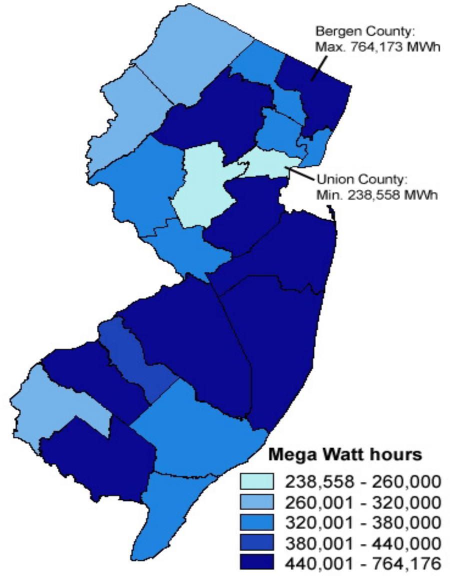
Total biopower potential is estimated to increase from 1,124 MW in 2007 to 1,299MW by 2020, a ~16% increase.



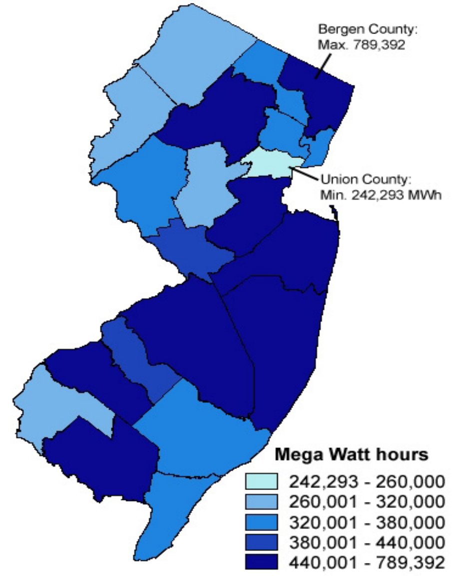
Electric Production Potential 2007



Electric Production Potential 2010

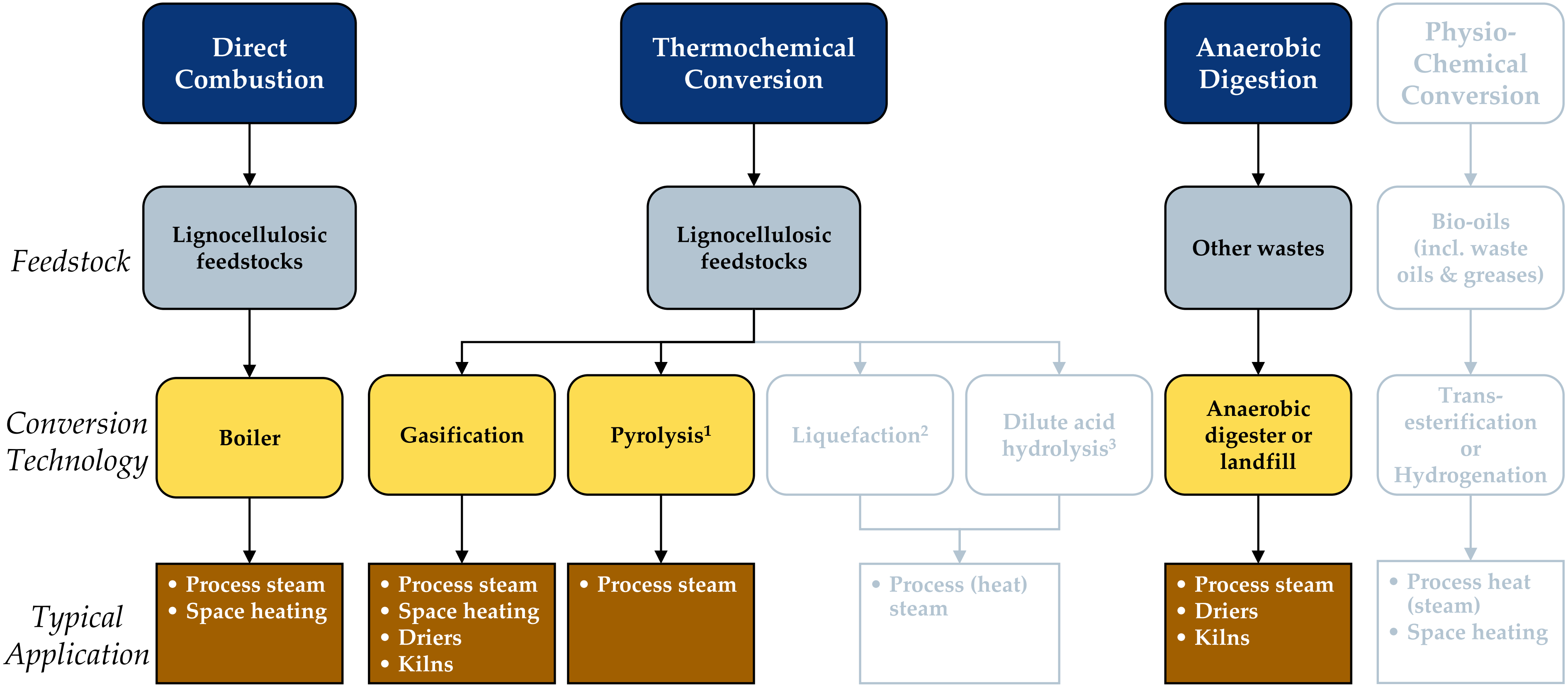


Electric Production Potential 2015



Electric Production Potential 2020

Bio-heat applications are similar to power generation in terms of technology, but solid wastes are not typically considered as feedstocks.



Direct Combustion
- *Feedstock*: **Lignocellulosic feedstocks**
- *Conversion Technology*: **Boiler**
- *Typical Application*: Process steam; Space heating

Thermochemical Conversion
- *Feedstock*: **Lignocellulosic feedstocks**
- *Conversion Technology*: **Gasification**
  - *Typical Application*: Process steam; Space heating; Driers; Kilns
- *Conversion Technology*: **Pyrolysis[1]**
  - *Typical Application*: Process steam
- *Conversion Technology*: Liquefaction[2]; Dilute acid hydrolysis[3]
  - *Typical Application*: Process (heat) steam

Anaerobic Digestion
- *Feedstock*: **Other wastes**
- *Conversion Technology*: **Anaerobic digester or landfill**
- *Typical Application*: Process steam; Driers; Kilns

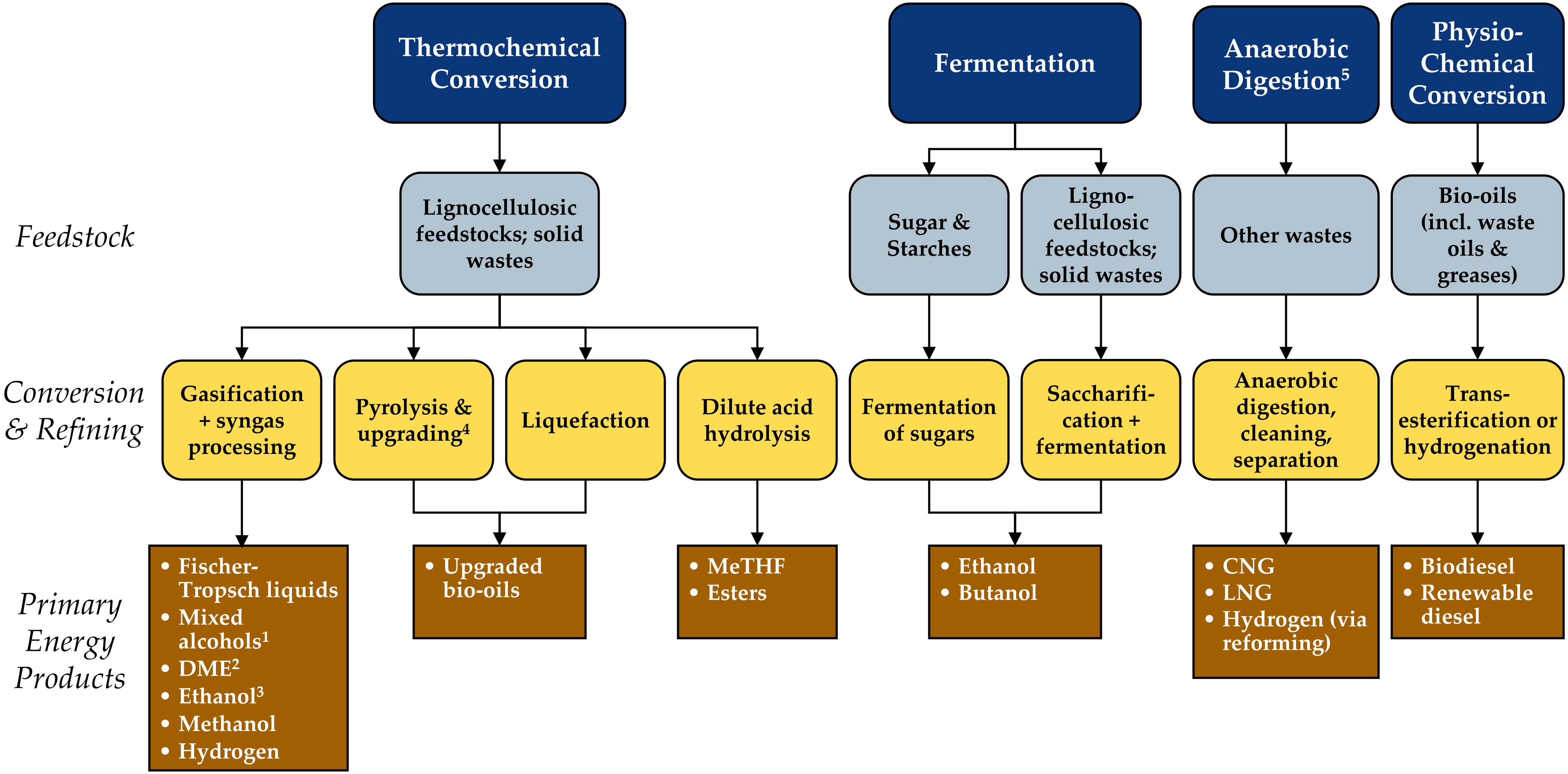
Physio-Chemical Conversion
- *Feedstock*: Bio-oils (incl. waste oils & greases)
- *Conversion Technology*: Trans-esterification or Hydrogenation
- *Typical Application*: Process heat (steam); Space heating

1. Pyrolysis produces non-condensable gases, pyrolysis oils and char. The gases and some char are burned to run the process. Some char can be sold and the pyrolysis oils are used in power generation. Alternatively, char can be crushed and mixed with the pyrolysis oils to be burned in a boiler.
2. Includes aqueous and non-aqueous liquefaction. Like pyrolysis, these processes generally produce a mixture of gases liquids and solids. It is assumed that the liquids are best suited to boiler applications.
3. Produces a range of chemicals (e.g., furfural) that can be upgraded to fuels (so-called "P-series" fuels).

Bio-heat was not evaluated in detail as a stand-alone application.

- Historically, most bio-heat applications are “captive” opportunities in biomass based industries like forest products, and are therefore limited in New Jersey.
- Some regions of the country have larger amounts of residential (e.g., wood stove) and commercial (e.g., wood-fired building heating systems) biomass heating applications, but these too are expected to be niche in New Jersey
- Moreover, since many of these applications would require some sort of retrofit, the economics are expected to be very site specific
- For the above reasons, detailed technology and economic analysis was not conducted for bioheat application
- This does not mean there will not be some application of this type in New Jersey in the future.
- Representative small-scale CHP analyses using direct combustion and gasification were included to capture the value of waste heat recovery as part of certain types of biomass power applications.

There are multiple pathways to create transportation fuels from biomass.



Thermochemical Conversion

Fermentation

Anaerobic Digestion[5]

Physio-Chemical Conversion

Feedstock

Lignocellulosic feedstocks; solid wastes

Sugar & Starches

Ligno-cellulosic feedstocks; solid wastes

Other wastes

Bio-oils (incl. waste oils & greases)

Conversion & Refining

Gasification + syngas processing

Pyrolysis & upgrading[4]

Liquefaction

Dilute acid hydrolysis

Fermentation of sugars

Saccharification + fermentation

Anaerobic digestion, cleaning, separation

Trans-esterification or hydrogenation

Primary Energy Products

- **Fischer-Tropsch liquids**
- **Mixed alcohols[1]**
- **DME[2]**
- **Ethanol[3]**
- **Methanol**
- **Hydrogen**

- **Upgraded bio-oils**

- **MeTHF**
- **Esters**

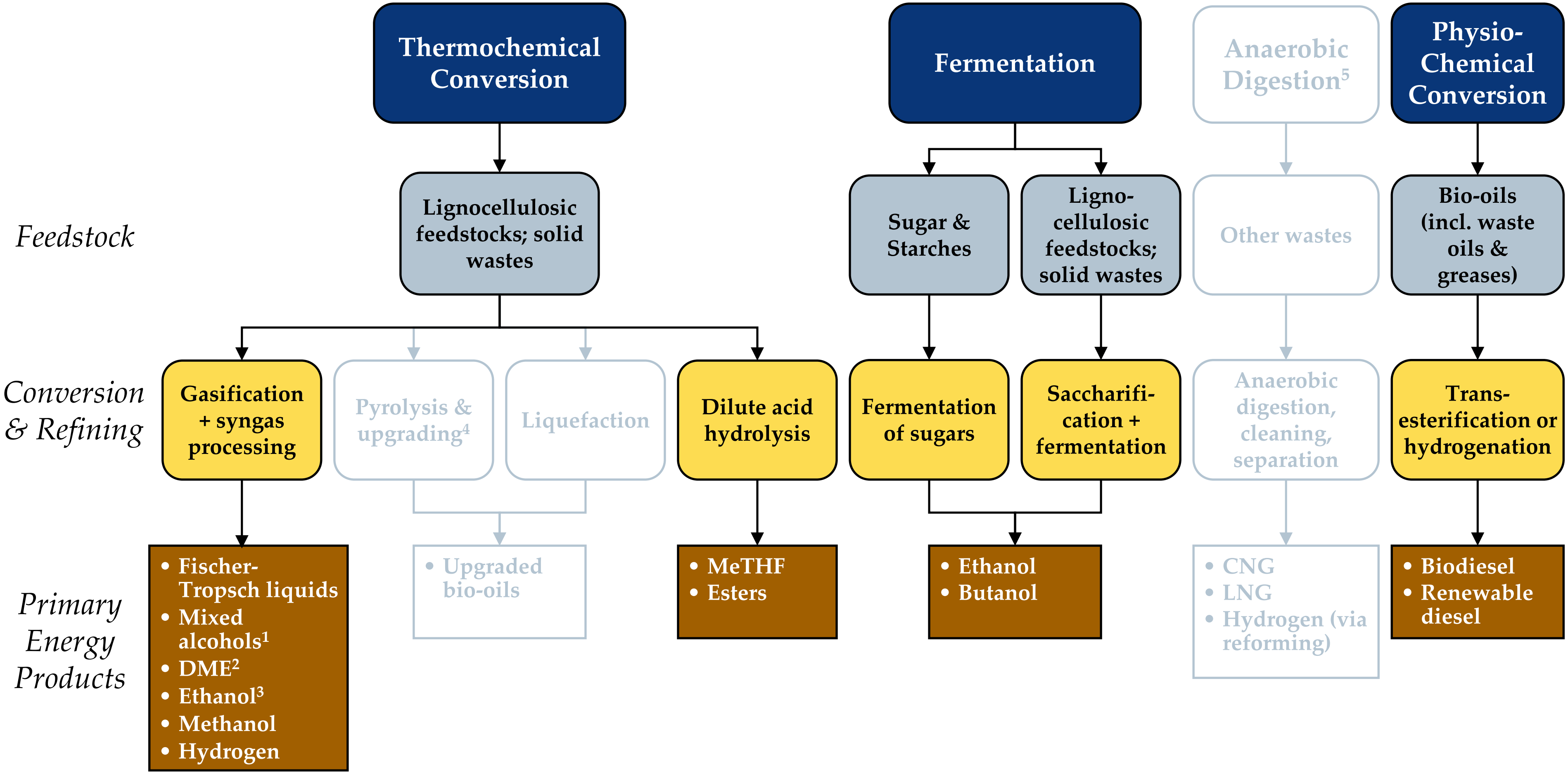
- **Ethanol**
- **Butanol**

- **CNG**
- **LNG**
- **Hydrogen (via reforming)**

- **Biodiesel**
- **Renewable diesel**

1. Via catalytic synthesis. 2. Dimethyl ether. 3. Via syngas fermentation or catalytic synthesis. 4. Pyrolysis oils require substantial upgrading before they can be used for transportation applications, and this processing is difficult. 5. Also includes direct microbial conversion of sunlight to hydrogen.

The five main biofuels options utilize three primary feedstocks.



Feedstock

Conversion & Refining

Primary Energy Products

Thermochemical Conversion

Lignocellulosic feedstocks; solid wastes

Gasification + syngas processing

- **Fischer-Tropsch liquids**
- **Mixed alcohols[1]**
- **DME[2]**
- **Ethanol[3]**
- **Methanol**
- **Hydrogen**

Pyrolysis & upgrading[4]

Liquefaction

- Upgraded bio-oils

Dilute acid hydrolysis

- **MeTHF**
- **Esters**

Fermentation

Sugar & Starches

Ligno-cellulosic feedstocks; solid wastes

Fermentation of sugars

Saccharifi-cation + fermentation

- **Ethanol**
- **Butanol**

Anaerobic Digestion[5]

Other wastes

Anaerobic digestion, cleaning, separation

- CNG
- LNG
- Hydrogen (via reforming)

Physio-Chemical Conversion

Bio-oils (incl. waste oils & greases)

Trans-esterification or hydrogenation

- **Biodiesel**
- **Renewable diesel**

1. Via catalytic synthesis. 2. Dimethyl ether. 3. Via syngas fermentation or catalytic synthesis. 4. Pyrolysis oils require substantial upgrading before they can be used for transportation applications, and this processing is difficult. 5. Also includes direct microbial conversion of sunlight to hydrogen.

The rationale for selecting the biofuels options is as follows:

Options Retained for Analysis

- **Gasification** is receiving significant attention for the production of fuels. It can take advantage of technology develops for similar processes for producing fuels from coal and natural gas.
- **Dilute acid hydrolysis** is mature technology, but it has not received significant attention for fuels applications, but specific plans are underway to develop a plant in New Jersey.
- **Fermentation of sugars** is the most common form of producing transportations fuels (ethanol) from biomass today
- **Saccharification + fermentation** is a current focus of major public and private commercialization efforts. This is the so-called "cellulosic ethanol" technology. The first commercial plants are expected within the next 1-3 years.
- **Transesterification** of vegetable oils is a common and mature technology for producing biodiesel. **Hydrogenation** is an emerging alternative.

Options Not Retained for Analysis

- **Pyrolysis & upgrading** is possible, but producing transportation fuels from bio-oils requires significant upgrading and is challenging. The commercialization focus is currently on power generation.
- **Liquefaction** has received limited development efforts to date and is not yet commercially available. One company (Changing World Technologies) is attempting to commercialize the technology, with a focus on animal renderings as feedstock. If successful, this approach could find application to fuels, but is not considered further here.
- **Anaerobic digestion** is commonly practiced in wastewater treatment plants and increasingly on animal farms. Landfill gas is also a product of natural anaerobic digestion in landfills. This option is being advanced in New Jersey and elsewhere but remains a niche opportunity and so reliable cost information is difficult to obtain. **This option is discussed qualitatively.**

In the biofuels analyses, differences in volumetric energy densities among biofuels were normalized to gallons of gasoline equivalent (GGE).

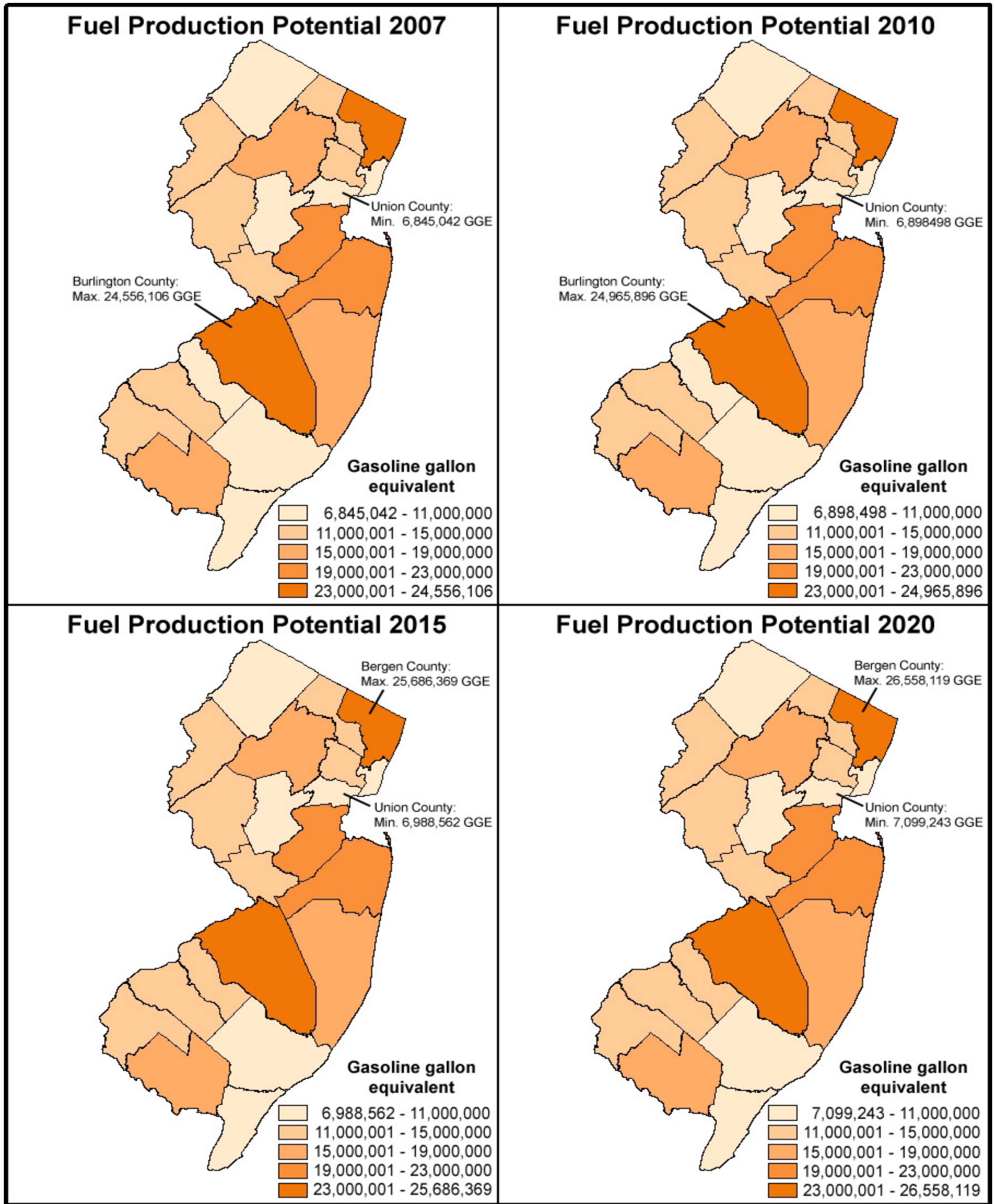
Liquid Fuels	HHV (Btu/gal)	GGE for 1 gallon of biofuel
Conventional Gasoline	124,340	-
Ethanol	84,530	0.68
Biodiesel	128,763	1.04
Fischer Tropsch Diesel	130,030	1.05
MeTHF	111,750	0.90

HHV – High Heating Value

MeTHF - methyltetrahydrofuran, an ether produced by hydrogenation of levulinic acid.

Biofuel Production Projections

Total biofuel potential is estimated to increase from 311 M GGE in 2007 to 335 M GGE by 2020, an ~8% increase.



Technology Profiles

Direct combustion of biomass is the most common option for power generation.

Application	Core technology platforms and applications				
	Direct Combustion	**Thermo-chemical Conversion**	**Fermentation**	**Anaerobic Digestion**	**Physio-chemical Conversion**
Power/CHP	**1.**Stand-alone rankine (steam) cycle plant **2.**Small-scale rankine cycle CHP plant **3.**Biomass co-firing with coal	4. Stand-alone BIGCC plant 5. Small-scale gasification-IC engine CHP plant 6. Stand-alone pyrolysis plant		11.Food waste anaerobic digester with IC engine CHP plant/ Landfill gas with microturbine	
Heat Only	• Discussed qualitatively and shown in context of CHP applications above.				
Transportation Fuels		7. .Biomass-to-liquids plant (Fischer-Tropsch) 8..Dilute acid hydrolysis for biofuels production[1]	9. Corn-ethanol dry mill 10.Cellulosic ethanol plant	12. CNG or LNG from landfill gas/AD gas	13.Transester-fication Biodiesel

1. Involves the production of ethers (gasoline blendstock) and esters (diesel blendstock).

Feedstock, conversion process, and end-use are considered in biomass power generation and combined heat and power (CHP).

Feedstock

Power can be produced from a range of solid biomass resources:

- Wood and wood residues, mostly from forest products mills, but also from urban sources (e.g., used pallets, tree trimmings, construction debris) is the primary feedstock
- Agricultural residues can also be used although they present some additional challenges (e.g., ash content a properties)
- In the future woody or herbaceous energy crops may be grown
- Municipal waste is also largely composed of biomass, and about 15% nationally is burned today in waste to energy plants

Conversion

Biomass power production via direct combustion is mature technology:

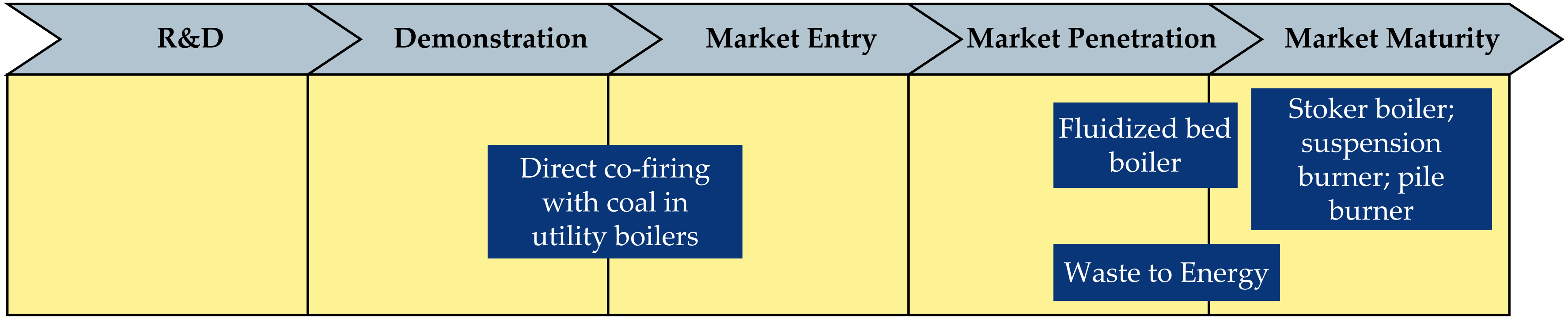
- High-pressure steam is produced in a boiler, which is then expanded in a steam turbine to generate electricity
- The high moisture content of the fuel and the relatively small scale of the plants (<50MW, likely much smaller in New Jersey) results in relatively low overall net electrical efficiencies of about 20-25%.
- Steam can be extracted for use in industrial processes in CHP applications, in which case the electrical generation efficiency will be lower, but overall efficiency (measured as electricity + use thermal output), will be higher (70-80%).
- In co-firing, 2-15% biomass (energy basis), depending on the boiler type and feed system, can be co-combusted with coal in existing utility boilers at much higher efficiency (30-35%)

End-Use

Power is generally sold into the grid or used onsite as part of a CHP system.

- Most biopower in the United States today is CHP in the forest products industry (~5,000 MW)
- In some states, stand-alone biopower is also common, e.g., California, New England (~1,000 MW)
- Municipal solid waste fuels about 2,700 MW of waste-to-energy (WTE) plants, with about 75% of the fuel being biomass.

Direct combustion is a well developed technology with several boiler types available. Fuel type is an important factor in boiler type choice.


R&D

Demonstration

Market Entry

Market Penetration

Market Maturity

Direct co-firing with coal in utility boilers

Fluidized bed boiler

Stoker boiler; suspension burner; pile burner

Waste to Energy

Emerging Technologies

- Developments are focused on increasing cycle efficiency, reducing CAPEX and OPEX and reducing emissions
- The introduction of fluidized-bed (FB) combustors is the most recent significant development. They burn biomass in a bed of hot granular material. Air is injected at a high-rate underneath the bed to create the appearance of a boiling liquid. This helps to evenly distribute the fuel and heat. FB combustors are becoming the systems of choice for biomass fuels, due to good fuel flexibility and good emissions characteristics.
- Developments in stoker technology involving the introduction of a much higher fraction of air above the grate could result in lower emissions, essentially turning a stoker into a two-stage gasification/combustion technology. For example, see http://mass.gov/doer/rps/hemphill.pdf.

Established Technologies

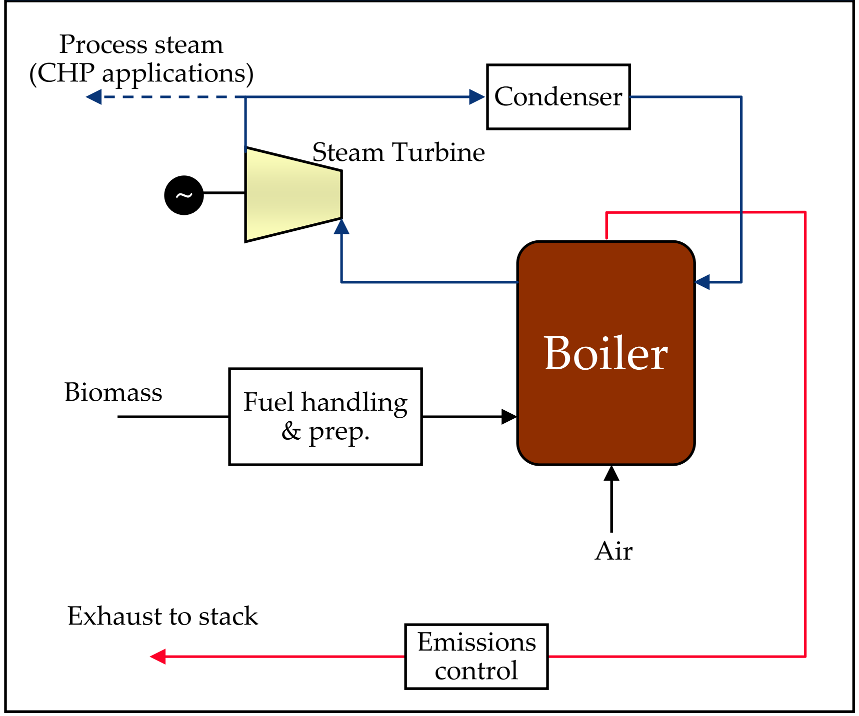
- The stoker boiler is the most mature and widely deployed. Biomass is added to a stoker boiler in a thin layer on a grate near the bottom of the boiler. Air is introduced both above and below the grate. There are three types of stoker boilers – stationary sloping grate, traveling grate and vibrating grate.
- Suspension burners are used in niche applications when the biomass fuel is available in small diameters (<1mm), typically through other processes (e.g., sawdust).
- Pile burners have been around since the 1700s and have limited applicability today.
- Co-firing with coal is relatively common in industrial boilers designed for that purpose, and it has been well demonstrated in utility boilers, especially using woody biomass. However, non-technical factors have limited market adoption among utilities.
- For waste-to-energy, so-called mass-burn, RDF fueled and modular combustors are available.

Direct combustion uses the same Rankine cycle technology as coal plants, only at a smaller scale.

Biomass Power Plant in California

Source: NREL.

Biomass Power Plant (Rankine cycle)



Source: Navigant Consulting, Inc.

- Emissions controls, such as an electrostatic precipitator (ESP) or baghouse for particulates, and some form of NOx control, such as ammonia injection or staged combustion, are standard on new plants today to meet typical emissions requirements.

Biomass can be co-fired with coal at rates of up to 15% (Btu basis) in existing boilers.

- Although co-firing is relatively routine in industrial multi-fuel boilers, most utility coal boilers were not designed to co-fire biomass.
- The two types of direct fire options are blended feed and separate feed. The choice depends on the boiler type and the amount of co-firing.
    - For pulverized coal boilers (the most common type), blended feed systems can be used up to about 2% biomass
    - For values of 2-15% biomass, a separate biomass feed system must be installed, and other modifications may be needed. Each potential application must be evaluated on a case-by-case basis.
- Gasified biomass (syngas) can also be fed into a coal boiler.[1] This would require fewer boiler modifications, but have higher capital costs for the gasifier.

Fuel mixing at the NIPSCO Power Plant in Bailey, Indiana

Source: NREL.

- The emissions impacts of co-firing will vary but generally, since biomass has less sulfur than coal, co-firing results in lower SO_2 emission. Also, in plants without NOx controls, it is generally accepted that co-firing should reduce NOx formation.

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1. Not discussed here. This application is at a much earlier stage of development than direct co-firing of solid biomass.

Feedstock supply is the least well developed aspect of the biomass power supply chain.

Supply Chain

- Except for CHP, where the fuel is typically a residue produced onsite, biomass feedstock supply is the key challenge and risk factor for biomass power plants
  - Both the price and availability of biomass over the long-term are major risk factors
  - The feedstock supply "industry" is highly fragmented and it can be difficult to secure long-term contracts for fuel
- Once the power is sold, the supply chain is essentially the existing electric power supply chain.

Other Issues Unique to Co-firing

- Co-firing has been limited because of several barriers
  - Inability to sell fly ash because it would not meet the ASTM specifications (loss of revenue for coal plant)
  - Potential trigger for a New Source Review (NSR), which could result in other retrofits required at the plant.
  - Co-firing receives limited incentives and is not always eligible for state RPS programs.

Markets

- The power is either used onsite (CHP applications) or sold to the grid (stand-alone systems and excess power from CHP)
- Biomass power benefits from Federal and state incentives and is also eligible for many state RPS programs.
  - The key Federal incentive is the 10-year 0.9¢/kWh production tax credit for "open loop" biomass (the value is 1.9 ¢/kWh for "closed loop" biomass [energy crops]). Co-firing is not eligible for the open loop credit but does receive 0.9 ¢/kWh if using energy crops
  - Biomass projects that receive "qualifying facility" designation under PURPA[1] also receive 5-year accelerated depreciation.
  - In New Jersey, the biomass eligibility requirements are relatively stringent, which may preclude the use of many of the resources identified in this report for RPS compliance

[1] Public Utility Regulatory Policy Act.

Costs for conventional biomass power plants are not expected to change significantly in the future.

	Solid Biomass Economic Assumptions for Given Year of Installation					
	Central (Fluidized bed)			Distributed Combined Heat and Power		
	2007	2010	2015	2007	2010	2015
Plant Capacity (MW)	25	25	25	5	5	5
Total installed cost ($/kW)[1]	$2,000	$1,900	$1,800	$3,500	$3,300	$3,100
Non-Fuel Fixed O&M ($/kW-yr)[2]	$120	$115	$110	$210	$200	$190
Non-Fuel Variable O&M ($/MWh)[2]	$2.50	$2.50	$2.50	$2.50	$2.50	$2.50
Capacity Factor (%)	85%	85%	85%	85%	85%	85%
Project Life (yrs)	25	25	25	25	25	25
Net Electrical Efficiency (%, HHV basis)[3]	21%	22%	23%	14%	15%	16%
Net Heat Rate (Btu/kWh, HHV)[3]	16,250	15,510	14,835	20,070	17,960	17,060
Useful Heat Recovered (Btu thermal/kWh)[4]	N/A	N/A	N/A	14,867	13,648	12,582

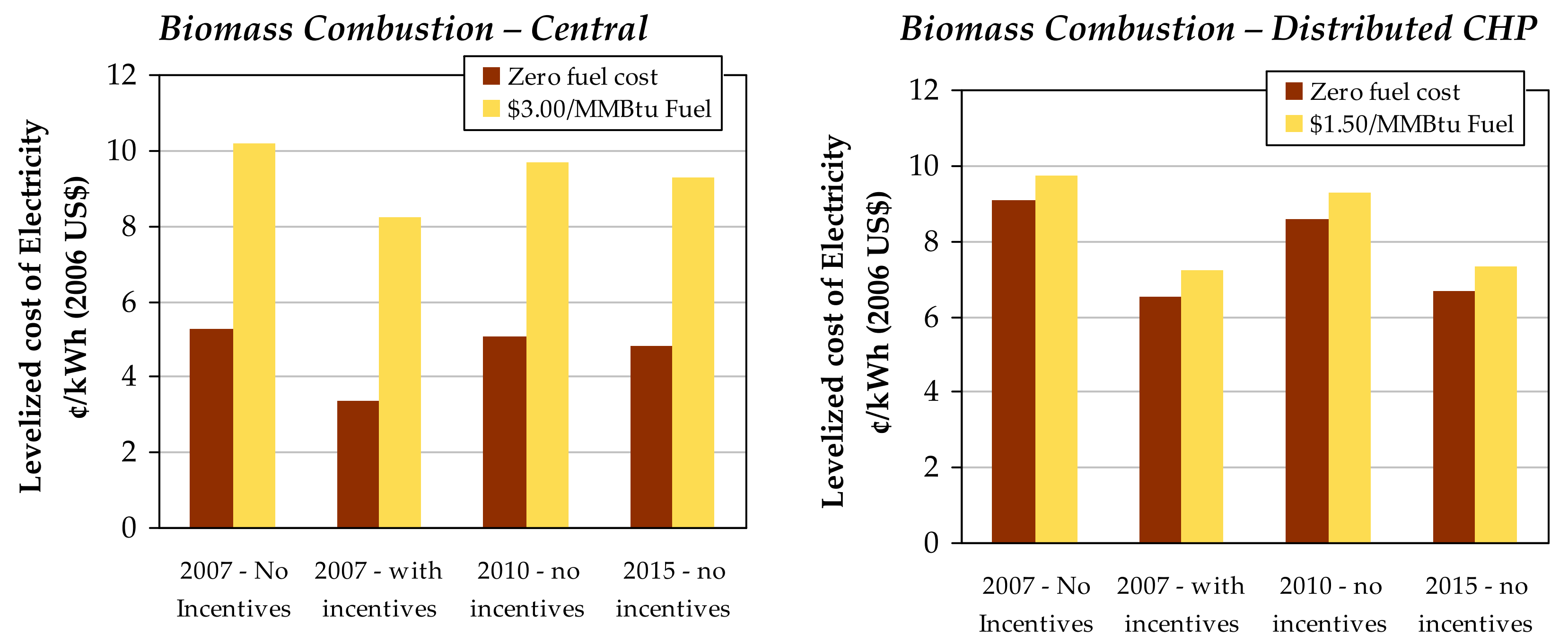
Plant size assumptions: These sizes are representative – actual plant sizes in New Jersey will depend on the availability of biomass at any given location. It is assumed here that a central plant would collect biomass from various sources to achieve a scale of 25MW. A distributed CHP plant is sized consistent with the assumption that it uses biomass generated onsite at a single location.

1. Includes all development costs, such as permitting and interest during construction. All data are in 2007 US$.
2. Variable O&M is the costs for consumables, chemicals, and ash disposal. Labor and maintenance are included in the fixed component of O&M.
3. HHV = Higher Heating Value.
4. Assumes 75% biomass boiler efficiency and a back-pressure steam turbine taking 100% of the steam to process.

Source: NCI estimates based on *Renewable Energy Technology Characterizations*, TR-109496, EPRI and US DOE, December 1997; *Biopower Technical Assessment*, NREL/TP-510-33132, National Renewable Energy Laboratory, January 2003; *Lessons Learned from Existing Biomass Power Plants*, NREL/SR-570-26946, National Renewable Energy Laboratory, February 2000.

While Direct Combustion is the most developed biopower technology, cost improvements are expected to be limited.

Levelized Cost of Electricity for Biomass Direct Combustion (2007$)


Biomass Combustion – Central

Biomass Combustion – Distributed CHP

Key assumptions: Debt equity ratio: 60%:40%, cost of equity = 15%, cost of debt = 8%, Federal income tax rate = 35%; NJ state income tax rate = 9%; Property tax = 1.5%, Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 10 years. Project economic life = 25 years.

- *Biomass Combustion CHP* also includes a cogeneration credit assuming biomass is otherwise burned for heat only at the same prices shown above. The CHP credit could be higher if displaced fuel is natural gas or fuel oil.
- Incentives included for 2007 calculation: 0.9 ¢/kWh production tax credit for 10 years; 5-year accelerated depreciation.
- Excludes revenues from REC sales.

As a retrofit application at an existing plant, co-firing with coal has the potential for very low cost of energy.

	Biomass Co-firing with Coal Economic Assumptions for Given Year of Installation					
	Blended Feed			**Separate Feed**		
	2007	**2010**	**2015**	**2007**	**2010**	**2015**
Biomass Capacity (MW)	10			25	25	25
Fraction of Total Plant Capacity (%)	2%			5%		
Total Installed Cost ($/kW)[1]	$50			$250	$230	$200
Non-Fuel Fixed O&M ($/kW-yr)[2]	$29			$22		
Non-Fuel Variable O&M ($/MWh)[3]	$6			$6		
Capacity Factor (%)	85%			85%		
Project Life (yrs)	25			25		
HHV Efficiency (%)[4]	32.9%			32.8%		

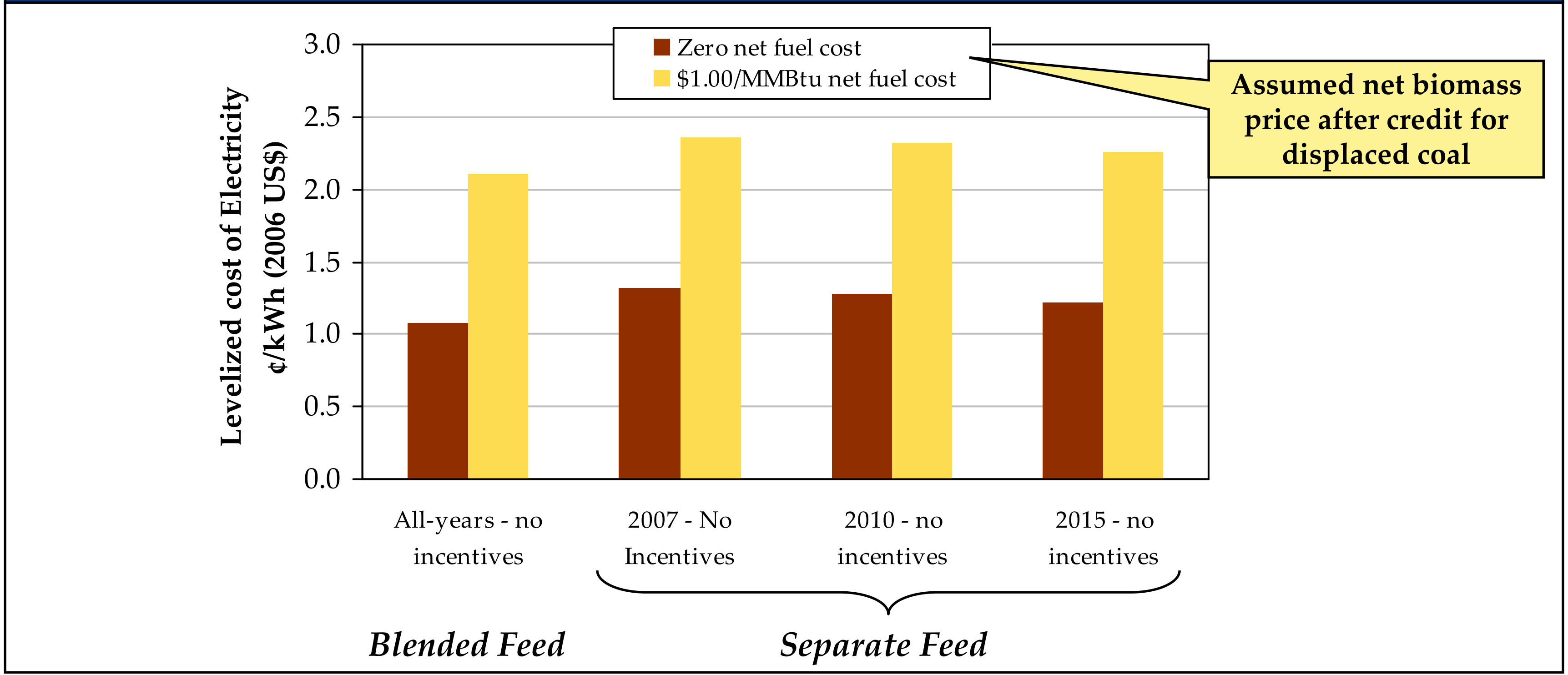
Plant size assumptions: Assumes a 500MW coal plant at the levels of co-firing shown above (2% and 5%)

1. Includes all development costs, such as permitting and interest during construction. Assumes that host plant is fully depreciated.
2. Assumes 6 additional staff for the separate feed system and 4 additional staff for the blended feed system to operate the biomass fuel yard and feed equipment @ $70K/yr, plus 2% of installed capital in maintenance.
3. This is the assumed ongoing non-fuel O&M cost of the coal plant.
4. Based on a coal plant efficiency of 33% and assuming a 0.2% point degradation in efficiency for the 5% co-firing case and a 0.1% degradation in the 2% case. HHV = Higher Heating Value.

Source: NCI estimates based on *Renewable Energy Technology Characterizations,* TR-109496, EPRI and US DOE, December 1997.

Co-firing with coal has the potential for very low cost of energy.

Levelized Cost of Electricity for Biomass Direct Co-firing with Coal (2007$)



Assumed net biomass price after credit for displaced coal

- Key assumptions: Debt equity ratio: 60%:40%, cost of equity = 15%, cost of debt = 8%, Federal income tax rate = 35%; NJ state income tax rate = 9%; Property tax = 1.5%, Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 10 years. Project economic life = 25 years.
- No incentives assumed for co-firing. Excludes any value of emissions allowance credits. Cost shown are direct costs associated with the biomass portion of the plant. Assumed host coal plant is fully depreciated.
- Excludes revenues from REC sales.

There are several thermo-chemical conversion processes emerging as suitable technologies for power generation and/or fuels.

Application	Core technology platforms and applications				
	Direct Combustion	Thermo-chemical Conversion	Fermentation	Anaerobic Digestion	Physio-chemical Conversion
Power/CHP	1.Stand-alone rankine (steam) cycle plant 2.Small-scale rankine cycle CHP plant 3.Biomass co-firing with coal	4. Stand-alone BIGCC plant 5. Small-scale gasification-IC engine CHP plant 6. Stand-alone pyrolysis plant		11.Food waste anaerobic digester with IC engine CHP plant/ Landfill gas with microturbine	
Heat Only	• Discussed qualitatively and shown in context of CHP applications above.				
Transportation Fuels		7. .Biomass-to-liquids plant (Fischer-Tropsch) 8..Dilute acid hydrolysis for biofuels production[1]	9. Corn-ethanol dry mill 10.Cellulosic ethanol plant	12. CNG or LNG from landfill gas/AD gas	13.Transester-fication Biodiesel

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1. Involves the production of ethers (gasoline blendstock) and esters (diesel blendstock).

Gasification and pyrolysis are emerging alternatives to direct combustion for power, and could be used to make fuels as well.

Feedstock

Gasification and pyrolysis can use a range of solid biomass resources, similar to combustion

- Wood and wood residues, mostly from forest products mills, but also from urban sources (e.g., used pallets, tree trimmings, construction debris) is the primary feedstock
- Agricultural residues can also be used. The challenges faced by combustion technologies (e.g., ash content a properties) are generally less of an issue with thermochemical conversion.
- In the future woody or herbaceous energy crops may be grown
- Municipal waste must be processed into refuse derived fuel (RDF) before it can be used

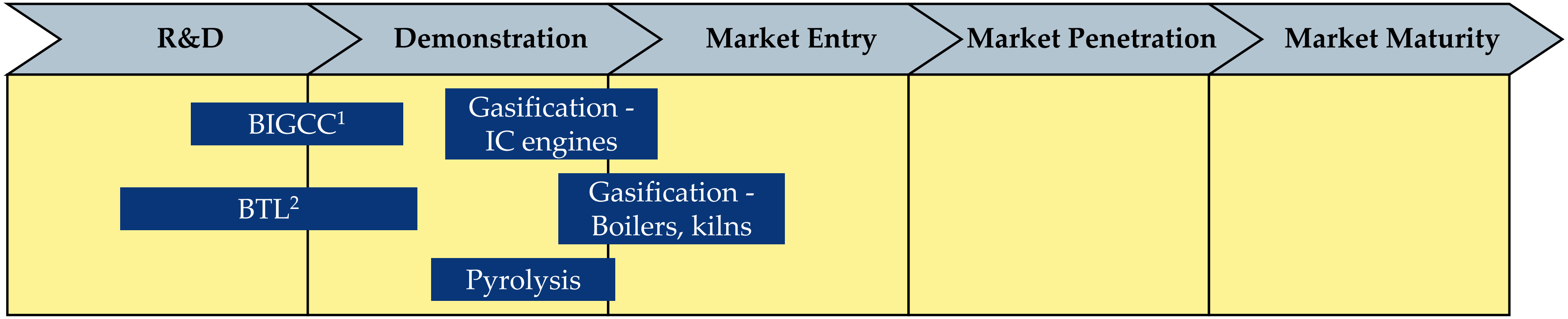
Conversion

- Gasification produced a low-medium Btu gas (100-300 Btu/scf) that can be cleaned and used in power generation or, depending on the type of gasifier, in fuel synthesis.
- Steam can be co-produced for CHP applications
- For power generation, air-blown or oxygen-blown gasifiers are appropriate
- For fuel synthesis, pressurized, oxygen-blown gasifiers, or indirectly heated gasifiers, are required
  - Virtually any type of fuel or chemical can be made from clean syngas.
- Pyrolysis produces pyrolysis oils, char (carbon) and non-condensable gases. Typically, the gases and some char are burned to run the pyrolysis reactor. Pyrolysis oils are suitable for power generation and, with significant upgrading, can be transformed into transportation fuels.

End-Use

- For power or CHP, the end-use is the same as for direct combustion (electricity)
- For gasification to fuels, the end-use is transportation fuels. The near-term application is likely to be the blending of biofuels at low levels with petroleum-based fuels, but Fischer-Tropsch (FT) fuels can be blended in any quantity, up to 100%, since their properties are consistent with petroleum-based fuels.

Gasification and pyrolysis are at relatively early stages of commercialization.



Emerging Technologies

- In China and India, there is a recent push to develop small-scale biomass gasification power systems (<2MWe) using reciprocating engines. A number of European and North American companies are also developing similar systems.
- Key technology developments that would improve efficiency of gasification systems include hot-gas cleanup and tar cracking.
- Several novel gasification concepts are being developed to address waste fuels or to address tar problems. Choren (Germany) is an example of a company that has developed a multi-stage gasifier for FT synthesis.
- BIGCC integration and long-term operations are still required for commercial deployment of this technology.
- Pyrolysis remains at a relatively early stage of development.

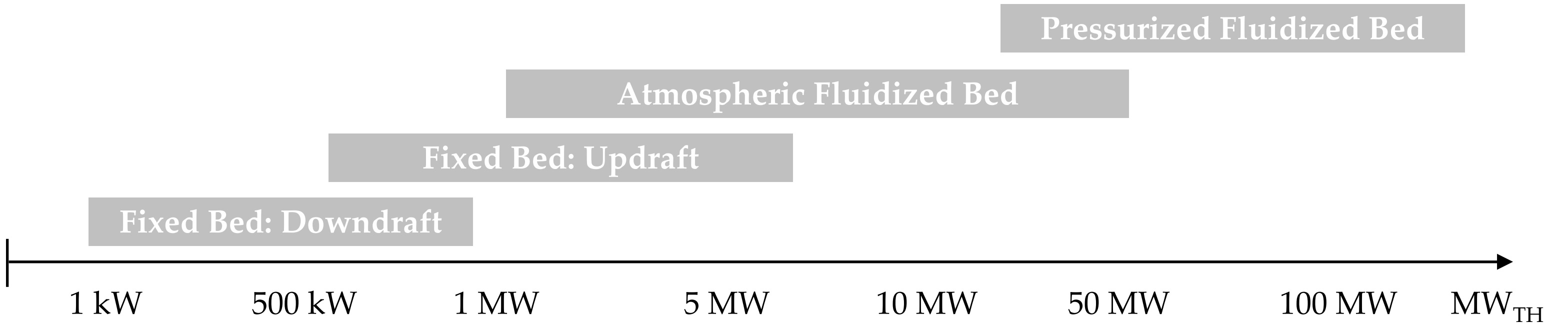
Established Technologies

- Although gasification has been developed over many decades, biomass gasification has not seen significant commercial market penetration – its main use has been to produce low-Btu "producer gas" that can be used as a substitute for fuel oil or natural gas in existing boilers and kilns (e.g., pulp & paper mill lime kilns).
- Nevertheless, many of the technology platforms are in place and are relatively well developed – what has been lacking is integration and successful commercialization.
  - Air-blown gasifiers of various sizes and types
  - Gas turbines and IC engines designed to run on low-Btu gas
  - Conventional gas cleanup technologies (cyclone separators, wet scrubbers, acid gas removal systems)
  - Fuel synthesis technology

1. Biomass Integrated Gasification Combined Cycle.
2. Biomass to liquids – the production of biofuels via catalytic synthesis of syngas derived from biomass gasification.

Fixed-bed gasifiers are suitable for small-scale application – fluidized bed gasifiers can achieve much higher throughput.

Gasifier design vs. biomass input rates


Pressurized Fluidized Bed
Atmospheric Fluidized Bed
Fixed Bed: Updraft
Fixed Bed: Downdraft
1 kW
500 kW
1 MW
5 MW
10 MW
50 MW
100 MW
MW_{TH}

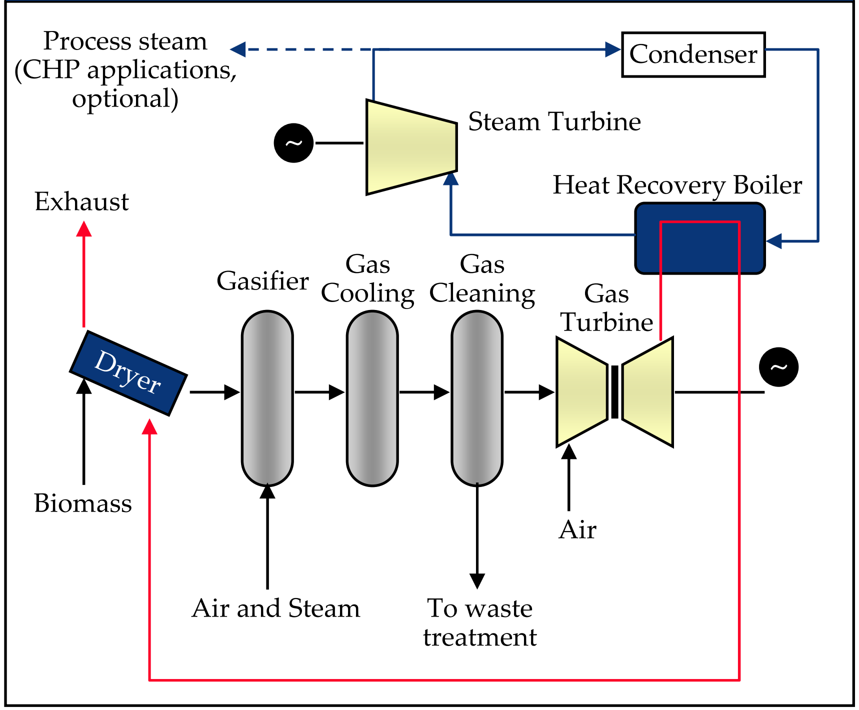
Note: 1 MWth of biomass input is approximately 4.5 dry tons per day of woody biomass.

- **Fixed Bed** Gasifiers are cheaper to build, easier to operate and produce a synthesis gas that is suitable for IC engines (lower content of dust and tars and lower temperature)
  - Fixed-bed units are suitable for sizes ranging from <100kWe to about 5MWe (higher using multiple gasifiers).
  - For power applications, **downdraft designs** are preferred to updraft versions because of the lower tar content in the gas, despite stricter fuel requirements (both in terms of size and moisture) and lower efficiencies (due to higher gas temperature)
- **Fluidized Bed** technologies have been developed for power and fuel synthesis applications up to about 50MWe. Benefits of this design are:
  - Compact construction because of high heat exchange and reaction rates
  - Greater fuel flexibility than fixed-bed units in terms of moisture, ash, bulk density and particle size
  - Pressurization and the ability to use pure oxygen instead of air make them suitable for fuels synthesis.

Biomass integrated gasification combined cycle technology offers the prospect of high conversion efficiency and low emissions

- The use of a gas turbine and steam turbine (a combined cycle), coupled with heat integration from the gasifier, offers the potential for efficiencies about 50% higher than for direct combustion.
- The syngas is a mixture of mainly H_2, CO, CO_2, CH_4, N_2, and other hydrocarbons.
  - At a minimum, the syngas must be cleaned of particulates, alkali compounds, and tars to make it suitable for combustion in a gas turbine.
- BIGCC systems are inherently low polluting when compared to biomass combustion
  - The syngas must be clean enough so as not to damage the gas turbine
  - Because combustion occurs in the gas turbine, emissions of NOx, CO and hydrocarbons are comparable to those of a natural gas-fired GTCC
  - Depending on the type of biomass, the ash can be used as fertilizer

Biomass Integrated Gasification Combined Cycle (BIGCC)

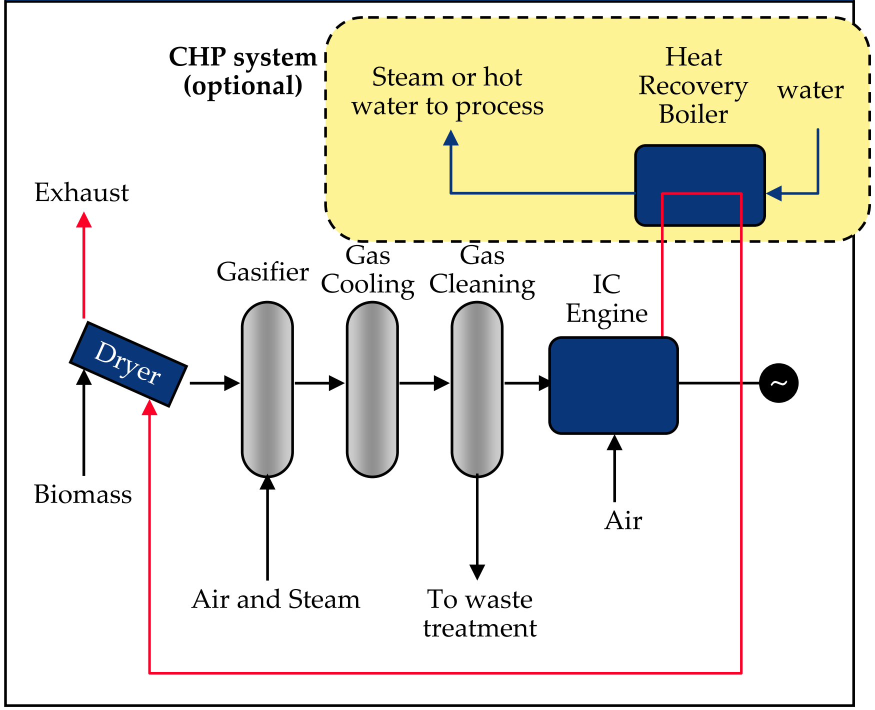


Source: Navigant Consulting, Inc.

Small-scale gasification can be used to supply syngas to an internal combustion engine or a small gas turbine.

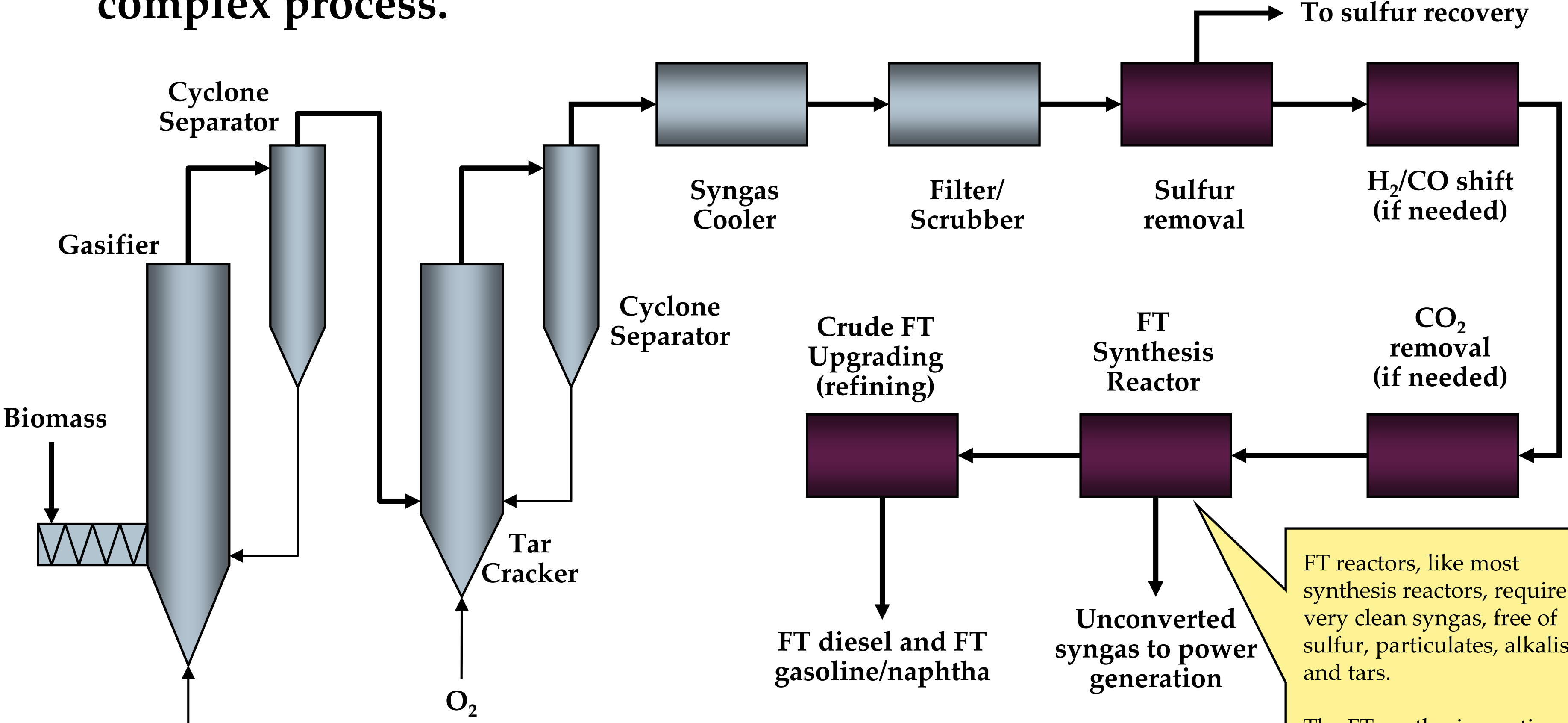
- For small-scale applications, biomass combustion for use with a steam cycle may not be practical (e.g., need for high-pressure steam)
  - Gasification coupled to an IC engine is more practical at small scales.
- The syngas is a mixture of mainly H_2, CO, CO_2, CH_4, N_2, and other hydrocarbons.
  - At a minimum, the syngas must be cleaned of particulates, alkali compounds, and tars to make it suitable for combustion in a gas turbine or internal combustion engine.
- Both compression ignited (diesel) and spark ignited (otto) engines can be used; the power output of both deteriorates when operating on producer gas but emissions should be similar to natural gas operation.

Small-scale Biomass Gasifier with Internal Combustion (IC) Engine



Source: Navigant Consulting, Inc.

Production of liquid transport fuels such as Fischer-Tropsch fuels, is a complex process.



Requires oxygen instead of air to prevent N_2 dilution

⬜ Similar to power applications using gasification

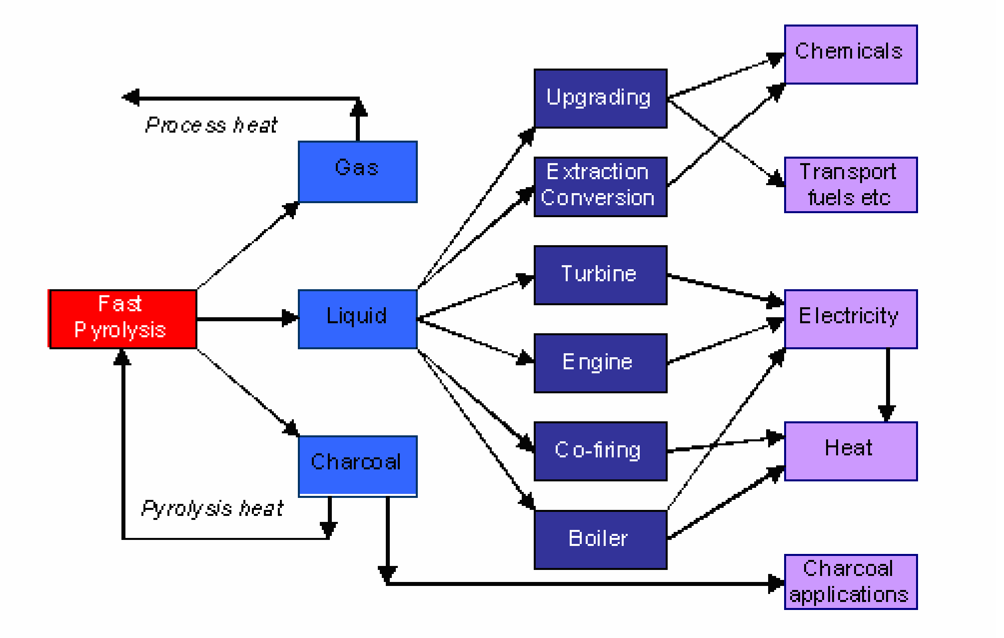
🟪 Additional steps needed for liquid fuel synthesis

FT reactors, like most synthesis reactors, require a very clean syngas, free of sulfur, particulates, alkalis, and tars.

The FT synthesis reaction produces long-chain hydrocarbons from CO+H_2 that must then be upgraded (refined) into transportation fuels.

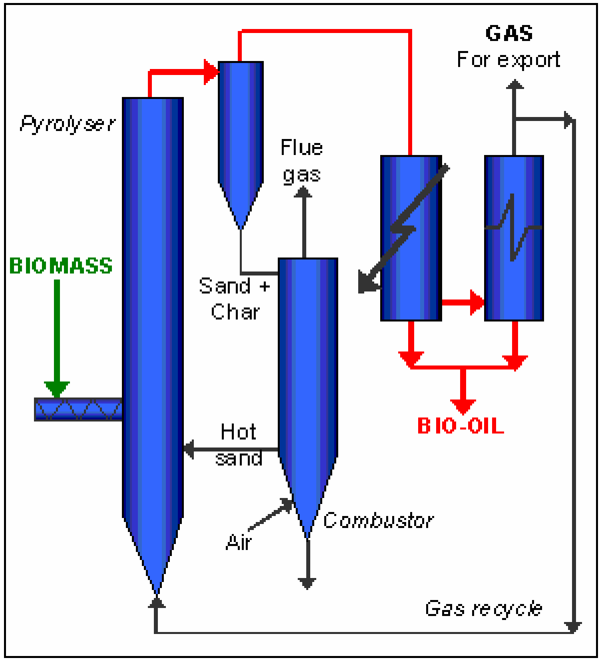
Pyrolysis converts biomass to a mixture of gases, solids and liquids (pyrolysis oils or bio-oils) using technology similar to gasification.

Pyrolysis Products and Applications



Source: The Pyrolysis Network (PyNE)

Circulating Fluidized Bed System



- Pyrolysis involves the rapid heating of biomass and rapid quenching of the gas, which produces mostly condensable hydrocarbons.
- The liquid bio-oil is the primary product (typically 60-75% by weight of the incoming biomass) - it is about 20-25% water by weight, has a low pH (~2) and contains suspended char and ash particles.

Supply of feedstock is the least well developed aspect of the biomass power supply chain.

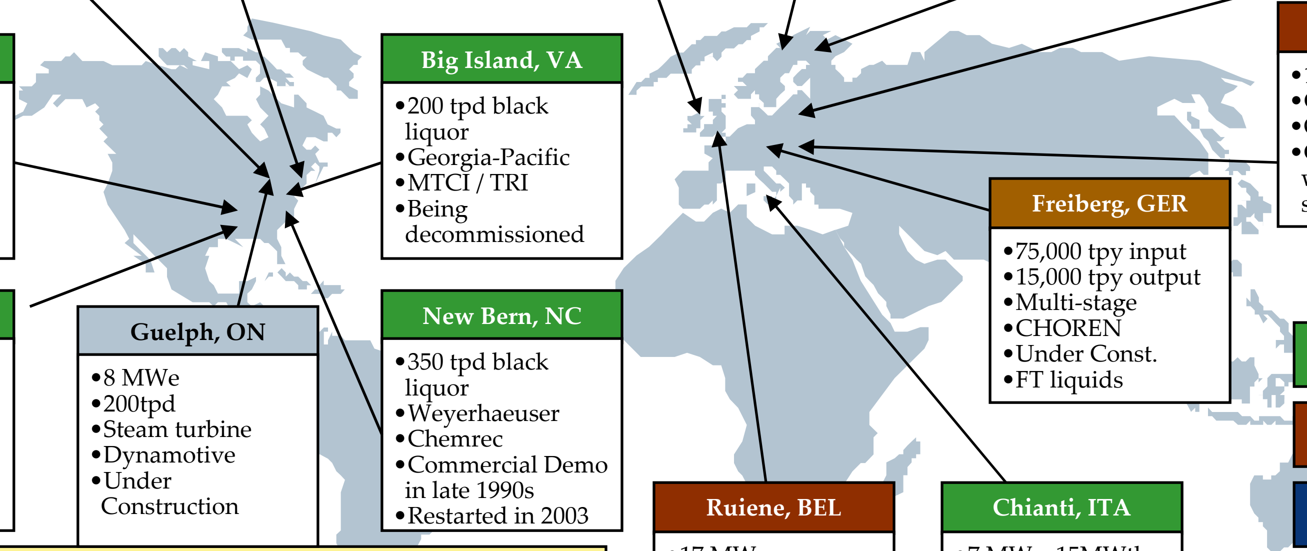
Supply Chain

- Except for CHP, where the fuel is typically a residue produced onsite, biomass feedstock supply is the key challenge and risk factor for biomass power plants
  - Both the price and availability of biomass over the long-term is a major risk factor
  - The feedstock supply "industry" is highly fragmented and it can be difficult to secure long-term contracts for fuel
- Once the power is sold, the supply chain is essentially the existing electric power supply chain.
- For BTL, it will be necessary to integrate with the existing petroleum supply chain. Depending on the product, this may occur upstream or downstream of the refinery.
- FT liquids are generally more compatible with existing fuels than ethanol or biodiesel.

Markets

- The power is either used onsite (CHP applications) or sold to the grid (stand-alone systems and excess power from CHP)
- Biomass power benefits from Federal and state incentives and is also eligible for many state RPS programs, including the one in New Jersey.
- From the point of view of incentives, the treatment of BTL fuels is different from ethanol or biodiesel.
  - The existing excise tax credit, the most significant Federal incentive, does not apply to FT or to any other biofuel that does not meet the definitions of eligibility
  - BTL fuels are eligible for the Federal Renewable Fuels Standard.

A number of commercial-scale gasification & pyrolysis projects are in operation or under development (not an exhaustive list).



🟩 Trenton, ON
- 115 tpd black liquor
- Norampac Project
- MTCI / TRI
- Commissioning started Q3 2003

🟥 Burlington, VT
- 8MWe, 60MWth
- 200 tpd of wood
- Oper. 2000 - 2003
- Batelle/FERCO
- Demo complete

🟦 Yorkshire, GBR
- 10 MWe
- ARBRE Project
- Oper. 8 days in 2001 (bankrupt)
- TPS Termiska Processer AB

🟦🟧 Värnamo, SWE
- 6 MWe, 9 MWth
- Oper. 1993 - 1999
- Developed by Sydkraft AB and Foster Wheeler
- Being restarted for fuels production

🟥 Lahti, FIN
- 60 MWth
- CFB
- Foster Wheeler
- Oper. since 1998
- Co-fires 360MWth PC boiler

🟥 Amer, NED
- 85 MWth
- CFB
- Lurgi
- Start-up in 2000
- Co-fires 600MWe PC boiler

🟥 Zeltweg, AUT
- 10 MWth
- CFB
- Oper. 1998 - 2001
- Closed gasifier when power plant shut-down

🟩 Stuttgart, AR
- 12 MWe
- Riceland Foods
- Rice husk
- Primenergy
- Installed in 1996

🟩 Big Island, VA
- 200 tpd black liquor
- Georgia-Pacific
- MTCI / TRI
- Being decommissioned

🟧 Freiberg, GER
- 75,000 tpy input
- 15,000 tpy output
- Multi-stage
- CHOREN
- Under Const.
- FT liquids

🟩 Greenville, MS
- 6.5 MWe
- Producers Rice Mill
- Rice husk
- Primenergy
- Installed in 1995

⬜ Guelph, ON
- 8 MWe
- 200tpd
- Steam turbine
- Dynamotive
- Under Construction

🟩 New Bern, NC
- 350 tpd black liquor
- Weyerhaeuser
- Chemrec
- Commercial Demo in late 1990s
- Restarted in 2003

🟥 Ruiene, BEL
- 17 MWe
- 8.5 t/hr of wood waste
- CFB
- Oper. since May 2003
- Foster Wheeler

🟩 Chianti, ITA
- 7 MWe, 15MWth
- 100 tpd of RDF pellets
- CFB
- Operated 1992-2000, dismantled
- TPS Termiska Processer AB

🟩 **Gasifiers for boiler fuel**
🟥 **Cofiring Gasifiers (existing power plants)**
🟦 **Integrated Gasification and Combined Cycle**
🟧 **Biomass to Liquids**
⬜ **Pyrolysis**

- tpd = tons per day
- tpy = tons per year
- MWe = megawatt electric
- MWth = megawatt thermal
- CFB = circulating fluidized bed
- RDF = refuse derived fuel
- ARBRE = ARable Biomass Renewable Energy
- MTCI = Manufacturing and Technology Conversion International
- TRI = ThermoChem Recovery International

Gasification technologies have relatively high capital costs, but the tradeoff is high efficiency.

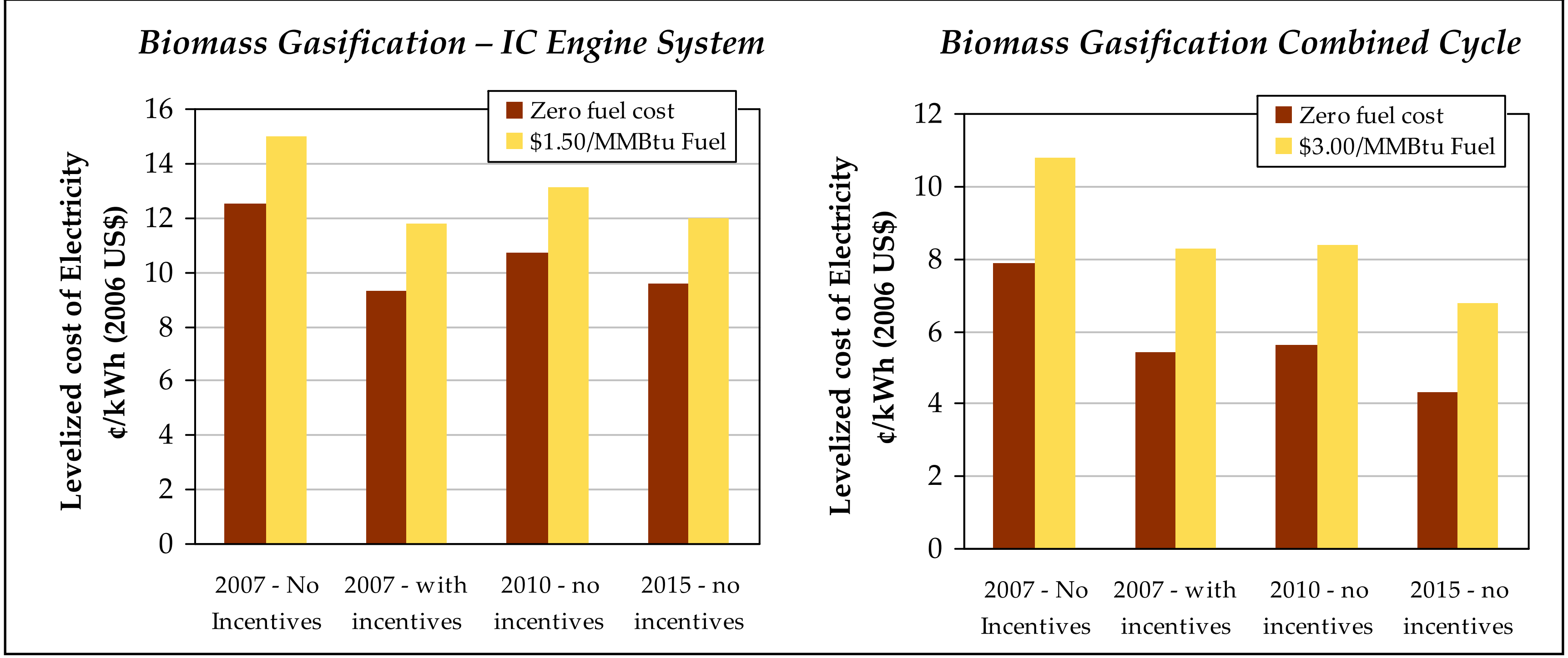
	Biomass Gasification Economic Assumptions for Given Year of Installation					
	Gasifier-IC Engine			BIGCC		
	2007	2010	2015	2007	2010	2015
Plant Capacity (MW)	1.5	1.5	1.5	15	30	40
Total Installed Cost ($/kW)[1]	$4,500	$4,000	$3,800	$3,000	$2,200	$1,700
Non-Fuel Fixed O&M ($/kW-yr)	$240	$230	$220	$130	$105	$90
Non-Fuel Variable O&M ($/MWh)[2]	$1.25			$1.25		
Capacity Factor (%)	75%	80%	85%	75%	80%	85%
Project Life (yrs)	25			25		
HHV Efficiency (%)[3]	21%	21%	21%	36%	37%	39%
Useful Heat Recovered (Btu thermal/kWh)[4]	6,418	6,418	6,418	N/A	N/A	N/A

1. Includes all development costs, such as permitting and interest during construction. All data are in 2007 US$.
2. Costs for consumables, chemicals, and ash disposal. Labor and maintenance are included in the fixed component of O&M.
3. HHV = Higher Heating Value.
4. Assumes 50% recovery of available waste heat from the entire system (syngas cooling, engine exhaust and engine cooling water)

Source: NCI estimates based on *Renewable Energy Technology Characterizations,* TR-109496, EPRI and US DOE, December 1997; *Biopower Technical Assessment,* NREL/TP-510-33132, National Renewable Energy Laboratory, January 2003;

If scale can justify the installation of a combined cycle, biomass gasification economics become promising over time.

Levelized Cost of Electricity for Biomass Gasification (2007$)



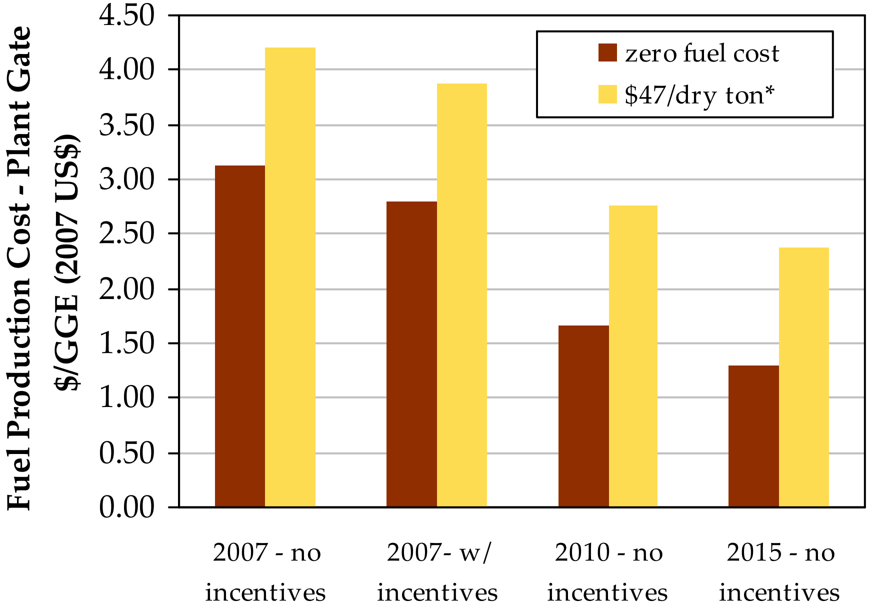
Key assumptions: Debt equity ratio: 55%:45%, cost of equity = 15%, cost of debt = 8%, Federal income tax rate = 35%; NJ state income tax rate = 9%; Property tax = 1.5%, Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 10 years. Project economic life = 25 years.

Incentives included for 2007 calculation: 0.9 ¢/kWh production tax credit for 10 years; 5-year accelerated depreciation.

The production costs of biomass-derived FT diesel are expected to decrease with scale and learning curves as the technology is established.

Production Cost for Fischer-Tropsch Diesel (2007$)

Assumptions	**2007**	**2010**	**2015**
Plant Capacity (Mgallons/yr)	10	25	25
Total Installed Cost ($/gal-yr)	18.4	12.9	11.2
Yield (gal/dry ton)	41.4	41.4	41.4
Materials / Chemicals ($/gallon)	Included in fixed costs		
Labor (M$/year)	Included in fixed costs		
Fixed costs (M$/year)	6.56	11.46	9.96
Export Electricity price (¢/kWh)	6		
Excess Electricity (kWh/gal)	17.93	21.52	21.52
Project Life (yrs)	25		
Capacity Factor (% capacity)	92%		



* Equal to $3/MMBtu for switchgrass, the feedstock assumed in the analysis.

- Key assumptions: Debt equity ratio: 40%:60%, cost of equity = 15%, cost of debt = 8%, Federal income tax rate = 35%; NJ state income tax rate = 9%; Property tax = 1.5%, Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 20 years. Loan period = 25 years. Project economic life = 25 years.
- Incentives included for 2007 calculation: 0.9 ¢/kWh production tax credit for 10 years on power sales; 20% Gasification Tax Credit. Non production-related subsidies (blender's tax credit, the Renewable Fuels Standards and other blending mandates) are not included as they impact the sales price rather than production costs. Other incentives may apply.

Source: NCI estimates based on *Gasification-Based Fuels and Electricity Production from Biomass, without and with Carbon Capture and Storage,* Eric D. Larson (Princeton University), Haiming Jin, Fuat E. Celik (Dartmouth College), October 2005.

Dilute acid hydrolysis is an advanced thermo-chemical technology suitable for fuels production from most lignocellulosic feedstocks.

Feedstock

Most lignocellulosic feedstocks can be processed: suitable biomass feedstocks include energy crops, ag. residues, woody biomass and a range of cellulosic biomass waste, such as paper sludge, food and food processing wastes, yard and wood wastes

The range of feedstocks suitable for dilute acid hydrolysis processing is greater than for cellulosic ethanol or gasification FT liquids:

- The process accepts feedstocks with high moisture contents as the water is never evaporated
- Feedstocks with very strong bonds between the various macromolecules, such as untreated hardwoods and wood wastes, can be processed; this is more problematic for cellulosic ethanol technologies, as the heavy pre-treatment required would destroy the sugar polymers

Conversion

The dilute acid hydrolysis process can be geared to the production of specialty chemicals or biofuels

- This is a benefit as demonstration plants can operate profitably producing marketable chemicals as the technology is proven and scaled-up to reach the economies of scale necessary for fuels
- The 2-step dilute acid hydrolysis breaks down cellulose and hemicellulose, decomposing them into intermediate chemicals for conversion into a range of marketable chemicals, such as furfural, formic acid and levulinic acid (identified by DOE as one of the top 12 biorefinery chemicals)
- These intermediate chemicals can be further processed to fuels; the most promising conversions are the hydrogenation or the esterification of levulinic acid to a range of fuels (ethers and esters)

End-Use

On the chemicals side, levulinic acid is used in food, fragrance and other specialty chemical applications. Furfural and formic acid are also specialty chemicals. The process will also produce sizeable quantities of sodium sulfate (a generic chemical)

The most promising fuels include:

- MeTHF (methyltetrahydrofuran), an ether produced by hydrogenation of levulinic acid, can be used as a gasoline additive. Patented mixtures of MeTHF, ethanol and natural gas liquids are also marketed as a gasoline replacement
- Methyl or Ethyl-levulinate, produced by esterification of levulinic acid, are biomass derived diesel fuel and heating oil replacements or additives

Dilute acid hydrolysis is being commercialized for chemicals production; at the appropriate scale, the technology can be deployed for biofuels production.

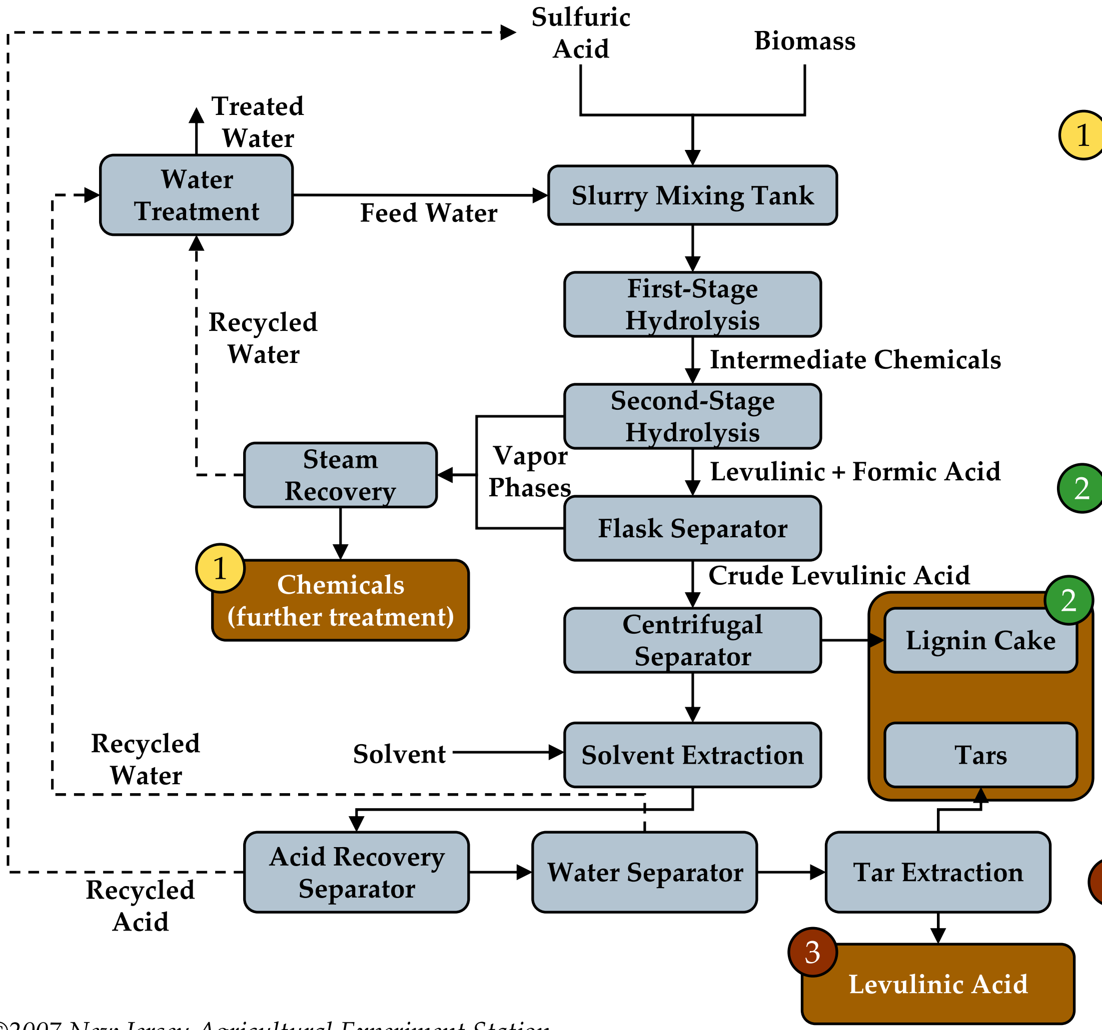
<u>Dilute Acid Hydrolysis to Biofuels</u>

- Two major routes for converting the intermediate chemicals (levulinic acid), to marketable fuels:
  - Esterification
  - Hydrogenation
  - Furfural (another intermediate chemical) can also be converted to an alcohol grade fuel
- Compared to the cellulosic ethanol technologies, dilute acid hydrolysis for fuels production will have:
  - Higher capital costs
  - Higher energy requirements
- The process has a good environmental footprint: it is relatively compact, has a good profile of both liquid and solid effluent, low noise and odor, no vent stack.
- Economies of scale allow for distributed operations based on feedstock availability
- The technology has not been commercially deployed

<u>Dilute Acid Hydrolysis to Chemicals</u>

- Dilute acid hydrolysis is a well known century-old process; it has been traditionally used to produce fermentable sugars for conversion to ethanol
  - The application typically has low yields due to the destructive effect of the acid on the sugar precursors
- This approach exploits the above-mentioned weakness by chemically transforming the degradation products into valuable chemicals:
  - Depending on the characteristics of the biomass and the demand for chemicals, the process can be geared to produce a number of specialty chemicals
- A number of small demonstration projects are operating in the US; in addition, a first commercial (300 tons/day) facility has recently started operation

The dilute acid hydrolysis to P-series process description.



Sulfuric Acid
Biomass
Treated Water
Water Treatment
Feed Water
Slurry Mixing Tank
First-Stage Hydrolysis
Recycled Water
Intermediate Chemicals
Second-Stage Hydrolysis
Vapor Phases
Steam Recovery
Levulinic + Formic Acid
Flask Separator
① **Chemicals (further treatment)**
Crude Levulinic Acid
Centrifugal Separator
② **Lignin Cake**
Tars
Recycled Water
Solvent
Solvent Extraction
Acid Recovery Separator
Water Separator
Tar Extraction
Recycled Acid
③ **Levulinic Acid**

① Two chemicals produced at this phase:
- Furfural (FF) can be sold directly as a chemical or converted to either Furfuryl Alcohol (for sale to the foundry binders market) or THFA (a solvent that is also a P-series fuel component)
- Formic Acid can be sold as a chemical or used to produce hydrogen

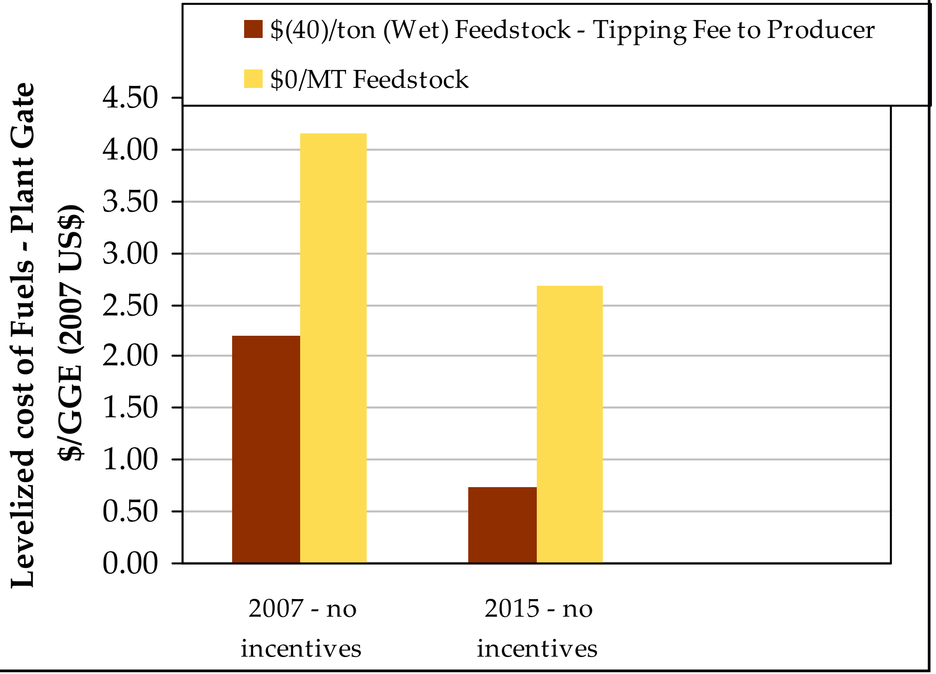
② Lignin / Tar slurry is a low sulfur substitute for #6 fuel oil:
- It can be used in a boiler to provide the heat requirements for the process
- It can be sold for its energy content
- In the case of fuels production, it can be used to produce hydrogen needed for the hydrogenation of levulinic acid
- The inorganic residue in the boiler or gasification chamber can be disposed of in a landfill or used for concrete aggregate (unless the feedstock contains hazardous inorganic contaminants)

③ Levulinic acid can be sold as a chemical or converted to fuels through
- Esterification to produce Methyl-levulinate (a substitute for #2 heating oil) or Ethyl-levulinate (a diesel fuel additive)
- Hydrogenation to produce methyltetrahydrofuran (MeTHF), an ether used as a gasoline additive or replacement

Tipping fee costs are the main driver of the economics of dilute acid hydrolysis for biofuels production.

Fuel Production Cost for Dilute Acid Hydrolysis (for Biofuels Production) (2007$)

Assumptions	2007	2015
Plant Capacity (Mgallons/yr)	10	50
Yield (gallons fuel / ton)	65	
Total Installed Cost ($/gal-yr)	7	3
Materials/Chemicals ($/gallon)	1.37	1.25
Labor (M$/year)	1.4	2.2
Fixed costs (M$/year)	1.6	2.5
Sodium Sulfate Price ($/lb)	0.08	
Char Price ($/MMbtu)	2	
Electricity (kWh/gal)	4.5	3.5
Heat (MMBtu/gal)	0.05	0.04
Project Life (yrs)	25	
Capacity Factor (% capacity)	92%	



- Key assumptions: Debt equity ratio: 40%:60%, Cost of equity = 15%, cost of debt = 8%, Federal income tax rate = 35%; NJ state income tax rate = 9%; Property tax = 1.5%, Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 25 years. Project economic life = 25 years.
- No incentives have been factored into the analysis. Non production-related subsidies (blender's tax credit, the Renewable Fuels Standards and other blending mandates) are not included as they impact the sales price rather than production costs. **The Alternative Fuel Credit of $0.50/gallon, for which P-series fuels are eligible, has not been considered in the analysis as it is likely to be claimed further down the value chain (at the point of blending or sales of the fuel), in a similar to how the Alcohol Fuel Mixture Credit and Biodiesel Mixture Credit are claimed. It is important to recognize that, nevertheless, the fuels produced with this technology will stand to benefit from this tax credit through increased market prices**

Among fermentation conversions, corn ethanol and the cellulosic ethanol (via enzymatic hydrolysis) technology were profiled.

Application	Core technology platforms and applications				
	Direct Combustion	Thermo-chemical Conversion	**Fermentation**	Anaerobic Digestion	Physio-chemical Conversion
Power/CHP	**1.** Stand-alone rankine (steam) cycle plant **2.** Small-scale rankine cycle CHP plant **3.** Biomass co-firing with coal	**4.** Stand-alone BIGCC plant **5.** Small-scale gasification-IC engine CHP plant **6.** Stand-alone pyrolysis plant		**11.** Food waste anaerobic digester with IC engine CHP plant/ Landfill gas with microturbine	
Heat Only	• Discussed qualitatively and shown in context of CHP applications above.				
Transportation Fuels		**7.** .Biomass-to-liquids plant (Fischer-Tropsch) **8.**.Dilute acid hydrolysis for biofuels production[1]	**9.** Corn-ethanol dry mill **10.** Cellulosic ethanol plant	**12.** CNG or LNG from landfill gas/AD gas	**13.** Transesterfication Biodiesel

1. Involves the production of ethers (gasoline blendstock) and esters (diesel blendstock).

Ethanol is a clean burning, high octane additive to (or replacement for) petroleum gasoline.

Feedstock

Corn ethanol is produced by fermenting the starch contained in corn

- Other established feedstocks for ethanol production are those containing sugars (sugar crops, sorghum, molasses) or where sugars can be easily extracted (barley, wheat, potatoes, rye)
- ~15% of the 2005 US corn harvest was used for ethanol production

Cellulosic ethanol is being developed with the goal of increasing feedstock options

- Agricultural residues (corn stover, wheat straw), energy crops (switchgrass, miscanthus, woody crops such as poplar), forestry residues, municipal wastes (organic fraction), industry wastes

Conversion

Corn ethanol production is a mature technology

- In a dry mill, the starch fraction is extracted from the grain, grinded, liquefied and hydrolyzed to liberate the sugars for fermentation. The alcohol is then distilled and denatured. Distiller's Dried Grain (DDG), an animal feed ingredient, is the by-product
- Wet mills are more capital intensive and designed to optimize the value of co-products
- Technology improvements will continue to yield better efficiencies and lower costs

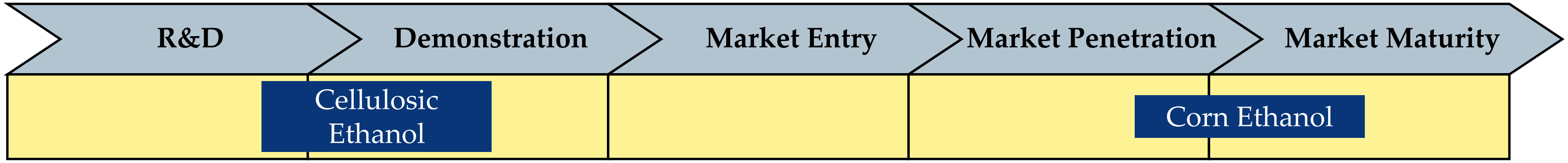
Cellulosic ethanol production technologies are being developed

- Technical and economic hurdles still need to be overcome before the technology can be deployed
- Enzymatic hydrolysis has received attention as the most promising enabling technology

End-Use

- Ethanol in the US is mostly used as an additive to gasoline (up to 10%) for environmental and regulatory compliance, as an octane enhancer or to reduce fuel costs
- The use of ethanol as a replacement for gasoline (E85) requires modest engine modifications and reduces vehicle range (but not efficiency) due to the 30% lower energy content of ethanol
- The US and Brazil are the main consumers (and producers) of ethanol; in Brazil, 25% of all motor fuel is ethanol and 80% of new car sales are Flexible Fuel Vehicles (FFV)

While corn ethanol is an established technology, cellulosic ethanol technologies still need to be fully validated.



<u>Cellulosic ethanol</u>

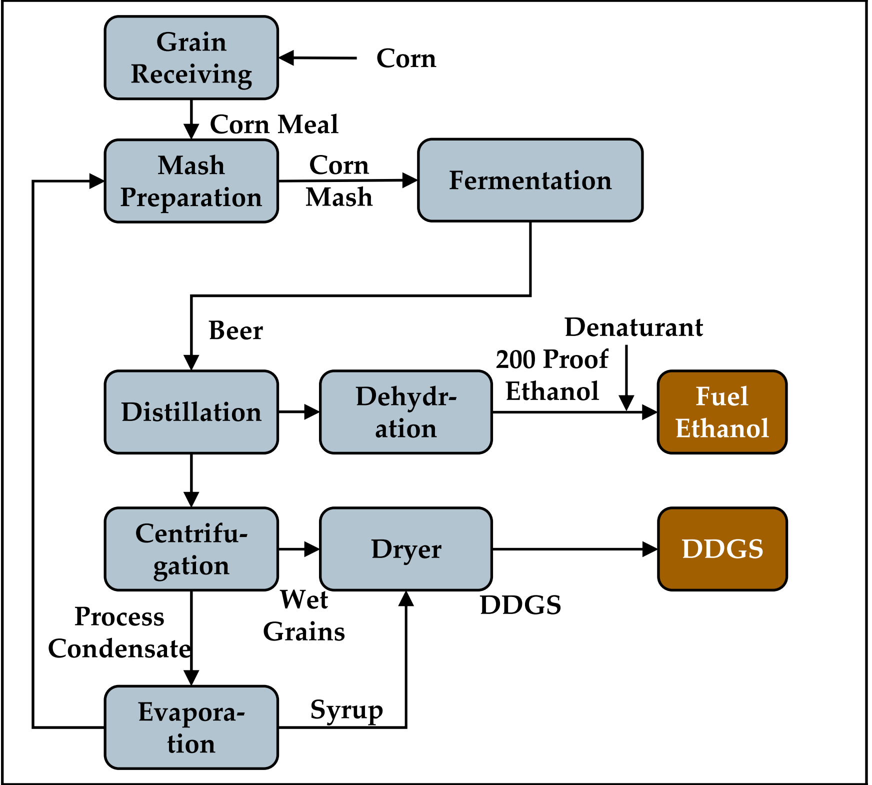
- The conversion technologies still need to be fully developed and validated. Areas of research include:
  - Processes that will break-up the complex biomass matrix to free the sugar precursors for hydrolysis and fermentation to ethanol: **enzymatic hydrolysis** is the most promising area of research; significant reductions in the cost of enzymes have already been achieved
  - Micro-organisms that will efficiently ferment sugars from both cellulose and hemicellulose.
  - Significant private and public money is funding these research activities
- Other areas of technology research include the genetic engineering of ideal energy crops (for example by reducing the lignin content, increasing land yields)
- A number of companies are looking to construct the first commercial cellulosic ethanol operation; it is generally believed that, unless market conditions deteriorate, this will happen in 2008-2010

<u>Corn Ethanol</u>

- Established and commercially deployed technology
  - >100 plants in operation in the US (4.5 bgpy capacity) + 3 bgpy capacity under development
  - Larger plants (80-100 mgpy) are being built to exploit economies of scale
  - Smaller operations are at a significant disadvantage
  - Major capacity build-up occurred in the past 2 years with high oil prices and favorable policies and incentives
- Continuous technology improvements, such as genetically enhanced seeds, fractionation and corn oil extraction will further reduce costs of corn ethanol
- While technology risk is low, a corn ethanol operation presents significant commodity price risk
- Given the expected size of crops and the use of corn as foodstuff, the consensus is that the upper limit for corn ethanol production in the US is 15 bgpy (10% of 2005 gasoline demand)

The corn and cellulosic ethanol process descriptions.

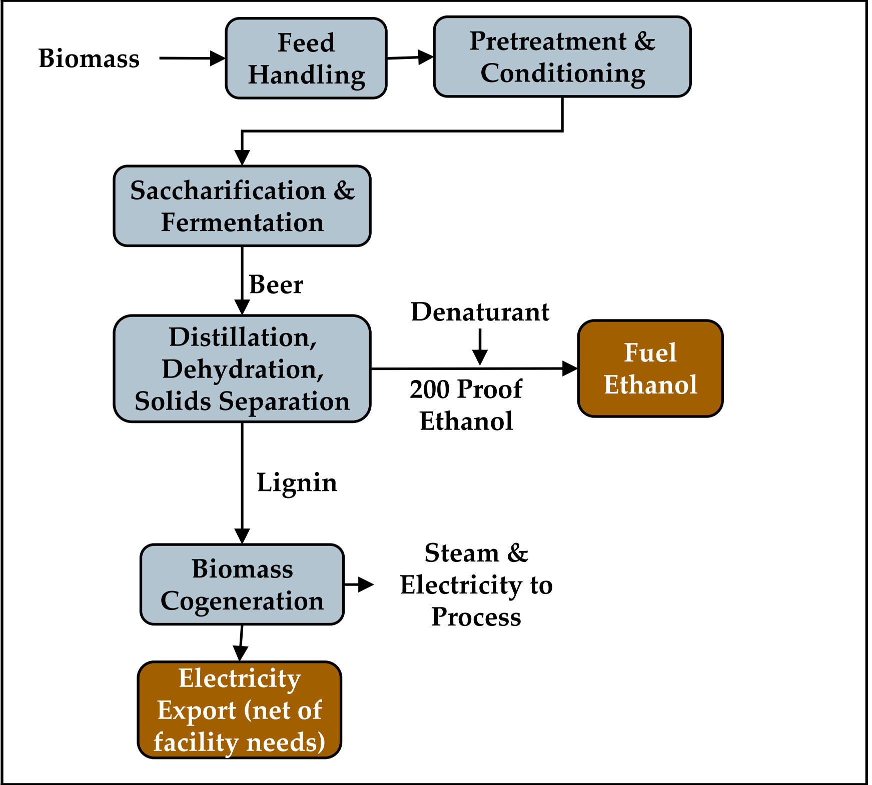
60 Mgpy Corn Ethanol (Dry Mill)



Grain Receiving
Corn
Corn Meal
Mash Preparation
Corn Mash
Fermentation
Beer
Distillation
Dehydration
200 Proof Ethanol
Denaturant
Fuel Ethanol
Centrifugation
Wet Grains
Dryer
DDGS
DDGS
Process Condensate
Evaporation
Syrup

Feedstock flow (Bushels/day)	65,000
Co-product flow – DDGs (tons/day)	500
Electricity Requirements (kWh/gal)	0.75
Heat Requirements (MMBtu/gal)	0.035

10 Mgpy Cellulosic Ethanol (SSF*[1])



Biomass
Feed Handling
Pretreatment & Conditioning
Saccharification & Fermentation
Beer
Distillation, Dehydration, Solids Separation
200 Proof Ethanol
Denaturant
Fuel Ethanol
Lignin
Biomass Cogeneration
Steam & Electricity to Process
Electricity Export (net of facility needs)

Feedstock flow (dry tons/day)	470
Co-product flow (MWh/day)	62
Electricity Requirements (kWh/gal)	N/A
Heat Requirements (MMBtu/gal)	N/A

[1] Simultaneous Saccharification and fermentation

Feedstock sourcing costs are critical to the economics of both corn and cellulosic ethanol supply chains.

Supply Chain

- Corn ethanol plant locations are generally served with the corn harvested in a 50-100 mile radius
  - Transportation of corn for long distances is less cost effective than shipping ethanol
  - Locating a plant far away from a corn supply requires special circumstances, such as highly concentrated demand or a good outlet for the DDG co-product
- Future cellulosic ethanol plant will also be located to minimize biomass sourcing costs
- The fuel is distributed to the market in blends with regular gasoline; blending occurs downstream at the wholesale terminal:
  - Ethanol is shipped to local petroleum terminals by barge and truck; use of barges is increasing
  - Due to ethanol's low water tolerance and corrosive nature, transportation by pipeline (which would be the most cost-effective mode) is not practiced
- Ethanol benefits from a range of subsidies throughout the supply chain: most significant is the federal tax credit and blending requirements (state or federal)

Markets

- Ethanol is used in low blends (<10%) with gasoline:
  - For environmental compliance to meet oxygen content requirements in ozone non-attainment areas (such as most of NJ). The rapid phase-out of MTBE[1] has given ethanol an almost-monopoly of the market
  - To meet blending requirements such as the Renewable Fuels Standard or State mandates
  - In "discretionary blends", when the wholesale price of ethanol, net of subsidies and corrected for energy content, is lower than that of gasoline (with the added benefit of enhancing the octane rating)
- Ethanol is used as a fuel in concentrated (85% = E85) blends with gasoline:
  - Distribution is limited to areas of the Midwest
  - E85 requires special infrastructure, such as specifically designed retail pumps and slightly modified engines (FFV)

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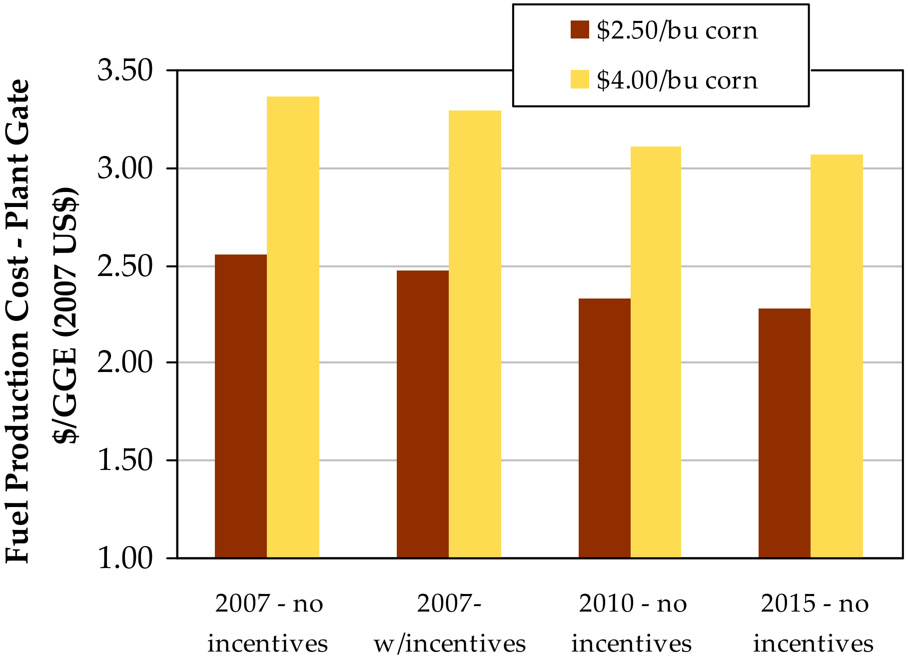
[1] methyl tertiary-butyl ether

Ethanol production costs, on an energy basis, are negatively impacted by the low energy density of the fuel; however, incremental improvements in the economics of corn ethanol are expected over time.

Fuel Production Cost for Corn Ethanol (2007$)

Assumptions	2007	2010	2015
Plant Capacity (Mgallons/yr)	50		
Total Installed Cost ($/gal-yr)	1.35	1.15	1.00
Yield (gal / bu)	2.7	2.8	
Materials / Chemicals ($/gallon)	0.16	0.14	
Labor (M$/year)	1.5		
Fixed costs (M$/year)	1.3		
DDGs ($/MT)	80		
Electricity (kWh/gal)	0.8		
Heat (MMBtu/gal)	0.035	0.028	
Project Life (yrs)	25		
Capacity Factor (% capacity)	92%		

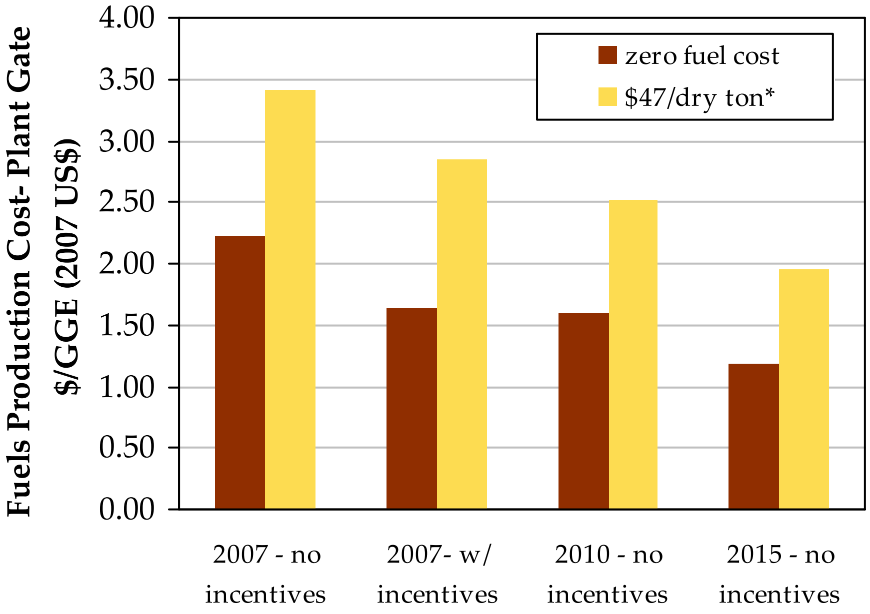


- Key assumptions: Debt equity ratio: 40%:60%, cost of equity = 15%, cost of debt = 8%, Federal income tax rate = 35%; NJ state income tax rate = 9%; Property tax = 1.5%, Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 25 years. Project economic life = 25 years.
- Incentives included for 2007 calculation: 10 ¢/gallon small producer tax credit (for 15 MGPY). Non production-related subsidies (blender's tax credit, the Renewable Fuels Standards and other blending mandates) are not included as they impact the sales price rather than production costs.

If the projected cost reductions in cellulosic ethanol materialize, this technology promises to be competitive with gasoline.

Fuel Production Cost for Cellulosic Ethanol (2007$)

Assumptions	2007	2010	2015
Plant Capacity (Mgallons/yr)	10	25	50
Total Installed Cost ($/gal-yr)	6.18	4.32	3.05
Yield (gal/dry ton)	58	75	90
Materials / Chemicals ($/gallon)	0.32	0.26	0.23
Labor (M$/year)	Included in fixed costs		
Fixed costs (M$/year)	1.04	2.60	5.19
Export Electricity price (¢/kWh)	6		
Excess Electricity (kWh/gal)	2.28		
Project Life (yrs)	25		
Capacity Factor (% capacity)	92%		



* Equal to $3/MMBtu for corn stover, the feedstock assumed in the analysis.

- Key assumptions: Debt equity ratio: 40%:60%, cost of equity = 15%, cost of debt = 8%, Federal income tax rate = 35%; NJ state income tax rate = 9%; Property tax = 1.5%, Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 20 years. Loan period = 25 years. Project economic life = 25 years.
- Incentives included for 2007 calculation: 10 ¢/gallon small producer tax credit (up to 15 MGPY), 0.9 ¢/kWh production tax credit for 10 years on power sales; 50% bonus depreciation in first year. Non production-related subsidies (blender's tax credit, the Renewable Fuels Standards and other blending mandates) are not included as they impact the sales price rather than production costs.

Source: NCI estimates based on *Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover*, National Renewable Energy Laboratory, NREL/TP-510-32438, June 2002.

Among anaerobic digestion technologies, conversion of biogas and LFG to power and fuels were profiled.

Application	Core technology platforms and applications				
	Direct Combustion	Thermo-chemical Conversion	Fermentation	Anaerobic Digestion	Physio-chemical Conversion
Power/CHP	1.Stand-alone rankine (steam) cycle plant 2.Small-scale rankine cycle CHP plant 3.Biomass co-firing with coal	4. Stand-alone BIGCC plant 5. Small-scale gasification-IC engine CHP plant 6. Stand-alone pyrolysis plant		**11.**Food waste anaerobic digester with IC engine CHP plant/ Landfill gas with microturbine	
Heat Only	• Discussed qualitatively and shown in context of CHP applications above.				
Transportation Fuels		7. .Biomass-to-liquids plant (Fischer-Tropsch) 8..Dilute acid hydrolysis for biofuels production[1]	9. Corn-ethanol dry mill 10.Cellulosic ethanol plant	**12.** CNG or LNG from landfill gas/AD gas	13.Transester-fication Biodiesel

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1. Involves the production of ethers (gasoline blendstock) and esters (diesel blendstock).

Biogas (AD gas / LFG) is the product of the microbial gasification (i.e. anaerobic digestion) of highly biodegradable organic feedstocks.

Feedstock

- Biomass naturally high in moisture content is considered ideal for AD because the micro-organisms need a water-rich environment (and because it is less suited to other technologies, such as combustion)
- Landfills naturally produce biogas (LFG)
- Traditional AD feedstock include farm waste (manure), waste water treatment sewage sludge, food processing wastes
- Increasingly, feedstocks such as animal feed crops, food waste and the organic residual of MSW[1] are being used in ADs
- The general order of decreasing biodegradability of biomass components is: glucose, hemi-cellulose, cellulose, proteins and lignin

Conversion

AD of biomass is a well understood and commercially developed technology:

- Farm based digesters for animal manure are the most typical installation: in addition to energy production, they address broader environmental and agricultural issues
- In Europe, regional digesters processing manures, crops and urban (organic) waste are common

Technology advancements, including biomass pre-treatment, two-stage AD and innovative flow designs, are being developed to improve economics and process more cumbersome and drier waste streams

End-Use

The AD gas / LFG is typically used to generate power (and heat / steam in CHP[2] applications):

- Biogas is a medium-energy gas (40-70% methane)
- The IC engine is the most common prime mover for small scale power generation(< 5MW)
- Microturbines are a more expensive and less proven technology, but have an improved environmental footprint
- Steam turbines are used for larger applications (> 10MW), such as wastewater treatment plants

More recent technology development include the clean-up of biogas to Natural Gas and the further processing of this to chemicals or transportation fuels (CNG / LNG)

1: Municipal Solid Waste

2: Combined Heat and Power

Biogas production and combustion for heat, steam and electric power are established technologies; production of fuels is also possible.

R&D | Demonstration | Market Entry | Market Penetration | Market Maturity

Biogas to Fuels

Biogas Micro-turbines

AD /LFG to Power (IC)

<u>Biogas to Transportation Fuels</u>

- The biogas will need to be cleaned up (reduce H_2O and H_2S) prior to undergoing a 2-stage CO_2 removal
- A pure methane stream will be produced (in addition to a food grade CO_2 stream)
- The methane can then be compressed to CNG[1] or liquefied to LNG[2] (to take advantage of the higher energy density) and used as a transportation fuel
- Alternatively the methane could also be injected into a natural gas pipeline
- The technology is established, but has seen limited deployment due to mostly unfavorable economics
- However, specific circumstances (such as captive fleets with fueling infrastructure in proximity to landfills or large digesters) may have more favorable economics

<u>Biogas Micro-turbines</u> (for power)

- Significantly more extensive biogas clean-up is needed than for use in an IC engine
- The technology is generally more costly than IC engines but has lower emissions, which helps to obtain the required permitting.

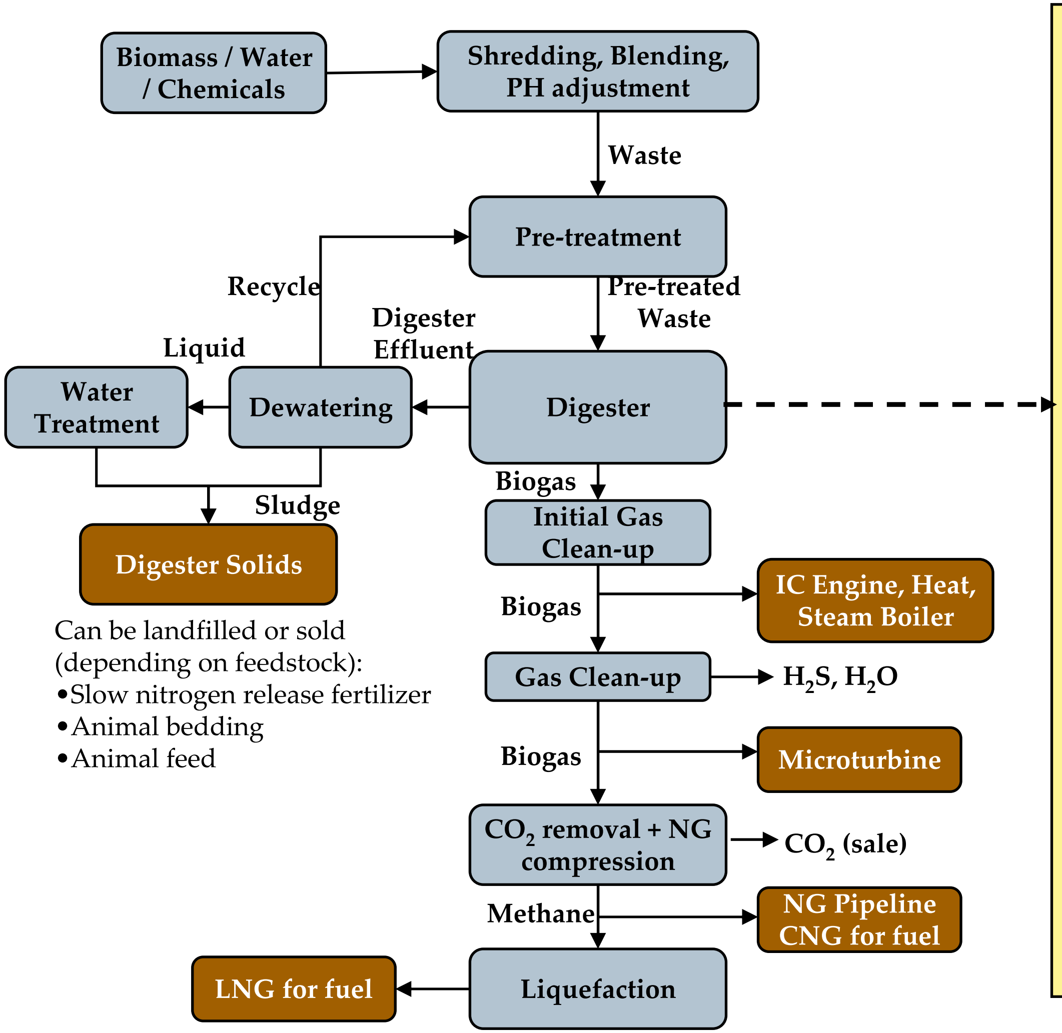
<u>AD / LFG to Power</u>

- Established technology with limited market penetration
  - Small operations (farm wastes & crops, most LFG, food wastes) generally use IC eng. as prime movers
  - Operations such as regional digesters and waste water treatment plants may be large enough for a steam cycle. Gas turbines are less common
- **Conventional digesters** can be classified in 3 categories: **Covered lagoon** (cheapest, suitable for warm climates, <3% solids, farm operations); **Plug-Flow** (rectangular flow-through tank, 11-13% solids); **Complete Mix** (large tanks, >10% solids, most expensive)
- More **advanced digestion technologies** include:
  - Multi-stage digesters allow to create optimal conditions for different groups of microorganisms by separating the process in different tanks.
  - New "flow" designs and the use of "thermophilic" (high temperature) microorganisms improve yields and enable processing of higher moisture feedstock
  - Feedstock pretreatment to break down lignin is also being pursued in order to increase yields

[1] Compressed Natural Gas

[2] Liquefied Natural Gas

Anaerobic Digestion process description.



Biomass / Water / Chemicals

Shredding, Blending, PH adjustment

Waste

Pre-treatment

Pre-treated Waste

Digester

Digester Effluent

Dewatering

Recycle

Liquid

Water Treatment

Sludge

Digester Solids

Can be landfilled or sold (depending on feedstock):
- Slow nitrogen release fertilizer
- Animal bedding
- Animal feed

Biogas

Initial Gas Clean-up

Biogas

IC Engine, Heat, Steam Boiler

Gas Clean-up

H_2S, H_2O

Biogas

Microturbine

CO_2 removal + NG compression

CO_2 (sale)

Methane

NG Pipeline CNG for fuel

Liquefaction

LNG for fuel

Anaerobic Digestion Process

Four main microbial steps of the AD process:
- **Hydrolytic bacteria** break down organic materials into sugars and amino-acids
- **Fermentative bacteria** convert these into organic acids
- **Acidogenic bacteria** convert acids into CO, H2 and acetate
- **Methanogenic archea** convert these into methane

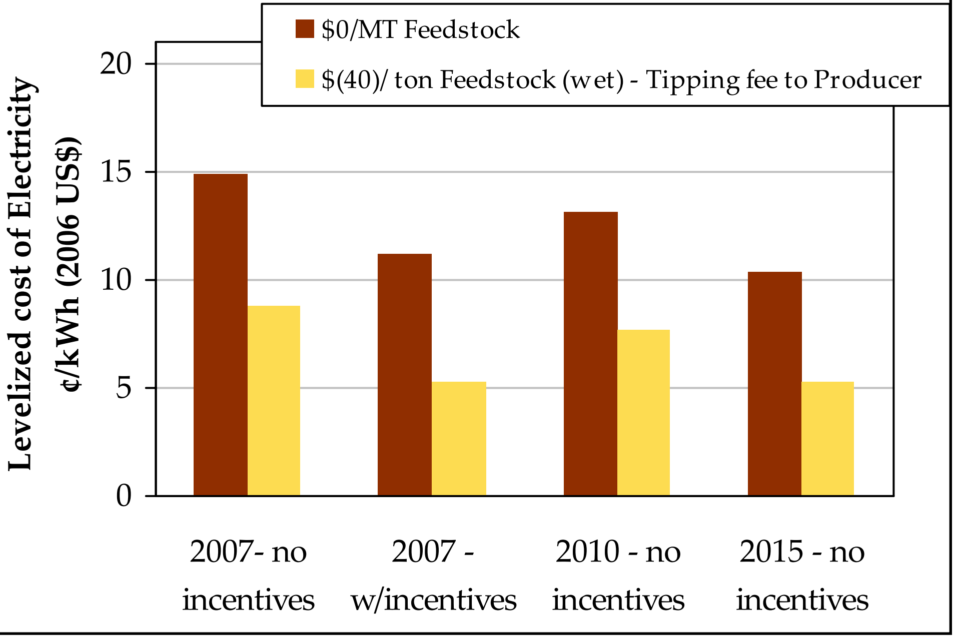
In the **two phase digesters**, the acidogenic and methanogenic micro-organisms operate in separate tanks in optimum environments. The first tank can be also pressurized to achieve fast hydrolysis. The benefits are:
- Lower capital costs due to smaller tanks
- Ability to process higher solid content material
- 30% higher biomass conversion rates
- Higher methane content and cleaner biogas
- Reduced pathogen content in the digestate solids

Other interesting **process improvements** include:
- Innovative flow designs that enable higher hydraulic and solid retention times (HRT, SRT) such as the Valorga process
- Biomass pre-treatment done to break down the lignin, increasing biodegradability and yield
- The use of microorganisms that work at higher (thermophilic) temperatures allows for lower retention times. Process parameters are sensitive and more diligent operations are required.

Tipping fees are critical to make anaerobic co-digestion of different waste streams economically viable.

Levelized Cost of Electricity for AD of mixed feedstocks[1] via IC engine (2007$)

Assumptions	**2007**	**2010**	**2015**
Plant Capacity (kW)	500	1,000	5,000
Total Installed Cost ($/kW)[2]	5,500	5,000	4,000
Non-Fuel Fixed O&M ($/kW-yr)[3]	400	350	300
Non-Fuel Variable O&M ($/MWh)	Included in fixed O&M		
Capacity Factor (%)	75%		
Project Life (yrs)	25		
HHV Efficiency (%)[4]	17%	19%	20%
Economics benefits from by-products (heat, digester solids ($/kW-yr)[5]	125		



1. Focus is on food waste and the organic fraction of MSW as an abundant source of feedstock in New Jersey
2. Includes all development costs, such as permitting and interest during construction. All data are in 2007 US$.
3. Costs for consumables, chemicals, and ash disposal. Labor and maintenance are included in the fixed component of O&M.
4. HHV = Higher Heating Value.

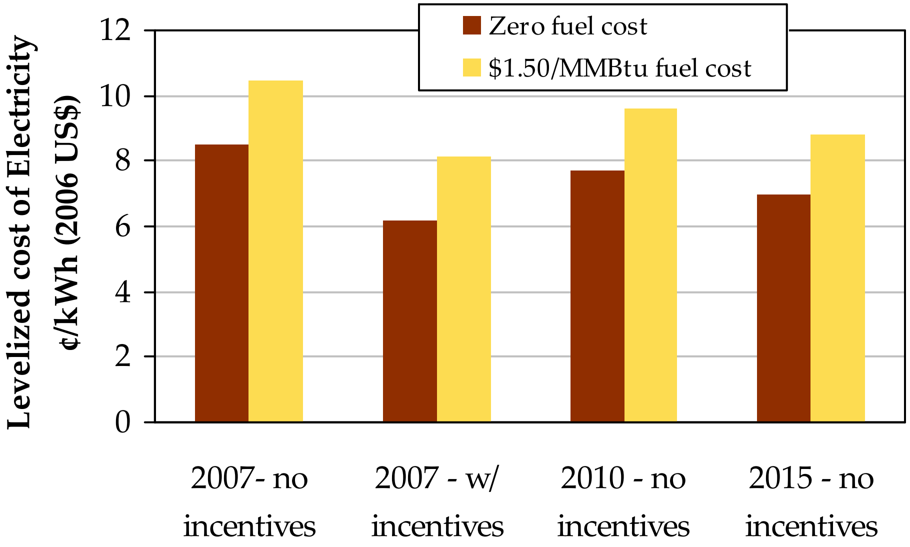
Key assumptions: Debt equity ratio: 55%:45%, cost of equity = 15%, cost of debt = 8%, Federal income tax rate = 35%; NJ state income tax rate = 9%; Property tax = 1.5%, Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 10 years. Project economic life = 25 years.

Incentives included for 2007 calculation: 0.9 ¢/kWh production tax credit for 10 years; 5-year accelerated depreciation, but not REC sales

Even though microturbines are still more expensive than IC engines, LFG to electricity remains a competitive renewable energy option.

Levelized Cost of Electricity for Landfill Gas to Electricity with a microturbine (2007$)

Assumptions	2007	2010	2015
Plant Capacity (kW)	250		
Total Installed Cost ($/kW)[1]	3,000	2,750	2,500
Non-Fuel Fixed O&M ($/kW-yr)[2]	250	225	200
Non-Fuel Variable O&M ($/MWh)	Included in fixed O&M		
Capacity Factor (%)	85%		
Project Life (yrs)	25		
HHV Efficiency (%)[3]	26%	27%	28%



1. Includes all development costs, such as permitting and interest during construction. All data are in 2007 US$.
2. Costs for consumables, chemicals, and ash disposal. Labor and maintenance are included in the fixed component of O&M.
3. HHV = Higher Heating Value.

Key assumptions: Debt equity ratio: 55%:45%, cost of equity = 15%, cost of debt = 8%, Federal income tax rate = 35%; NJ state income tax rate = 9%; Property tax = 1.5%, Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 10 years. Project economic life = 25 years.

Incentives included for 2007 calculation: 0.9 ¢/kWh production tax credit for 10 years; 5-year accelerated depreciation, but not REC sales

Among physio-chemical conversions, soy biodiesel technology was profiled.

Application	Core technology platforms and applications				
	Direct Combustion	Thermo-chemical Conversion	Fermentation	Anaerobic Digestion	**Physio-chemical Conversion**
Power/CHP	1.Stand-alone rankine (steam) cycle plant 2.Small-scale rankine cycle CHP plant 3.Biomass co-firing with coal	4. Stand-alone BIGCC plant 5. Small-scale gasification-IC engine CHP plant 6. Stand-alone pyrolysis plant		11.Food waste anaerobic digester with IC engine CHP plant/ Landfill gas with microturbine	
Heat Only	• Discussed qualitatively and shown in context of CHP applications above.				
Transportation Fuels		7. .Biomass-to-liquids plant (Fischer-Tropsch) 8..Dilute acid hydrolysis for biofuels production[1]	9. Corn-ethanol dry mill 10.Cellulosic ethanol plant	12. CNG or LNG from landfill gas/AD gas	13.Transester-fication Biodiesel

1. Involves the production of ethers (gasoline blendstock) and esters (diesel blendstock).

Biodiesel is a low-sulfur, high-cetane substitute to petroleum distillate fuels derived from organic oils and fats.

Feedstock

Biodiesel can be obtained from any lipid-bearing feedstock

- Most (95%) of the 1 bgpy[1] of biodiesel consumed world-wide is derived from the virgin vegetable oils of food crops (canola, soy, sunflower, palm). This feedstock source has limited scalability potential due to low land yields and competition from food uses
- Niche opportunities exist for the conversion of recycled vegetable oils and animal fats to biodiesel
- Significant efforts are in place to develop alternative biodiesel crops, with higher land yields, no food use and lower costs (jatropha, algae)

Conversion

Biodiesel production from soy and other food crops is a mature technology:

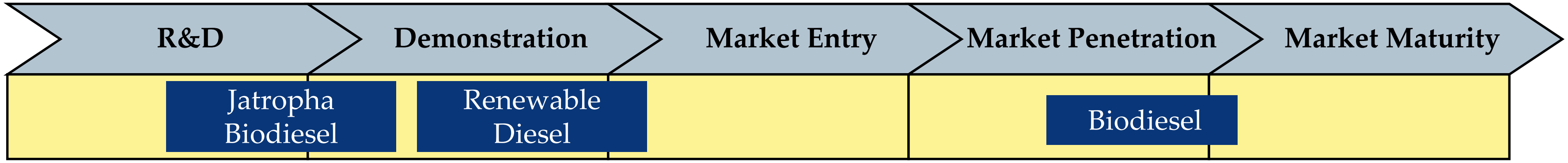
- The methyl-esters of fatty acids (biodiesel) are the product of the trans-esterification reaction between glycerides (oils and fats) and an alcohol (generally methanol) in the presence of a base catalyst
- Glycerin is the by-product of biodiesel production and, traditionally, an important source of revenue: over-supplied markets for glycerin are a major concern for the industry
- Technology improvements and breakthroughs include new low-cost biodiesel crops and innovative conversion technologies

End-Use

- Biodiesel is mainly used as an additive to, or extender of, petroleum based distillate fuels, such as diesel and heating oil. Differences in product characteristics occur as a consequence of the use of different feedstocks: cold flow properties and storage stability will vary significantly
- In 2005, 75 Mgpy were used in the US, whereas the total US demand for distillates is 60 Bgpy. A part of the consumption is driven by regulatory compliance; subsidies also help offset the cost differential with petroleum diesel
- In Germany, the major biodiesel market globally, B100 (100% canola based biodiesel) is sold retail

[1] Billion Gallons Per Year

Biodiesel is a developed technology; the use of other feedstocks as well as innovative approaches are being demonstrated.



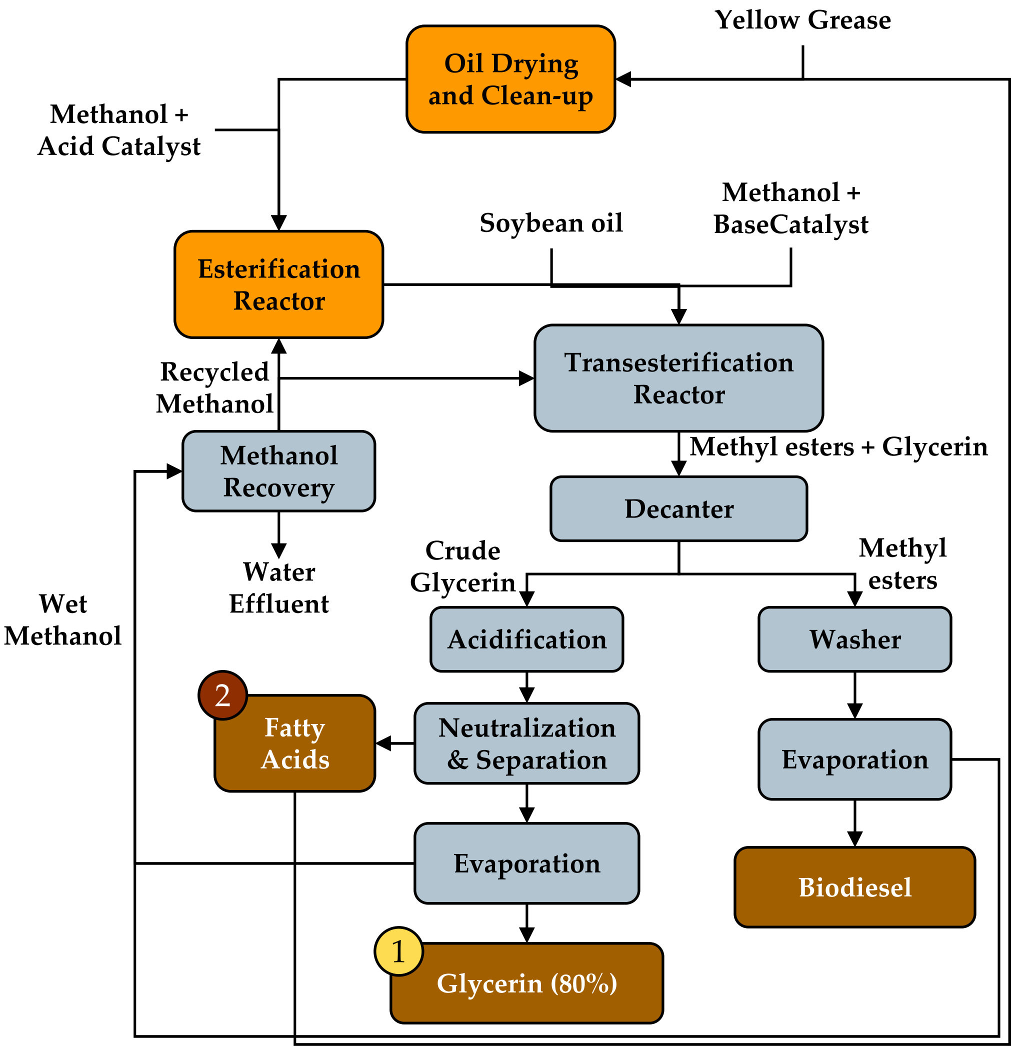
Emerging Technologies

- Biodiesel from non-food crops
  - Lower costs: grown on marginal lands and no competition from food and feed markets
  - Jatropha plant is receiving the most attention; marine-based feedstock (algae) is a promising but longer-term opportunity
  - No major technology breakthrough is needed, but the entire supply chain needs to be built
- Catalytic hydroprocessing of vegetable oil (Renewable Diesel)
  - Produces straight chain paraffinic hydrocarbons (identical to the high cetane components of diesel) with very low sulfur content
  - Technology is proven; first scale-up is under construction in Finland
  - Likely to be adopted by the petroleum industry as it is a "refinery friendly" renewable option

Biodiesel

- Biodiesel is a mature technology with limited market penetration:
  - 60 Plants in operation in the US (300 mgpy capacity) with additional 36 in development using mostly soybean oil as feedstock
  - Larger plants (50-100 mgpy) are being built to exploit economies of scale
  - Smaller operations based on niche and regional feedstocks, such as YG or captive animal fats
- While technology risk is low, a biodiesel operation presents significant commodity risk
- Total US Soybean harvest could yield a maximum of ~5 Bgpy of soy biodiesel
  - This represents <10% of the 60 Bgpy distillate fuel market in the US (2005)
  - In addition, soy oil, while being mostly phased out of the food industry has other established markets (animal feed, soaps, etc..)
  - This points to the limited scalability of soy biodiesel

The Biodiesel process description.



Yellow Grease
Oil Drying and Clean-up
Methanol + Acid Catalyst
Esterification Reactor
Soybean oil
Methanol + BaseCatalyst
Transesterification Reactor
Recycled Methanol
Methanol Recovery
Methyl esters + Glycerin
Decanter
Water Effluent
Wet Methanol
Crude Glycerin
Methyl esters
Acidification
Washer
2 Fatty Acids
Neutralization & Separation
Evaporation
Evaporation
Biodiesel
1 Glycerin (80%)

🟧 Process step typical of a YG-based operation

① Markets for glycerin:
- Refined to 99.7% glycerin and sold as a specialty chemical in the food and cosmetics industry
- Boiler fuel (low btu content)
- Filler in animal feed (no protein value)

Increased biodiesel production has created oversupply of glycerin. New applications include:
- To produce Propylene Glycol (a building block chemical)

② Fatty Acids are either:
- Recycled in the plants in an esterification pre-treatment unit and converted to biodiesel
- Sold into the oleochemical industry

50 MGPY Soy Biodiesel	
Feedstock flow (gal/day)	140,000
Co-product flow – Glycerin (lbs/day as is)	100,000
Electricity Requirements (kWh/gal)	0.26
Heat Requirements (MMBtu/gal)	0.004

The biodiesel supply chain crosses the agriculture and petroleum sourcing and distribution infrastructures.

Supply Chain

- Soy oil is produced at bean crushing facilities
  - These are concentrated in dense soybean growing regions such as the Midwest and owned by a handful of agribusinesses (ADM, Cargill, Bunge, co-ops)
  - Soy oil is shipped for conversion to a biodiesel plant or converted onsite if the biodiesel and bean crushing plant are co-located
- The fuel is distributed to the market through the petroleum distribution infrastructure:
  - In Europe, blending with petroleum products occurs mostly upstream (at the refinery)
  - In the US, it typically occurs at the downstream (wholesale) terminal through splash blending (due to the limited quantity of biodiesel sold and to concerns of pipeline operations)
- Biodiesel benefits from a range of subsidies throughout the supply chain: most significant is the federal tax credit and blending requirements (state or federal)

Markets

- Biodiesel is mostly used as a transportation fuel:
  - In blends of 5-20% (B5 – B20) with petroleum diesel
  - Higher blends are less common (though feasible) due to poor cold flow properties and engine warranty issues
  - Has received interest as a low blend additive to enhance the lubricity and increase cetane of ULSD[1] and to improve the performance of DPF[2]
- In some markets (including NJ) biodiesel is being marketed for heating oil or power generation:
  - In blends with #2 and #6 fuel oil
  - Lower value reference product (#2 and #6 fuel oil and of lower quality, and price, than on-road diesel)
  - Targeted subsidies may distort these basic economics (REC's[3] for use of biodiesel in power generation or sales tax exemptions for "Bioheat" can be additive to general incentives such as the federal tax credit and blending requirements)

1: Ultra Low Sulfur Diesel
2: Diesel Particulate Filter
3: Renewable Energy Credits

Although the technology is relatively mature, increases in the scale of biodiesel operations over the next 10 years are forecasted.

Biodiesel Technology Cost and Performance Assumptions

Soy Biodiesel Plant

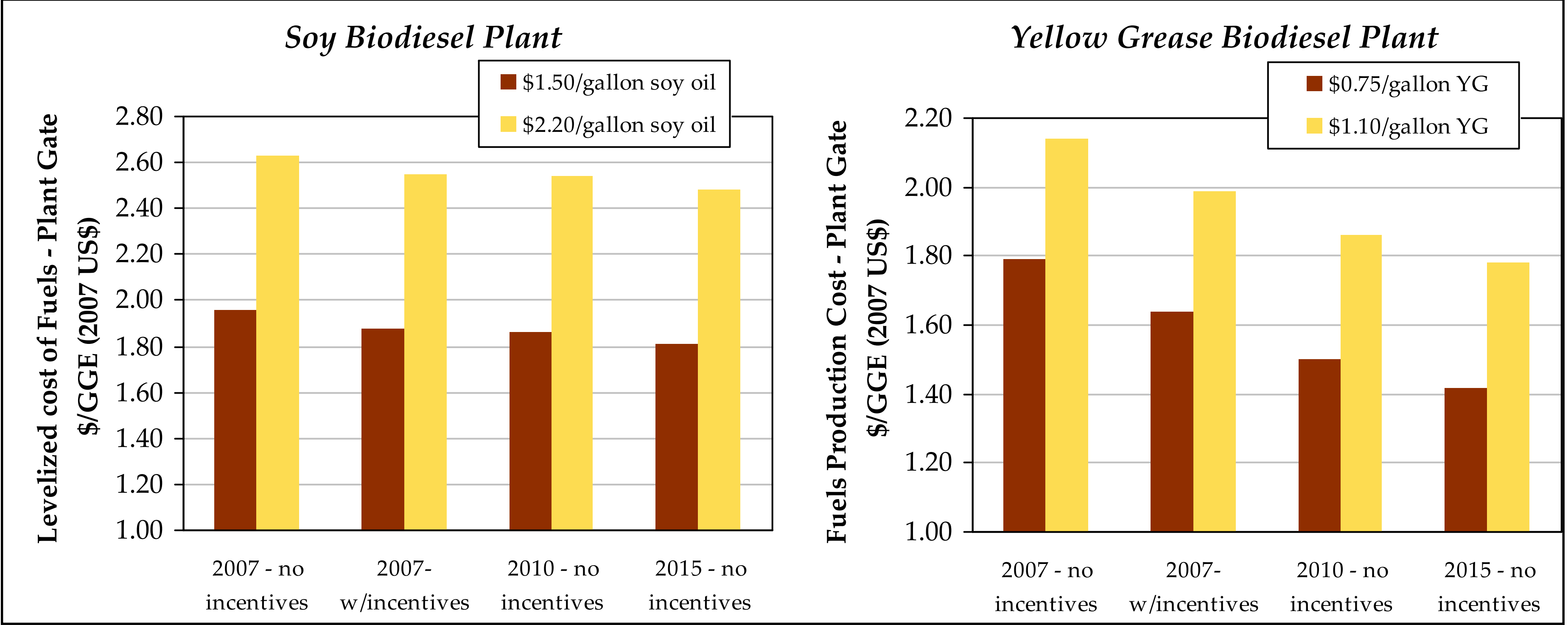
Assumptions	2007	2010	2015
Plant Capacity (Mgallons/yr)	30	50	80
Total Installed Cost ($/gal-yr)	1.25	1	0.9
Yields (gal / gallon feedstock)	1		
Materials / Chemicals ($/gallon)	0.18	0.15	0.13
Labor (M$/year)	1.5	2	2.2
Fixed costs (M$/year)	1	1.25	1.5
Glycerin price ($/lb)	0.07		
Electricity (kWh/gal)	0.26		
Heat (MMBtu/gal)	0.004		
Project Life (yrs)	25		
Capacity Factor (% capacity)	92%		

Yellow Grease Biodiesel Plant

Assumptions	2007	2010	2015
Plant Capacity (Mgallons/yr)	3	10	
Total Installed Cost ($/gal-yr)	2.5	2	1.5
Yields (gal / gallon feedstock)	0.96		
Materials / Chemicals ($/gallon)	0.22	0.20	0.17
Labor (M$/year)	0.5	0.7	
Fixed costs (M$/year)	0.3	0.4	
Glycerin price ($/lb)	0.04		
Electricity (kWh/gal)	0.40		
Heat (MMBtu/gal)	0.006		
Project Life (yrs)	25		
Capacity Factor (% capacity)	92%		

Feedstock costs dominate the economics of biodiesel; the potential impact of technology advancements and scale are noticeable for yellow grease.

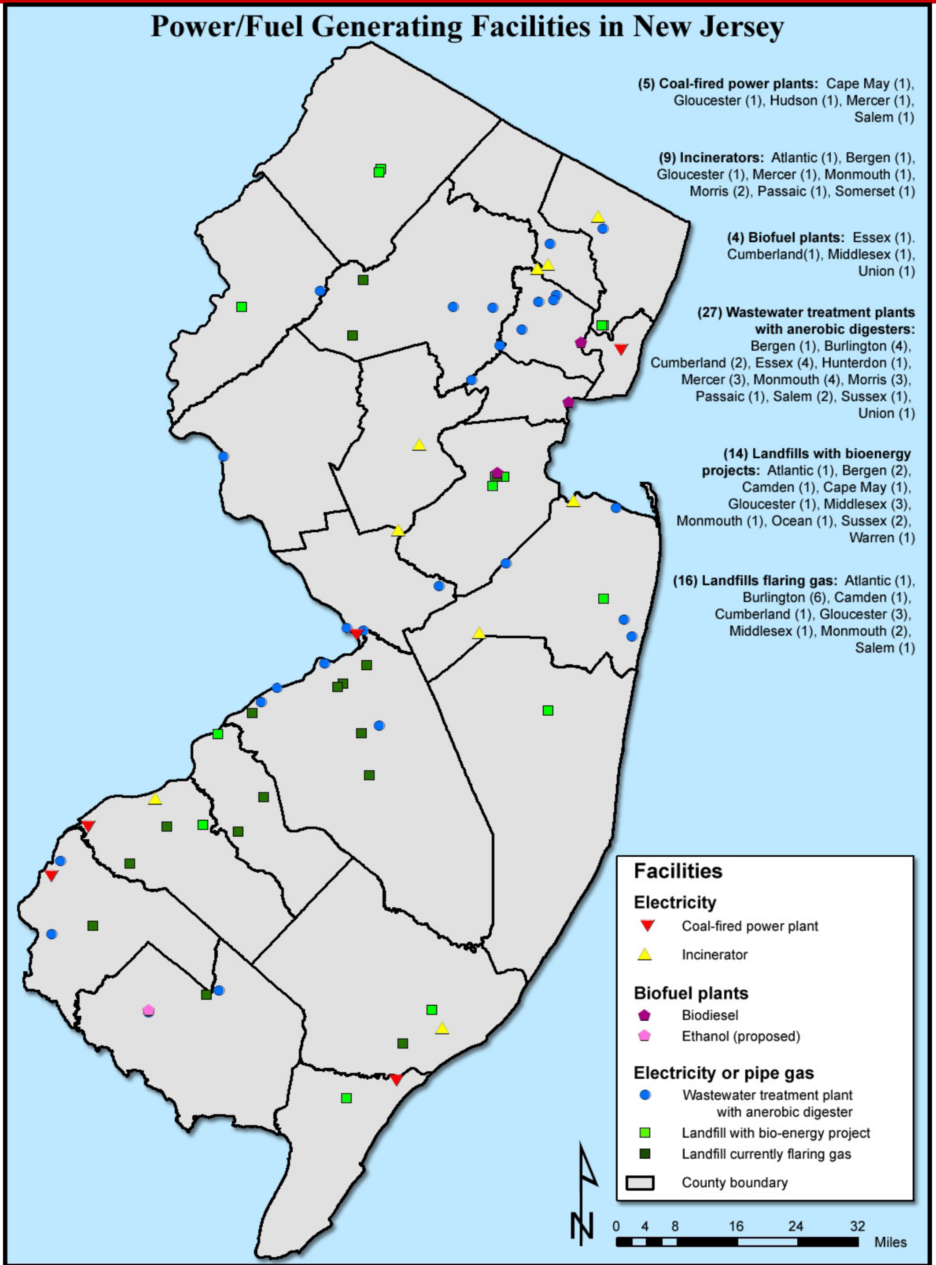
Fuel Production Costs for Biodiesel (2007$)



- Key assumptions: Debt equity ratio: 40%:60%, cost of equity = 15%, cost of debt = 8%, Federal income tax rate = 35%; NJ state income tax rate = 9%; Property tax = 1.5%, Insurance = 0.5%, Depreciation under Modified Accelerated Cost Recovery System (MACRS): Depreciation period considered is 15 years. Loan period = 25 years. Project economic life = 25 years.
- Incentives included for 2007 calculation: 10 ¢/gallon small producer tax credit (for 15 MGPY). Non production-related subsidies (blender's tax credit, the Renewable Fuels Standards and other blending mandates) are not included as they impact the sales price rather than production costs. As a note, soy biodiesel is considered "agri" and therefore granted a higher blender's tax credit ($1/gallon) than that granted to YG biodiesel ($0.5/gallon)

Energy Generation Facilities in New Jersey

New Jersey's large municipal waste biomass resource, combined with its proximity to a petrochemical infrastructure, makes it a good location to utilize advanced power and fuels technologies.



Power/Fuel Generating Facilities in New Jersey

(5) Coal-fired power plants: Cape May (1), Gloucester (1), Hudson (1), Mercer (1), Salem (1)

(9) Incinerators: Atlantic (1), Bergen (1), Gloucester (1), Mercer (1), Monmouth (1), Morris (2), Passaic (1), Somerset (1)

(4) Biofuel plants: Essex (1), Cumberland(1), Middlesex (1), Union (1)

(27) Wastewater treatment plants with anerobic digesters: Bergen (1), Burlington (4), Cumberland (2), Essex (4), Hunterdon (1), Mercer (3), Monmouth (4), Morris (3), Passaic (1), Salem (2), Sussex (1), Union (1)

(14) Landfills with bioenergy projects: Atlantic (1), Bergen (2), Camden (1), Cape May (1), Gloucester (1), Middlesex (3), Monmouth (1), Ocean (1), Sussex (2), Warren (1)

(16) Landfills flaring gas: Atlantic (1), Burlington (6), Camden (1), Cumberland (1), Gloucester (3), Middlesex (1), Monmouth (2), Salem (1)

Both combustion and gasification technologies present opportunities in New Jersey

- New Jersey's yard waste collection system could potentially form a backbone of a biomass supply infrastructure for small (<10MW) distributed biomass power facilities that represent a higher-value use of the biomass than current practice (assumed to be mainly composting).
- Biomass co-firing offers environmental benefits to existing coal fired power production.
- The New Jersey RPS should provide good additional value for qualifying biomass, but the RPS rules on biomass eligibility are fairly strict.
- Despite a lack of commercial status, gasification technology is relatively well developed and can be deployed at a range of scales for power generation, which makes it suitable to New Jersey's biomass resources. Gasification is also suitable for municipal wastes, and could offer lower emissions than conventional incineration.
- Pyrolysis is at a much earlier stage of development than gasification. New Jersey should monitor development in Canada and the EU, where most activity is concentrated.

Anaerobic digestion is a commercialized and well developed technology that can help capture New Jersey's biomass energy potential.

- High population density ensures a concentrated stream of food wastes, landfill gas and MSW (the organic component of which will need to be separated from the non digestible materials)
- Other biomass streams add to this potential:
  - Farm wastes such as manure
  - Yellow and Brown Grease
  - Lower value in-state crops and crop residues
  - Organic waste from large industrial and food processing facilities
  - Other cellulose-rich biomass (such as waste paper)
- An in-depth analysis of these biomass and waste streams could allow New Jersey to identify optimal location(s) for centralized large-scale digesters
  - Some European countries (Germany and Denmark) have successfully deployed this regional digester concept
  - This would allow not only the production of more renewable energy, but also more environmentally friendly waste management practices
- There also remain untapped opportunities for landfill gas and for installing cogeneration at wastewater treatment plants, and these projects are likely to have very attractive economics.

Feedstock availability for 1st generation biofuels are limited. Any plants of this type would require New Jersey to import feedstock with the exception of biodiesel from yellow grease.

- Corn ethanol would likely require regional importation of feedstock to present a viable commercial-scale technology opportunity in New Jersey.
- Similarly, New Jersey has limited potential in terms of biodiesel feedstock; however some characteristics make it attractive as a location for biodiesel production and trading activities as new industry trends emerge:
    - New Jersey's significant petroleum refining and distribution infrastructure will increasingly become an upstream blending point for biodiesel into petroleum diesel.
    - The high concentration of population in New Jersey and the surrounding states may provide reasonable economies of scale for locating facilities to convert used vegetable oils (in the form of yellow greases) into biodiesel.
- Other examples of ways to leverage New Jersey's petroleum infrastructure include:
    - New Jersey's petroleum and petrochemical industry is in an ideal position to capitalize on some areas of technological innovation, such as the direct conversion of vegetable oils and fats into a renewable diesel at oil refineries
    - New Jersey's import / export infrastructure, in addition to the substantial local fuel demand, makes the state an ideal center for biofuels trading activities as a global trade emerges

Emerging biofuels technologies can provide New Jersey an opportunity to become a recognized leader in biofuels in the future.

- New Jersey has enough biomass resources that are suitable to produce cellulosic ethanol, Fischer-Tropsch liquids, and other 2nd generation biofuels to achieve meaningful economies of scale, and additional resources might be collected in neighboring states.
- As with biodiesel and renewable diesel, the production of FT biofuels presents integration opportunities with the state’s existing refining infrastructure (e.g., producing a “crude FT” product and selling that to existing refineries).
- Although not addressed specifically in this report, there may be opportunities to produce syngas or hydrogen from biomass and integrate that directly with the existing petroleum and petrochemical industry.
- Production of LNG and CNG from biogas could fill niche, but important, fleet fueling operations.
- However, some of these technologies are not yet commercially available
    - Current costs are not competitive with either gasoline or corn ethanol and technology development and demonstration are still needed
    - The first commercial plants will face significant technology, development and market risks and will need government support to “get steel in the ground”
    - While the federal government has already put in place mechanisms for supporting this nascent industry (such as grants, loan guarantees, RFS carve-outs), New Jersey could add its support to become a recognized leader in these technologies.

I. Executive Summary

II. Biomass Supply Analysis

III. Technology Assessment

IV. Economic Analysis

V. Policy Recommendations/Next Steps

VI. Appendix

Economic Analysis

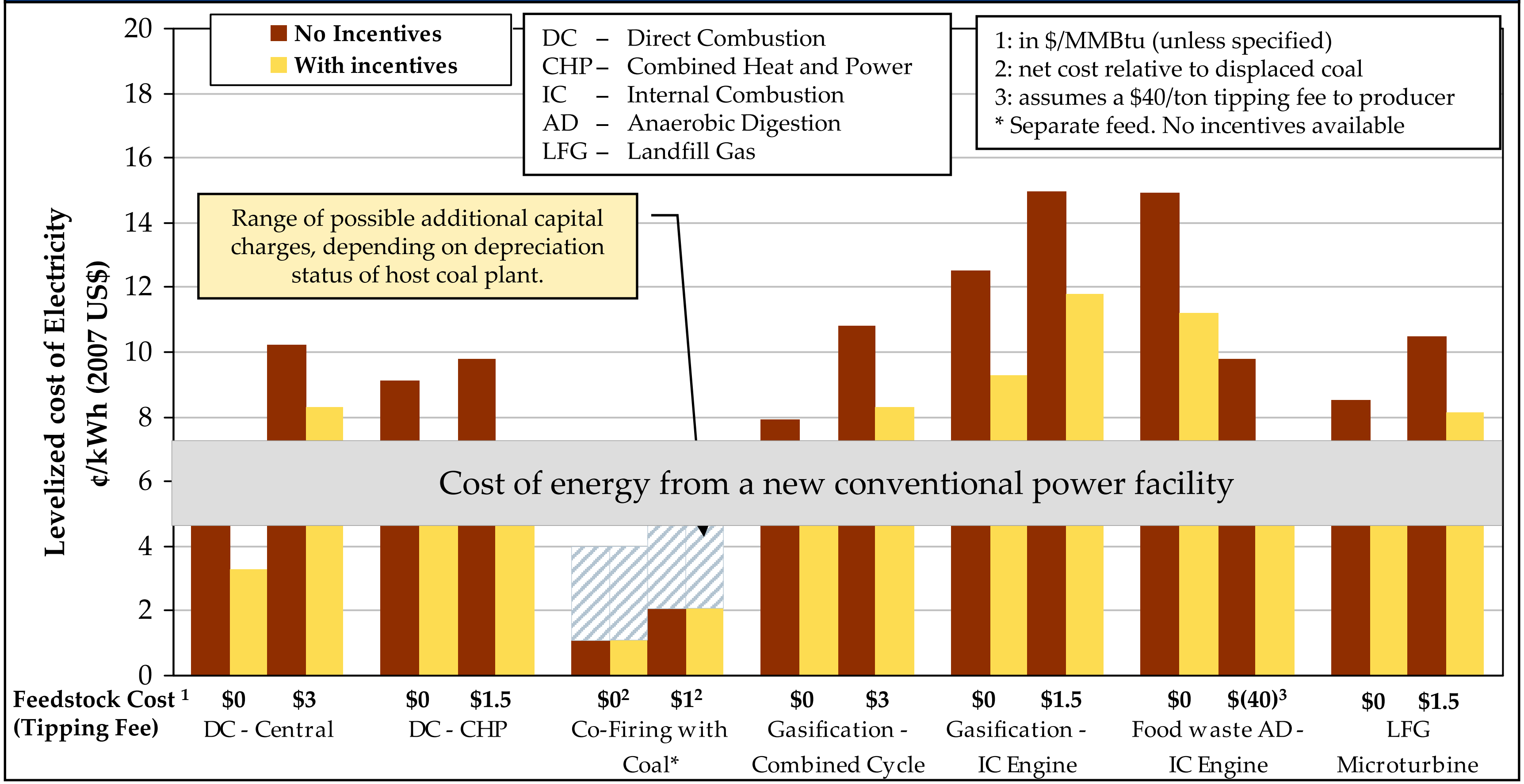
- The economic analyses are indicative for a "typical" application using a feedstock **type** (i.e., an analysis of "lignocellulosic biomass" was conducted, not separate analyses for each type of lignocellulosic biomass)
    - Feedstock types have been defined such that the economics of a conversion process should not be strongly dependent on the specific feedstock
        - e.g., conversion of woody biomass vs. agricultural residues to ethanol is substantially similar
- Bio-heat only applications (e.g., wood-fired building heating systems) are expected to be niche in New Jersey and the economics are very site specific. As such:
    - Separate economics analyses of these options were not conducted
    - Representative small-scale CHP analyses using direct combustion and gasification were included.
- Economics for fuels are presented in *gallons of gasoline equivalent* (GGE), which enable comparisons between fuels with different volumetric energy densities.
- Costs of production are expected to decrease over time due to improvements in technology efficiencies, new innovations, and improved feedstock infrastructure.

The economic analysis is subject to a range of assumptions.

Economic Analysis Issue	Comments
Biomass fuel prices	• The analysis has been conducted using a range of fuel prices depending on the technology/application. • In general, each analysis includes a case with zero fuel cost, which would be representative of a situation where *opportunity fuels* are available (i.e., these fuels would otherwise require disposal. In general a tipping fee has not been modeled since it is assumed that as markets develop for biomass feedstocks, waste materials, once viewed as liabilities will be viewed as saleable products. • $3/MMBtu (~$45-50/dry ton for most biomass) is generally assumed as a high-end for biomass feedstocks. For biomass that is produced and used at the same location, a lower price of $1.50/MMBtu has been assumed, which is representative of the opportunity cost of not selling that biomass into the market. • Where waste is the primary feedstock (e.g., food waste from MSW), a tipping fee has been assumed. This tipping fee is lower than current values in New Jersey assuming that as demand for these feedstocks rise, this will increase their value and result in lower tipping fees. • For corn-ethanol and soy-biodiesel, feedstock prices cover a range typical for these agricultural commodities
Project scale	• Project scale will be highly dependent on the availability of biomass at a specific site and the cost to deliver it to that site. • The analyses presented here are for “typical” plant sizes and the resulting production costs should therefore be viewed as indicative of the application vs. definitive. Projects that will be typical of the New Jersey setting may be different than those assumed here.
Technological maturity	• For emerging technologies, published cost and performance data are typically only available for mature (“Nth plant) technology, assuming cost reductions and performance improvements associated with successful commercialization. • As such cost and performance data for near-term deployment are not available. These costs have been estimated assuming reasonable scaling factors and best judgment.

Some biopower technologies are becoming cost competitive. Economics are driven by feedstock cost, incentives, and technology type.

LCOE Comparison for Biomass Power Options: 2007 with and without incentives



DC	Direct Combustion
CHP	Combined Heat and Power
IC	Internal Combustion
AD	Anaerobic Digestion
LFG	Landfill Gas

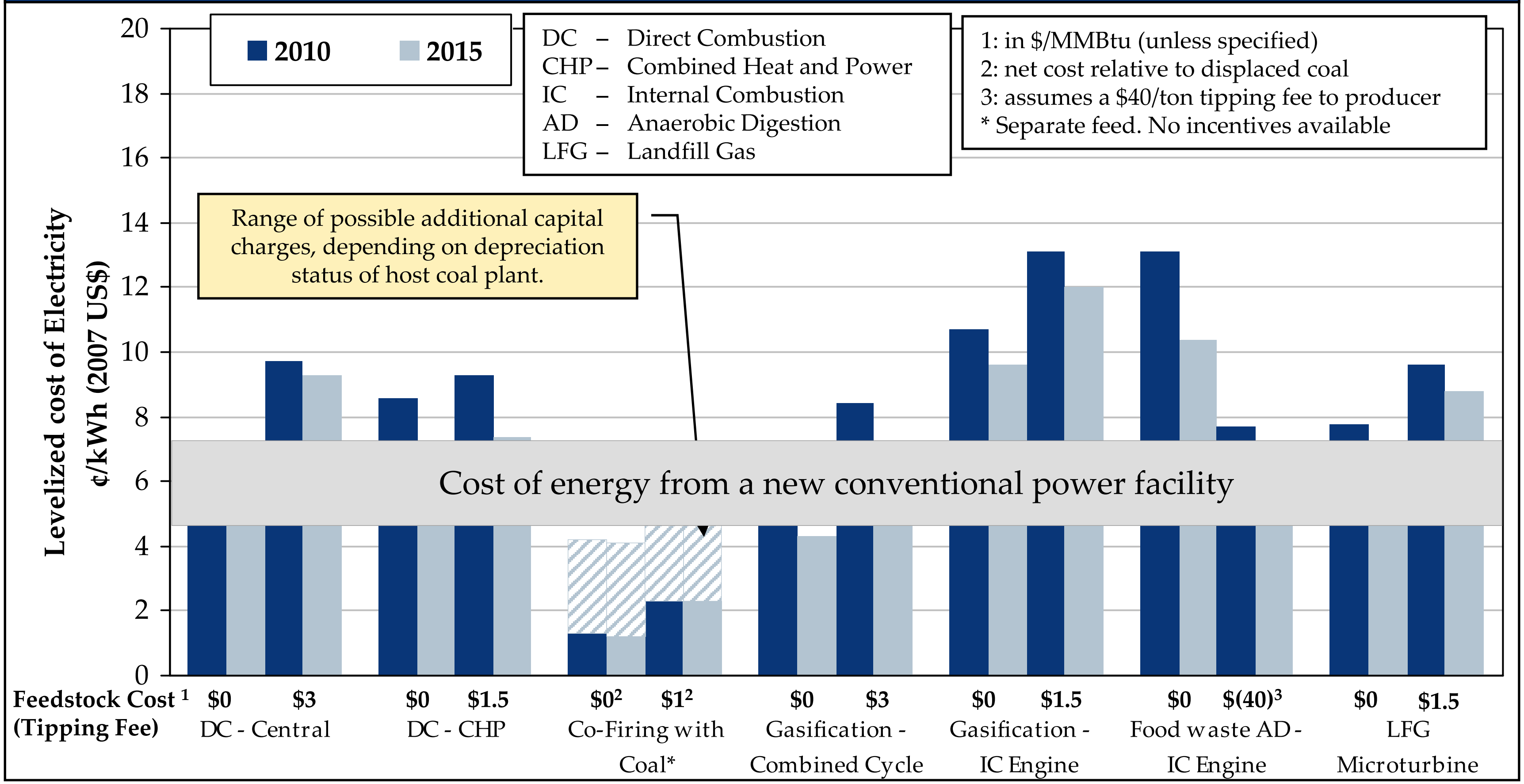
1: in $/MMBtu (unless specified)
2: net cost relative to displaced coal
3: assumes a $40/ton tipping fee to producer
* Separate feed. No incentives available

Range of possible additional capital charges, depending on depreciation status of host coal plant.

Cost of energy from a new conventional power facility

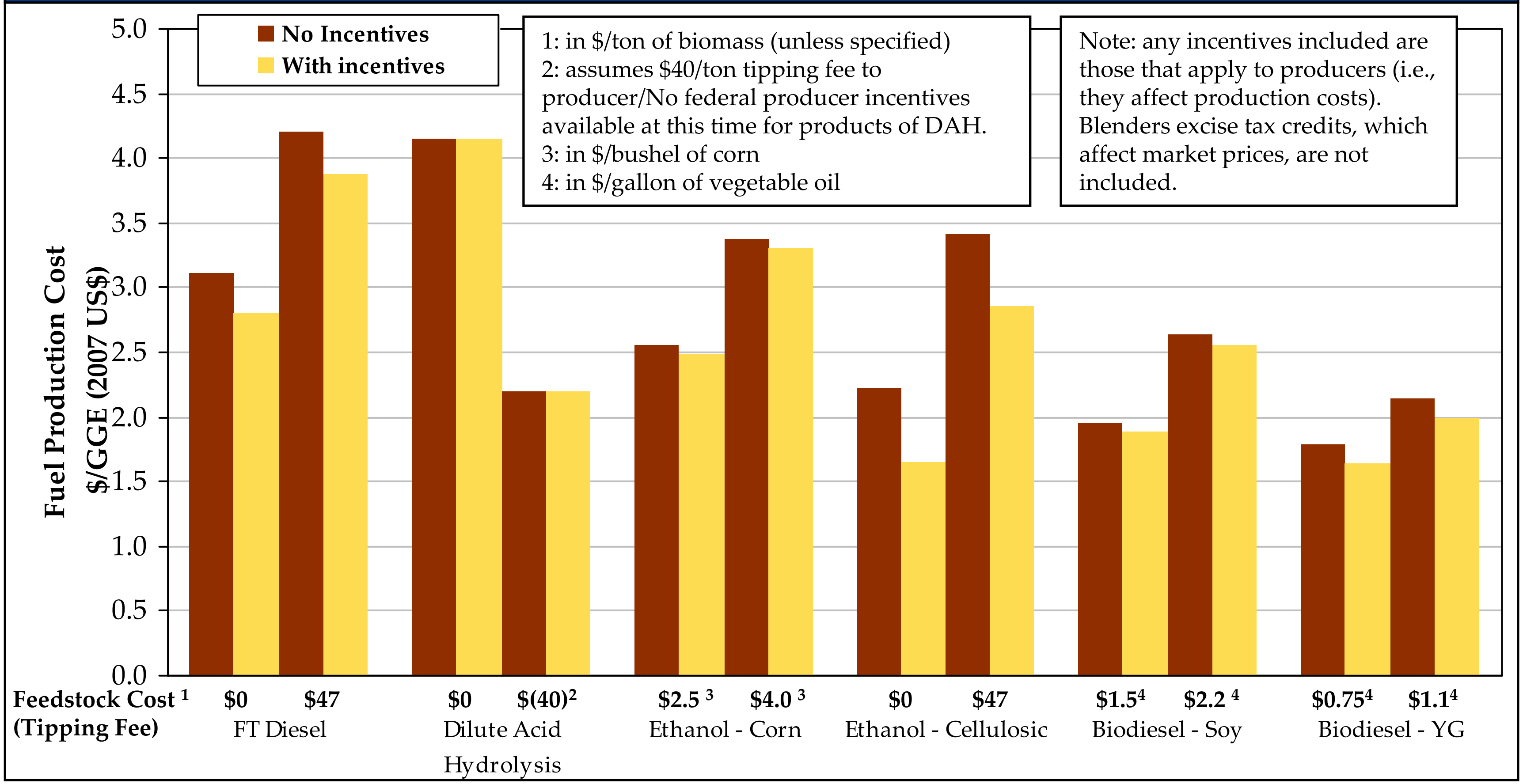
By 2010 and 2015, cost reduction potential should bring additional biopower technologies into the realm of commercial application.

LCOE Comparison for Biomass Power Options: 2010 & 2015 without incentives



Incentives, feedstock costs, and possible tipping fees are also a key to promoting the production of biofuels.

Fuel Production Cost Comparison for Biofuels Options: 2007 with and without incentives

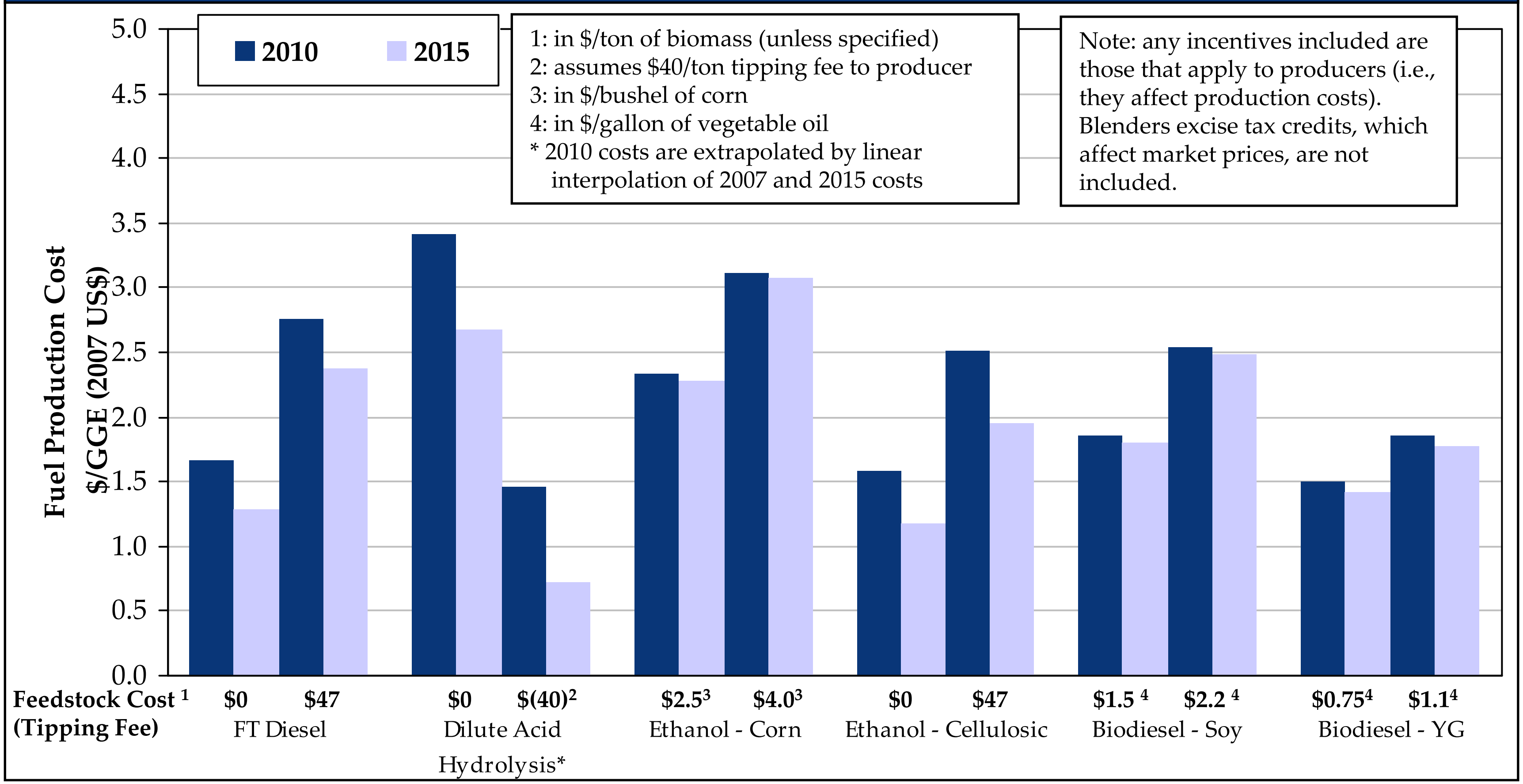


1: in $/ton of biomass (unless specified)
2: assumes $40/ton tipping fee to producer/No federal producer incentives available at this time for products of DAH.
3: in $/bushel of corn
4: in $/gallon of vegetable oil

Note: any incentives included are those that apply to producers (i.e., they affect production costs). Blenders excise tax credits, which affect market prices, are not included.

Major cost reductions are expected over the next 3-8 years that should allow new biofuels technologies to become more cost competitive.

Fuel Production Cost Comparison for Biofuels Options: 2010 & 2015 without incentives



1: in $/ton of biomass (unless specified)
2: assumes $40/ton tipping fee to producer
3: in $/bushel of corn
4: in $/gallon of vegetable oil
* 2010 costs are extrapolated by linear interpolation of 2007 and 2015 costs

Note: any incentives included are those that apply to producers (i.e., they affect production costs). Blenders excise tax credits, which affect market prices, are not included.

Creating an effective regulatory, management and implementation infrastructure at the state level is key to the successful achievement of bioenergy goals.

- The following recommended actions would help to establish the capacity and infrastructure needed for rapid biofuels and biorefinery development and to create sustainable markets for biofuel products. They address four key components:

1) Institutional infrastructure
2) Regulations
3) Market-based incentives
4) Market transformation through technological innovation:

Market transformation will occur once the technological and infrastructure capabilities exist and can function in an economically viable and environmentally sustainable fashion.

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1) *Institutional Infrastructure*

- Establish/appoint a state agency with primary responsibility for developing the bioenergy industry. This entity will need dedicated personnel, authority and financial resources to accomplish this goal.
- Facilitate policy harmonization across all state agencies so that the state's alternative energy goals can be successfully achieved. This effort will need to be fully integrated, include public and private partnerships, and incorporate comprehensive research, policy and marketing plans.
- Build regional partnerships with surrounding states to take advantage of related programs, maximize utilization of biomass feedstocks, coordinate research activities and share expertise.
- Create educational programming to encourage more rigorous recycling efforts

2) *Regulations*

- Consider a societal benefits charge on petroleum based fuels to support bioenergy incentive programs.
- Identify and alleviate regulatory conflicts across permitting agencies to streamline and simplify approval processes.
- Integrate new bioenergy efforts (i.e. biofuels) into existing policies (e.g. RPS, Clean Energy Program, & MSW recycling requirements).

3) *Market Based Incentives*

- Establish Bioenergy Enterprise Zones around concentrations of biomass feedstocks and/or where bioenergy can be strategically utilized.
- Develop a consumer-based biofuels incentive program
- Provide incentives for waste-based bioenergy research, development and production
- Provide incentives for small companies to pursue bioenergy technology demonstration projects
- Provide incentives for development of biomass feedstock infrastructure

4) *Market Transformation Through Technological Innovation*

- Establish a ***Bioenergy Innovation Fund*** to support the research, development and commercialization of new bioenergy technologies. Build partnerships with BPU, EDA, NJCST, NJDA and other state agencies, as well as higher education institutions, federal agencies, private investors, utilities, and foundations with a goal to transform the market for bioenergy through innovations in technology.

- Facilitate bioenergy market development by identifying ways to take advantage of New Jersey's existing petrochemical, refining and distribution infrastructure.

Establishing Capacity for Achieving New Jersey's Bioenergy Goals

1) *Institutional Infrastructure*

- Establish/appoint a state agency with primary responsibility for developing the bioenergy industry. This entity will need dedicated personnel, authority and financial resources to accomplish this goal.
- Facilitate policy harmonization across all state agencies so that goals can be successfully achieved. This effort will need to be fully integrated, include public and private partnerships, and incorporate comprehensive research, policy and marketing plans.
- Build regional partnerships with surrounding states to take advantage of related programs, maximize utilization of biomass feedstocks, coordinate research activities and share expertise.

2) *Regulations*

- Identify and alleviate regulatory conflicts across permitting agencies to streamline and simplify approval processes.
- Integrate new bioenergy efforts (i.e. biofuels) into existing policies (e.g. RPS, Clean Energy Program, & MSW recycling requirements).
- Consider a societal benefits charge on petroleum based fuels to support bioenergy incentive programs.

3) *Market Based Incentives*

- Develop a consumer-based biofuels incentive program
- Provide incentives for energy from waste bioenergy research, development and production
- Provide incentives for small companies to pursue bioenergy technology demonstration projects
- Provide incentives for development of biomass feedstock infrastructure
- Establish Bioenergy Enterprise Zones around concentrations of biomass feedstocks and/or where bioenergy can be strategically utilized.

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- Facilitate bioenergy market development by identifying ways to take advantage of New Jersey's existing petrochemical, refining and distribution infrastructure.

Capturing New Jersey's Biomass Energy Potential – Possible Policy Considerations				
Develop Policies to Provide Better Access to Biomass Resources	**Make NJ a Leader in Support of New Technologies**	**Integrate with Existing NJ Petrochemical/ Refining Infrastructure**	**Capitalize on Existing Policies and Practices**	**Address Regulatory Roadblocks and Inconsistencies**
• Create incentives to develop biomass "nodes" as possible plant sites, and to increase waste diversion practices • Establish Bioenergy Enterprise Zones • Create incentives to support development of feedstock infrastructure • Create educational programming to encourage more rigorous recycling efforts	• Establish/appoint a state agency with primary responsibility for developing bioenergy industry • Create Bioenergy Innovation Fund to support ongoing R&D • Promote NJ as premier location for biomass technology companies • Leverage expertise in academia & pharma/ biotech industries	• Further evaluate technologies (e.g., FT, biodiesel) that may benefit from proximity to petrochemical infrastructure • Engage industry experts in efforts to develop workable solutions	• Integrate new efforts (i.e. biofuels) with existing policies (e.g. RPS, Clean Energy Program, & MSW recycling reqs.) • Should not undermine the viability of RPS projects such as waste incineration • Analyze highest and best use of feedstocks by measuring the value of tradeoffs of alternative uses	• Biomass feedstocks and end products may be subject to different regulatory oversight; need to identify and address incongruous policies and regulations • Streamline regulatory process

In order to monitor progress and ensure that performance goals are being met, the identification of a comprehensive set of metrics is crucial. Suggested metrics include:

- Gallons of biofuels produced in the state
- Gallons of biofuels sold in the state
- MW of biopower produced in the state
- Number of new bioenergy start-up companies or firms re-locating to New Jersey
- Amount of investment made through Bioenergy Innovation Fund
- Number of new bioenergy technologies commercialized
- Amount of fossil fuel displaced by bioenergy
- Number of new jobs created in the bioenergy industry
- Amount of waste diverted to bioenergy conversion

***A systems approach* to maximizing NJ's bioenergy potential – a comprehensive analysis which incorporates the interaction of a large scope of issues (including social, environmental, regulatory, economic, technological, etc.), is needed for a long-term sustainable bioenergy strategy.**

- A detailed systems analysis can reveal where the largest opportunities are, and more importantly, how various strategies and policies might impact each other .

- The current team of NJAES researchers, along with additional collaborators, have the unique diversity of capabilities required to conduct a bioenergy systems analysis for New Jersey.

Examples of Systems Analysis Components and Proposed Projects

- ***Environmental:***

-Develop and conduct Bioenergy Lifecycle Analyses, which include assessments of carbon intensity, for various biomass feedstocks and technologies appropriate for New Jersey.

-Evaluate environmental and economic impact of converting marginal agricultural lands and lands enrolled in preservation and "set-aside" programs to bioenergy crop production.

- ***Socio-Economic:***

-Update and improve accuracy of biomass resource data and fill in data gaps
-Evaluate highest and best use of biomass resources that yield greatest societal and economic benefits
-Identify nodes of biomass feedstocks and develop a gravity model that can optimize bioenergy facility site location
-Conduct economic analysis of optimal level of various bioenergy incentives and subsidies

- ***Policy/Regulatory:***

  -Develop a comprehensive "Bioenergy Industry Development Plan" that incorporates harmonization of state policies, targets most abundant and readily available feedstocks (i.e. waste) and streamlines regulatory processes. Build collaborative relationships with other states doing this well, such as California.

  -Develop a utilization policy for publicly managed lands that includes harvesting biomass from these areas, as well as for production of energy crops. Evaluate the economics of collecting these resources, as well as conversion into energy.

  -Organize industry roundtables of potential feedstock supply industries (i.e. food, waste, forestry) to engage them in the planning process and determine the feasibility of various policy options.

- ***Technological:***

  -Conduct demonstration projects to evaluate technologies in real world conditions so that procedures and processes can be evaluated, refined and verified to facilitate commercialization.

Appendix I - Feedstocks for Technologies Evaluated

Appendix » Feedstocks for Technologies Evaluated

	Technologies (in bold were used to calc totals)
1	Direct Combustion-Stand Alone for Solid Biomass
2	Direct Combustion-Small Scale CHP for Solid Biomass
3	Direct Combustion--Co-Firing
4	**Direct Combustion-ADG/Landfill Gas**
5	**Gasification- Stand Alone BIGCC**
6	Gasification- Small Scale CHP
7	Pyrolysis
8	**Ethanol from Starch**
9	**Transesterification**
10	Cellulosic Ethanol
11	**Dilute Acid Hydrolysis**
12	**Gasification-F-T**
13	**AD/Landfill Gas to Transportation Fuel**

Feedstocks	**Potential Power Technologies**	**Potential Fuels Technologies**
Sorghum		8
Rye		8
Corn for Grain		8
Wheat		8
Sweet Corn Residues	1,3,5,7	10,11,12
Rye Residues	1,3,5,7	10,11,12
Corn for Grain Residues	1,3,5,7	10,11,12
Corn for Silage Residues	1,3,5,7	10,11,12
Alfalfa Hay Residues	1,3,5,7	10,11,12
Other Hay Residues	1,3,5,7	10,11,12
Wheat Residues	1,3,5,7	10,11,12
Forestry Residues	1,3,5,7	10,11,12
Processing Residues (lignocellulosic	1,2,3,5,6,7	10,11,12
Brush/Tree Parts	1,3,5,7	10,11,12
Grass Clippings	1,3,5,7	10,11,12
Leaves	1,3,5,7	10,11,12
Stumps	1,3,5,7	10,11,12
MSW	1,5,7	11,12
Waste paper, Landfilled	1,5,7	10,11,12
Food waste, Landfilled	4	11,12,13
C&D, not recycled	1,3,5,7	10,11,12
Tires	1,3,5,7	12
Food Waste (Recycled)	4	11,12,13
Wood Scraps	1,3,5,7	10,11,12
Corrugated	1,3,5,7	10,11,12
Mixed Office Paper	1,3,5,7	10,11,12
Newspaper	1,3,5,7	10,11,12
Other Paper/Mag/JunkMail	1,5,7	10,11,12
Soybeans		9
Oils - Used cooking oil "yellow"	4	9,13
Oils - Grease trap waste "brown"	4	9,13
Beef Cattle	1,2,4,5,6	11,13
Dairy Cows	4	13
Equine	1,2,4,5,6	11,13
Sheep	4	13
Goats	4	13
Pigs	4	13
Poultry (layers)	1,2,4,5,6	11,13
Turkeys	1,2,4,5,6	11,13
Wastewater treatment plant biosolids	1,2,3,5,6	11,13
Wastewater treatment plant biogas	4	13
Landfill Gas	4	13