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Aggressive Growth in the Use of Bioderived Energy and Products in the United States by 2010

Final Report

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The objective of this study was to identify ways to increase significantly the consumption of bioderived energy, fuels and products by 2010.

- The objectives were based in part on:
  - The Biomass Research and Development Act of 2000 (Public Law 106-224)
  - The National Sustainable Fuels and Chemicals Act of 1999
  - Former President Clinton's Executive Order 13134 "Developing and Promoting Biobased Products and Bioenergy"
- The objectives are also supported by the Bush Administration's National Energy Policy[1]
  - Increased production and utilization of biomass will likely utilize environmentally friendly technology that will increase energy supplies and help raise the living standards of the American people, particularly in rural and semi-rural areas
- This report covers a broad range of biomass energy and products, based on open literature data
  - Biopower and bio-heat (e.g. wood-fired power plants, co-firing of biomass with coal or natural gas)
  - Biofuels (e.g. bioethanol, biodiesel, bio-FT-diesel[2])
  - Bioproducts (primarily carbohydrate and lipid based chemicals) both for existing and new products and applications
- Two scenarios were developed to illustrate the potential for and impact of increased biomass use for energy and products:
  - A Business As Usual scenario represented what could happen if no special additional supports are implemented
  - An Aggressive Growth scenario aimed at achieving more than doubling[3] by 2010 or soon thereafter
- The study's scope specifically excluded several categories of products conventionally made from biomass:
  - Paper, lumber and other conventional wood products
  - Food, food ingredients and food by-products
  - Pharmaceuticals and "nutraceuticals"
  - Textiles

1. "National Energy Policy: Reliable, Affordable, and Environmentally Sound Energy for America's Future", Report of the National Energy Policy Development Group, May 2001
2. FT-diesel is diesel fuel made via Fischer-Tropsch synthesis.
3. A tripling benchmark was used in this study

Arthur D. Little and USDOE identified the underlying policy objectives for the aggressive targets for increases in biomass use.

Broad Study Objective	More than double the use of biomass-derived materials in the U.S. by 2010

To Address the Underlying Objectives...	...the policies options should:
Reduce environmental burden of producing and utilizing energy and products	• Be focused on the environmental end-result, not the path to get there • Address all relevant environmental concerns
Stimulate rural economic development	• Focus on developing competitive economic activity in rural areas, preferably value-added activity
Improve U.S. balance of payments position	• Focus on U.S.-generated biomass (e.g. options should not support import of Indonesian rubber or Brazilian ethanol)
Improve United States energy security	• Focus on pathways that directly offset fossil fuel (e.g., not food & feed or pulp & paper)
Accelerate development of competitive U.S. technology	• Focus on technologies with competitive potential for U.S. industry, not necessarily on ones that are closest to large-scale application • Eliminate barriers for technology development

With sufficient investment and government support, significant increases in the use of biomass energy and products in the U.S. by 2010 are feasible...

- Sufficient biomass is expected to be available in the United States to more than double its use but prices at high volume are expected to exceed $20/dry ton farm-gate (~$1.1/GJ; $1.2/million BTU)
- Several significant implementation options appear nearly ready for implementation, though they will require a supportive regulatory and tax environment to achieve rapid and substantial market penetration:
  - Biogas-to-power (primarily landfill gas) and biomass co-firing with coal provide relatively attractive ways to considerably increase biopower capacity
  - Increased use of bioethanol as a gasoline oxygenate; it alone represents a potential significant increase in use from today's biofuel consumption (provided the current tax credit is continued and the oxygenate requirement in RFG remains)
  - Fermentation-based monomers, pyrolysis-derived phenolics and lipid-based products offer near-term opportunities for increasing bioproduct use
- These options could provide significant environmental and rural economic benefits by 2010 with aggressive deployment:
  - Over 95 million ton per year reduction in carbon dioxide reduction emissions
  - Significant criteria pollutant emission reductions (390 thousand tons SOx avoided; 440 thousand tons NOx avoided)
  - Over three billion dollars per year added economic activity in rural areas by 2010 from feedstock production alone (primary impact with aggressive implementation)
- When looking out to 2020, additional long-term options now under development may significantly expand that impact and could help double biomass-based energy and product use by 2015:
  - Biogas-to-power (e.g. including landfill, sewage, and digester gases) and gasification based biopower (e.g. BIGCC for onsite power)
  - Ethanol for gasoline blending obtained with advanced cellulosic-based technology
  - Advanced gasification for fuels production for Fischer-Tropsch (FT) diesel
  - Bio-polymers via fermentation based processes
  - Lipid-based feedstocks for polyurethane foam and coatings applications as an example

... though doubling of use is not likely to happen before 2015.

1. Energy and fuel prices were compared with the 2010 reference case of the USDOE EIA 2001 Energy Outlook, $21.4/B oil price.

Together the most attractive options can significantly increase biomass use in an aggressive growth scenario.

Application Category	Growth Potential		Support Requirements
	Business as Usual (BAU)	Aggressive Growth	
Biopower	• 40% increase in capacity from baseline of 10,000 MW to 14,000 MW in 2010 • Baseline does not grow and stays at 10,000 MW in 2010	• Capacity increases by 100% in 2010 (additional 13,000 MW from baseline of 10,000 MW) • Biopower plants based on advanced BIGCC important in post 2010 timeframe	• Modest support, expected to produce power at competitive cost[1]
Biofuels	Gasoline additives (e.g. as oxygenates for MTBE replacement) – 50% increase by 2010, ~800 million additional gallons of ethanol over baseline of 1500 million gallons ethanol consumed in 2010 – Baseline growth results in 200 million gallon ethanol	• Gasoline additives –100% increase by 2010, additional 2300 million gallons over baseline of 1600 million gallons ethanol in 2010 • FT-diesel from gasification in post 2010 period (leverage biopower development) • Baseline grows 300 million gal. ethanol	• Continuation of oxygenates requirement in reformulated gasoline • Continuation of current bioethanol fuel tax credit or similar direct support (e.g. renewable content standard) • Extension of tax credit to all bio-derived fuels • Renewable fuel content requirement • Advanced ethanol technology may eventually reduce need for tax credit
Bioproducts	• Additional 600 million pounds product in 2010 over baseline of 21 billion pounds products (3% increase) • Baseline grows 3400 million pounds bioproducts	• 7.5 billion pounds product additional in 2010 over 21 billion pound baseline (35% increase) • Baseline grows 3400 million pounds • Broad implementation of fermentation-based processes, primarily for polymers	• Aggressive government support in technology development and demonstration • In long-term, expect cost competitiveness with petroleum analogs

1. Energy prices were based on U.S. EIA's 2001 Annual Energy Outlook, 2010 reference case of $21.4/barrel oil in 1999 dollars. The cost of energy sources was taken from the industrial sector, transportation sector, and electricity generators for 2010, reference case.

The implementation of the attractive options can lead to significant environmental benefits, particularly CO_2 abatement.

Category	Environmental Benefits in 2010	
	Business as Usual (BAU)	Aggressive Growth
Greenhouse Gas Emissions	• 26 million metric tons per year CO_2 avoided and 24 thousand metric tons per year CH_4 avoided in 2010 for biopower • 5 million metric tons per year CO_2 avoided in 2010 from biofuels • 0.1 million metric tons per year CO_2 avoided in 2010 from bioproducts	• 80 million metric tons per year CO_2 avoided and 87 thousand metric tons per year CH_4 avoided in 2010 from biopower • 14 million metric tons per year CO_2 avoided in 2010 from biofuels • 1.3 million metric tons per year CO_2 avoided in 2010 from bioproducts
Criteria Air Pollutant Emissions	• 130 thousand metric tons per year NO_x and 130 thousand metric tons per year SO_x avoided in 2010 from biopower	• 440 thousand metric tons per year NO_x and 390 thousand metric tons per year SO_x avoided in 2010 from biopower
	• Improvements in criteria pollutant emissions are not a driving factor in biofuel and bioproduct options	
Water and Soil Quality	Biomass production could have some positive impacts on the water and soil quality in the US, although very careful management and attention will be necessary to prevent degradation.	

Achieving significant impact will require the application of new biomass technologies to new applications...

- Existing biomass utilization is based on mature technology and occurs mostly in mature markets (e.g. pulp & paper, starch manufacture)
- Combinations of new technologies and new applications are required to achieve rapid and significant growth in the use of bioderived energy and products
- Key improvements in technology for targeted markets could aid the implementation of biomass-derived energy and products:
  - Development of lower cost, high-quality biomass feedstocks (e.g. energy crops, “harvesting” of agricultural residues) and the establishment of large-scale distribution infrastructure to make these biomass feedstocks available in high volume
  - Development and demonstration of low-cost biomass conversion processes, which could result in broader cost-competitiveness for biomass-derived power, fuels, and products in the long term (post 2010)
  - Demonstration of the viability and reliability of technologies currently under development
  - Development of new product applications with enhanced performance
  - Development of optimal information systems to minimize the impact of industry inertia on the market penetration rate of biomass technologies and their products
- Integrated production of energy and products in “Bio-refineries” could contribute to improving the cost competitiveness of biomass options with fossil-based counterparts; this will likely require new inter- and intra industry collaborations

... but rapid near-term growth will also require expansion of existing uses.

To achieve these benefits, significant cost barriers must be overcome which will require significant and focused government support.

- Given current projections for crude oil and utility prices[1], some of the long-term[2] options are expected to require considerable one time investments by stakeholders and some will require sustained support
- Developments in crude oil price are likely to have considerable impact on all options, particularly on the fuels & products options that are competing directly with petroleum-analogs and will shift the competitiveness of the options versus petroleum fueled alternatives
- Projected feedstocks of >$20/dry ton farm-gate pose a challenge with oil prices projected for 2010 by EIA
- High feedstock and capital recovery costs are the main barriers to significant increases in the use of biomass-derived energy and products in the U.S.:
  - Most current technologies are not cost-competitive with fossil-derived fuels, power, and products in new markets without government support
  - Considerable research, development and demonstration funding will be required to prepare the technologies for commercial application
  - Significant one-time cumulative investments (tens of billions of dollars) will be required for plant construction and infrastructure development (Not accounting for investment that otherwise may be made)
  - Even then many of the options will carry higher operational costs than conventional alternatives
- To overcome these barriers, two types of support are critical:
  - Sustained support for crop (resource) production, biomass conversion, and product use through tax credits, farm supports, and subsidies will be required if use of biomass-derived energy and products is to be dramatically increased
  - Strong support for R&D/D focused on long-term improvements in technology that will eventually make the technology cost-competitive with conventional fuels and power sources
  - Coordination and careful planning of such support will be critical to its success
- The USDOE, USEPA and USDA could play a key coordinating role with interested industries if such an effort were undertaken

1. The EIA 2001 Annual Energy Outlook reference case has a $21.4/B oil price in 2010 (in 1999 dollars). The 2010 prices are: Industrial sector: electricity $11.2/million BTU; natural gas $3.3/million BTU; Electric generator sector: natural gas $3.0/million BTU and steam coal $1.0/million BTU; Transportation sector: motor gasoline $10.9/million BTU and distillate fuel $8.9/million BTU (excluding taxes).
2. In this context, near-term means having significant impact before 2010, while long-term means significant impact in the 2010-2020 timeframe.

The scope for this report was defined jointly by DOE and ADL...

Task I: Biomass Resource Assessment
- Review literature (an independent assessment was out of scope)
- Segment biomass by geography, source, type and availability
- Identify price/volume relationships
- Identify gaps in available literature

Task II: Identify Routes for Significant Increases in Biomass Utilization
- Review current projects and programs
- Develop list of potential biomass products and technologies
- Identify technical, economic, infrastructure and market barriers to the implementation of biomass supply chains
- Identify the most attractive biomass supply chains

Task IV: Benefits and Impact Analysis
- Modify existing fuel chain tools to apply to U.S. and a range of products
- Quantify the emissions and economic impact of alternative supply chains
- Quantify relative attractiveness of competing chains
- A life cycle analysis of costs and/or emissions was not part of the scope of this study

Task III: Market / Scenario Analysis
- Use ADL "visioning" tools to identify the tasks which must be taken to achieve DOE goals
  - Aggressive increases in biomass use by 2010 (more than double)
  - "Business as Usual" scenario
- Identify barriers to achieving this level of increase
- Develop a strategy for the United States Government moving forward, taking advantage of all knowledge gained in preceding tasks and synergies among alternative chains

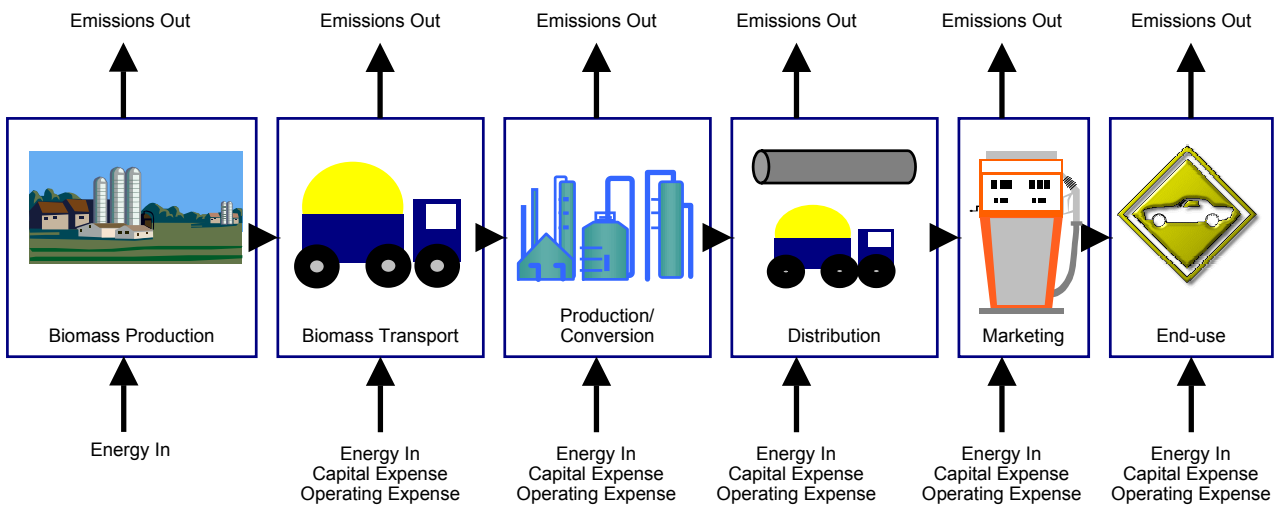
... USDOE and USDA staff were given opportunities to provide input to and comments on the analysis.

The report focuses on near-term[1], high-impact solutions.

- The near-term (primarily until 2010) nature of the scope forced us to focus on technologies that are close to commercialization, though some less mature technologies could have higher impacts
- The high-impact aspect of the scope focused our analysis on options that are broadly applicable at high market volume, though some other options may be attractive in the near-term:
  - While in a long-term, high-impact scenario negative feedstock values are unlikely to be sustainable, in the short term they can materially impact the economics of early plants (e.g. Masada MSW to ethanol project)
  - Use of idled capacity plants (paper mills, biopower plants, etc.) could provide significant capital cost advantages for some early plants (especially in California)
- The cost impact of environmental degradation was not internalized in the economic analysis in this project:
  - Environmental degradation can have significant economic impact in the long term
  - Similar to most economic analyses, this study considered these factors as externalities (i.e. they are not included in the economic evaluation) as they are difficult to quantify
  - Some researchers internalize these factors into the economic evaluation, which negatively affects the economics of less environmentally friendly technologies
- Secondary or tertiary impacts on energy use and environmental impact were not considered, as would be done in a life cycle analysis

1. In this context, near-term means having significant impact before 2010, while long-term means with potentially significant impact in the 2010-2020 timeframe.

Throughout the report, each potential fuel/power/product was analyzed on a "value chain" basis: from plantation/collection site to the market of use.



Biopower, all pieces, including energy losses of transmission and distribution (but not investment costs of transmission and distribution)

Biofuels, "well to wheel" analysis, not including vehicle retrofit costs

Bioproducts, up to primary processing plant-gate

Value Chain Analysis:

- Considers all steps involved in production and use of biomass energy, fuels and products
- Incorporates multiplicative effects in value chain
- Allows for detailed analysis of each module and consideration of a range of combinations
- Considers all energy inputs into the value chain, including secondary not tertiary inputs; i.e. energy used to produce diesel for trucks is included but energy use to make the trucks or the refinery is not included

A life cycle analysis was not part of the scope of this study.

The baselines were defined on a output basis (biomass ending up in product) to ensure that efficient process technology is emphasized.

References	• **Biopower** – **Pulp & Paper Industry Steam Production:** Estimated that 100% of electricity production from wood & wood wastes is in the pulp & paper industry and is converted into electric power at 20% efficiency, with 80% of the waste heat recovered. Difference between actual use of hog, bark and spent liquor solids as internal fuels and implied need at 20% generation efficiency is assumed to be converted directly into heat and used onsite. (Data from Manufacturing Consumption of Energy Survey, EIA) – **Electricity Production from Wood & Wood Wastes; Electricity Production from MSW; Electricity Production from Other Biomass Wastes** from the EIA Renewable Energy Annual 1999 • **Biofuels** – For ethanol: Energy Information Administration (EIA) website: http://www.eia.doe.gov/cneaf/solar.renewables/alt_trans_fuel98/table10.html –Data for 1999: – 890,200,000 GGE[1] ethanol as a fuel oxygenate, – 2,489,000 GGE E85 (2,116,000 GGE ethanol) – 59,000 GGE E95 (56,000 GGE ethanol) • **Bioproducts:** Ahmed & Morris, The Carbohydrate Economy, 1992
Methodology	• The biomass baseline was defined on an output basis. The biomass mass equivalent was estimated with 17.5 GJ/ton biomass energy density for fuels and electricity. Industrial products were estimated to have an energy density of 80% of raw biomass (0.8 X 17.5 GJ/ton = 14 GJ/ton). The actual biomass used to make the products is greater than the amount shown because of process inefficiencies. • The economic value of the categories was estimated with EIA 2001 Energy Outlook 2010 reference case prices of $4.4/million BTU for primary energy (used to value steam); $11.2/million BTU for industrial sector electricity; and $10.9/million BTU for transportation sector motor gasoline. Products were assigned a value of $0.30/lb.

1. GGE: gallons gasoline-equivalent. Converted into gallons of ethanol at 129 MJ/gallon gasoline, 91 MJ/gallon ethanol (HHV)

Current annual use of bioenergy & bioproducts amounts to 108 million tons of biomass (output), ~2 Quads of energy, or $14 billion in product value[1].

- Biomass is a small part of the current United States primary energy mix (3.2% of primary energy use)
- In the United States, 75% of non-hydro renewable power generation is biomass-based, accounting for 1.5% of total power generation
- Biomass fuels (mostly ethanol) represent less than 1% of total transportation fuel consumption (and 20% of alternative fuel use including MTBE and CNG)
- For nonpower and fuel applications, industry is by far, the largest consumer of biomass (in the form of wood)
  - Applications are dominated by wood and starch for paper products, although a portion is used for selected materials and chemicals

Category	Baseline Annual Production: Output Basis			
	Conventional Units	Mass-basis (tons)	Energy-basis (TJ, 10^{12} J)	Economic-basis ($million value)
Biopower				
Pulp & paper industry steam production	1.4 billion MMBTU	82 million	1,440,000	$6000
Electricity production from wood & wood wastes	33 billion kWh	6.8 million	120,000	$1300
Electricity production from MSW	19 billion kWh	3.9 million	69,000	$730
Electricity production from other biomass wastes	3.4 billion kWh	690,000	12,000	$130
Biofuels				
Ethanol	1.3 billion gallons	6.4 million	113,000	$1,200
Bioproducts				
Industrial products	8.7 million tons	8.7 million	121,000	$5,200
Total		**108 million**	**1.9 million**	**$14,600**

1. Detailed assumptions are in the "Baseline Use of Biomass" section of this report.

Sufficient biomass is available to more than double biomass use but farm-gate prices at high volume are expected to exceed $20/dry ton[1].

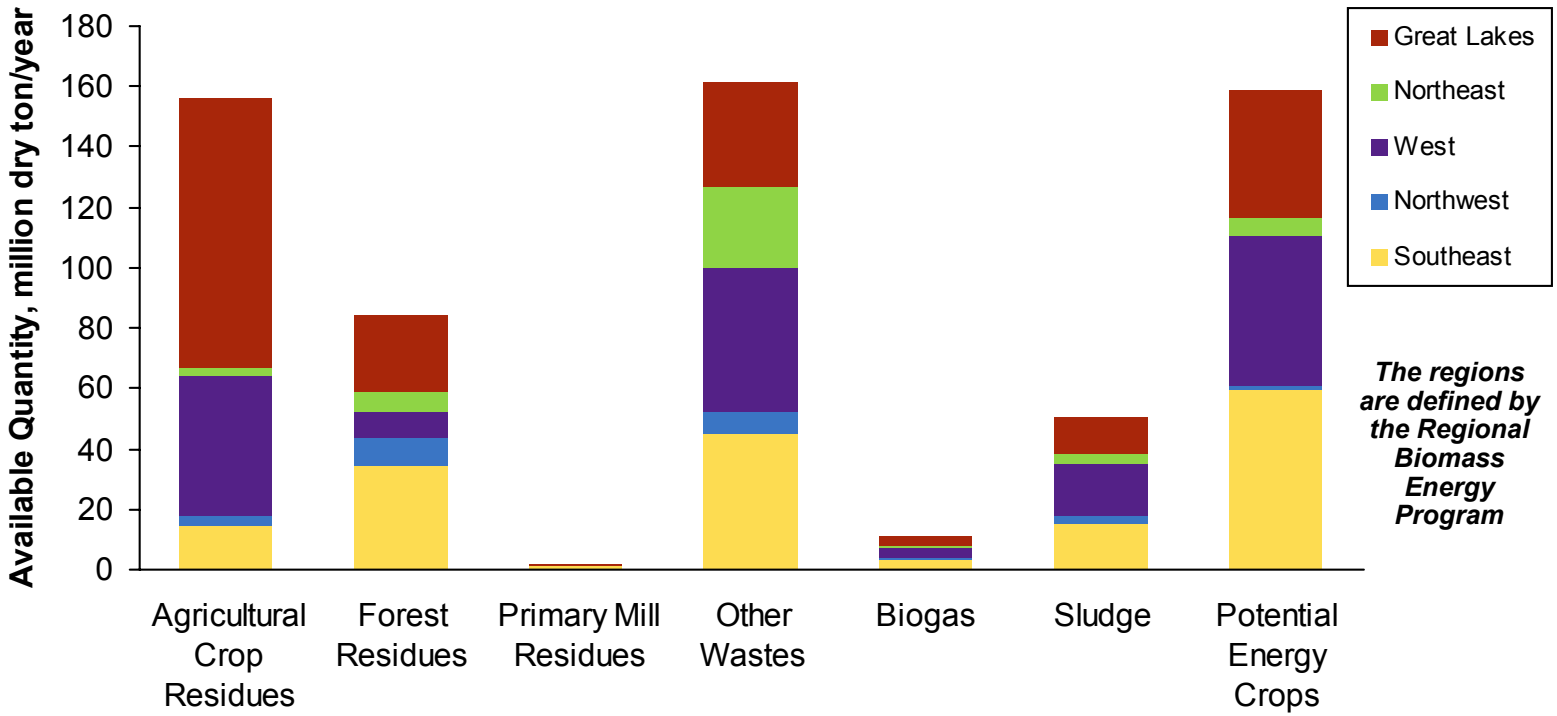
- Available literature data indicates that over 600 million dry tons of biomass are available within the U.S. at farm-gate prices between 0 and 40 $/dry ton (0 to ~$2.3/GJ or $2.4/million BTU):
  - Available biomass is defined as a resource that is currently or potentially collectable and not currently used as energy, fuel or any beneficial use and is potentially usable (not contaminated or comingled)
  - Available biomass in significant quantities below $20/dry ton farm-gate are heterogeneous wastes (Organic municipal solid waste, and urban tree residues)
  - Manure is potentially available in large quantities and at low cost, but off-site applications may be limited due to high transportation costs
  - Based on USDOE agricultural sector model projections[2], energy crops could be the largest source of biomass at prices in excess of $40/dry ton farm-gate, but energy crops are not currently produced in high volume
- Consistent and homogeneous biomass supplies are only available in large quantities at prices in excess of $20/dry ton farm-gate (e.g. energy crops, agricultural residues such as corn stover, wheat straw)
- The biomass sources with the highest potential in the 0-40 $/dry ton farm-gate price range are:
  - Corn stover (Great Lakes region: Minnesota, Iowa, Wisconsin, Illinois, Indiana, Ohio and Michigan)
  - Switchgrass (Southeast and West regions: all other states)
  - Organic municipal solid waste (Northeast: New England, New York, Pennsylvania, New Jersey, and Delaware)
  - Forest residues (Northwest :Washington, Oregon, Idaho, and Montana)
- Feedstock cost reductions are critical to enable broader competitiveness for most biomass technologies but feedstock cost reduction alone are not likely to be enough

Further cost reductions (through more efficient production and co-production with foods & feeds) could broaden the appeal of biomass use in industry.

1. For comparison for the industrial sector 2010 reference case: coal $1.3/million BTU; residual fuel oil is $3.4/million BTU; natural gas $3.3/million BTU in the EIA 2001 Annual Energy Outlook. The price of biomass is a farm-gate price; transportation of biomass is included in the costs of the various options.
2. Model results were obtained from Ugarte, D., M. Walsh, H. Shapouri, and S. Slinsky (July 2000), "The Economic Impacts of Bioenergy Crop Production on US Agriculture". Additional resource references are in the Data Volume to this report.

Region specific data were generated for available quantities of all biomass types.

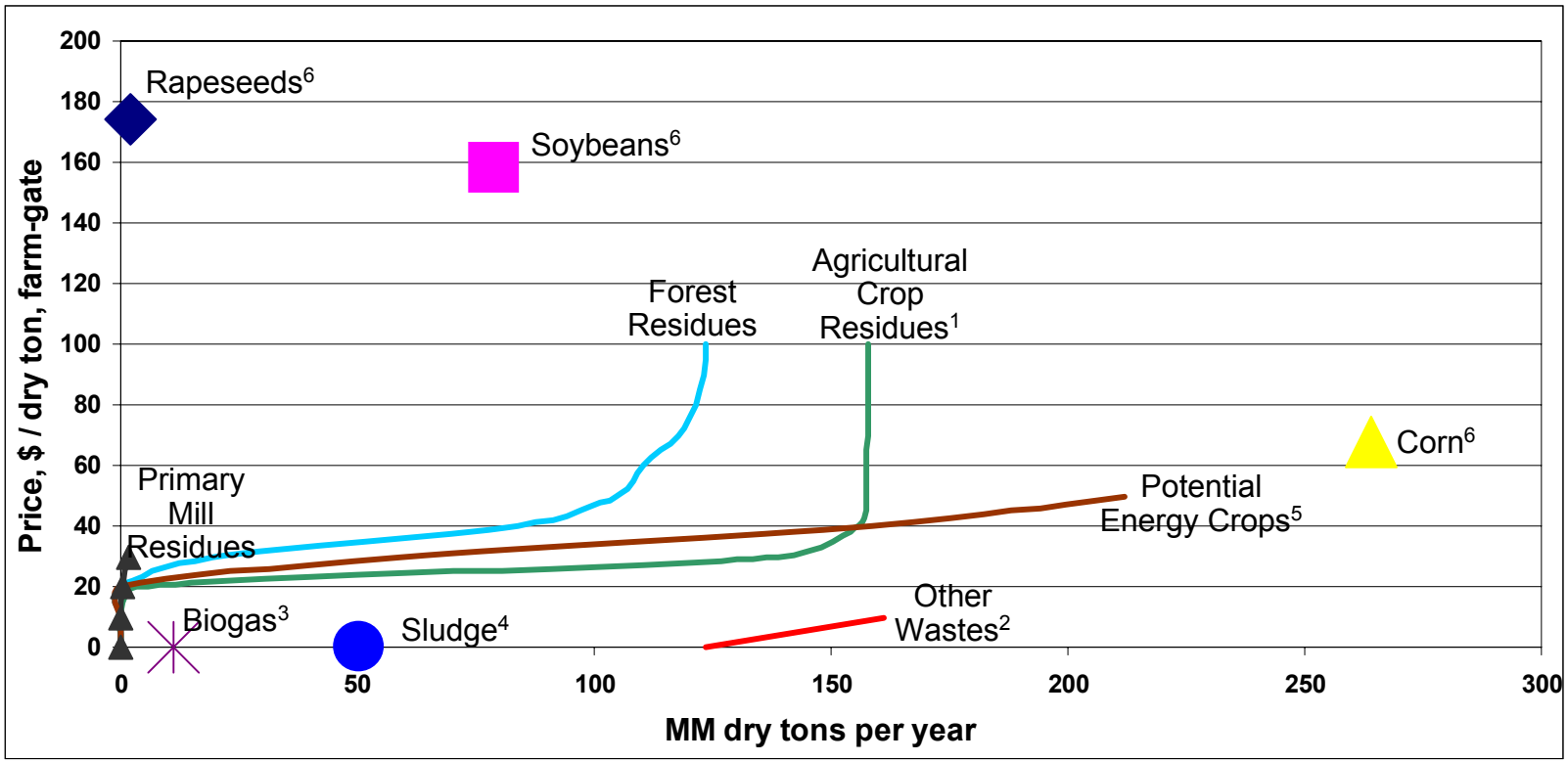
Cumulative Regional Available Quantities at 0 to 40 $/dry ton Farm-gate
Available Quantity, Million Dry Ton per Year



1. Regions defined by Regional Biomass Energy Program: Great Lakes region: MN, IA, WI, IL, IN, OH and MI; Northeast: New England, NY, PA, NJ, and DE; Northwest :WA, OR, ID, and MT; Southeast: MD, WV, VA,NC, SC, GA, FL, AL, MS, LA, AR, MO, KY, TN; West: CA, NV, WY, ND, SD, NE, KN, OK, TX, NM, CO, UT, AR; Data did not include Hawaii and Alaska
2. Agricultural crop residues includes corn stover, wheat straw, rice straw, and cotton stalks.
3. Other wastes include the organic fraction of municipal solid waste, urban tree residues, and construction and demolition wood
4. Biogas includes landfill gas, digester gas, and sewage gas.
5. Sludge includes manure and bio-solids.
6. Potential energy crops include switchgrass, hybrid poplar, and willow.

Some biomass may be available at low cost, but most is expected to command prices in excess of $20/dry ton farm-gate.

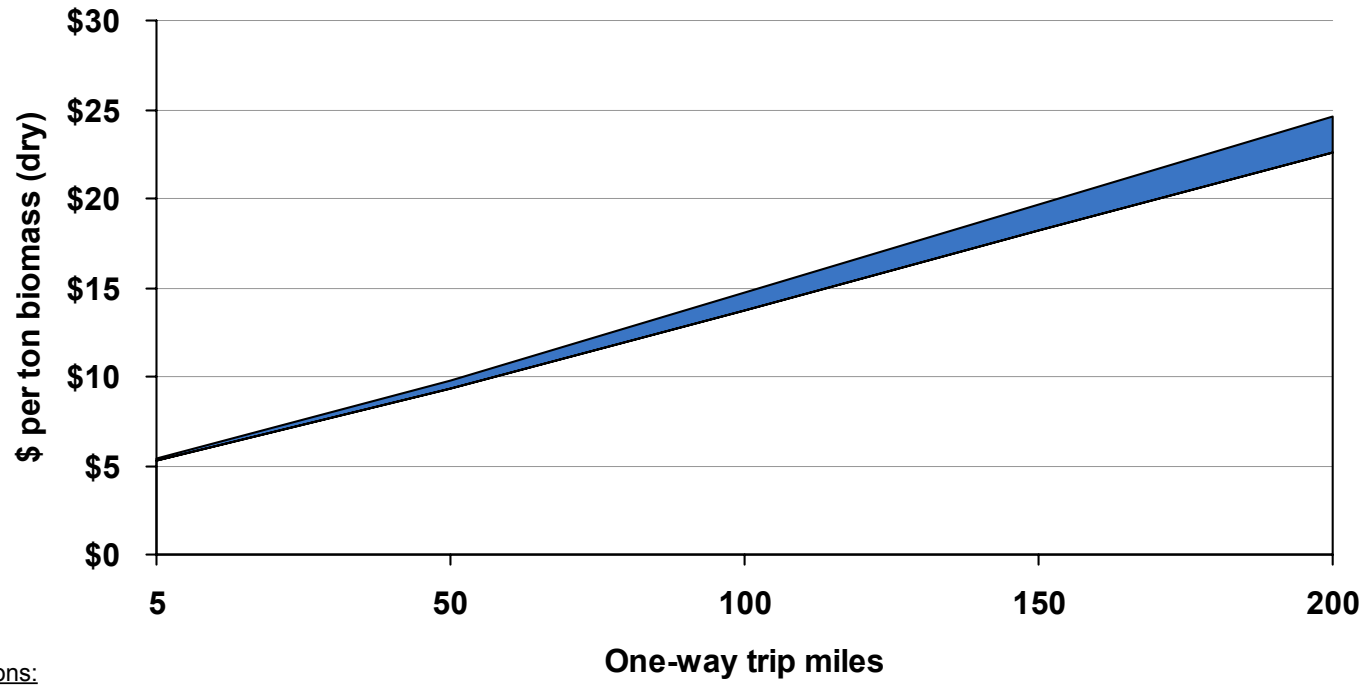
U.S. Available Biomass Supply Curve: Cost per Dry ton vs. Available Quantity Million Dry Tons per Year, Farm-gate Price



1. Agricultural crop residues includes corn stover, wheat straw, rice straw, and cotton stalks.
2. Other wastes include the organic fraction of municipal solid waste, urban tree residues, and construction and demolition wood.
3. Biogas includes landfill gas, digester gas, and sewage gas. This analysis assumes all biogas is available at zero cost and is used on-site.
4. Sludge includes manure and bio-solids. We assume that all sludge is zero cost and used on-site.
5. Potential energy crops include switchgrass, hybrid poplar, and willow. Note that production was not evaluated above $50/dt.
6. A supply curve analysis was not done for traditional crops (corn, soybeans, and rapeseeds). Used the national average price and total quantity produced.

Transport costs of raw biomass may be a key factor in limiting the economy of scale achievable particularly for fuels and product production.

Example of One-way Transportation Costs of Dry Biomass, Dollars per Dry Ton



Assumptions:
6 miles/gallon average fuel economy (from Transportation Energy Databook, volume 19)
$0.92-1.35/gallon diesel fuel
$1,000 maintenance cost per year, + $20 oil change every 5,000 miles
$50,000/year driver salary, + $25,000/year benefits, driver operates truck 3120 hours/year (60 hour weeks)
5 miles of each trip at local speeds, remainder at highway speeds. 2 hours of each trip spent loading/unloading
10 year truck life, lease rate 8% per year with 10% residual value at end of lease (.131 capital recovery factor)
$113,000 truck capital cost, 29 ton capacity

For this study, the assumption made was 50-mile one-way transport.

Biomass production for new industries could provide environmental benefits, provided careful management practices are implemented.

- Converting traditional crop lands into perennial energy crop production could yield net benefits in increased soil carbon and nutrients
  - Energy crop production can have erosion concerns unless managed properly
  - Reduced runoff contamination and improved biodiversity are additional potential benefits
- If agricultural residue collection is managed properly, soil quality (e.g. organic matter, nutrients, and soil stability) can be maintained and/or improved and increased runoff contamination avoided
- Marginal lands (not currently used for crop production) need to be carefully managed to realize net benefits from energy crop production
- Forest residue collection must be managed properly to prevent erosion and realize benefits from fire prevention
- Several areas of additional research are necessary to assess the potential environmental impacts and benefits of bioenergy and bioproducts industries
  - The information currently available is based on smaller scale studies
  - Studies at larger scale are needed to validate results and determine landscape scale effects
- Carbon dioxide capture benefits are accounted for in the biomass end-use step in this analysis

Options both with short-term and long-term potential to approach the set aggressive goals were identified for each application category.

Application Category	Long-Term Potential to Achieve Aggressive Goals	Potential for Short-Term Implementation	Potential Biomass Use in 2010, Output Basis
Biopower	• Biopower plants based on advanced BIGCC(biomass integrated gasification combined cycle) • Biogas based power generation (e.g. landfill, sewage, digester gases)	• Biomass co-firing with coal • Biogas based power generation (particularly landfill gas)	• Additional 4400 MW or 0.14 exajoule (electric) for BAU over baseline of 10,000 MW • Additional 13600 MW or 0.37 exajoule (electric) for Aggressive implementation over baseline of 10,000 MW
Biofuels	• Broad use of bioethanol as a gasoline blend stock • Use of bio-FT-diesel as a diesel blend stock • Niche applications of each as neat fuels	• Use of ethanol as a gasoline additive and octane booster (bioethanol as MTBE replacement)	• Additional 800 million gallons ethanol for BAU (0.07 exajoules) over baseline of 1520 million gallons • Additional 2.3 billion gallons ethanol equivalent for aggressive implementation (0.2 EJ) over baseline of 1580 million gallons ethanol
Bioproducts	• Broad implementation of fermentation-based processes, primarily for polymer (feedstock) replacements	• Pyrolysis- or low-temperature processing-based options utilizing cellulosics and lipids, preferably integrated with an existing chemical plant • Fermentation derived polymer building-blocks	• Additional 600 million pounds in for BAU (~4200 TJ) over baseline of 21 billion pounds bioproducts • Additional 7.5 billion pounds for aggressive implementation (52,000 TJ) over baseline of 21 billion pounds bioproducts

TJ is 10^{12} Joules or 9.5E-7 Quads; 1.054 Exajoule (10^{18} Joule)= 1 Quad (10^{15} BTU)

Integration of these options could lead to “biorefineries” and could improve the long-term attractiveness of some of these options.

Several options for biomass-derived power and products appear to approach commercial competitiveness with their conventional counterparts...

- Some biomass options are approaching commercial competitiveness:
  - Biogas power (e.g. utilization of landfill gas) and biomass co-firing with coal are cost competitive in a broad range of geographic markets
  - Certain bioproducts are cost-competitive with their conventional counterparts and can offer performance advantages
- Bioethanol currently competes successfully in additive markets but currently relies on a significant ethanol fuel tax credit
- Feedstock availability is not a barrier to increased biomass implementation, but ready, consistent availability of low-cost feedstock would aid the economics and mitigate risks for investors:
  - Some feedstock is available at low cost now (and even at negative cost), which will help economics of some early entrants
  - As demand rises for high-impact applications, cost of feedstock is expected to become a significant factor and tipping fees will not likely be sustainable
- Nevertheless, the principal barrier to broader implementation of bioderived energy and products is the high production cost of almost all of the options:
  - Most green-field biopower options are expected to carry a net cost premium over natural gas-fired gas turbine combined cycle power generation of between 50% and 100%
  - Where biofuels are valued only on fuel energy content, they carry net pre-tax cost penalties of over 60% over conventional fuels (not taking into account the tax credit)
  - Despite significant advances in technology, many bioproducts appear to carry some cost-premium over fossil derived analogs

... but the production cost of biomass-derived energy and products remains the main factor limiting the ultimate potential for broad implementation.

From an initial list of over fifty options, ADL selected four classes of biopower for short and long-term implementation.

All biogas combustion options	• While the technical market potential is modest in size, the economic attractiveness of most options suggests that this "low-hanging fruit" is cost competitive now and should be developed wherever possible • Biogas includes landfill gas, sewage gas, and digester gas
Co-firing of solid biomass and of gasified biomass	• The economics are nearly competitive with wholesale power (but typically not with the marginal cost of coal-based power) • The large market potential could significantly contribute to the aggressive goals • This also retains utility-scale gasification technology in the mix of options
RDF Gasification	• Because the feedstock is potentially available at low to zero cost, the economics can be attractive • Because only a small fraction (~15%) of municipal waste is combusted for energy today, this leaves a very large untapped potential market • There are likely to be hurdles with respect to permitting and public resistance
Gasification of process wastes	• Where onsite waste fuels are available, gasification technology could be cost competitive, and have modest near-term market impact and significant long-term impact – Successful deployment of IGCC in the pulp & paper industry is critical to making this a high-impact option. • The cost of stand-alone biomass IGCC power for sale into the wholesale market is expected to be well above the cost of competing conventional technologies, but represents an enormous long term opportunity – Gasification, which will enable the long-term viability of new, biomass-only grid power, was retained for analysis in applications with better near-term economics.

Biomass co-firing at existing coal plants appears to be an attractive near-term option for biomass-based grid power.

Advantages	Barriers
• Much lower marginal capital cost than new biomass-only power plants ($50-500/kW vs. $1,500-$2,000/kW) • Emissions benefits at the coal plant (NOx and SO_2) have real economic value due to emissions trading • Able to take advantage of the higher efficiency of large coal-fired power plants (30-35%) compared to existing biomass-only power plants (15-25%) • Flexibility in biomass firing rates	• Fly ash regulations need to accommodate biomass content • Co-firing may trigger New Source Review requirements and may be incompatible with SCR for NOx control • Plant owners may perceive or encounter risks: – Biomass fuel price and availability relative to coal – Technical issues that could impact overall plant reliability and availability • Many coal plants are 30+ years old – the long-term future of these coal plants may be uncertain – Increased future interest in clean-coal technologies has the potential to offset the impact of retirements, at least partially.

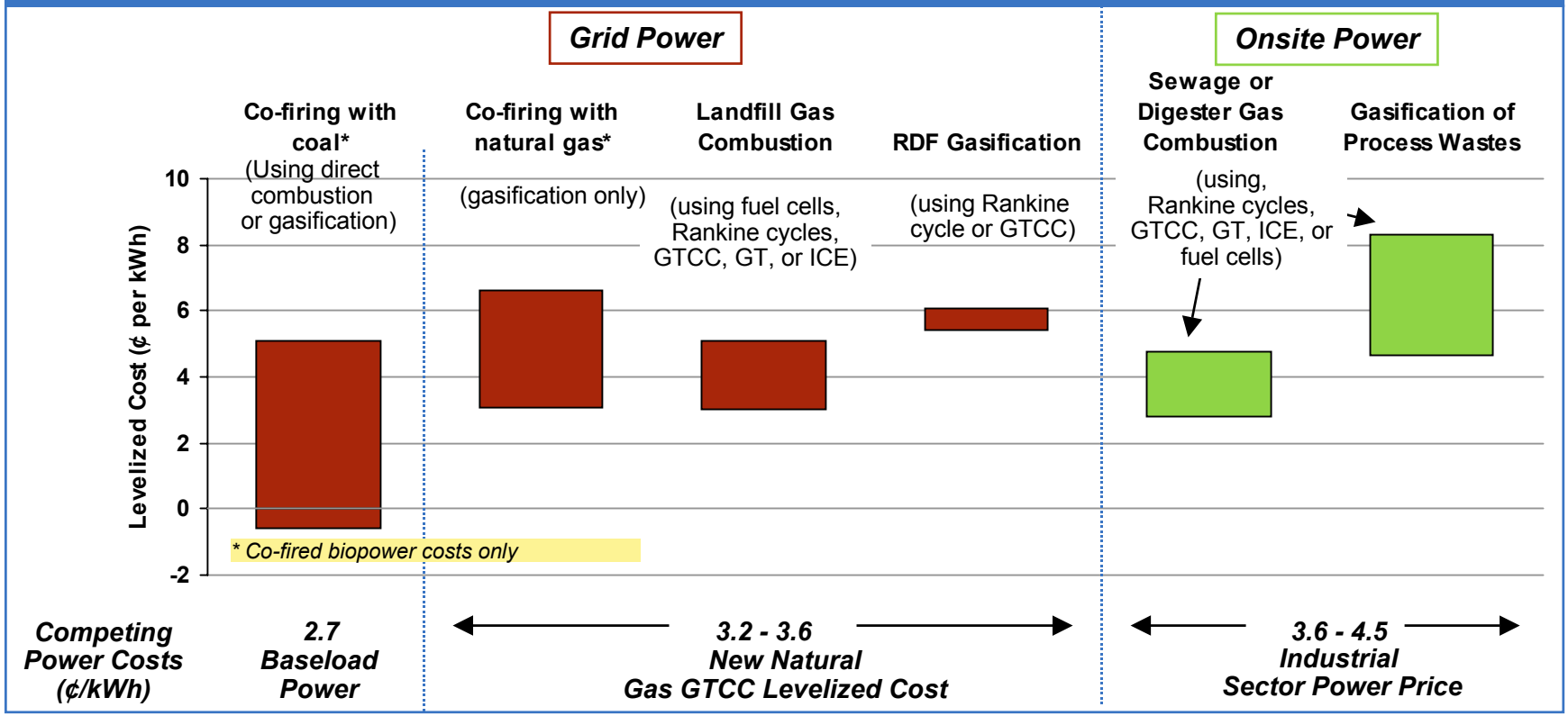
- The United States has an installed coal-fired capacity of approximately 320,000 MW (more than 1,000 individual units)
- Biomass can be co-fired at rates of up to 10-15% on a energy basis, yielding a theoretical market potential for biomass of 32,000–48,000 MW
  - This is likely to be limited by biomass supply and other factors, but the potential is still significant

Co-firing with coal and utilization of biogas appear very attractive relative to grid and industrial power rates, provided that fuel costs are very low.

Assumptions and Methodology	• The costs shown are based on the levelized (all-in) cost of electricity (COE). The range in COE for a given application is due mainly to a range of feedstocks costs ($30-60/dry ton farm-gate for agricultural residues & energy crops; 0 to $30/dry ton farm-gate for process wastes (e.g. black liquor, hogged fuel, other solid residues); $0 - 0.50/GJ farm-gate for gaseous biomass); Detailed assumptions are in the data volume and in the biopower section • Results are expressed per kWh delivered. For grid-sited, this includes transmission and distribution energy losses of 7.2 percent, but not the actual costs of delivering the power • For options employing biomass co-firing with coal or natural gas, the economic calculations *are for the biomass portion only* • For biogas options (e.g. landfill gas, sewage gas, digester gases), the cost of generating and collecting the biogas is assumed to be accounted for outside the cost of power • Coal plants were assumed to be fully depreciated so that the cost of power from coal plants is effectively the marginal cost only. In order to better compare the levelized COE of biomass co-firing options to a similar grid option, data for electricity futures contacts were reviewed. Based on these data, 2.7¢/kWh was determined to be a reasonable cost for grid base load power
Comments	• Biomass co-firing has the potential to significantly reduce NOx emissions from coal plants, in addition to SO_2 reductions. These reductions were included in the levelized COEs, based on futures prices for NOx credits , and current prices for SO_2 credits. Co-firing in a natural gas GTCC does not produce emissions savings (other than CO_2), so there are no monetized credits for NOx or SO_2 included in the analysis • Although today some residues may have negative cost, for this analysis the minimum cost is assumed to be zero, a general assumption made throughout the study, consistent with the concept that as biomass utilization increases, residues that were once thought of as liabilities now have market value • For some industries, most notably pulp & paper, process residues are utilized for power and heat regardless of the power economics, because their use is integral to the core industrial process
Conclusions	• For grid-sited power plants utilizing solid biomass feedstocks, the cost of the biomass feedstock is an important component of total levelized costs • The range in levelized cost of electricity is from slightly negative for RDF and sewage sludge co-firing with coal to approximately 8-11 ¢/kWh biomass only Rankine cycle power for grid applications using agricultural residues & energy crops (not shown on plot of attractive options) • New, grid-based biomass-only power falls in the 7-11 ¢/kWh range for feedstock costs of $10-60/dry ton farm-gate using Rankine or IGCC technology (not shown on plot of attractive options) • Landfill gas and other biogas options appear to fall in the 3-5 ¢/kWh range, driven in part by very low fuel costs • Co-firing options appear the most attractive, due to low capital costs and in the case of coal, emissions credits

The lowest cost biopower options are co-firing with coal (due mainly to low capital costs) and biogas combustion (due mainly to low fuel costs).

Summary of Levelized Costs for Biomass Power Generation Options (¢ per kWh delivered)



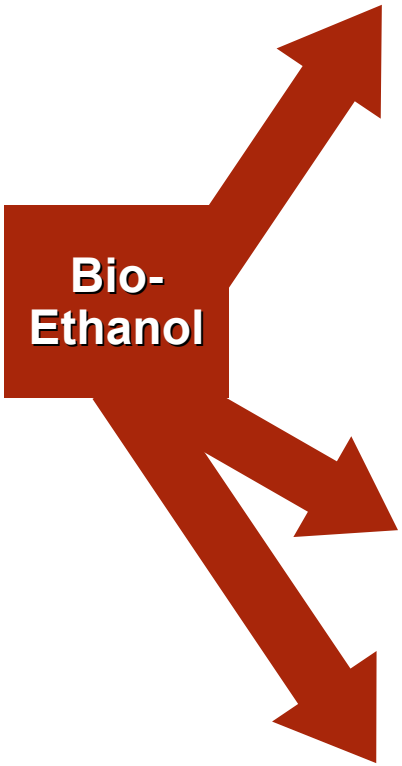
1. For co-firing cases, biomass is co-fired at a rate of 10 percent based on heating value. Natural gas is assumed to cost $2.90-3.47/MSCF.
2. Biogases such as landfill gas, sewage gas & digester gas; process wastes are generated and used onsite.
3. Co-firing with coal was compared to an estimated baseload wholesale cost of 2.7 ¢/kWh. All other grid power cases were compared to new capacity natural gas-fired combined cycle levelized cost of 3.2-3.6 ¢/kWh. Onsite power options were compared to industrial sector rates of 3.6-4.5 ¢/kWh (EIA *Annual Energy Outlook 2001*, Base Case price in 2010).
4. The analysis includes transmission and distribution energy losses of 7.2 percent for the grid power options, but not the actual electricity delivery costs.
5. Biogas costs range in price from 0-0.50 $/GJ; RDF & process wastes from $0-10/ton; agricultural residues & energy crops from $30-60/ton.

From an initial list of over 100 biofuel options, ethanol provides the economically most viable option for broad application.

- Currently, all biofuels are significantly more expensive to manufacture than petroleum fuels on an energy basis (e.g. dollars per million BTU energy content)
- Ethanol manufactured from corn continues to be a key current and near term option for oxygenates for MTBE replacement and octane blend stock
- Ethanol offers additional value in use as an additive and blend stock, respectively
  - Ethanol offers additive qualities which can increase its value far beyond its energy value, and can be cost-competitive, especially when considering the current ethanol fuel tax credit
- Bioethanol can be used as a blend stock in the existing fuel infrastructure

Ethanol	• Ethanol is attractive as an alternative additive to MTBE in reformulated gasoline or as an octane booster • Ethanol comes closest to cost-competitiveness with conventional fuels and there is significant experience with its use • Current and near-term demand is likely to be fulfilled by ethanol made from corn; cost projections of next generation SSCF cellulosic ethanol technology may make that technology competitive in mid around 2010

Ethanol is being used in three different modes, with its use as a gasoline additive being the economically most favorable one.



Gasoline Additive or Blend Market (Primary existing market with significant potential for near-term expansion)

- Current regulations limit blends to 10 percent by volume ethanol
- Higher concentration ethanol blends (likely up to 20%) are technically feasible
- Blended at 5 to 10% in gasoline by volume (typically 5.7, 7.7, 10%*)
- Works in conventional vehicles without any adjustments
- Provides octane improvement, emissions reduction, and a near-zero sulfur blend stock

Conventional Gasoline

- Ethanol value based on gasoline price with a premium based on ethanol's octane value
- Historically, ethanol is used as an octane enhancer and gasoline extender
- Suboctane gasoline for ethanol blending is now being produced in areas with high ethanol use
- E10 has an RVP waiver to compensate for its RVP increase in gasoline blends

Reformulated Gasoline (RFG) and Oxygenated Gasoline

- Clean Air Act requires a minimum oxygen content (Primary oxygenates are ethanol and MTBE; public acceptability of use of ethanol as ETBE is questionable)
- Value is based on oxygenate content (based on MTBE); minimum is based on competing MTBE prices
- Ethanol market will likely expand with an extended MTBE ban and continuation of oxygenate use in RFG
- Higher premium is possible if MTBE is phased-out suddenly resulting in an effective ethanol mandate
- Requires adjustment of summer RFG gasoline blend stocks to produce low vapor pressure gasoline
- May require more gasoline blend-stock; and may put more pressure on gasoline supply

Neat fuel (Existing, small market with largest potential size; least potential for expansion in near to mid term)

- Denatured with gasoline (e.g. Ed-85 in U.S.; Ed-95 in Europe); requires modest modifications to some vehicles, though new vehicles sold in the U.S. are increasingly fuel flexible, requires slightly increased maintenance
- Receives no premium over super premium gasoline (value based on heat content)

E-diesel

- Ethanol may also be used as a diesel oxygenate in e- diesel or oxydiesel (~10% vol ethanol; 5-10% other additives)

*5.7% and 7.7%vol are blends that correspond to the oxygen content standards for gasoline sold in ozone nonattainment and carbon monoxide nonattainment areas under the CAAA. Higher volume percentages needed for MTBE

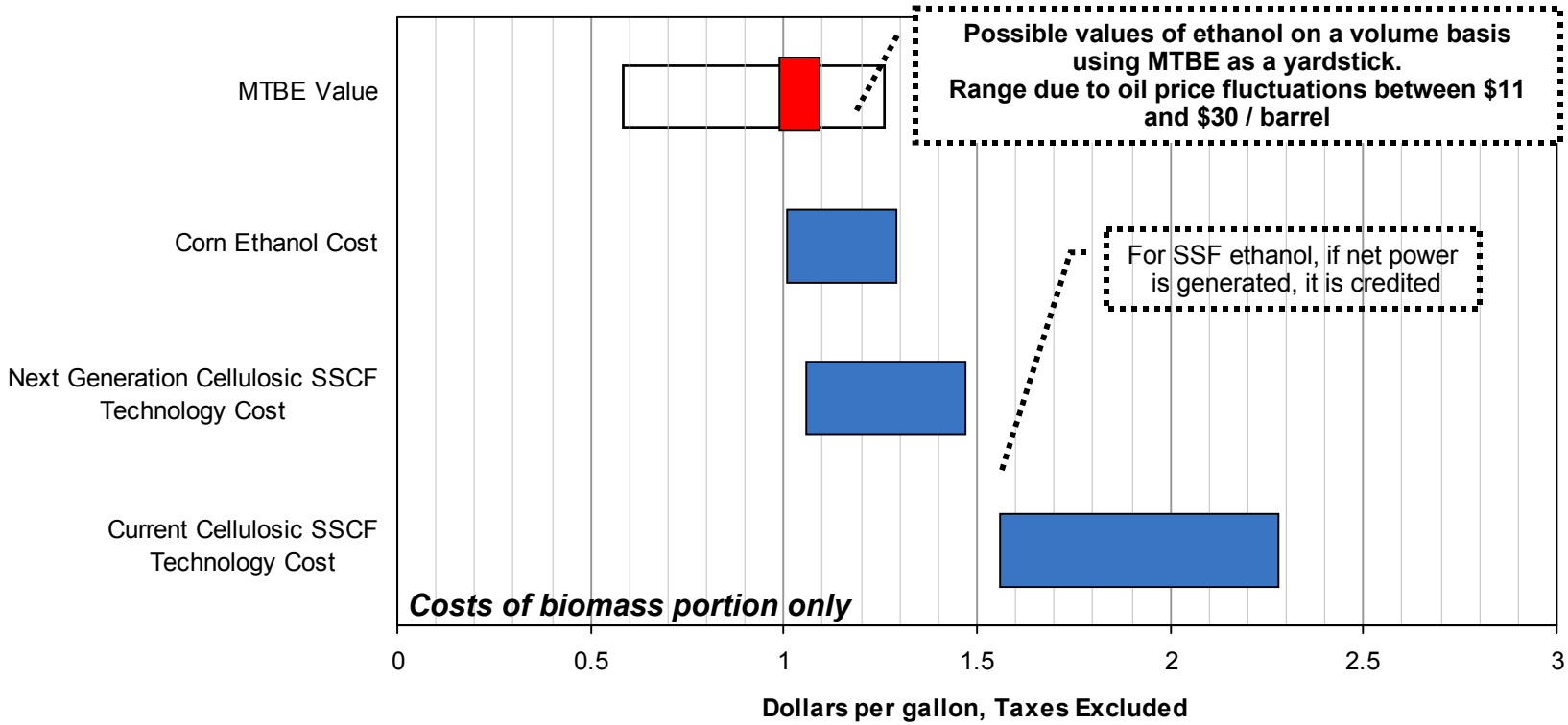
Ethanol use as a additive provides an attractive biofuel option, which eventually could become cost-competitive without the tax credit...

Assumptions and Methodology	• Bars represent range of feedstock costs ranging from agricultural residue feedstocks to energy crops ($30 - 60/dry ton, farm-gate) • We used EIA price projections for regular gasoline for 2010 and estimated MTBE prices based on these prices and the current premium of MTBE over regular gasoline (octane 89) • Bioethanol is transported by truck, train, or barge (not pipeline) to blending terminals • Assumed no vehicle modifications. Assumed no engine efficiency impact of biofuels
Comments	• Opportunity for increased use of ethanol as an additive is created by MTBE ban in California and other states considering MTBE restrictions • The uncertain outcome of the MTBE debate creates uncertainty around this ethanol use option (e.g. continued MTBE use, complete MTBE ban, removal of oxygenate requirement; are all possible) • In the long run, (post 2015) ethanol made from cellulosic-feedstocks could be cost-competitive without a tax credit with MTBE under most oil price scenarios, reducing the need for a tax credit • In the near term the tax credit will be necessary under most oil price scenarios and provides a “cushion” for producers and buyers • Potential for low-cost ethanol from corn will eventually be limited by markets for corn-mill co-products
Conclusions	• Current starch / sugar-based ethanol provides a practical MTBE alternative under modest to high oil price scenarios with a tax credit • Developmental SSCF technology could make ethanol production independent from food and feed production and possibly reduce the price differential in high volume, eventually perhaps obviate the need for the tax credit

... but in neat form would add significantly to the overall fuel cost.

Ethanol used as an additive commands a significant premium over its value based on energy content (~50 percent premium including taxes).

Levelized Cost of Ethanol as an Additive , $ per Gallon (Taxes excluded)



1. The bar range represents the spread of feedstock cost.
2. Corn ethanol price is based on ($1.5/bu with 2.8 gal ethanol yield per bushel corn) to ($2.9 per dry bushel corn with 2.7 gal ethanol per bushel); total chain cost.
3. The blended fuels are blended at a level of 10 percent by volume. The costs represented are for the biomass-derived fuel portion
4. The bar range of the SSCF options reflects feedstock cost of $30 to 60 per dry ton; farm-gate
5. SSCF is simultaneous saccharification and co-fermentationtechnology that utilizes cellulosics as the feedstock

Several bioproduct options appear to approach cost and performance parity with conventional petroleum-derived products.

Fermentation-Based Polymer Building Blocks	• Could offer cost-competitive routes to commodity plastics provided key technology challenges are met: – High primary product yield from substrate and high concentration in broth – Large-scale, continuous-reactor fermentation production technology – Ability to use low-cost feedstock (i.e. waste or inexpensive feedstock) – Offsite (e.g. Outside battery limit infrastructure) requirements that are similar to conventional petrochemicals
Pyrolysis- & Low-Temperature Processing-Based Products	• May be competitive in medium-sized markets: – Phenolics from wood pyrolysis for resin applications – Fatty alcohols from seed oils – Other lipid based products for lubricant & surfactant applications – Lipid-based feedstocks for polyurethane foam and coating applications
C1-Chemistry (Syngas) Based Products	• Do not appear to come close to being cost-competitive on a stand-alone basis • Even though it is less attractive, there might be a need to consider it as a technology to produce co-products as part of a bio-refinery concept (e.g.in FT-diesel or dimethyl ether production) • May require similar market premium or subsidy as current biofuels

Current bioproducts are derived from starch and lipids. Future growth may be through the use of cellulosics.

Starch & Sugars	Most current activity, especially for fermentation based processes, uses simple carbohydrates such as glucose as feedstock to make specialty chemicals and new polymer building blocks. The feedstocks are derived from food processing waste streams and pre-processed starches and are generally high in cost. For future high growth scenarios, research and development will be required to utilize more complex (and cheaper) feedstocks such as cellulose and hemicelluloses from cellulosic biomass
Lipids	Lipids are oils derived from plant and animal fats. Products have been used that incorporate the lipid as is but are limited in application. Typically the lipids are further processed by oil splitting and transesterification to produce glycerol, fatty acids,esters and alcohols. The ultimate market volume for lipid derived products may be limited by the supply of seed oils so that large scale application in some segments of the lubricant and surfactant market may be resource limited
Cellulosics	Cellulosics represent the feedstock with the largest potential volume for use for power generation, fuels production and chemicals production. For chemicals production, a key hurdle is using all constituents of the biomass (e.g. cellulose, hemicellulose, and lignin fractions). Research using the tools of biotechnology may enable broader use of the more recalcitrant fractions of the biomass (hemicellulose and lignin) for markets other than for power generation.

Trade-offs between the different types of process technologies are based on their inherent processing characteristics coupled with properties of the feedstock.

Physical Separation	Fermentation	Low Temperature Processing	Pyrolysis	C_1 Chemistry

Increasingly takes advantage of biomass' inherent chemical structure. This typically helps the economics of the plant provided all fractions of the biomass (and co-products) have an end disposition

Increasing flexibility in product slate that can be produced. Therefore, increasingly likely to be able to cover large potential markets

Increasing impact of genetic engineering developments on process performance and product features

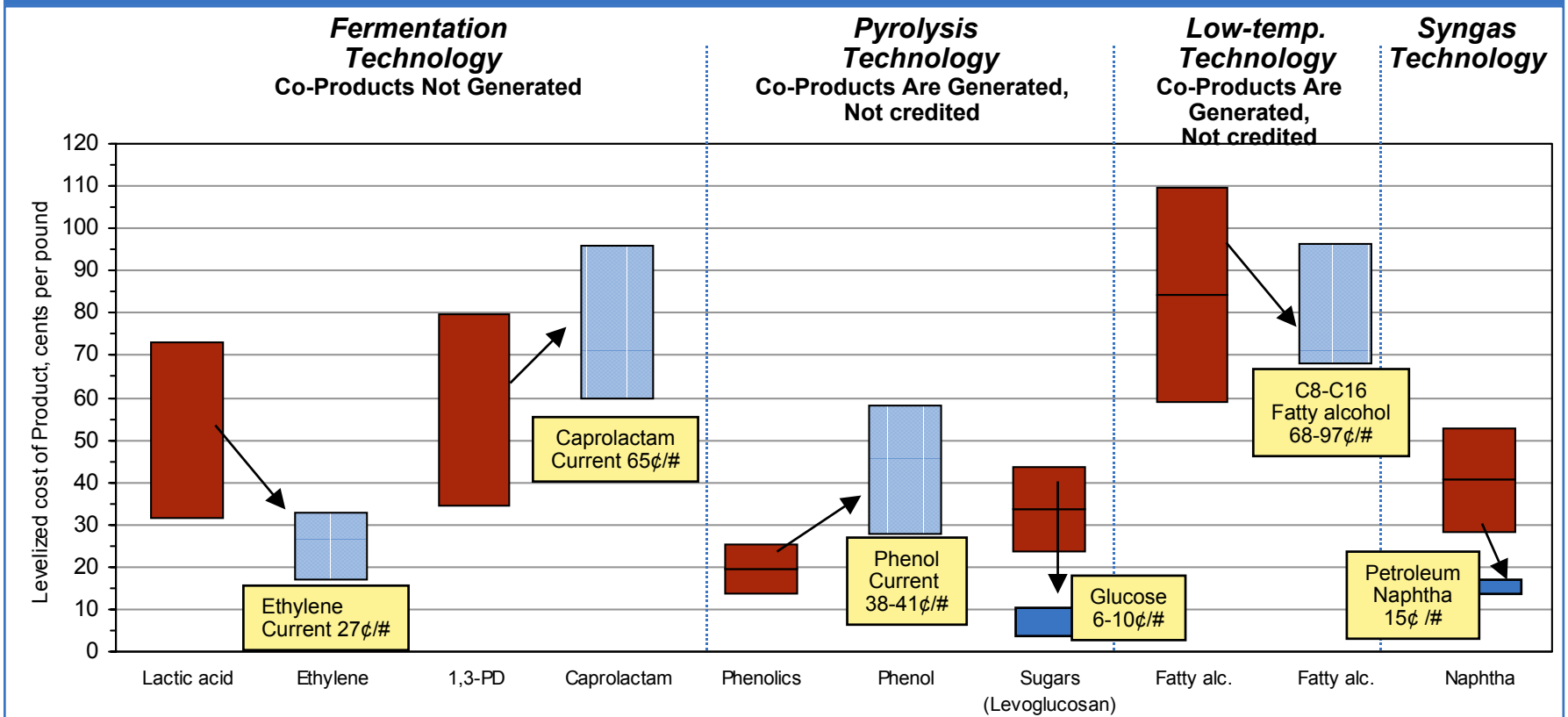
Increasing importance of system thermal integration for process performance and cost

Fermentation based products for biomonomers appear promising if large scale continuous commodity processing can be achieved.

Assumptions and Methodology	• The plant-gate levelized product costs shown include the cost of the biomass feedstock, biomass transportation and primary product manufacture. Further costs for product transportation and distribution & marketing of the product or derivative manufacture/formulation are not included; it is a primary plant-gate cost. • The range in the bioproduct costs reflect: for fermentation products the range of likely technologies used (batch and continuous bubble column technology); for pyrolysis products, plus/minus 30 percent of the plant-gate estimated cost; for low temperature process products, plus/minus 30 percent of the plant-gate estimated cost; for syngas derived products, plus/minus 30 percent of the plant-gate estimated cost • The range of comparative prices for ethylene, caprolactum, and phenol reflect historical prices ~1990 to present with the current prices shown • Green field plants are assumed. Plants using existing infrastructure were not analyzed
Comments	• The level of offsite investments has been estimated for each technology. Especially for fermentation based products, the level of infrastructure required for large scale commodity manufacture is an unknown. For example, investments for water treatment and investments required for microorganism containment should be further investigated • The extent of economy of scale savings for fermentation based processes has been estimated for continuous processes using scaling methodology. The likely impact of increased scale on the total investment cost of the entire plant is an area of necessary attention since it will impact the viability of green field “biorefineries” which share infrastructure costs and produce a slate of products
Conclusions	• Fermentation processing for “biomonomers” appears promising if large scale continuous processing can be achieved which delivers cost savings from economy of scale • Pyrolysis technology may be used to produce medium-size market products cost effectively (even at an advantage compared to petrochemicals). Additional costs may accrue from investments in product application & market development. Products such as sugars will likely be too expensive to be used as a fermentation feedstock • Low temperature processes such as oil splitting are a mature technology and may be limited due to raw material availability and marketing of glycerol co-product • Syngas processes based on biomass are likely to be too capital intensive for broad application on a stand alone basis even though it promises high flexibility towards the product slate

Bioproducts particularly using fermentation technology have potential to cost effectively compete as monomers.

Plant-gate Levelized Cost of Products, Cents per pound, Co-products Not Credited



1. The price of corn was $2.92 per dry bushel farm-gate. Wood for phenolics and levoglucosan is $50 per dry ton farm-gate. Seed oil is $0.17 per pound. Cellulosics were $30 per ton farm-gate.

Products using pyrolysis and low temperature (oil-splitting) are competitive today with sufficient raw material cost; market may be resource limited.

Biopower use could double by 2010 if a biomass infrastructure is established early, technology is developed successfully and strong government support is available.

- Biomass co-firing with coal provides the best options for rapid, near-term growth and is expected to account for over 50% of the growth until 2010
  - Direct co-firing using non-woody fuels (e.g. crop residues and grasses) will likely be required, which will itself require further technology development and demonstration
- Biomass integrated gasification combined cycle (BIGCC) technology in the pulp & paper industry is the second most important contributor with almost 20%of the growth through 2010, and with greater potential post-2010, provided the technology is adopted by the industry and cost is reduced
- Landfill gas and other biogases such as sewage and digester gas also figure prominently in the aggressive growth scenario for early growth
  - Technologies are available today
  - USDOE should focus on removing economic or regulatory barriers
- Other gasification options are less important in the near-term but are important for sustained growth:
  - Other industries that generate residues are expected to contribute modestly throughout the 2000-2020 timeframe
  - RDF could become a significant source of biopower in the long term, provided technical and environmental issues are addressed successfully
  - Gasification for co-firing could become significant beyond 2010, in both coal- and natural gas-fired power plants
- Implementation of the Aggressive Growth scenario would require several successful simultaneous developments:
  - Biomass supply infrastructure to develop rapidly if the market potential is to be realized
  - Successful development of gasification technology
  - Successful elimination of regulatory barriers to biopower implementation
- It would also require significant government support to overcome the cost difference of some longer-term options and expected market prices

In the desired "end-state", multiple biopower technologies are commercially available with some markets fully exploited.

2020[1] End State

Co-Firing

Biomass co-firing with coal fully exploited at a variety of scales and firing percentages

10-15,000 MW co-firing in operation

Biomass infrastructure developed to deliver large quantities of biomass (energy crops, residues)

- Large companies involved
- Market mechanisms in place similar to other fuels (e.g., futures, B2B)

Grid Power

Gasification-based technology is scale independent and low cost

RDF gasification fully accepted as viable option - commercially viable

Landfill gas fully exploited - 3,000 MW added

Common technologies between utility-scale IGCC are transferred to P&P industry for hogged fuel and bark residues

Onsite Power & CHP

Conversion technology is scale independent and low cost

Residues used for highest value application

5-6000 MW added in P&P through efficiency gains from gasification (black liquor, hogged fuel, bark, sludge). (Capacity added via increased biomass utilization for power only, which is part of the 2020 Vision of the pulp & paper industry, would be in addition to this amount).

Common technologies between landfill, sewage and digester gases and other applications are transferred across market segments. Technology developments are applicable to biomass fuels and products applications

- Small-scale power generation
- Gas cleanup
- Low-medium Btu combustion systems
- Project development learning and business models (e.g., for many small-scale sites)
- Partnerships

Biomass Co-firing with coal

Gasification/IGCC

Biogases

Power in P&P

Regulations & Biomass markets

Small-scale Gasification

1. We selected 2020 as the year to focus the vision to avoid missing attractive technologies that only barely achieve market introduction by 2010.

The aggressive growth scenario will require early technology demonstration combined with significant market and regulatory support.

- Biomass Co-firing with coal
- Gasification/ IGCC
- Biogases
- Power in P&P
- Regulations & Biomass markets
- Small-scale Gasification

2002 | **2003** | **2004** | **2005**

Co-Firing

- NO_x Trading begins
- Specs for fly ash accepted - biomass content is OK
- Special co-firing incentive to encourage early adoption - targeted to first 15-20 commercial plants
- U.S. demo of gasification co-firing in a coal plant
- Co-firing broadly accepted as green power - certification is given
- Solid co-firing with herbaceous biomass is as "easy" as with woody biomass
- Biomass fuel infrastructure responds to growing demand - large companies enter
- 1st commercial gasification co-firing in a coal plant
- 3000-5000 MW in operation
- Demonstration of gasification co-firing in GTCC

Grid Power

- U.S. demo of utility-scale biomass IGCC
- Aggressive development of Landfill gas projects begins
- Lack of landfill space renews interest in RDF conversion
- Standardization for Landfill gas projects streamlines development & reduces cost & shortens lead time
- EPA strengthens commitment to methane mitigation
- Microturbines deployed routinely for smaller Landfill gas projects
- Biomass-based green power is available/offered from new biomass capacity
- Advanced gas cleanup for turbines is proven
- 1st U.S. commercial utility-scale biomass IGCC
- Demonstration of gasification of RDF to prove environmental acceptability

Continued electric and gas price volatility and regional supply/demand imbalances provides additional impetus for distributed power, CHP, and fuel diversity.

Market optimization occurs for use of biomass residues:
- buying & selling ("residues.com")
- onsite utilization (power vs. bedding, vs. mulch, etc.)

Onsite Power & CHP

- Next generation small-scale gasification systems
- Demo of IGCC using hogged fuel, bark & sludge
- Chemical recovery hurdles overcome
- Advanced gas cleanup for turbines is proven
- Concern over impact of animal waste from CAFO on environment grows
- Deployment of Digester gas conversion technologies accelerates
- Microturbines deployed routinely for biogas projects
- Multiple small-scale gasification systems commercially available:
  - multiple fuels
  - multiple technologies
  - scaleable
- Black liquor gasification demo in full operation

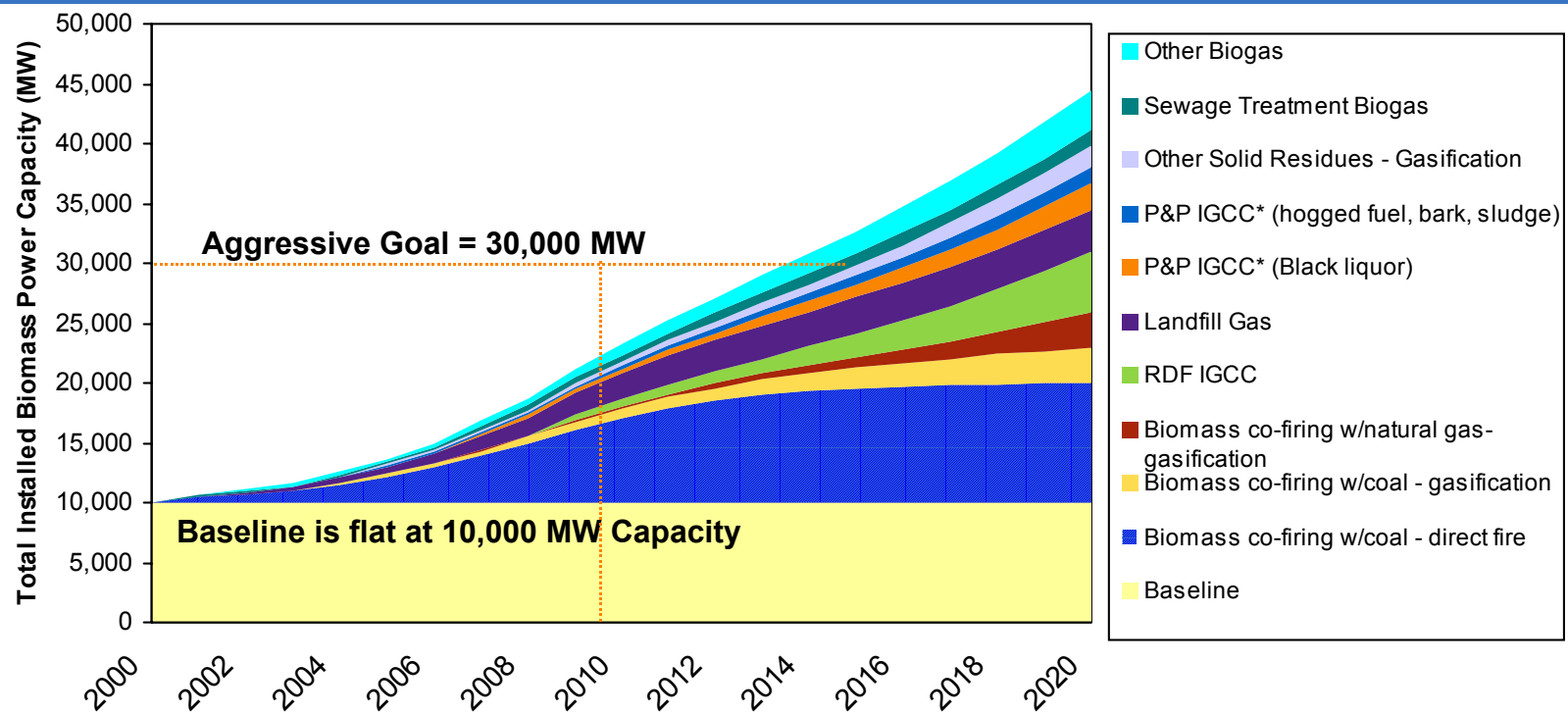
To achieve the aggressive goal before 2020, continued improvement of technology competitiveness will be required.

- Biomass Co-firing with coal
- Gasification/ IGCC
- Biogases
- Power in P&P
- Regulations & Biomass markets
- Small-scale Gasification

	2007	2010	2015	2020
Co-Firing	First commercial gasification co-firing in GTCC	6,000-9,000 MW in operation	Best coal plant sites exploited - growth slows; 10-15,000 MW co-firing in operation	Shift to co-firing with gasification in GTCC is accelerating; Some conventional coal plants retiring - Co-firing may be decreasing
Grid Power	First commercial RDF gasification IGCC	Fuel cells running on Landfill gas are competitive relative to other biogas technologies; Biomass IGCC deployment at multiple scales accelerates	RDF IGCC deployment accelerates (new and retrofit); $1000/kW or less for IGCC with > 40% efficiency	Landfill gas fully exploited - 3,000 MW added
Onsite Power & CHP	Commercial application of IGCC using hogged fuel, bark & sludge	Demonstrate that IGCC can generally replace Kraft boiler "on the fly" - minimal mill disruption during retrofit; Fuel cells running on digester gas are competitive relative to other biogas technologies	Acceptance in mills to replace recovery boiler with gasification - deployment accelerates; Digester gas fully exploited - 3-5,000 MW added	Gasification of onsite residues 1-2,000 MW added

Electricity from biomass could be tripled by 2015 provided that multiple feedstocks and technologies are exploited aggressively.

Total Installed Biomass Power Capacity (MW) - Aggressive Growth Scenario



*P&P IGCC represents incremental capacity resulting from repowering with IGCC. Existing capacity included in baseline.

Provided biomass is available, growth is still possible after 2020 because some applications are still in relatively early stages of market penetration.

Biofuel utilization could be tripled by 2010, albeit at a significant cost.

- In a Business As Usual scenario, increases in production and use of biofuels would be approximately 800 million gallons ethanol by 2010 (above baseline growth):
  - Limited by current technology cost and government incentives
  - Gasification-based technology is not likely to become commercial
  - Ethanol looks like the preferred MTBE replacement but die is not cast
  - Implementation of ethanol as an MTBE replacement in California is thought to have net positive impact on California economy (but not necessarily on the country)
- Achieving tripling of biofuels use by 2010 would require:
  - Strong regulatory support for bioderived oxygenates for RFG nationwide
  - Highly successful technology development and cost reduction
  - Highly packaged plants for integration with conventional blending and distribution terminals
  - Continued and stable incentives for biofuel productions
- However, the cost associated with achieving this impact rapidly would be very high:
  - Cost of current bioethanol is supported by a $0.54 per gallon tax credit, higher than most other bioenergy support instruments
  - Achieving a tripling goal would probably require construction of cellulosic ethanol facilities based on first generation technology since markets for conventional corn-based ethanol co-products would be saturated

The vision for the aggressive growth scenario incorporates successful development of advanced technology combined with regulatory stimuli and incentives.

2020 End State

Ethanol

- Greater than 750 million gallons of cellulosic ethanol
  At least 10 plants in operation using cellulosic feedstocks
- Medium-scale conversion technology integrated with blending terminals
- Cellulosic ethanol primarily used in blending for octane enhancement and oxygenate content
- Piggy back off biomass infrastructure developed to deliver large quantities of biomass (energy crops, residues) for co-firing
  - Large companies involved
  - JVs between fuel marketers and agro-companies
  - Market mechanisms in place similar to other fuels (e.g., futures, B2B)
- Fuel specs require ultra-clean transportation fuels
  - Ultra-low sulfur
  - Low aromatics
  - Oxygenate requirement for diesel and gasoline
- Bio-blend-stocks receive preference over petroleum derived ones
- Green fuel premium is available for neat fuels in niche urban and fleet markets
- Alternative fuel status and tax credits are extended to other bioderived fuels other than ethanol

FT-Diesel

- Medium-scale gasification-based technology integrated with blending terminals
- 2 Demo FT-Diesel plants
- FT Diesel demonstrated as low sulfur blending agent

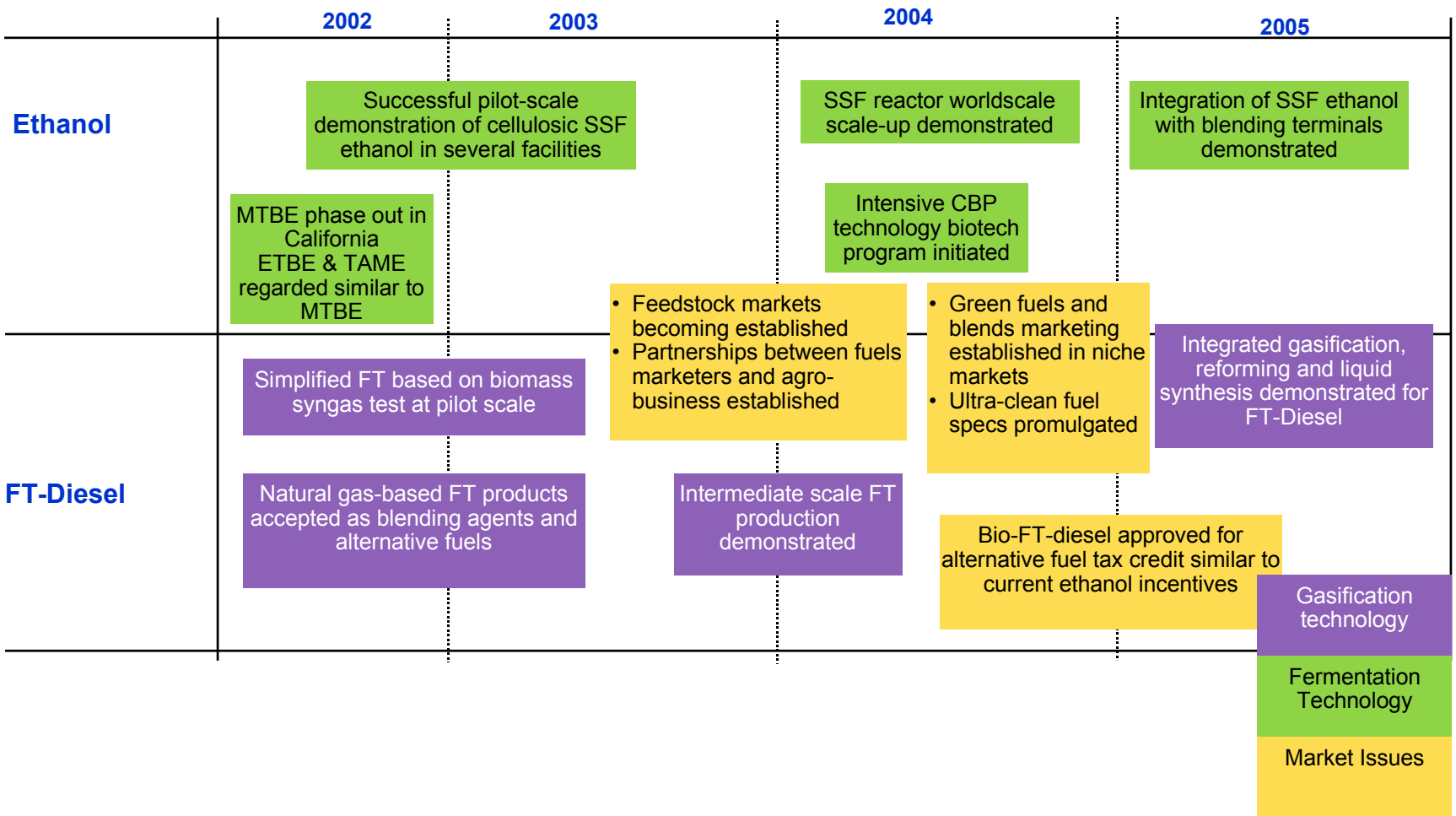
Gasification technology

Fermentation Technology

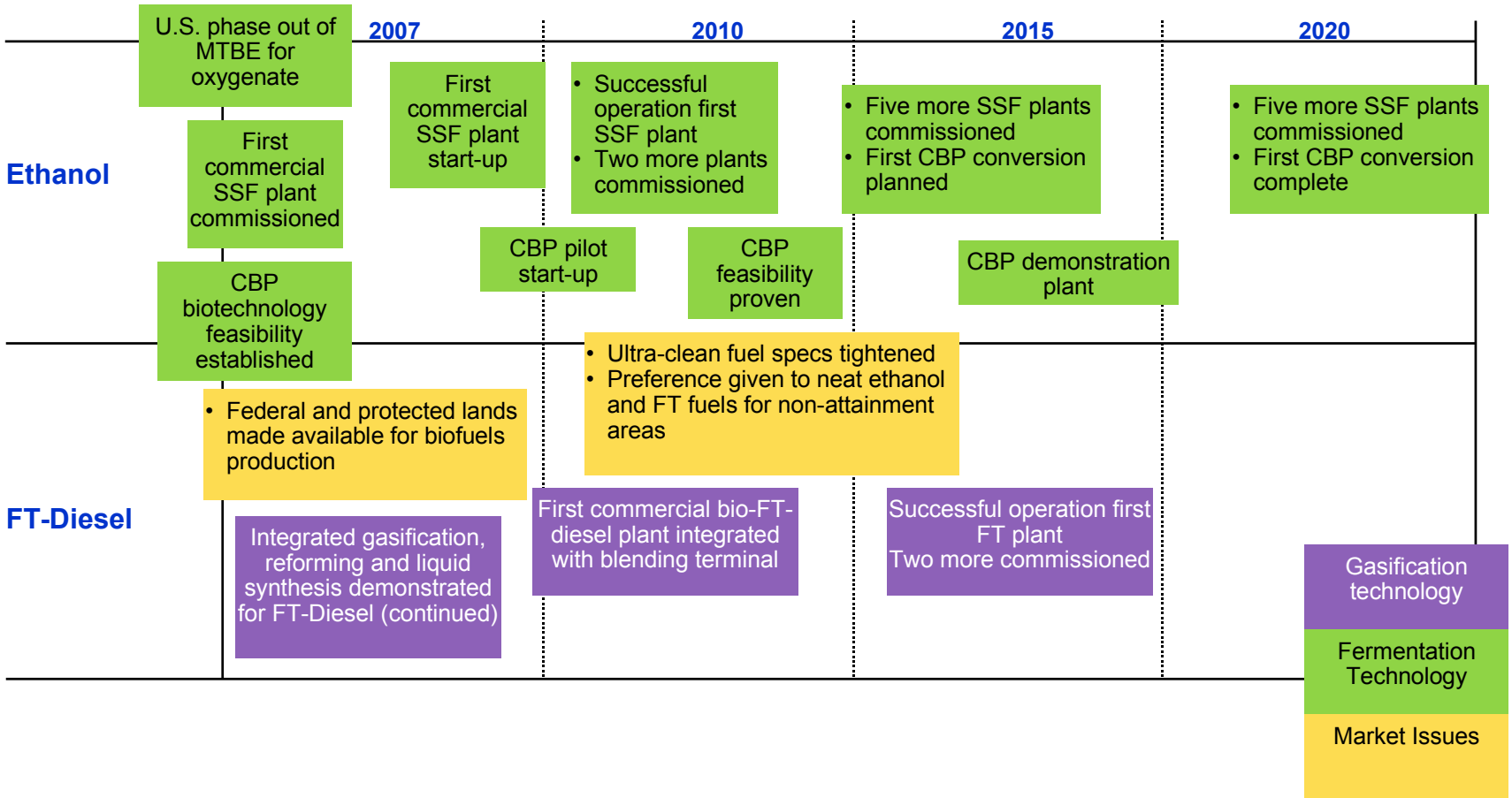
Market Issues

1. We selected 2020 as the year to focus the vision to avoid missing attractive technologies that only barely achieve market introduction by 2010.

Near-term milestones on the aggressive growth scenario timeline involve mainly technology development and fuel specifications.

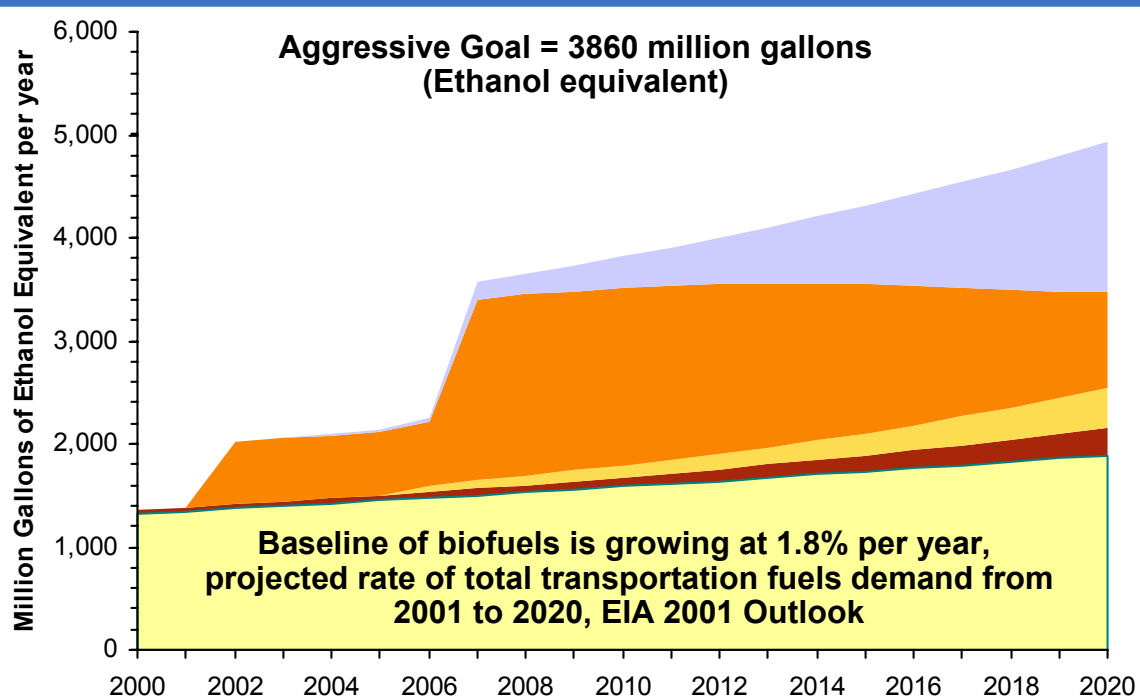


In the long term, sustained technology development and supporting regulation and incentives are critical to continued biofuels growth.



Biofuel production could technically be tripled by 2010 but this would require aggressive technology development and very rapid and significant new plant capacity investments.

Aggressive Growth Scenario, Cumulative Installed Capacity to 2020



The size of the near-term market for California (2003) depends upon unsettled requirements for oxygen content in California gasoline, nevertheless, current estimates place ethanol demand in the range of 580 million to 715 million gallons per year (or 37,834 barrels/day to 46,641 barrels/day).
Additional requirements for RFG or oxygenated gasoline in rest of U.S. ~ 114,000 BD (1750 million gal ethanol/y)

SUPPLY AND COST OF ALTERNATIVES TO MTBE IN GASOLINE, TECHNICAL APPENDIXES, Technical Documents, California Energy Commission, 1998, prepared by Purvin & Gertz, Inc.

Growth may be limited due to the time and infrastructure (and investment) required to build the new plants and possibly feedstock availability.

Bioproducts use could be tripled by 2020 requiring aggressive technology and market development but not sustained government support.

- In a Business as Usual scenario, bioproducts would capture a small fraction of the growth volume of specific chemical markets
  - No current large-scale incentives for bioproduct use (such as tax credits for ethanol fuel, green power and other renewable power credits)
  - Most of the growth comes from traditional bioproduct growth (e.g. starches) and from products produced by physical extraction (e.g. seed oils), in which bioproducts already have a high market share
  - Limited potential market for low-hanging fruit
  - Technologies with greater potential impact do not reach the market until much later and will penetrate the market slowly
  - Even in the BAU scenario, however, we expect bioproducts to have a considerable impact in the longer term, since competitive economics will be achieved for broad-based application of bioproducts to polymers and solvents
- With aggressive technology and market development and some government support (but not necessarily product price support), a significant impact (even tripling) may be achievable by 2020, though not by 2010
  - Technologies with high impact potential (such as fermentation-based polymers and monomers) would become commercially available in the 2010 timeframe
  - With plant construction and market penetration inertia significant market penetration would not be achievable before 2020
- Given the limited volume of product markets (as compared with fuels and power markets) the relative impact of bioproducts on greenhouse gas emissions and rural economic development can be considerable, but not large in absolute terms
  - Because of the more limited scale, at least early facilities may well be integrated into existing chemicals plants or into existing corn or paper mills
  - The projected economics of bioproducts will eventually not require sustained government financial support for several of the options, resulting in potentially very modest cost for investment, but not for sustained subsidies

The aggressive scenario focuses heavily on successful development, demonstration, and implementation of fermentation-based technology.

2020 End State

Commodity Bioproducts

Greater than 750 million gallons of cellulosic ethanol
At least 10 plants in operation using cellulosic feedstocks

Conversion technology is scale independent and low cost

- Bioproducts are seen as "Green" with enhanced properties that can carry a price premium
- Bioproducts will compete with petroleum products that are biodegradable which is also viewed as "Green"
- EPC industry has developed a new market, construction and operation of large scale bio-processing plants

Piggy back off biomass infrastructure developed to deliver large quantities of biomass (energy crops, residues) for coal co-firing

- large companies involved
- market mechanisms in place similar to other fuels (e.g., futures, B2B)

An incremental 20 billion pounds of material derived from biomass is being produced per year in 2020. Most of the new capacity will leverage fermentation technologies. Growth will continue to leverage existing and new uses for ag products such as seed oils. High temperature processes using cellulosics make specialty products for small to medium volume applications.

The consumers drive the demand for products seen as green.

The processing technology for bioproducts has been significantly improved and seen as clean. Biomass plants are no longer viewed similar to a MSW incineration plant.

Specialty Products

Products are:
- Solvents
- Polymers
  - –Propanediol polyester
  - –Lactic acid
- Other organic acids such as citric, succinic
- Paints & inks
- Detergents
- Specialty Chemicals
- Adhesives/Sealants/Coatings
- Polyurethane intermediates (polyol)

Bioproduct Technology Developments

Biofuel Technology Developments Leveraged

Biopower Market Development Leveraged

Bioproducts leverage the aggressive advances made by biofuels and biopower.

1. We selected 2020 as the year to focus the vision to avoid missing attractive technologies that only barely achieve market introduction by 2010.

In the short term, the aggressive scenario will require a mix of aggressive technology development and facilitation of bio-engineering from a regulatory perspective.

2002 | 2003 | 2004 | 2005

- Commodity Technology Developments
- Biofuel Technology Developments Leveraged
- Biopower Market Development Leveraged
- Specialty Technology Developments

Commodity Bioproducts

- Current likely fermentation-based commodity bioproducts are made with simple starch & glucose feedstocks obtained from dedicated & waste streams (e.g. corn mill and food processing waste streams)
- Future fermentation-based bio-commodities may have to use dedicated high-volume cellulosic feedstocks. Programs are put in place to leverage experience gained with cellulosic ethanol organism design

Studies on possible cost savings of co-locating bioproduct plants near existing chemicals, refining, resource, & grain mill plants. Identification of possible shared infrastructure.

Demonstration semi-works plant runs for SSF ethanol technology are conducted

Improved reactor designs for continuous commodity scale fermentation processes at bench to pilot scale

R&D and pilot studies continue with varied feedstocks (e.g.agricultural residues, energy crops, woody feedstocks, MSW) to develop operating windows for optimal microorganism (MO) performance using existing metabolic pathways

Develop policy instruments to encourage growth of new resource industry to supply glucose; make glucose the bio-industry "ethylene"

Study on what are the likeliest products that can be derived from existing metabolic pathways Create a wish list of possible "building blocks" that could be made with "to be designed" metabolic pathways

Biomass-based green power is available/offered from new biomass capacity

Commodity lactic acid commercial plant on-line

1,3-propanediol (1,3-PD) from glucose semi-works plant on-line

Biomass resource infrastructure responds to growing demand for biopower- large companies enter

Engineering MO to make glucose (or derivatives) as feedstock Inter-agency coordination and cooperation on bioproducts development/ road map

Start programs that encourage long-term research on utilizing hemicellulose and lignin to produce commodity high-value products. Long term research to use cellulose as feedstock to provide glucose source

Advanced gas cleanup for turbines is proven

Co-ordinate with NIH and NSF for long-term research for new metabolic pathways for promising future "building block" chemicals

Bio-Polymers are a hit for disposables. "Cheap and Green" has resounded with the market

Lactic acid plant-2 online at existing site

Market optimization occurs for use of biomass residues:
- buying & selling ("residues.com")
- onsite utilization (power vs. bedding, vs. mulch, etc.)

Specialty Products

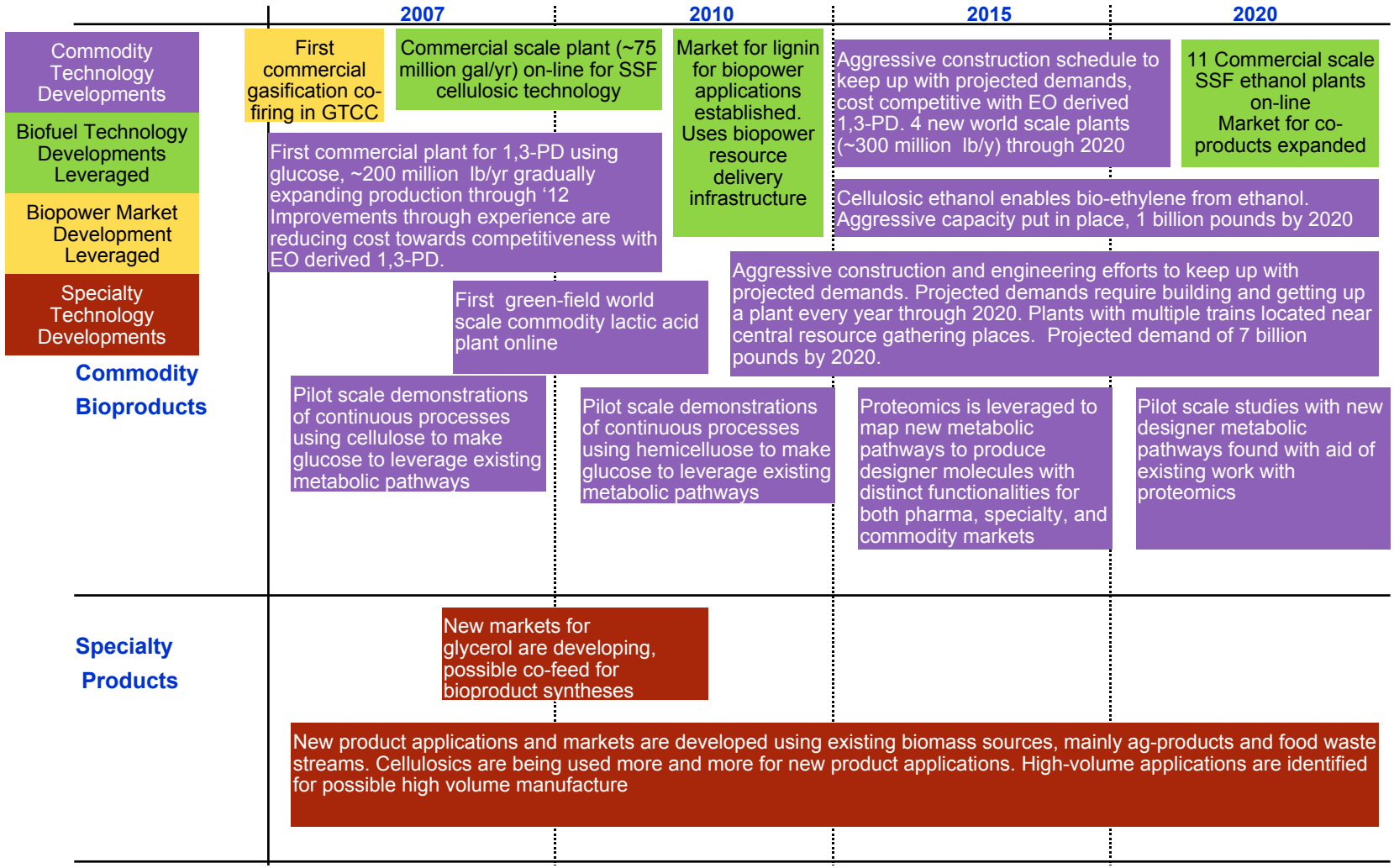
Lessons learned from biopower gasification enable use of syngas based products as part of a biorefinery concept (stand-alone plants not likely to be competitive)

Specialty products derived from seed oils, fermentation processing, and high temperature processing will continue to be developed when the delivered performance and cost offers advantages over competitive petroleum derived products

External instruments will continue to influence the adoption of bioproducts. For example halogenated solvents may be gradually replaced by alternatives that offer price competitiveness and enhanced properties

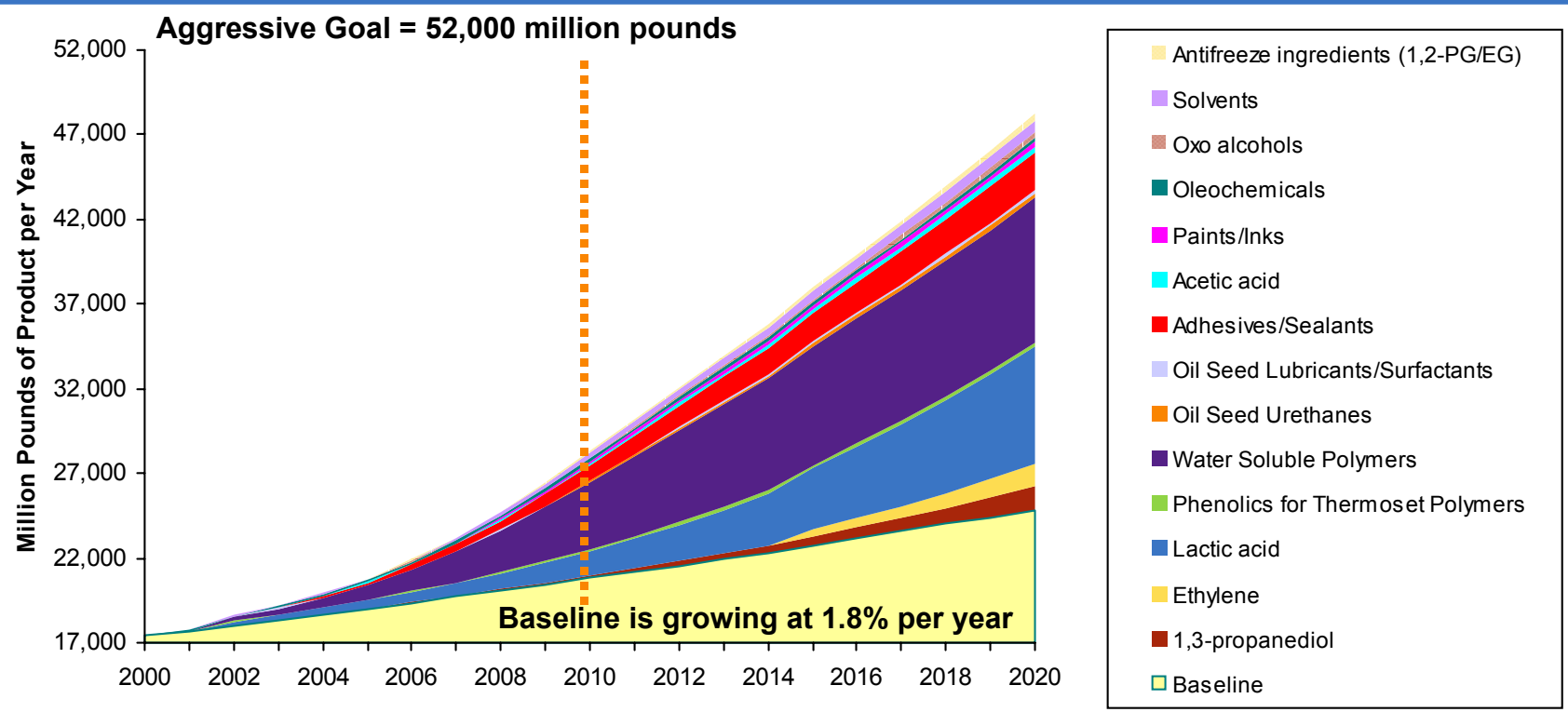
Additional resources may be required for application development, market development, and necessary infrastructure investments

In the long term, the aggressive scenario will require continued focus on technology development combined with considerable consumer education and leveraging with fuels and power applications.



The aggressive scenario reaches over 50% of the aggressive goal by 2010 and almost reaches it by 2020.

Aggressive Growth Scenario, Cumulative Installed Capacity to 2020



The scenario includes an aggressive plant construction schedule for fermentation-based processes, which will probably have to be combined with SSF ethanol production.

Rapid increases in bioenergy and bioproduct use would carry significant investment and operating costs to the country.

Application Category	Economic Benefits & Impact
Biopower	• At a national level, the incremental cost of implementing biopower could be on par with COE of new capacity natural gas-fired GTCC by 2010 provided that a significant amount of capacity is used with very low cost feedstocks (e.g. process wastes at zero cost). In the BAU scenario: 2500 MW are in co-firing with coal using existing capacity; ~1850MW are associated with zero cost gaseous biomass and zero cost process wastes. In the Aggressive scenario: 210MW in co-firing with NG GTCC; 7800 MW in co-firing in coal plants; 1015MW for RDG gasification; and 4540MW in utilizing zero cost gaseous biomass and zero cost process wastes • This would not be off-set by reduced imports, as biomass would predominantly replace domestic coal and natural gas resources • For co-firing, the vast majority of economic activity will occur in rural areas
Biofuels	• At a national level, the incremental cost of implementing increased biofuels could reach ~$130 million to $500 million by 2010 not including any tax credit and provided ethanol for blending commands value equivalent to MTBE on a volume basis. This cost is partially off-set by increased tax revenues and other benefits of increased economic activity in the U.S., due to reduction in oil imports • Ethanol may serve as a leading oxygenate replacement additive for MTBE as other ethers (TAME, ETBE) may find similar resistances as for MTBE and alcohols such as TBA may be capacity limited in the short term • Biofuel production will significantly benefit rural areas
Bioproducts	• On average, the incremental cost of bioproducts over conventional avenues to the nation is moderate, due to the modest cost premium. Biomass feedstock cost is less a driver for bioproducts at this stage of development. Capital cost and operating cost reductions will greatly increase the competitiveness of bioproducts when compared to fossil-derived analogs • Though some of the bioproducts options are ultimately economically attractive, they require significant up-front investment • The benefits for rural communities are modest, as most economic activity is likely to take place in processing plants which may be placed in semi-rural areas

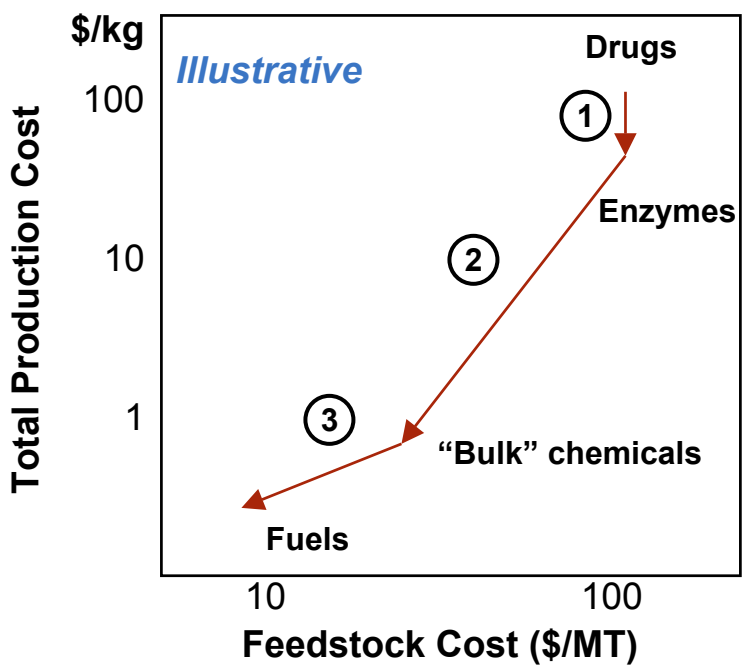
Technology development has the potential to significantly improve the performance of biomass technologies...

- Performance improvements include:
  - Higher efficiency of conversion (e.g. direct combustion to integrated gasification combined cycle)
  - Use of lower cost feedstock (e.g. processed starch to cellulosic)
  - Improved and demonstrated reliability and safety (e.g. black liquor gasification)
- The time required for technology development and commercialization is often underestimated and is expected to limit the rate of implementation of biobased products, fuels, and power:
  - Technology development for industrial conversion processes from pilot to fully commercial scale typically takes about three to five years, five more years can be added for bench-scale development
  - Especially for chemical and derivative products (e.g. Polymers, additional development time will be required for application and market development)
  - Achieving complete market penetration following market introduction typically takes twenty to forty years for capital-intensive processes such as fuels or power production, slightly less for chemicals
  - The time period of market penetration may change with modular technologies

... but timeline for technology development and industry inertia are the main factors limiting the rate of implementation.

Reduction of production cost through cuts in feedstock cost, improvements in primary conversion, and success in scale-up are all key to mass market penetration.

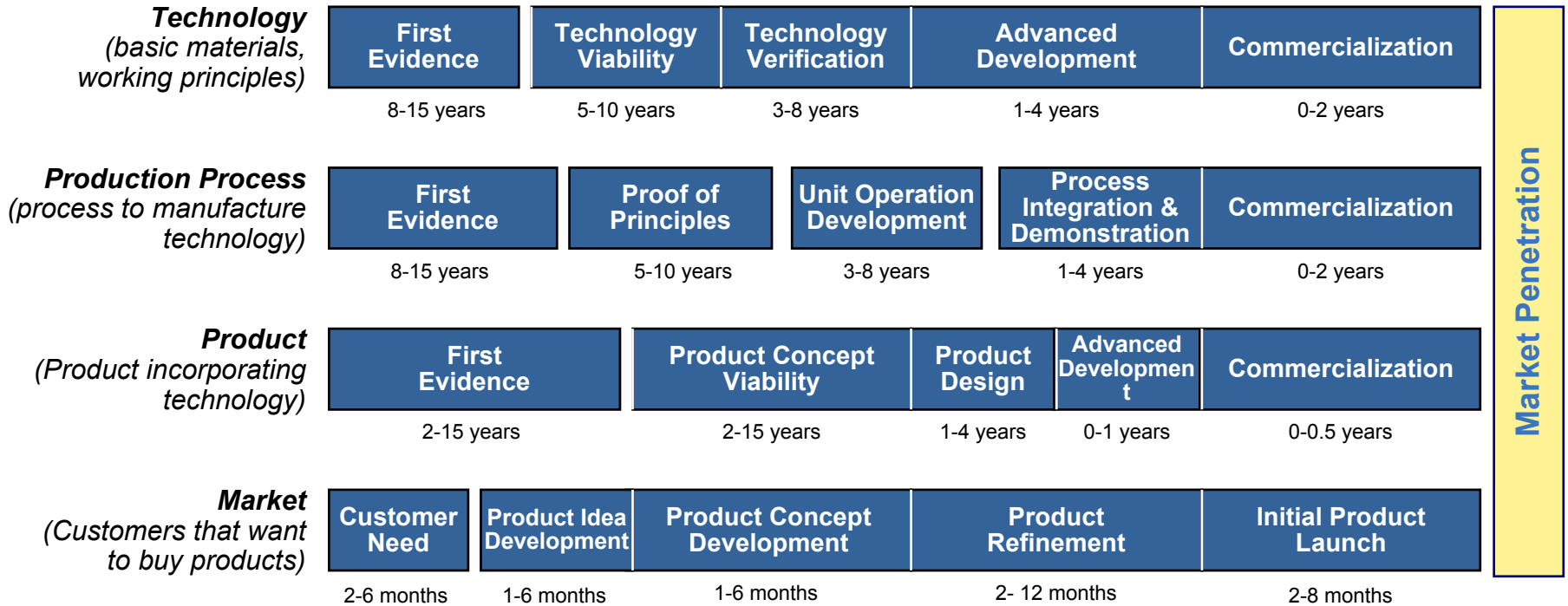
Required Production Cost Reduction



1. Reduction of cost by scale-up of existing processes is required to minimize capital and operating costs (e.g. ADM world-scale wet corn mills)
2. Fundamental primary conversion process improvement is the most critical step (e.g. Cargill-Dow LLC lactic acid development):
   - Improved product yield
   - Higher product concentration
   - Higher selectivity
   - Increased feedstock flexibility
3. Additional reductions in feedstock cost will be required to meet cost-targets for fuels and certain high-volume chemicals (e.g. possibly through genetically engineered crops)

Processing in a "biorefinery" may reduce the overall production cost and allow for the production of "premium" products with high value but small market volume.

Typical times for each aspect of technology development and commercialization will limit the rate of market penetration of new biomass-derived energy and products.



Depending on the product; market development may require longer times; in the order of double to triple shown

In order to facilitate the overall process, these developments must take place in parallel: the U.S. government can help guide and coordinate this process.

A number of uncertain factors could considerably benefit or detract from the growth and impact of biomass-derived energy and products.

- Conventional energy prices:
  - Developments in ***crude oil prices*** are likely to have considerable impact on all options, particularly on the fuels and products options, which are competing directly with petroleum-based products
  - ***Gasoline shortages*** in 2000 due in part to localized rulemaking leading to boutique fuel requirements provide an opportunity for biofuels
  - Uncertainty in ***natural gas and electric power prices*** also could have a significant impact on bioenergy viability, particularly for biopower options
  - Fluctuations in prices cause uncertainty which concerns investors in biomass plants
- Political factors:
  - The situation around ***RFG oxygenates (MTBE)*** is unresolved and though it currently appears favorable for biofuels, other outcomes are still possible
  - ***Tax incentives for biofuels*** have been rather stable over the past fifteen years
  - Discontinuation of PURPA support for biopower plants has caused concern over long-term reliability of government support
- Public opinion:
  - Public environmental concern drives most interest in biomass-derived energy and products
  - Until recently ***use of Genetically Modified-crops*** for non-human food-uses was considered uncontroversial in the U.S., but experience with GM-corn crossfertilization has called this into question; this could have significant ramifications for the feasibility of certain crop improvement efforts for energy and product applications
  - NIMBY concerns for waste to energy facilities might affect RDF biopower options
  - Impact of biomass production/collection/transport on local environment may be a concern

Bio-refineries where true synergy between production processes can be achieved, deserve additional attention.

- Combining biomass-based processes into "Bio-refineries" can offer two potential benefits:
  - Maximizing the value of the products per ton of feedstock (for combining biomass-derived processes only)
  - Maximizing the economy of scale of the overall process (for combining biomass-based with fossil-based processes)
- "Bio-refineries" that do not involve any synergy between the production processes may be attractive in some cases, in which case, they will be implemented readily
- "Bio-refineries" that do offer direct synergy between the production processes offer greater potential benefit, but are also more complex and are not well-understood
- The U.S. government could further support the study of such synergistic bio-refineries, but should focus on realistic options

Bioenergy and bioproduct industries could provide environmental benefits, provided careful management practices are implemented in biomass production.

Application Category	Environmental Benefits & Impact
Biopower	• Due to the very large potential market, carbon dioxide reduction benefits on the order of 26 to 80 million tons per year can be expected by 2010, especially since efficiency of biopower compares well with conventional power • SO_2 and NO_x emissions could also be significantly reduced, especially in co-firing with coal • In other cases, SO_2 and NO_x impacts vary drastically, mainly depending on the type of conversion technology and the appropriate conventional alternative power option • Methane emissions are cut in biomass co-firing with coal
Biofuels	• Due to the large market potential, carbon dioxide reduction benefits of over 5 to 14 million tons per year can be expected, even if ethanol use as an additive is the primary mode of use • Use of ethanol as an MTBE replacement could provide similar NOx, CO, and HC benefits as MTBE, but without the groundwater contamination concerns • When ethanol is used in pure form, the emissions benefits will likely be traded off against engine performance and cost by automotive original equipment manufacturers where possible
Bioproducts	• Carbon dioxide reduction benefits of bioproducts are more modest (120 to 1300 thousand tons per year, due to the smaller overall volume of the chemicals markets) • Criteria pollutant emissions benefits are modest as well

Relative to the appropriate competitive power option, biopower offers the greatest emissions benefits for CO_2, SO_2 and, in some cases, NO_x.

- In all cases CO_2 reductions (per kWh) are significant, ranging from 65-100%
- Except when compared to natural gas GTCC, biomass power results in significant SO_2 reductions (80-97%)
  - Biomass is generally much lower in sulfur than coal
  - In some processes (e.g. gasification) sulfur removal to very high levels is possible
- NO_x benefits are more mixed, and generally are technology (versus fuel) dependent
  - Natural gas GTCC technology sets a very high standard for NOx (Low generation levels),
  - Biogas-fired (including landfill gas, sewage gas, & digester gas) GTCCs are expected to have similar NOx benefits depending upon the nitrogen content of the biogas
  - Biomass co-firing with coal has the potential for significant NOx benefits (e.g., 20% overall reduction for 10% co-firing)
  - Reciprocating engines produce levels of NOx comparable to or greater than the grid average unless special control equipment is used
- Emissions of CH_4 are reduced with biomass co-firing with coal by avoiding coal production emissions of methane
- Emissions of non-methane hydrocarbons and carbon monoxide, are generally unaffected by the use of biomass as a fuel
  - Fugitive NMHC, & PM emissions that would have occurred regardless of the end use were excluded
- Advanced biopower conversion technologies should produce particulate matter (PM) reductions
  - All technologies that convert biogases produce less PM than the grid average
  - Co-firing biomass options do not produce PM reductions
- The solid waste and water effluent impact are expected to be moderate and manageable
  - Most biomass is low in ash and in most cases, the ash is non-toxic and can actually have value as fertilizer
  - Water effluents can contain suspended solids and biological oxygen demands but toxicity is not usually a serious concern

A life cycle analysis of the environmental impacts was not included in this study.

Biofuels can offer tremendous carbon dioxide reduction savings compared to petroleum fuels even when used as primarily a blending agent.

- Biofuels offer the only remotely affordable option to drastically reduce CO_2 emissions from transportation fuel chains
- When used as an oxygenate in RFG, ethanol could play a critical role in criteria pollutant emissions reduction
- Without legislative protection of the clean fuel benefit of biofuels when used as a neat fuel, these benefits may be lost in re-optimization of engines for power or cost
- The solid and water effluent waste is expected to be manageable
  - Solid wastes are expected to be biodegradable and usable as fuel (e.g. Cell mass)
  - Water will contain suspended solids and toxicity is not a serious concern
  - Water use for processing (especially for fermentation) may be a concern in arid or semi-arid regions
- Production costs for biofuels are around 25-60% more than those of conventional additives, however, tax credits are currently off-setting this difference
- In the long term, the cost of ethanol use could be largely off-set by the benefits of local production (in the U.S. vs abroad)
- About half of the economic activity involved in ethanol production is likely to occur in rural areas as a large fraction of biofuel cost is in the feedstock

The benefits of bioproducts can be significantly increased at a modest ultimate cost to the nation.

- CO_2 emissions of bioproducts could offer significant benefits but the absolute amount is somewhat limited by the size of chemicals markets
- Criteria pollutant emissions are not strongly impacted by the implementation of bioproducts
- The solid and water effluent waste is likely to have the same issues as for cellulosic ethanol implementation and is expected to be manageable
  - Solid wastes are expected to be biodegradable and usable as fuel (e.g. Cell mass)
  - Water will contain suspended solids and toxicity is not a serious concern
  - Water use for processing (especially for fermentation) may be a concern in arid or semi-arid regions
- Production As costs for bioproducts appear to be approaching those of conventional products, the cost of implementation of bioproducts could eventually be quite low
- Bioproducts will primarily off-set products now produced from partially imported petroleum, thus the cost of bioproducts, will be off-set partially by increased economic activity and tax revenues
- Most of the economic value-added in the production of bioproducts is added in the conversion plant, which is most likely located near existing chemical plants

We identified five key categories of barriers that impact all categories of options.

	Fundamental Technology Barrier	Cost not Acceptable	Address Early Adopter Markets	Poorly educated consumer	Regulatory Barriers
Biopower	• Gas cleaning for BIGCC must be improved • Design & eng. guidelines for co-firing implementation don't exist	• Cost of stand alone biopower is too high	• Black liquor gasifiers face market conservatism	• Biopower not seen as really green • RDF / Waste-to-energy seen as an "incinerator"	• Fly-ash regs for co-firing are restricting • Deregulation uncertainty • Biomass feedstock markets not well developed • New Source Review
Biofuels	• Organisms for CBP (consolidated bioprocessing) ethanol not robust • Gas cleaning for Bio-FT not adequate	• Cost of all options more than 1-2 times as expensive for fuel value of products	• Oxygenate markets prove difficult to substitute ethanol (market, infrastructure issues)	• Value of green fuels not recognized	• Ethanol credit only extend to all renewable fuels? • Limitations on GMO R&D and production
Bioproducts	• Fermentation-based commodity-scale production not well developed • Large-scale reactor technology not developed	• Cost of current technologies may still be too high for early adopter applications	• Need early markets for fermentation-based feeds	• U.S. consumer not very responsive to green branding • Competition with "biodegradable" fossil derived products	• Product standards for new chemicals not yet established • Limitations on GMO (genetically modified organism) R&D and production
Biomass Feedstock	• Recalcitrance of cellulosic biomass for applications other than power	• Biomass low energy density makes transportation costs key issue • Harvesting, yield	• Pulp & paper expand power production • Ag residues for more revenue for farmer	• Biomass equated with MSW; "garbage" • Biomass utilization plants perceived as "dirty"	• Markets for biomass not well developed • Competition among biomass forms (ag wastes vs energy crops)

Mapping the potential policy options against key barriers and considering their cost-effectiveness can help compare policy options.

Option Category	Absolute Cost	Typical Cost-Effectiveness	Effectiveness in Addressing Key Barriers				
			Fundamental Technology Barrier	Cost not Acceptable	Address Early Adopters	Poorly educated consumer	Regulatory Barriers
R&D Support	$	+++	+++	+	-	-	+
Direct subsidies	$$$$$	---	-	+++	+	-	-
Risk Sharing	$$$	++	+	++	++	-	-
Demonstration Projects	$$	+	-	-	++	-	-
Benchmarking / Best Practice	$	++	-	+	-	-	-
Voluntary Agreements	$$	++	+++	+	+++	+	+++
Standards / (de-) regulation	$	+++	+	+	++	-	+++
Infrastructure Investments	$$ / $$$$	+/-	-	+	+	-	-
Tax Measures	$$$	++	++	+++	++	-	-
Information Provision	$	+++	-	-	+	+++	-

Breakthrough Energy Technologies for Industry, Phase II Report, for Nederlandse Organizatie Voor Energie en Milieu. Arthur D. Little 1997

A selected set of policy options appear to be critical to achieving success in implementing increases in biomass use.

- R&D support is critical to achieve the necessary and sustained breakthrough improvements in technology performance and cost
- Voluntary agreements and public/private partnerships are critical to marshalling the level of resources necessary for large-scale implementation efficiently
- Tax measures can be used to entice early adopters and or bridge the cost-competitiveness gap for selected biomass options
- Information programs and consumer education programs are critical to internalizing the benefits of biobased energy and products in terms of product premiums
- Direct subsidies, price controls, or equivalent control measures (E.g. Renewable content standards) are likely the only way to have a chance at achieving the tripling goal can be achieved by 2020 in all sectors
- Sustained support, while not desirable from a global, free market perspective, may in fact be sensible on a national or regional basis

Overall, the opportunities for biomass-derived energy and products are considerable with environmental benefits and increased rural economic activity...

- In the near term, and with modest additional cost, considerable impact can be achieved by focusing on a number of practical options
- In the longer term, significant impact can be achieved with the further development of some higher-risk technologies
  - This impact takes the form of reductions in greenhouse gases and other pollutants
  - Increased domestic production of natural resources consumed in the U.S.
  - Increased high-value economic activity in rural areas
- Achieving a doubling or tripling of use of biomass energy and products is technically possible by 2015 or 2020
  - The development of new production and conversion technologies and the application to new markets could lead to this impact overall, and in each of the biomass use categories (power, fuel, and products)
- However, we recommend that the U.S. government carefully weigh the rate of increase in the use of biomass-derived energy and products against the cost
  - We believe that attempting to achieve rapid doubling of biomass energy and products use at all cost (e.g. by 2015) will lead to the application of technologies that could be superseded by superior and more cost-effective technologies only few years later
- Thus, we believe that a somewhat more long-term view of the biomass opportunity which allows for the development of technologies that could become commercial in the 2010-2020 timeframe, would be beneficial, and may lead to a more optimal use of resources for the benefit of the nation

...but the cost is very high so careful consideration of the desired rate is necessary.

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1 Background & Objectives

2 Baseline Use of Biomass

3 Identification of Options

4 Benefit & Impact Analysis

5 Scenario Analysis

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7 Conclusions & Recommendations

The USDOE selected Arthur D. Little to identify ways to increase significantly the current consumption of bioderived energy, fuels and products by 2010.

- The objectives were based in part on:
  - The Biomass Research and Development Act of 2000 (Public Law 106-224)
  - The National Sustainable Fuels and Chemicals Act of 1999 and
  - Former President Clinton's Executive Order 13134 "Developing and Promoting Biobased Products and Bioenergy"
- The objectives are also supported by the Bush Administration's National Energy Policy[1]
  - Increased production and utilization of biomass will utilize environmentally friendly technology that will increase energy supplies and help raise the living standards of the American people, particularly in rural and semi-rural areas
- This report covers a broad range of biomass energy and products, based on open literature data
  - Biopower and bio-heat (e.g. wood-fired power plants, co-firing of biomass with coal or natural gas)
  - Biofuels (e.g. bioethanol, biodiesel, bio-FT-diesel[2]) particularly for onroad transportation applications
  - Bioproducts (primarily carbohydrate and lipid based chemicals) for both existing and new products and applications
- Two scenarios were developed to illustrate the potential for and impact of increased biomass use for energy and products:
  - A Business As Usual scenario represented what could happen if no special additional supports are implemented
  - An Aggressive Growth scenario aimed at achieving more than doubling[3] by 2010 or soon thereafter
- The study's scope specifically excluded several categories of products conventionally made from biomass:
  - Paper, lumber and other conventional wood products
  - Food, food ingredients and food by-products
  - Pharmaceuticals and "nutraceuticals"
  - Textiles
- USDOE and USDA were afforded the opportunity to provide input at various points in the process

1. "National Energy Policy: Reliable, Affordable, and Environmentally Sound Energy for America's Future", Report of the National Energy Policy Development Group, May 2001
2. FT-diesel is diesel fuel made via Fischer-Tropsch synthesis.
3. A tripling benchmark was used in this study

Arthur D. Little and USDOE identified the underlying policy objectives for the aggressive targets for biomass use.

Broad Study Objective	More than double the use of biomass-derived materials in the U.S. by 2010

To Address the Underlying Objectives...	...the policies options should:
Reduce environmental burden of producing and utilizing energy and products	• Be focused on the environmental end-result, not the path to get there • Address all relevant environmental concerns
Stimulate rural economic development	• Focus on developing competitive economic activity in rural areas, preferably value-added activity
Improve U.S. balance of payments position	• Focus on U.S.-generated biomass (e.g. options should not support import of Indonesian rubber or Brazilian ethanol)
Improve United States energy security	• Focus on pathways that directly offset fossil fuel (e.g., not food & feed or pulp & paper)
Accelerate development of competitive U.S. technology	• Focus on technologies with competitive potential for U.S. industry, not necessarily on ones that are closest to large-scale application • Eliminate barriers for technology development

All options were categorized into three distinct areas in order to facilitate their comparison and ranking.

	Definition	Selected Examples
Fuels	Any biomass-derived material sold as a fuel for onroad transportation applications	• Ethanol via corn fermentation • Biodiesel via oil transesterification • Fisher-Tropsch diesel via bio-syngas
Electricity and heat	Electricity and/or heat produced from biomass	• Biomass co-firing with coal • Biomass gasifier with gas turbine • Improved black liquor recovery • Landfill gas-to-power
Bioproducts	Any biomass-derived product or material sold that is not otherwise described above	• Polymers via fermentation (e.g. polylactic acid) • Phenolics from pyrolysis • “Green solvents” via extraction or fermentation technology

Because of the disparate characteristics of the different markets today, each area was evaluated separately.

The study explicitly excluded several product classes that are conventionally made from biomass resources.

	Excluded from Analysis	Comments
Fuels	• None were excluded • Fuels for transportation applications were emphasized	• All fuels derived from biomass for on-road transportation applications were considered • Both pure fuels and fuel blending agents (including additives) were considered
Electricity and heat	None were excluded	• The steam (heat) and power generated by traditional biomass based industries such as the pulp&paper industry was included to take into account industry efficiency improvements • Included both grid and onsite power applications
Bioproducts	• Paper, lumber and other conventional wood products • Food, food ingredients and food by-products • Pharmaceutical and “nutraceuticals” • Textiles	• The actual product of the pulp&paper was excluded but the heat and electricity generated were included • Food and food by-products were excluded both for human and animal consumption (including animal bedding) • The scope was on large volume (by mass) markets so that pharmaceuticals were excluded; high-value products such as pharmaceuticals may be part of a biorefinery concept • Textiles involving natural fibers were excluded; also composites for wood and lumber applications using crop residues were also excluded

This study was carried out following a 4-task approach, based on the analysis of available data and information.

Task I: Biomass Resource Assessment
- Review literature (an independent assessment was out of scope)
- Segment biomass by geography, source, type and availability
- Identify price/volume relationships
- Identify gaps in available literature

Task II: Identify Routes for Significant Increases in Biomass Utilization
- Review current projects and programs
- Develop list of potential biomass products and technologies
- Identify technical, economic, infrastructure and market barriers to the implementation of biomass supply chains
- Identify the most attractive biomass supply chains

Task IV: Benefits and Impact Analysis
- Modify existing fuel chain tools to apply to U.S. and a range of products
- Quantify the emissions and economic impact of alternative supply chains
- Quantify relative attractiveness of competing chains
- A life cycle analysis of costs and/or emissions was not part of the scope of this study

Task III: Market / Scenario Analysis
- Use ADL "visioning" tools to identify the tasks which must be taken to achieve DOE goals
  - Aggressive increases in biomass use by 2010 (more than double)
  - "Business as Usual" scenario
- Identify barriers to achieving this level of increase
- Develop a strategy for the United States Government moving forward, taking advantage of all knowledge gained in preceding tasks and synergies among alternative chains

Throughout the study, interested USDOE and USDA staff were given opportunities to provide input to and comments on the analysis.

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To establish the potential for aggressive increases in the use of biomass in the U.S., a firm definition of its baseline use had to be established.

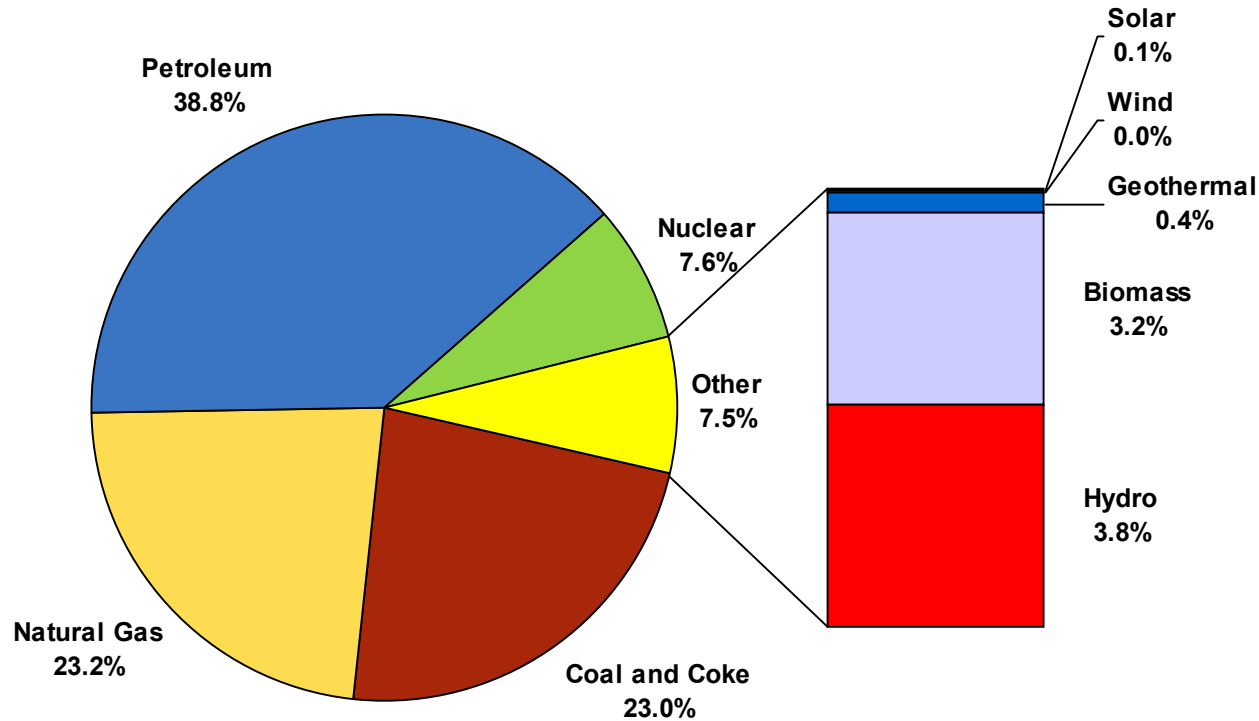
- The baseline was based on 1998 data for power and fuels
- For bioproducts, data from a 1992 study was used
- The scope of the analysis was refined during a kick-off meeting with DOE:
  - Reflects DOE's perspective on the intent of the study to dramatically increase (more than double) the use of biomass by 2010
  - Some categories of products typically made from biomass were defined as outside the scope of this study and are not included in the baseline, specifically:
    - Paper, lumber and other conventional wood products
    - Food, food ingredient and food by-products
    - Pharmaceuticals and "nutraceuticals"
    - Textiles
  - Pulp & Paper industry power and heat production was included to recognize the potential for significant increases in efficiency in that sector
- The following pages provide an overview of current biomass use in the United States and includes uses that are excluded from the baseline of *this* analysis

To date, biomass resources are a small fraction of the overall primary energy mix in the United States accounting for 3 percent of energy use.

- Current annual use of biomass for energy, fuels, and products amounts to 108 million tons of biomass output or 1.8 Quad (excluding out of scope categories)
  - The baseline was based on 1998 data for fuels and power and 1992 data for bioproduct applications
  - The baseline excluded food, paper and wood products and included steam and power production from the pulp&paper industry
- When looking at total biomass energy use (including wood, paper and food):
  - Industry is the largest user; the largest energy application is for heat (steam production)
  - Wood is the largest biomass resource currently used
- In the United States, 75% of non-hydro renewable power generation is biomass-based
  - Biomass accounts for 1.5% of total power generation
  - The bulk of biomass electricity capacity is with nonutilities
- Biomass fuels (primarily ethanol) represent 20% of alternative fuel use (including MTBE), but less than 1% of total fuel consumption for transportation
- Biomass use for products is dominated by food, wood and starch for paper products, although a portion is used for selected materials and chemicals

Biomass is a small part of the U.S. energy mix, representing 3.2% of energy use and second only to hydropower among renewable energy resources.

Total 1998 U.S. Primary Energy Consumption – All Sectors (Biomass Input Basis)



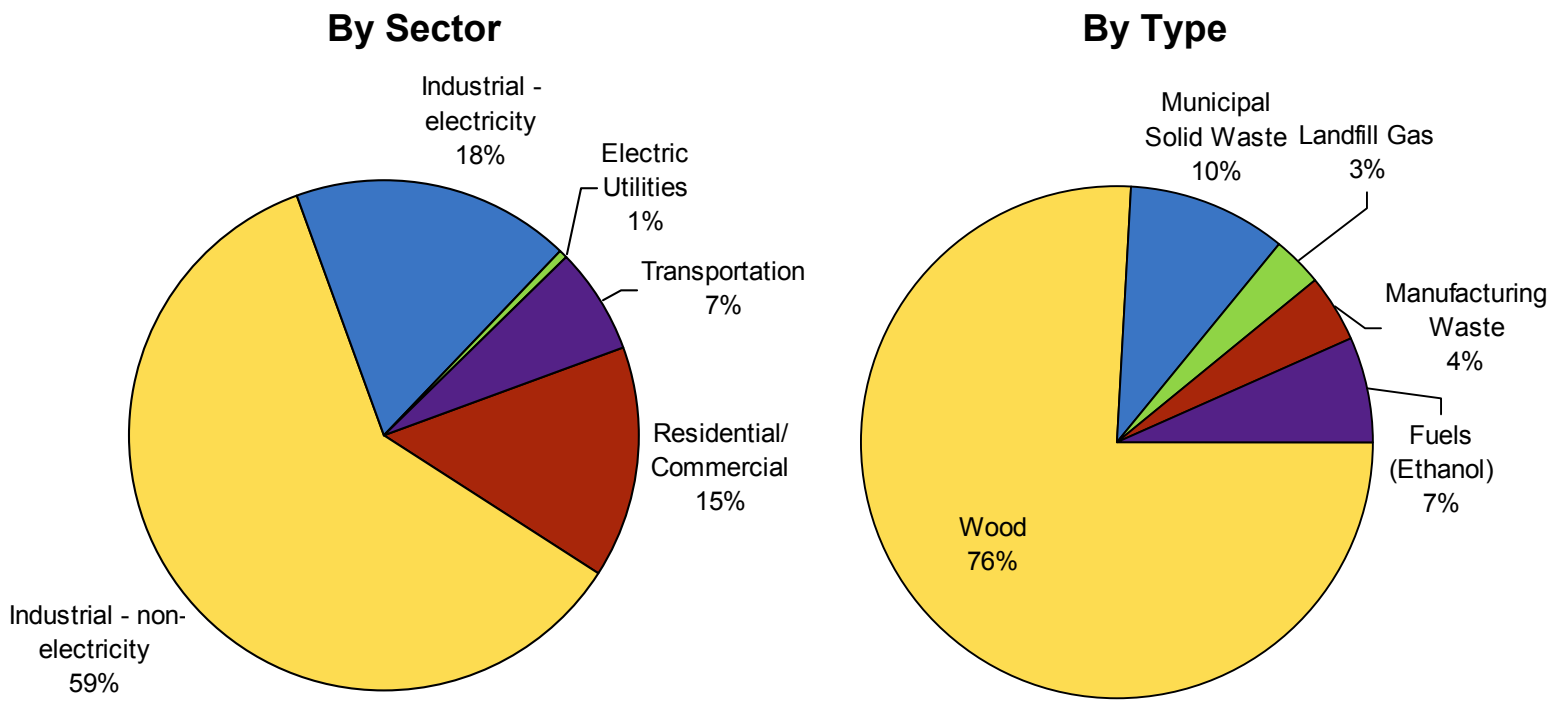
Total = 94.2 Quads

Total = 7.0 Quads
(Biomass* = 3.0 Quads)

* The data source Included in biomass the following: peat, municipal solid waste, landfill gas and tires.
Source:DOE/EIA Renewable Energy Annual 1999 (DOE/EIA-0603(99))
One Quad equals 1015 Btu or 1.054 Exajoules (1018)

Industry is by far the largest consumer of biomass; wood is the main type of biomass used.

1998 U.S. Biomass Energy Consumption by Sector and Type (Biomass Input Basis)

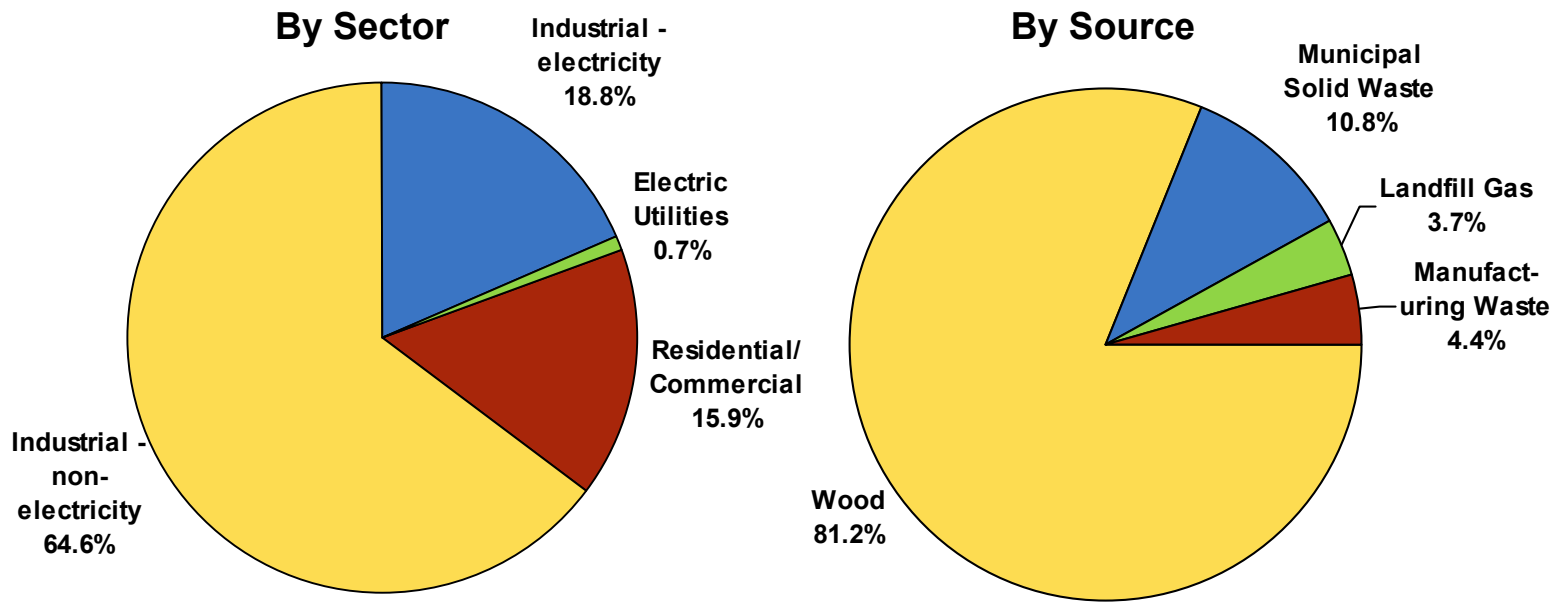


Total = 3160 Trillion Btu (3.16 Quad)

Notes:
Industrial includes electricity generation by cogenerators, IPPs and small power producers, including the use of municipal waste and landfill gas.
Source:DOE/EIA Renewable Energy Annual 1999 (DOE/EIA-0603(99))
Transportation represents the consumption of ethanol and not the biomass used to produce ethanol.
One Quad equals 1015 Btu or 1.054 Exajoules (1018)

Industry is by far the largest consumer of biomass for power and heat and is dominated by the pulp & paper industry.

1998 U.S. Biomass Energy Consumption for Power and Heat by Sector and Source (Biomass Input Basis)

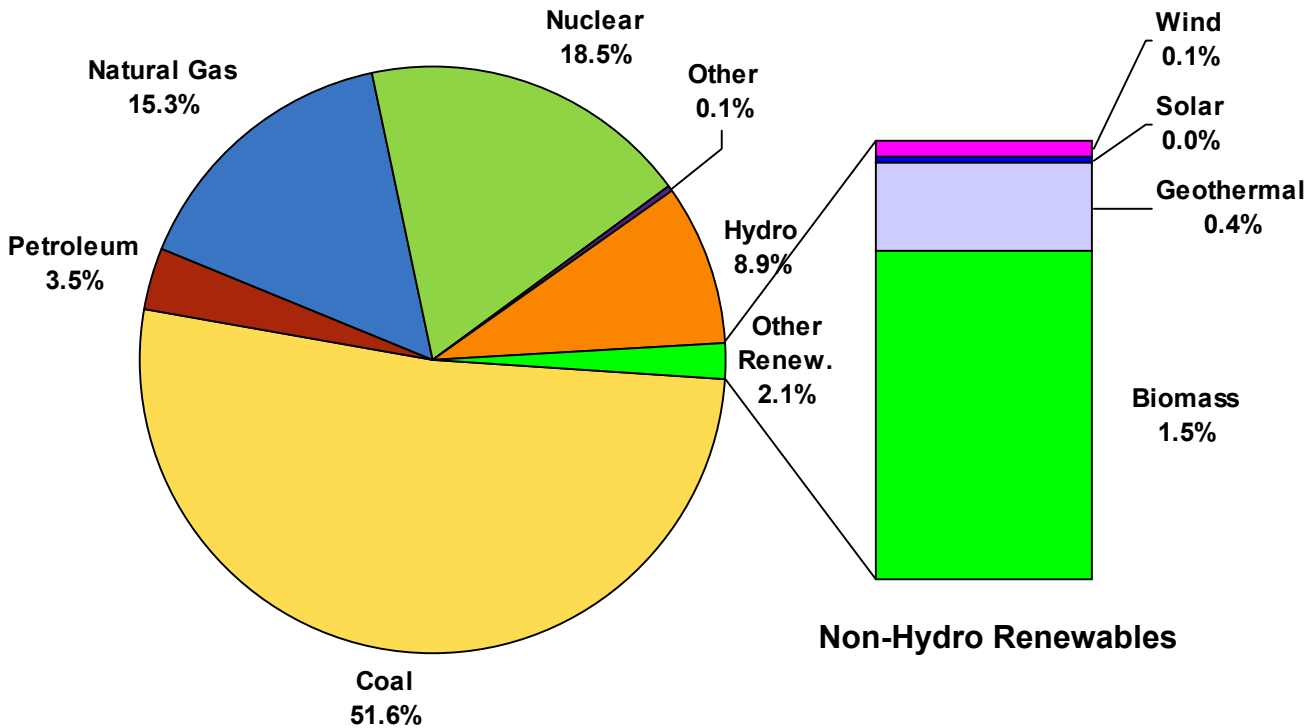


Total = 3,100 million GJ (2.95 Quads)

Notes:
Industrial includes electricity generation by cogenerators, IPPs and small power producers, including the use of municipal waste and landfill gas.
Wood includes wood residues (black liquor, bark, mill wastes, etc).
Source:DOE/EIA Renewable Energy Annual 1999 (DOE/EIA-0603(99))

In the United States, 75% of non-hydro renewable power generation is biomass-based, accounting for 1.5% of total power generation.

1998 U.S. Electricity Generation by Fuel Type



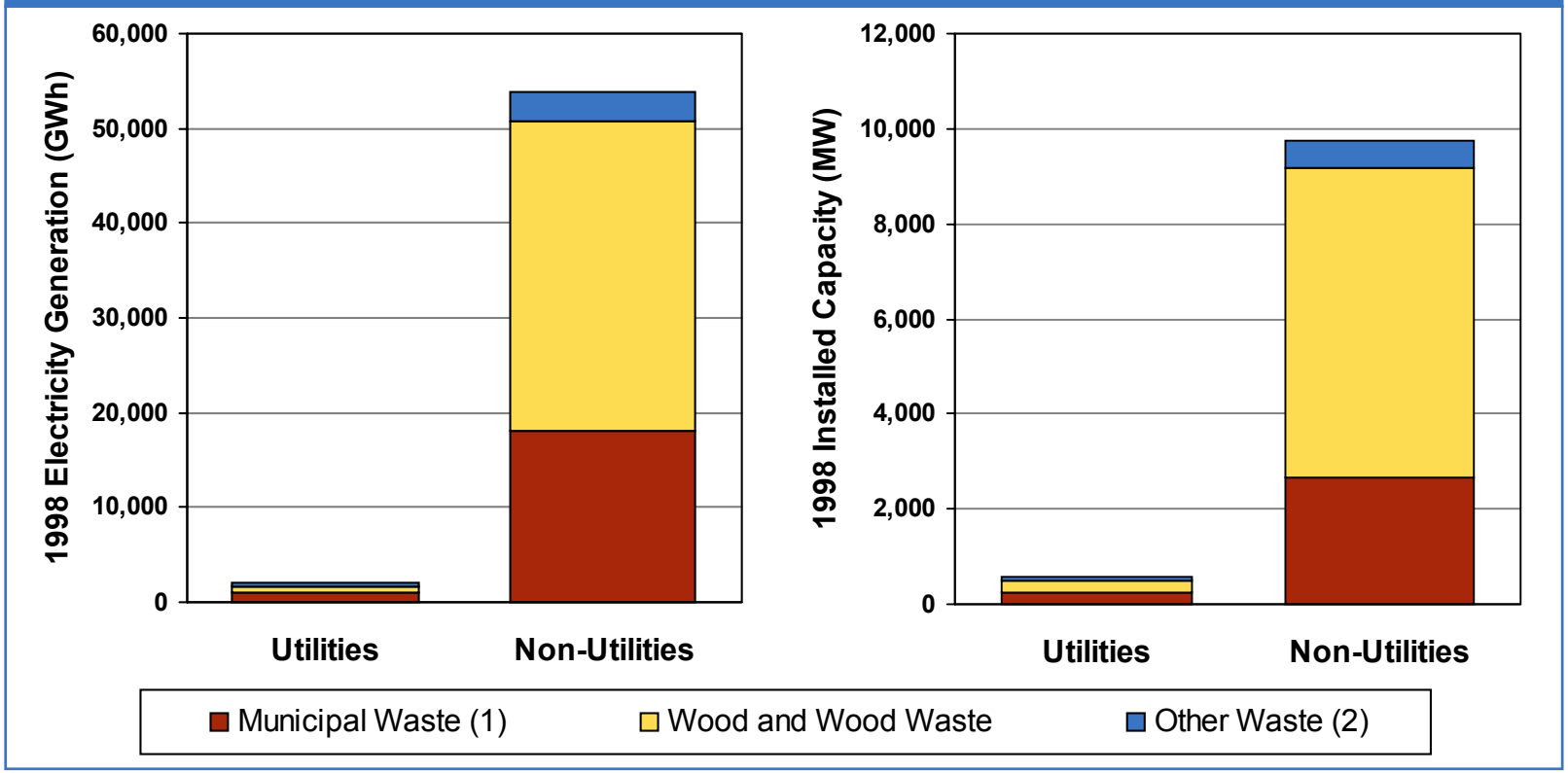
Total = 3,634 billion kWh (12.4 Quads)

Total = 74.7 billion kWh (Biomass[1] = 55.8 billion kWh, 0.2 Quad)

1. Data reported includes peat, municipal solid waste, landfill gas and tires.
Note that for electricity generation, hydro is often considered a "conventional" resource.
Source: DOE/EIA Renewable Energy Annual 1999 (DOE/EIA-0603(99)) and DOE/EIA Electric Power Annual 1998.
Totals may not equal sum of parts due to independent rounding

The 10,000 MW of biomass electricity generating capacity is dominated by non-utility generators associated with the pulp and paper industry[3].

1998 U.S. Biomass Electricity Generation and Capacity

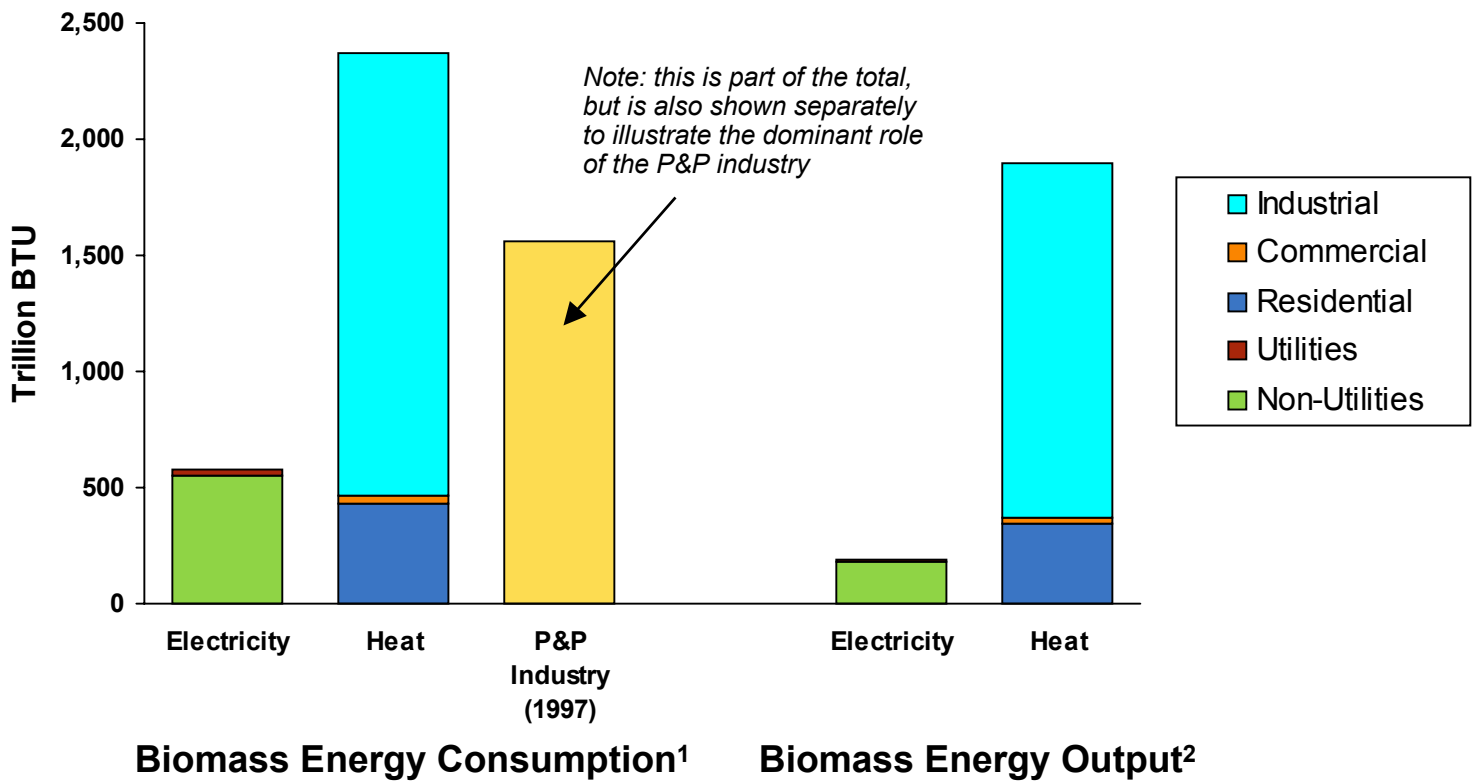


1. Municipal solid waste and landfill gas.
2. Agricultural wastes, straw, fish oils, paper pallets, tall oils, sludge waste, digester gas, methane and waste alcohol.
3. Most non-utility capacity is onsite generation, and is primarily found at pulp & paper mills. Power is generated from wood wastes and mill residues and generally consumed onsite rather than exported.

Source:DOE/EIA Renewable Energy Annual 1999 (DOE/EIA-0603(99))

Far more biomass is consumed for heat than for electricity production – the pulp and paper industry dominates these biomass energy uses.

1998 U.S. Electricity and Heat Production from Biomass

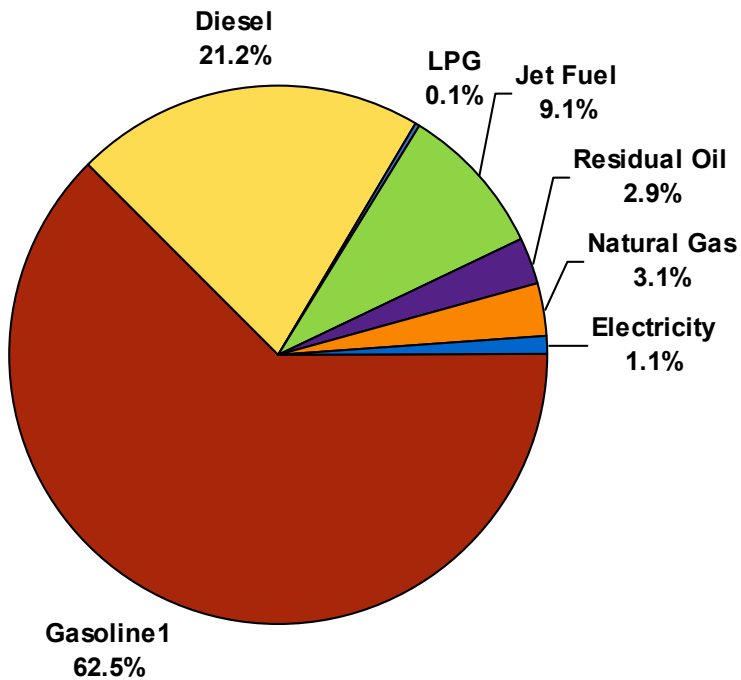


1. Pulp & Paper biomass consumption is part of industrial energy consumption for both electricity and heat. It is shown here for comparison.
2. Electricity output is based on EIA data. Heat output is based on an assumed 80% conversion efficiency.

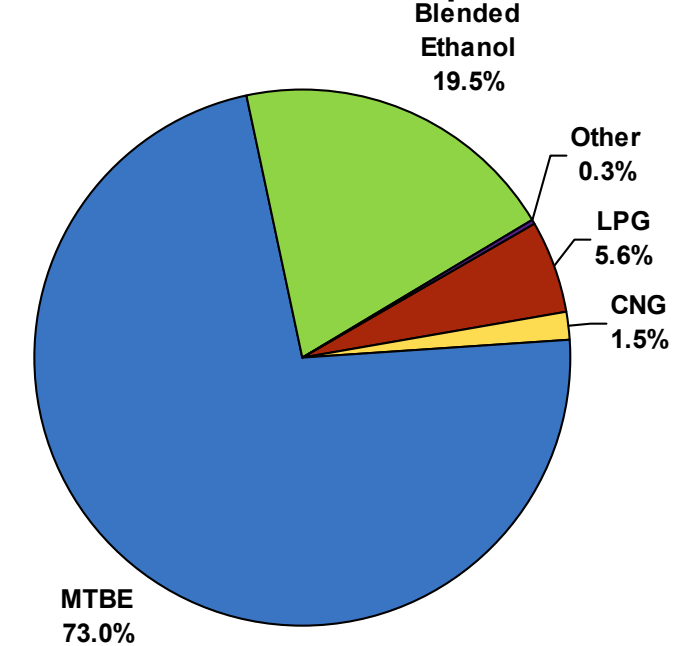
Sources:DOE/EIA Renewable Energy Annual 1999 (DOE/EIA-0603(99)); Pulp and Paper 1999-2000 North American Factbook (1997 data).

Biomass fuels (ethanol) represent 20% of alternative fuel use (including MTBE), but less than 1% of total fuel consumption.

1997 U.S. Fuel Consumption for Transportation



Total = 25.1 Quads

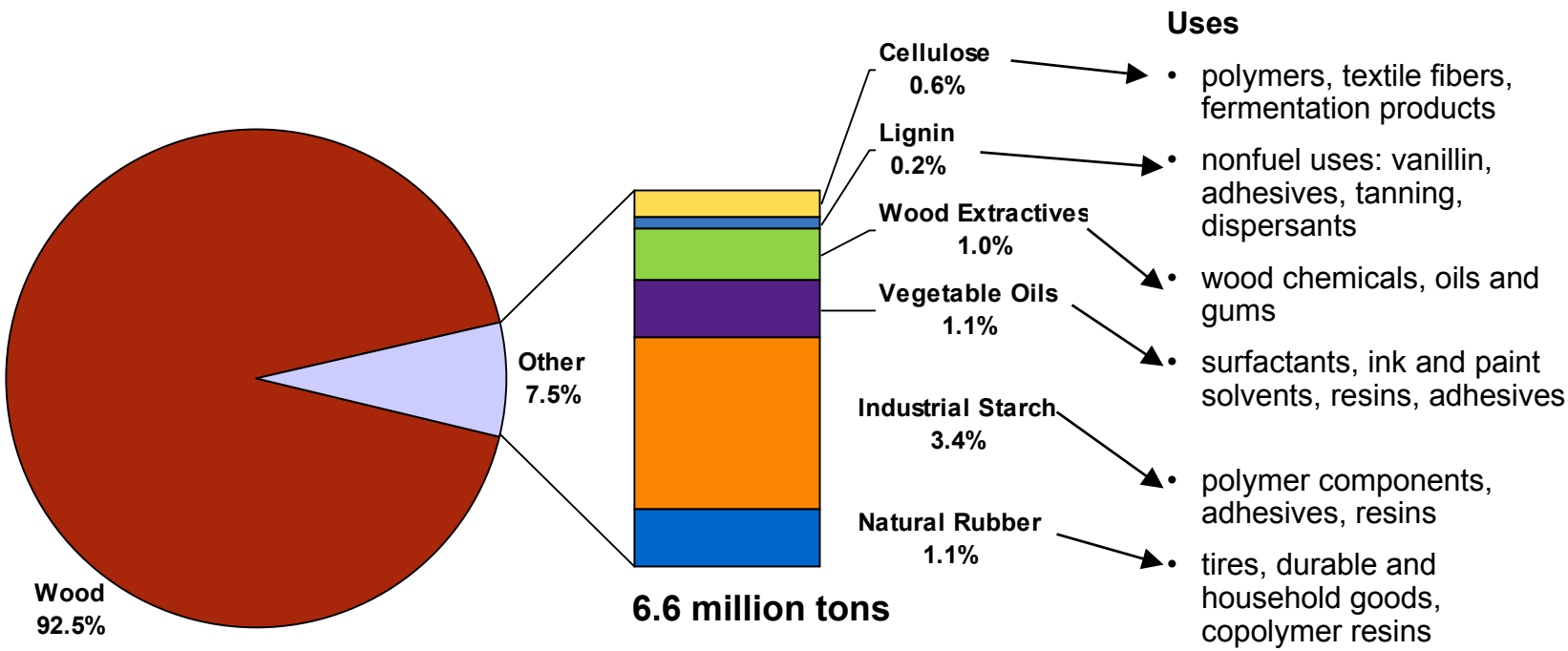


Total = 0.5 Quads
Ethanol = 0.1 Quads
(1.2 billion gallons)

1. Gasoline total includes ethanol blends and MTBE. Natural gas is primarily pipeline fuel. Total gasoline consumption was 119 billion gallons.
2. Other includes LNG, M85, M100, E85, E95, and electricity.
Source: Transportation Energy Data Book, Edition 19 (ORNL-6958).
LNG is Liquefied natural gas; M85/M100 are 85/100% methanol blends; E85/E95 are denatured ethanol fuels; LPG is liquefied petroleum gas; CNG is compressed natural gas; MTBE is methyl tertiary butyl ether.

Biomass use for products is dominated by wood and starch for paper products, although a portion is used for selected materials and chemicals.

1989 U.S. Use of Biomass in Industrial Products



Total = 87.5 million tons

Note: For comparison, total ethanol production in 1998 was 1.34 billion gallons (4.4 million tons)
Wood includes paper and fiberboard.
Source:The Carbohydrate Economy, Institute for Local Self-Reliance, August 1992.

Bioproducts have found significant market penetration in the applications of surfactants, adhesives and fatty acid applications.

1989 U.S. Use of Plant Matter in Industrial Products

	million tons	plant %	plant million tons
Wall Paints	7.8	3.5%	0.27
Special Paints	2.4	2.0%	0.05
Pigments	15.5	6.0%	0.93
Dyes	4.5	6.0%	0.27
Inks	3.5	7.0%	0.25
Detergents	12.6	11.0%	1.39
Surfactants	3.5	35.0%	1.23
Adhesives	5.0	40.0%	2.00
Plastics	30.0	1.8%	0.54
Plasticizers	0.8	15.0%	0.12
Acetic Acid	2.3	17.5%	0.40
Furfural	0.3	17.0%	0.05
Fatty Acids	2.5	40.0%	1.00
Carbon Black	1.5	12.0%	0.18
Total/average	**92.2**	**9.4%**	**8.67**

Note: For comparison, total ethanol production in 1998 was 1.34 billion gallons (4.4 million tons ethanol)
Source:The Carbohydrate Economy, Institute for Local Self-Reliance, August 1992.

The baselines were defined on a output basis (biomass ending up in product) to ensure that efficient process technology is emphasized.

References	• **Biopower** – **Pulp & Paper Industry Steam Production:** Estimated that 100% of electricity production from wood & wood wastes is in the pulp & paper industry and is converted into electric power at 20% efficiency, with 80% of the waste heat recovered. Difference between actual use of hog, bark and spent liquor solids as internal fuels and implied need at 20% generation efficiency is assumed to be converted directly into heat and used onsite. (Data from Manufacturing Consumption of Energy Survey, EIA) – **Electricity Production from Wood & Wood Wastes; Electricity Production from MSW; Electricity Production from Other Biomass Wastes** from the EIA Renewable Energy Annual 1999 • **Biofuels** – For ethanol: Energy Information Administration (EIA) website: http://www.eia.doe.gov/cneaf/solar.renewables/alt_trans_fuel98/table10.html –Data for 1999: – 890,200,000 GGE[1] ethanol as a fuel oxygenate, – 2,489,000 GGE E85 (2,116,000 GGE ethanol) – 59,000 GGE E95 (56,000 GGE ethanol) • **Bioproducts:** Ahmed & Morris, The Carbohydrate Economy, 1992
Methodology	• The biomass baseline was defined on an output basis. The biomass mass equivalent was estimated with 17.5 GJ/ton biomass energy density for fuels and electricity. Industrial products were estimated to have an energy density of 80% of raw biomass (0.8 X 17.5 GJ/ton = 14 GJ/ton). The actual biomass used to make the products is greater than the amount shown because of process inefficiencies. • The economic value of the categories was estimated with EIA 2001 Energy Outlook 2010 reference case prices of $4.4/million BTU for primary energy (used to value steam); $11.2/million BTU for industrial sector electricity; and $10.9/million BTU for transportation sector motor gasoline. Products were assigned a value of $0.30/lb.

1. GGE: gallons gasoline-equivalent. Converted into gallons of ethanol at 129 MJ/gallon gasoline, 91 MJ/gallon ethanol (HHV)

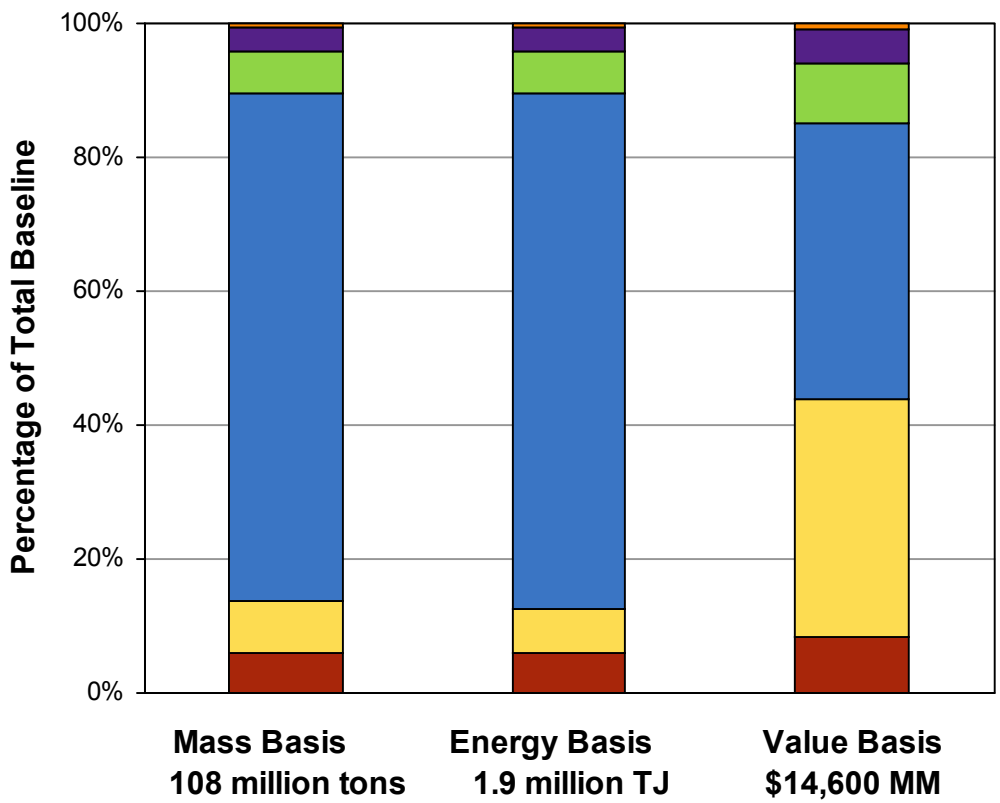
Baseline biomass use can be expressed in a variety of units to facilitate comparisons among different sectors.

Category	Baseline Annual Production: Output Basis			
	Conventional Units	Output Mass-basis[1] (tons)	Output Energy-basis[1] (TJ, 10^{12} J)	Output Economic-basis[1] ($million value)
Biopower				
Pulp & paper industry steam production[1,2]	1.4 billion MMBTU	82 million	1,440,000	$6000
Electricity production from wood & wood wastes[1,2]	33 billion kWh	6.8 million	120,000	$1300
Electricity production from MSW[1,2]	19 billion kWh	3.9 million	69,000	$730
Electricity production from other biomass wastes[1,2]	3.4 billion kWh	690,000	12,000	$130
Biofuels				
Ethanol	1.3 billion gallons	6.4 million	113,000	$1,200
Bioproducts				
Industrial products	8.7 million tons	8.7 million	121,000	$5,200
Total		**108 million**	**1.9 million**	**$14,600**
Tripling would require additional:		**216 million**	**3.8 million**	**$29,000**

1. Output mass basis is the mass equivalent of the category based on a biomass energy density of 17.5 GJ/ton; the actual amount of biomass used to make the product is higher due to process inefficiency (mass shown is on an output basis). Industrial products have been estimated to have an energy density of 80% of raw biomass (0.8 X 17.5 GJ/ton = 14 GJ/ton). The energy basis is on an outlet basis. The economic value is based on steam valued at $4.4/million BTU; motor gasoline $10.9/million BTU (also ethanol); industrial electricity $11.2/million BTU (EIA 2001 Energy Outlook 2010 reference case); industrial products $0.30/lb).
2. Pulp & paper steam production was estimated from 100% of wood & wood wastes is in the pulp & paper industry that is converted into electric power at 20% efficiency with 80% of waste heat recovered

To maximize value, it appears that the focus of expansion should be industrial products, steam and electricity.

Definition of Biomass Baseline



- Electricity from other wastes
- Electricity from MSW
- Electricity from wood
- Pulp & Paper steam
- Other industrial products
- Ethanol

1. Industrial products have been estimated to have an energy density of 80% of raw biomass (0.8 X 17.5 GJ/ton = 14 GJ/ton)
2. Ethanol, electricity and heat converted to a mass-equivalent basis based on an average biomass energy density of 17.5 GJ/ton
3. Ethanol value estimation based on $10.9/million BTU
4. Other industrial products value estimation based on 30 ¢/lb average product price (typical price for commodity chemicals, such as ethylene; actual average price may be higher)
5. Pulp & Paper steam production value estimation based on $4.4/million BTU heat value
6. Electricity production value estimation based on electricity value of $11.2/million BTU

For each sector a baseline was defined and projected out to 2010.

Sector	Conventional Units	BAU 2010 Baseline	Aggressive 2010 Baseline	Comments
Biopower	MW	10,000	10,000	No growth in baseline
Biofuels	million gallons ethanol	1500	1600	• In BAU, biofuels baseline grows at 1.4% per year (projected rate of motor gasoline demand • For aggressive implementation, biofuels baseline grows at 1.8% per year (projected rate of total transportation fuels demand)
Bioproducts	Billion pounds	21	21	Both the BAU and aggressive scenarios grow at 1.8% per year (projected rate of total transportation fuels demand)

1. All growth rate projections taken from USDOE EIA 2001 Energy Outlook, reference case.

Because of the disparate characteristics of the different markets today, each area was evaluated separately.

Product	Tripling Goal: Conventional Units		
	Conventional Units	1998 Baseline Use	What would be Required for Tripling Use
Biofuels	million gallons gasoline equivalent	882	2646
Bioproducts	million tons	8.7	26
Biopower (Heat & Electricity)	Billion kWh	457	1370
Biopower (Heat)	Billion kWh	401	1203
Biopower (Electricity)	Billion kWh	56	167

1. Biofuels are measured in gallons of gasoline equivalent using a HHV of 45.9 GJ/MT for gasoline.

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- Resource Assessment
- Biopower Options
- Biofuel Options
- Bioproduct Options

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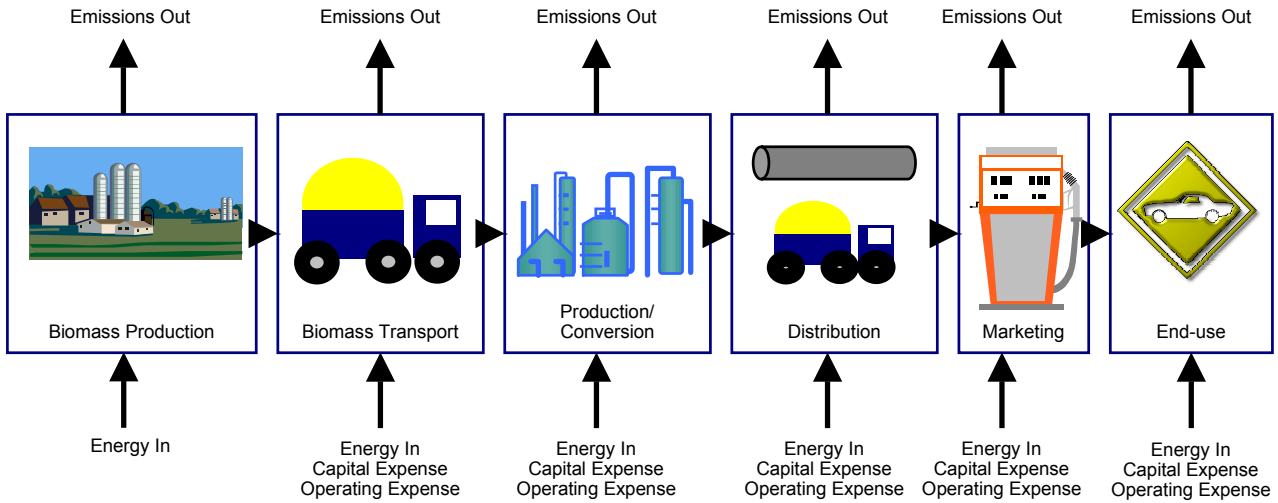
Throughout the study, each potential fuel/power/product was analyzed on a "value chain" basis: from plantation to the market of use.

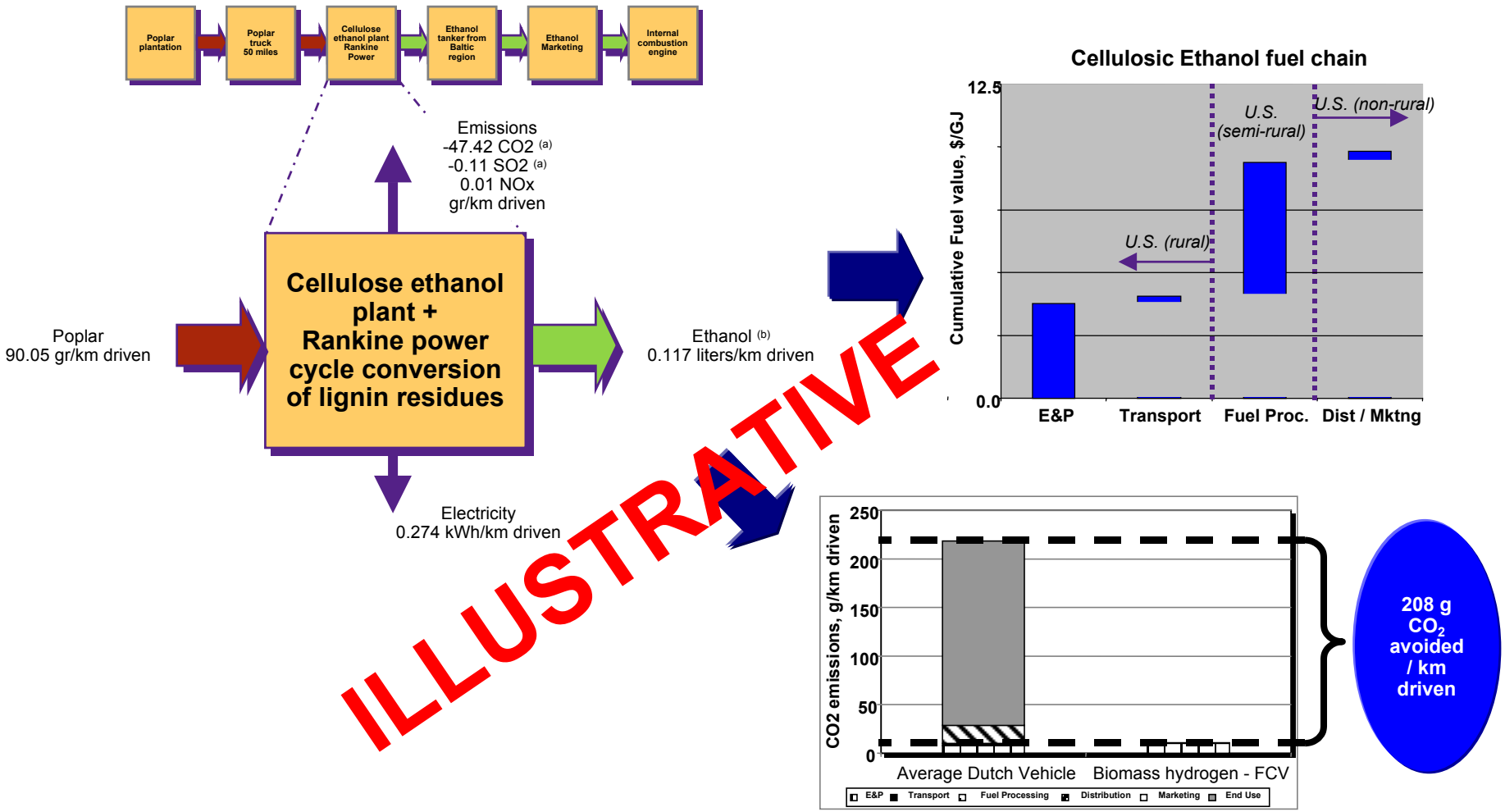


Value Chain Analysis:

- Considers all steps involved in production and use of biomass energy, fuels and products
- Incorporates multiplicative effects in value chain
- Allows for detailed analysis of each module and consideration of a range of combinations
- Considers all energy inputs into the value chain, including secondary not tertiary inputs; i.e. energy used to produce diesel for trucks is included but energy use to make the trucks or the refinery is not included

While this approach captures many of the associated costs and emissions, it is not a full lifecycle analysis, and should not be interpreted as such.

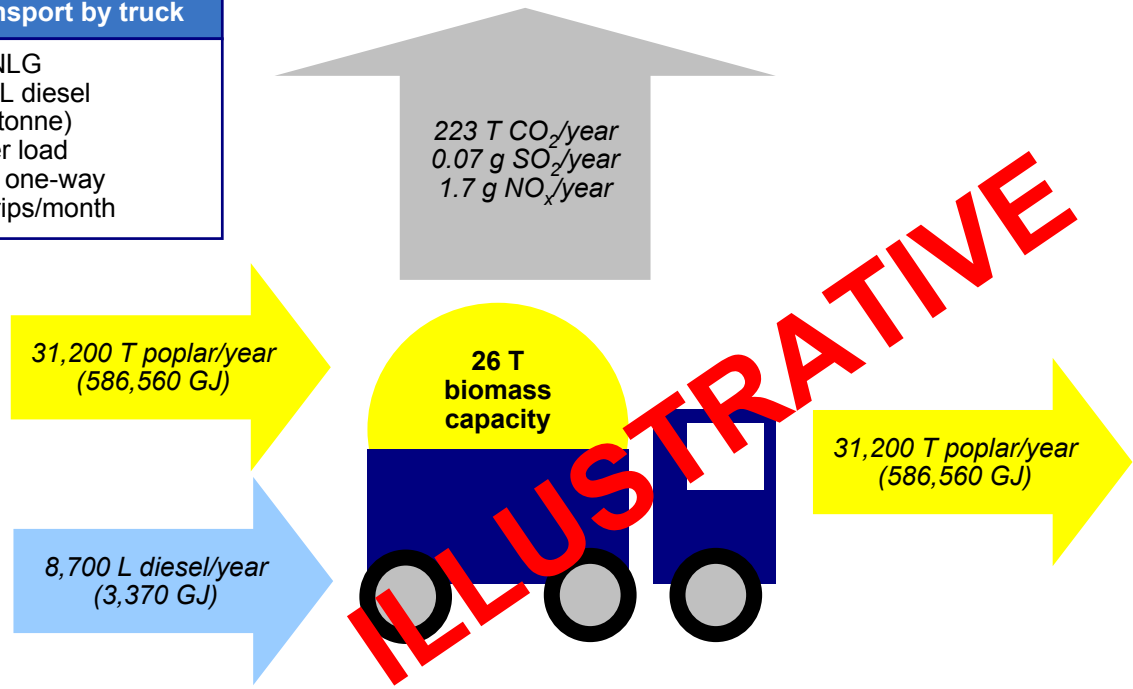
The approach uses a modular spreadsheet tool, previously developed over a number of years to analyze fuel chains.



The characteristic emissions and costs of each module can be readily quantified...

Example: Poplar transport by truck

Capital cost: 300,000 NLG
Fuel economy: 2.2 km/L diesel
Load: Poplar (18.8 GJ/tonne)
Capacity: 26 tonnes per load
Travel distance: 80 km one-way
Frequency: 50 round-trips/month



Efficiency	$\frac{\text{586,560 GJ biomass}}{\text{586,560 + 3,370 GJ total input}}$	= 99.4%

…and by linking modules together, the overall environmental and economic impact of a given fuel chain can be ascertained.

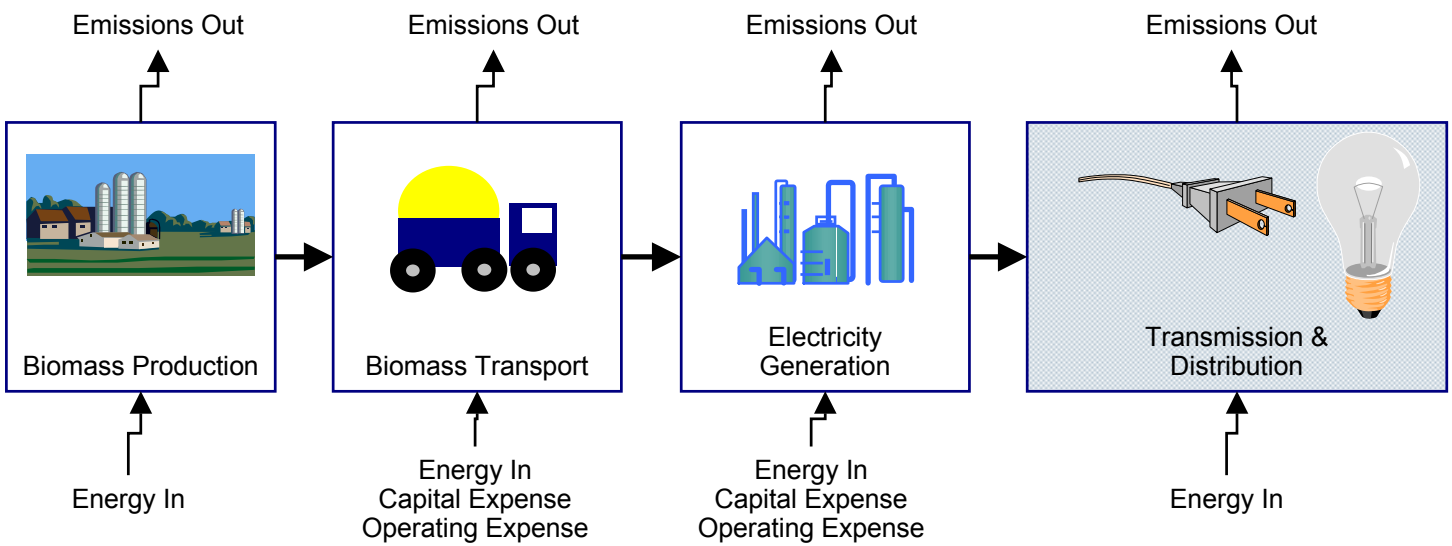
The logical end-point of the value chain analysis depends the final product, leading to slightly different value chain description for each category.

- For Biofuels, the large amount of data available on transportation fuel chain issues enabled a “well to wheels” analysis including:
  - Biomass production
  - Biomass transportation from the farm-gate to the processing plant
  - Transportation fuel production
  - Transportation fuel distribution
  - Transportation fuel marketing
  - Vehicle Use
- For Biopower, it was assumed that the power generated used the existing (paid-for) infrastructure for transmission and distribution (T&D)
  - Biopower value chains differ by whether they produce grid power (wholesale) or onsite power (retail)
  - The following steps were included:
    - Biomass production
    - Biomass transportation from the farm-gate to the power generation station (if grid power)
    - Power generation
    - Transmission and distribution energy losses (if grid power; onsite power applications did not include T&D losses)
- For Bioproducts, the vast array of products and lack of data required the use of a simplified value chain:
  - Biomass production
  - Biomass transportation from the farm-gate to the primary processing plant
  - Primary processing plant

A life cycle analysis was not part of the scope of this study. This has implications in both cost of the chain and associated emissions.

	Options	What was addressed
Biomass Production & Harvesting	• Agricultural residues (e.g. corn stover, wheat straw) • Cellulosic energy crops (e.g. hybrid poplar, switchgrass)	• Emissions for agricultural residues and the main crop (e.g. corn or wheat) were assigned equal emissions on an energy basis • Estimates for agricultural residues and energy crops includes energy required for fertilizer production in addition to fuels used for farm equipment • For fertilizer use (both for agricultural residues and energy crops) the emissions are based on the energy embodied in the fertilizers (gas & electricity), neglecting energy for transportation of the fertilizer • A multiplier was used for seeds, herbicides, pesticides and assumed to be 10% of the energy embodied in fertilizer for agricultural residues and energy crops • A 50/50 mix of best available control and uncontrolled technology were used for the emission factors emissions associated with fertilizer and planting & harvesting of agricultural residues and energy crops • For energy crops we assumed that the same fuel distribution as used for corn farming; also that 1/2 of the land is not fertilized • Emissions associated with the agricultural residues remaining on the field if not used were excluded from the analysis. Similarly any emissions from lands that would have occurred if energy crop production was not used were excluded
	• Gaseous biomass • RDF • Process wastes (e.g. black liquor, hogged fuel, other solid residues)	• Biogas (including landfill, sewage, and digester gas) is generated and used where it is produced so there is no energy use (and therefore no emissions) associated with biomass "harvesting" or gathering and no subsequent transport of the resource • For biogases, fugitive CH_4 , nonmethane hydrocarbon (NMHC), and particulate matter (PM) emissions that would have occurred regardless of the end use for the biogas were also excluded • For RDF, the emissions associated with collection and processing are not included as these would need to be done regardless of the use of RDF for fuel (The non-biomass portion of RDF is also excluded). The RDF is used at the collection site so that transportation emissions are not included • Process wastes (including black liquor, hogged fuel, and other solid residues) are generated and used where produced so there is no energy use (and therefore no emissions) associated with biomass gathering and no transport of the resource
Biomass Transport	• Agricultural residues • Cellulosic energy crops	• Transportation emissions are associated with a 50-mile one-way trips using a diesel fueled truck. A 50/50 mix of best available control technology and uncontrolled was used for the emission factors • Transportation costs and associated emissions were not included for gaseous biomass; refuse derived fuel, black liquor, hogged fuel, and other solid process residues

The cost of electricity was estimated from biomass production to electricity generation including energy losses of transmission and distribution.



Key Artifacts and Assumptions of the Methodology

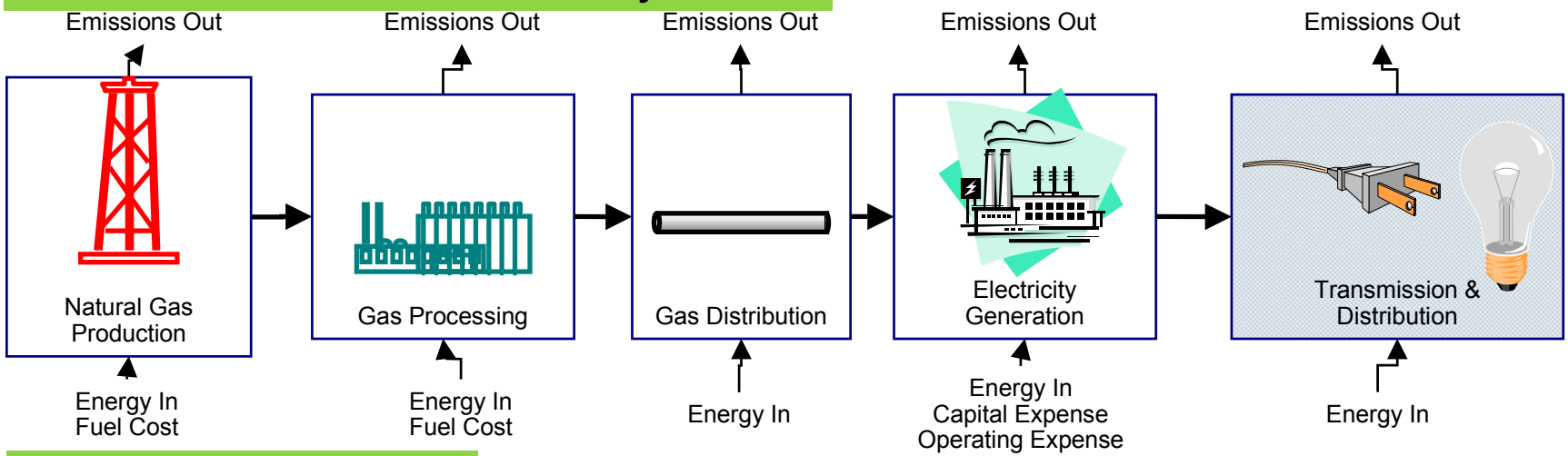
- The costs associated with biomass production (e.g. land, labor, seed, fuel, capital recovery) are assumed to be reflected by the price ($ per dry ton farm-gate) of the biomass. Emissions associated with biomass production are included (from fertilizer, petroleum fuel use) in the benefits and impact analysis.
- Biomass transport costs are associated with a 50-mile one way by truck
- Cases using biomass co-firing include only the cost associated with implementing the biomass
- Energy losses of 7.2% are included for transmission and distribution but not the associated investment costs

Closed-loop carbon cycle was assumed (net zero biomass CO_2 emissions) for biopower.

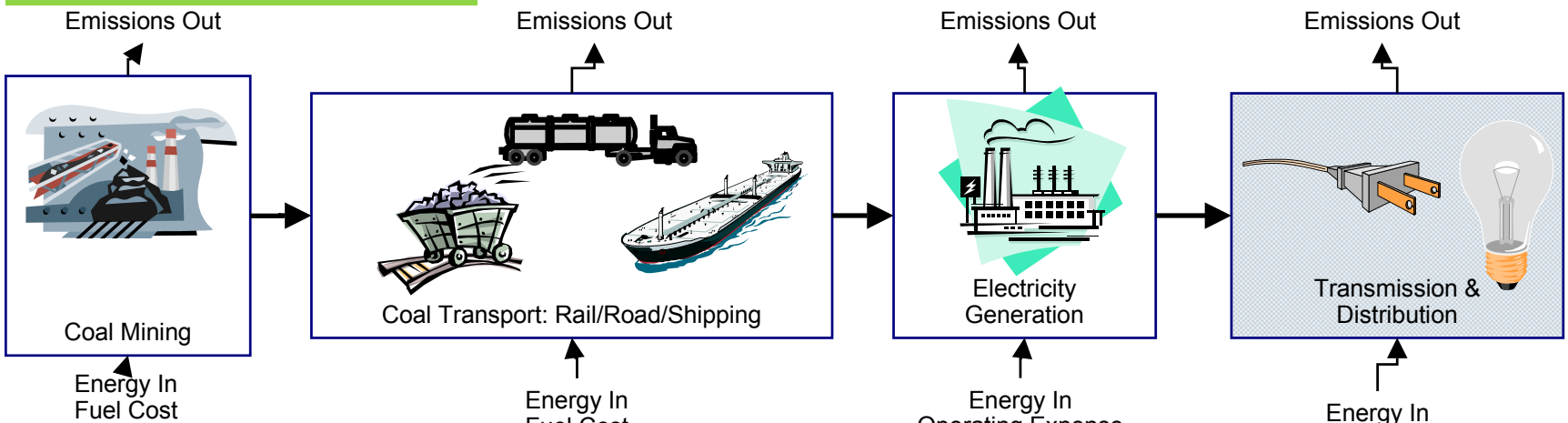
	Options	What was addressed
Biopower	• Resources –Biogases (e.g. landfill, sewage, & digester gases) –Agricultural residues –Energy Crops –RDF –Black liquor –Hogged fuel –Other solid residues • Technologies included: –Rankine cycle –Gas turbine –Gas turbine combined cycle –Integrated gasification combined cycle –Internal combustion engine –Fuel cell	• CO_2 emissions from the utilization of the biomass itself are assumed to be zero (closed-loop carbon cycle) • Biogas (including landfill, sewage, & digester gas), RDF, black liquor, hogged fuel, and other solid residues are generated and used where it is produced so there is no energy use (and therefore no emissions) associated with transport. Fugitive CH_4, NMHC, & PM emissions that would have occurred regardless of the end use were also excluded • Grid-sited options (e.g. utilization of landfill gas, co-firing with coal) include the effects of transmission & distribution energy losses • Most biomass is relatively low in sulfur and therefore no controls are used. For selected feedstocks that are higher in sulfur, such as black liquor, sulfur control technology was used • Fuel cell emissions of SO_2 are effectively zero, as the fuel must be scrubbed free of sulfur to avoid poisoning of the fuel cell stack • NOx emissions estimates are consistent with typical controls (e.g., dry low NOx combustion for gas turbines, lean burn technology for IC engines) • For co-firing with coal it is assumed that each percentage point of biomass co-firing results in a 2 percentage point decrease in overall NOx for direct firing and a 4 percentage point decrease for gasification co-firing (the latter is consistent with the use of the biomass as a reburn technology) • For co-firing with coal it is assumed that methane, NMHC and CO emissions are the same per BTU of fuel consumed as for the baseline coal plant, so that differences in emissions per kWh are related to differences in efficiency • For biomass co-firing with coal, the co-firing is assumed to reduce PM emissions based on the relative ash content of biomass and coal • Methane, NMHC emissions are generally uncontrolled emissions consistent with current good practices for combustion (e.g., dry low NOx combustion for gas turbines, lean burn technology for IC engines) • PM emissions are generally controlled emissions consistent with current good practices (e.g., electrostatic precipitators) • CO emissions are generally uncontrolled emissions consistent with current good practices for combustion (e.g., dry low NOx combustion for gas turbines, lean burn technology for IC engines)

The cost of electricity was estimated from resource production to electricity generation including energy losses of T&D.

Natural Gas: Gas Turbine Combined Cycle Plants



Coal: Rankine Cycle Plants

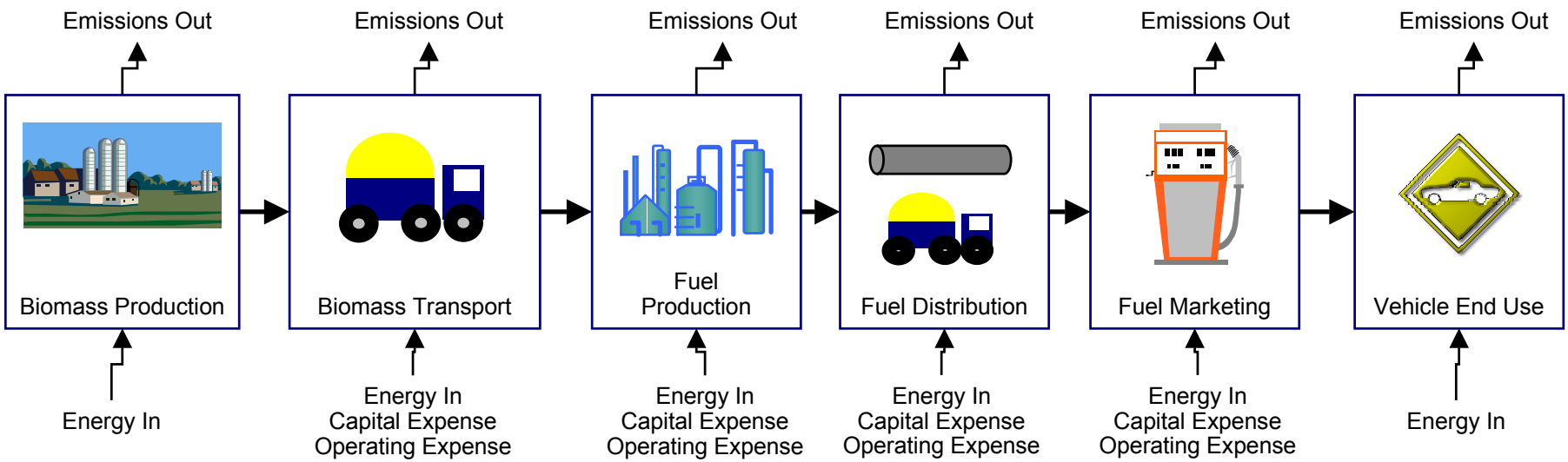


The complexity of the biopower market predicted the use of three distinct baselines for the comparison fossil alternative.

	Coal Rankine Electricity	Natural gas GTCC	Grid Average Electricity
Exploration & Production	• Emissions are associated with coal mining based on 1987 U.S. Coal Industry Statistics and DeLuchi, November 1993, based on DoC Census • Coal bed methane released during mining is included in emissions (90% vented; 10% used for fuel)	• Emissions are associated with extracting the natural gas from the well head and associated emissions from processing of the gas (e.g. removal of inerts, recoverable products (NGLs, LPG), and removal of impurities) • No gas flaring or venting included. Gas flaring associated with oil production assigned to fuels production	• Emissions are based on that from coal, natural gas, and nuclear generated power • Transmission & distribution energy losses of 7.2%
Fuel Transport	• Emissions are associated with a transportation mix of ship (18%), rail (65%), and truck (15%); transportation mix based on DeLuchi; total transport amount from 2000 data	• Emissions associated with national average pipeline for natural gas. Based on total natural gas supply since this is the amount shipped through U.S. pipelines annually.	
Electricity Generation	• Coal Rankine power production with a HHV efficiency of 32.9% • Did not include steam (heat) production credit • Transmission & distribution energy losses of 7.2%	• Natural gas-fired GTCC power production with a HHV efficiency of 54.0% • Transmission & distribution energy losses of 7.2%	

	% Mix	Efficiency
Coal	51.8	32.2%
Oil	2.4	32.6%
Gas	16.1	32.9%
Other	0.8	32.5%
Nuclear	18.4	32.5%
Other Non-fossil	10.4	32.5%

The cost of fuels was estimated from biomass production to vehicle end use not including the cost of any necessary vehicle modifications.



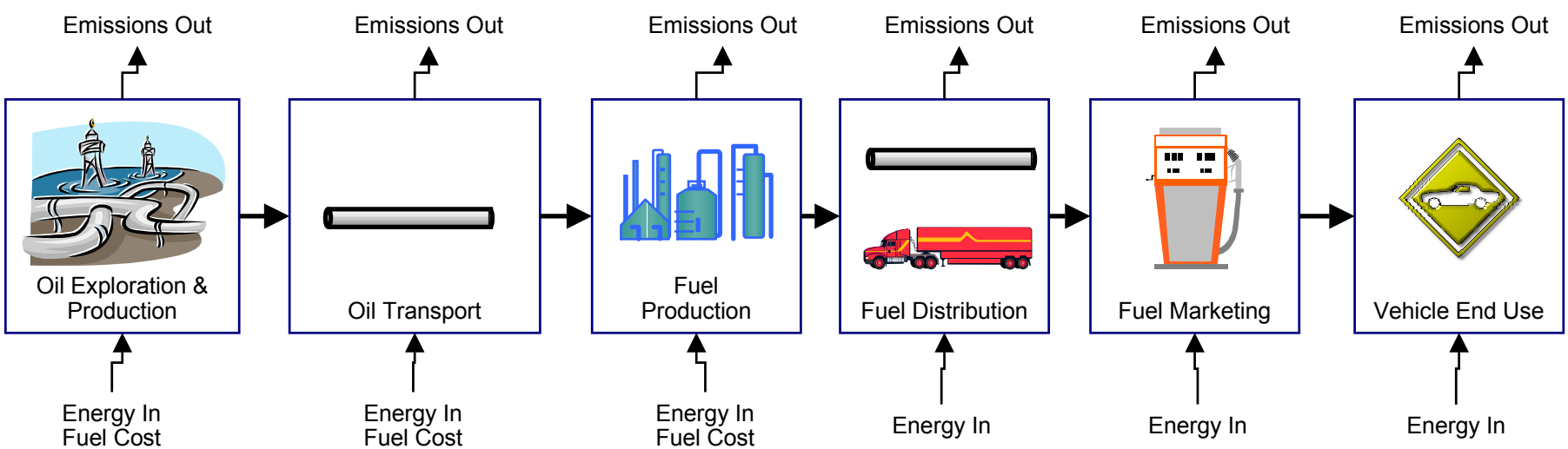
Key Artifacts and Assumptions of the Methodology

- The costs associated with biomass production (e.g. land, labor, seed, fuel, capital recovery) are assumed to be reflected by the price ($ per dry ton farm-gate) of the biomass. Emissions associated with biomass production are included (from fertilizer, petroleum fuel use) in the benefits and impact analysis.
- Biomass transport costs are associated with a 50-mile one way by truck
- Vehicle end use includes the efficiency of the vehicle with the fuel
- Costs associated with vehicle modifications are not included

Closed-loop carbon cycle was assumed (net zero biomass CO_2 emissions) for biofuel use. Regulated emissions used ULEV standards.

	Options	What was addressed
Biofuels	• Agricultural residues • Energy Crops • Corn • Technologies included: – Ethanol production from corn – Ethanol production from cellulosics – Fischer-Tropsch diesel production from agricultural residues or energy crops	• CO_2 emissions from the utilization of the biomass itself or its end product (i.e. the produced fuel) are assumed to be zero (closed-loop carbon cycle) • Carbon dioxide and sulfur dioxide emission are based upon the elemental composition of the fuel and the chain efficiency • For fuel manufacture, emissions within the plant gate are assumed to be from best available control technology. The exception is any vehicles used to move the biomass within the plant gate. These vehicles are assumed to be fueled with petroleum-diesel and have 50/50 emissions associated with a mix of uncontrolled and best available control technology • All grid electricity used for manufacture of the fuel used a grid average mix for emissions estimation • Emissions are included for distribution of the fuel to depot stations and transport to retail stations. Evaporative losses are included for retail marketing of the fuel • Emissions are associated with the biomass portion of the fuel only for blending applications • The vehicle emissions are based on that the vehicle is designed to meet the emission standard (ULEV), regardless of the fuel used. Regulated emissions for each fuel are set by the relevant emission standards – NOx, CO, and nonmethane hydrocarbon standards are set by the 50,000 mile durability ULEV standards for 2001-2006 Model Year for all passenger car's and light-duty trucks (0-3750 lbs LVW) – Particulate matter for compression ignition engines are the 100,000 mile durability standards for new 2001-2003 Model Year TLEV passenger cars and light duty trucks – Methane emissions are calculated from correlations based on the amount on nonmethane hydrocarbon emissions – The effect of ethanol as an oxygenate on emissions in the vehicle was not taken into account

The associated emissions of petroleum-derived fuels was estimated from oil production to vehicle end use.

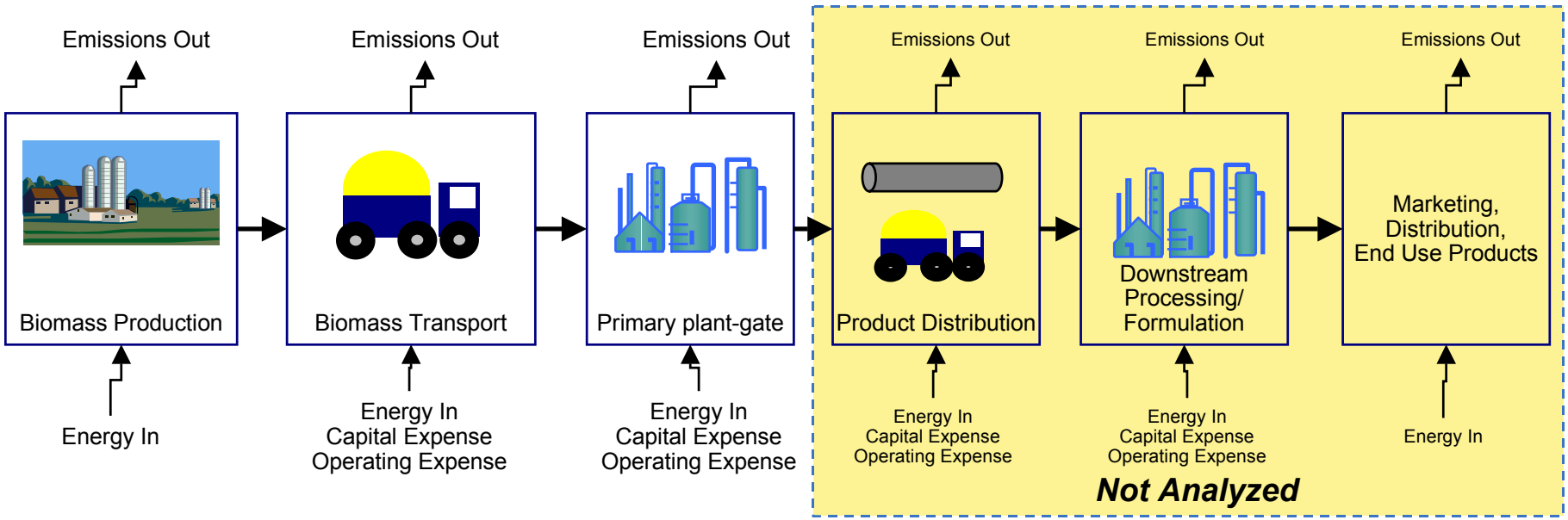


Existing infrastructure was used with zero associated capital and operating costs.

Biofuels were compared to a gasoline fuel chain or a diesel petroleum chain depending on engine use (spark versus compression ignition).

	Gasoline	Petroleum Diesel
Exploration & Production	• Petroleum extraction from Petroleum Extraction - 1987 DoC Census Data adjusted by DeLuchi (1993) including Alaska and Lower 48 Production • Includes natural gas flared during production. The natural gas is flared or used as fuel onsite • Segment efficiency 95.8%	
Raw Oil Transport	• Emissions are associated with shipping crude oil within Lower 48 and from Alaska to Lower 48 and shipping of oil imported into United States. • Modes of transport included pipeline, barge, tanker, train, and truck • Includes evaporative losses; segment efficiency of 99.1%	
Fuel Production	• Includes refining from petroleum for gasoline production with a segment efficiency of 87.8%	• Includes refining from petroleum for gasoline production with a segment efficiency of 94.8%
Fuel Distribution	• Includes emissions associated with transport of the gasoline to the bulk terminal by a combination of pipeline; tanker and barge; truck transport to the bulk plant and truck transport to the fueling stations	• Includes emissions associated with transport of the diesel to the bulk terminal by a combination of pipeline; tanker and barge; truck transport to the bulk plant and truck transport to the fueling stations
Fuel Marketing	• Includes energy usage at fueling stations and evaporative losses	• Includes energy usage at fueling stations and evaporative losses
Vehicle Use	• Use in spark ignition vehicle with 15.7% efficiency • Emissions are set to ULEV standards	• Use in CIE vehicle with 16.9% efficiency • Emissions are set to ULEV standards • Particulate matter set to 100,000 mile durability standards for new 2001-2003 Model Year TLEV vehicles

The cost of products was estimated from biomass production to primary product manufacture and ended at the primary plant-gate.



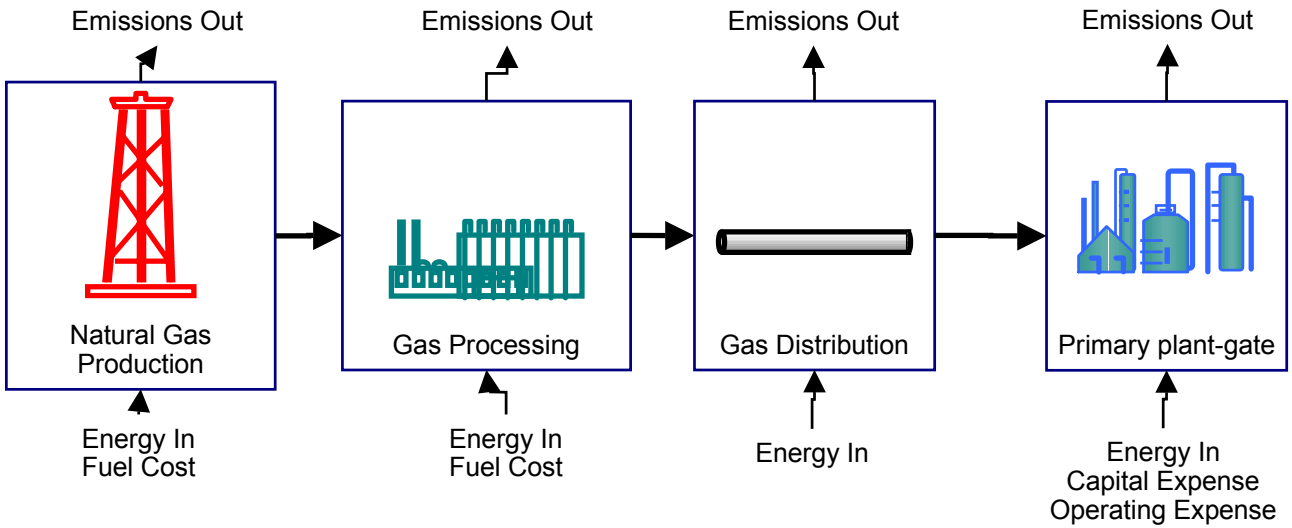
Key Artifacts and Assumptions of the Methodology

- The costs associated with biomass production (e.g. land, labor, seed, fuel, capital recovery) are assumed to be reflected by the price ($ per dry ton farm-gate) of the biomass. Emissions associated with biomass production are included (from fertilizer, petroleum fuel use) in the benefits and impact analysis.
- Biomass transport costs are associated with a 50-mile one way by truck

Products were analyzed up to wholesale level. The carbon in the bioproduct was treated as if it were "sequestered" carbon.

	Options	What was addressed
Bioproducts	• Agricultural residues • Energy Crops • Seed oils • Corn • Technologies included: –Fermentation –Oil Splitting of lipids –High temperature pyrolysis –Syngas based processes	• The biobased chemicals value chains were analyzed up to the wholesale level. Thus we did not analyze the potential impacts of changes in product design and usage. The implicit assumption was that the biobased chemicals would have comparable performance. For example, any increases or decreases in the weight of the final products could impact transportation costs of the products, or change energy use in the use of the product. • Also, energy use and emissions impacts associated with the end of the life of the chemical is not considered. We expect that on balance, the impact of this limitation will be neutral, since some bio-based chemicals will perform better, while others will perform less well. • For primary product manufacture, emissions within the plant gate are assumed to be from best available control technology. The exception is any vehicles used to move the biomass within the plant gate. These vehicles are assumed to be fueled with petroleum-diesel and have 50/50 emissions associated with a mix of uncontrolled and best available control technology • All grid electricity used for manufacture of the primary product used a grid average mix for emissions estimation • For fermentation based processes utilizing glucose; we included the comparable emissions to grow and transport the raw corn but did not include the emissions associated with making the glucose from starch in a wet or dry corn mill • Similarly for oil seed based materials; the emissions were assessed for the processing of the seed oil to make the product but did not include the upstream emissions associated with growing the plant, harvesting the seed, transporting the seed, and recovering the raw oil from the seed • Fugitive emissions from biomass stockpiles on the plant site or fugitive emissions associated with unused crop or resource materials were excluded

Methanol from natural gas was used as a fossil-analog for a industrial "building-block" chemical.



Two proxies of petroleum products were used for a high level comparison: methanol from natural gas and LPG from petroleum.

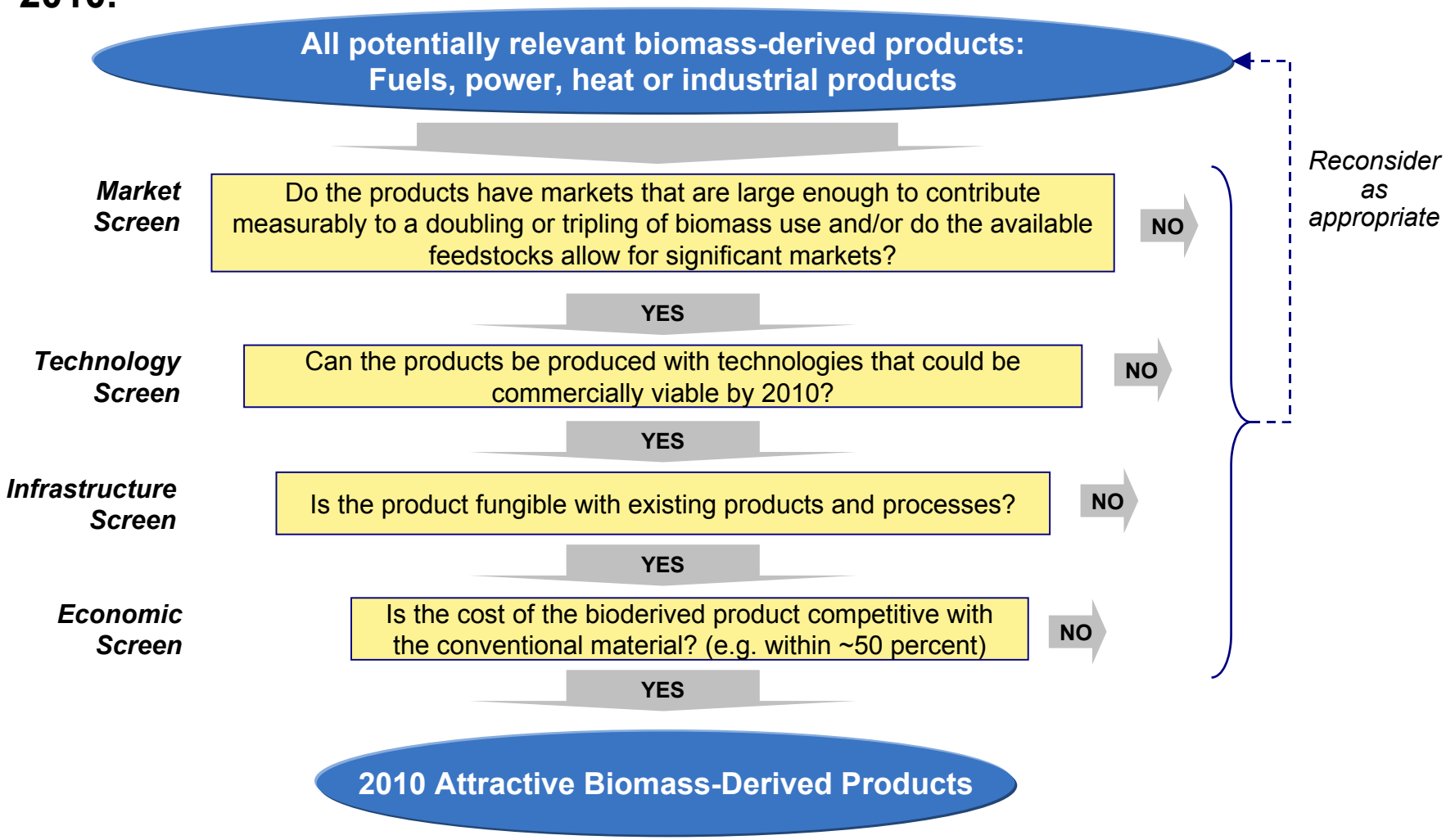
	Methanol from Natural Gas	LPG from Petroleum
Exploration & Production	• Emissions are associated with extracting the natural gas from the well head and associated emissions from processing of the gas (e.g. removal of inerts, recoverable products (NGLs, LPG), and removal of impurities)	• Petroleum extraction from Petroleum Extraction - 1987 DoC Census Data adjusted by DeLuchi (1993) including Alaska and Lower 48 Production • Includes natural gas flared during oil production • Segment efficiency 95.8%
Raw Fuel Transport	• Emissions associated with national average pipeline for natural gas. Based on Total Natural Gas Supply since this is the amount shipped through U.S. pipelines annually.	• Emissions are associated with shipping crude oil within Lower 48 and from Alaska to Lower 48 and shipping of oil imported into United States. • Modes of transport included pipeline, barge, tanker, train, and truck • Includes evaporative losses; segment efficiency of 99.1%
Primary Product Manufacture	• Methanol synthesis from synthesis gas made from natural gas with segment efficiency of 66.5%	• Includes refining from petroleum for LPG production with a segment efficiency of 95.3%

The 2001 EIA Energy Outlook 2010 energy prices were used for the reference case with an oil price of $21.4 per barrel.

RBEP Region	Electric Generators		Industrial Users		
	Natural Gas	Coal	Natural Gas	Electricity	Diesel
Great Lakes	$2.65/GJ	$1.00/GJ	$3.34/GJ	$10.48/GJ	$3.22/GJ
Northeast	$3.17/GJ	$1.00/GJ	$3.30/GJ	$12.47/GJ	$3.22/GJ
Northwest	$2.96/GJ	$1.00/GJ	$3.37/GJ	$10.04/GJ	$3.20/GJ
Southeast	$2.99/GJ	$1.00/GJ	$2.86/GJ	$10.80/GJ	$3.20/GJ
Western	$2.92/GJ	$1.00/GJ	$3.23/GJ	$10.14/GJ	$3.20/GJ
U.S. Average	$2.82/GJ	$1.00/GJ	$2.82/GJ	$10.65/GJ	$3.20/GJ

	Transportation Sector			
	Diesel		Gasoline	
U.S. Average	¢ 92.1/gallon	$6.43/GJ[1]	¢90.7/gallon	$7.03/GJ[1]

A separate screening process was used for each category to identify the options that could play a role a significant increase in U.S. biomass use by 2010.



The following stages of technology development were used to describe the technology status.

	Research & Development			Demonstration			Market Entry	Market Penetration
	Concept	Bench	Pilot	Initial System Prototypes	Refined Prototypes	Commercial Prototypes		
Description of Typical Activities	• Concept, bench and pilot scale activities • 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	• Initial 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
Key for following slides	**R&D**			**D**			**E**	**P**

Given the 2010 timeframe technologies that have not achieved the initial system prototype testing stage were screened out.

A structured screening approach was used to rank the infrastructure requirements of each of the fuel chains.

Rank	Definition
1	The existing infrastructure can be used without or with minor modification
2	Some of the existing infrastructure can be used and/or the existing infrastructure will require minor modifications and new construction
3	A completely new infrastructure is required

- Each component of each fuel chain was ranked.
  - Biomass Production (biomass growth & harvesting)
  - Biomass transportation
  - Fuel processing (e.g fuel, primary product, or power generation
  - Fuel distribution if applicable
  - Fuel marketing if applicable
  - Vehicle end use if applicable
- Fuel chains receiving a score of “3” for all components were removed from this screen
  - Such chains require retrofits to the entire fuel infrastructure, and are unlikely to contribute significantly to increased biomass utilization by 2010
- Fuel chains receiving a score of “3” for all components other than biomass production and biomass transportation were removed from further consideration
  - Since downstream operations are larger in number and more disperse, they will require the largest investment in capital and time to build up

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Generally, sufficient domestically available biomass exists to meet the aggressive goals of increasing biomass use in the United States. Based on available literature data, over 600 million dry tons of biomass appears to be available in the United States at between $0 and 40 dollars per dry ton farm-gate (e.g. available over the price range of $0 to 40/dry ton farm-gate; not at a single price point). However, high-quality biomass is unavailable in large quantities below $20/dry ton farm-gate. Those biomass resources that are available in significant quantities below $20/dry ton are heterogeneous wastes (e.g. organic municipal solid waste and urban tree residues). Manure is potentially available in large quantities and at low cost; however, off-site applications may be limited due to transportation costs. Based on DOE model predictions, energy crops could be the largest source of biomass at farm-gate prices greater than $40/dry ton. However, energy crops such as poplar, switchgrass, and willow are currently not produced at high volume.

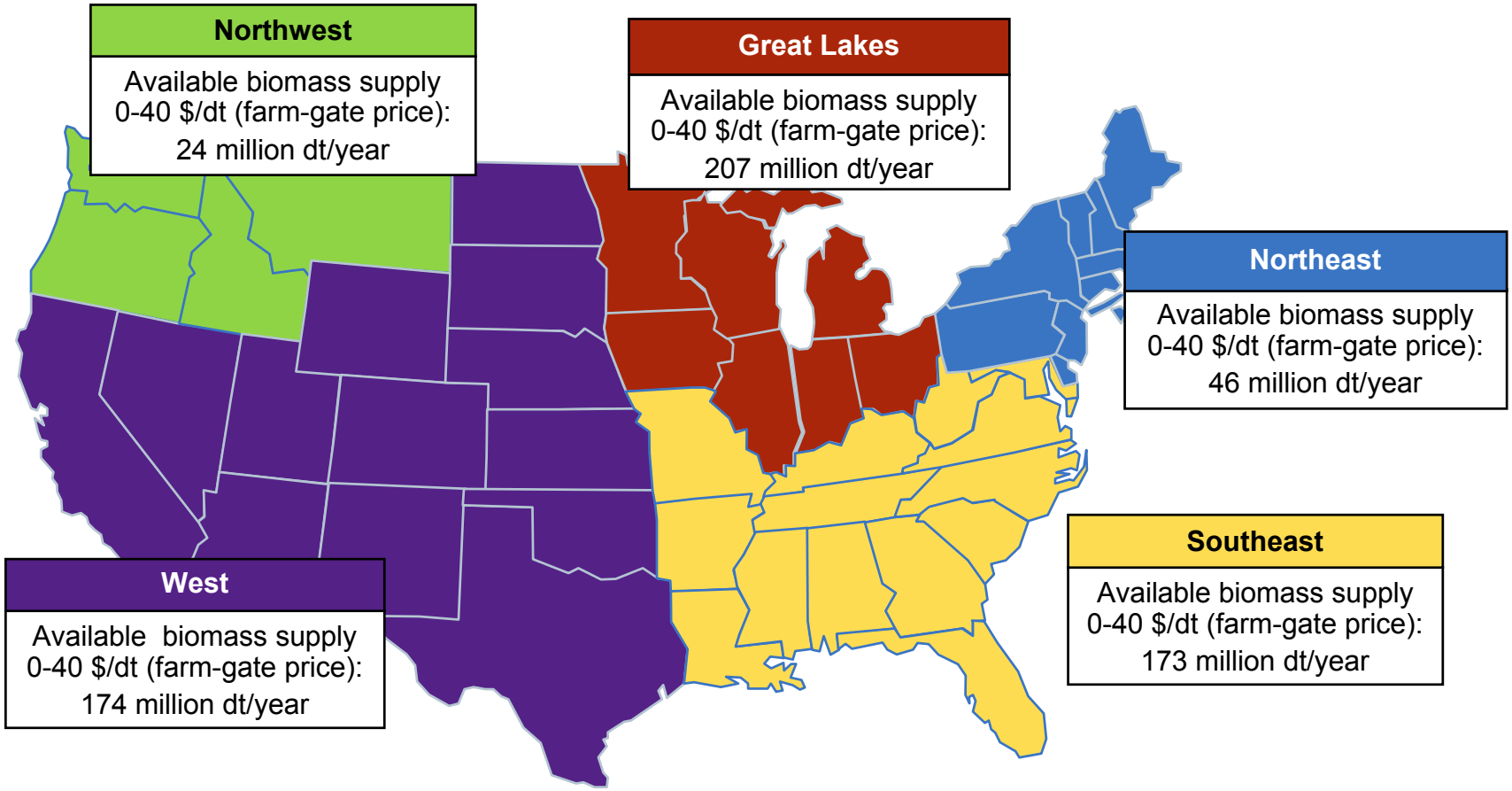
There is likely to be instances in which feedstocks have a negative cost, for example in the form of tipping fees. Examples include urban tree residues and municipal solid waste. However, in instances where the biomass is used more broadly, and a market for the biomass feedstock is created, it is unlikely that tipping fees will be sustained. Tipping fees or negative cost feedstocks are not used in this study.

The estimated supply curves could change if biomass becomes a traded commodity, similar to corn or soybeans. Agricultural crop residue available quantities could increase dramatically if residues are seen as having cash value to the farmer. Current agricultural production is optimized to minimize currently worthless residues. Production and harvesting methods for the agricultural product could be altered to give twice as much collectable residue if they had sufficient value.

The prices in this section are farm-gate prices and do not include transportation costs to the primary processing plant. A general assumption has been made in the study to include 50-mile one-way transportation costs for biopower, biofuel,and bioproduct applications. Transportation costs in addition to the farm-gate cost of the biomass may pose a significant hurdle for cost competitiveness of some biomass-based fuel chains.

The objective of the resource assessment was to generate supply/price curves for a range of biomass resources. ADL performed a resource assessment on *unused* biomass quantities and prices by reviewing the existing open literature. The scope did not include an independent assessment or critique of existing data. Food, feed, wood/lumber, and textiles were excluded from the analysis since they do not compete with non-biomass resources (primarily petroleum derived fuels, power, and products). Non-food uses of conventional crops such as wheat, corn, and soybeans were taken into account.

Based on available literature data, over 600[1] million dry tons of biomass is available in the U.S. at between 0 and 40 dollars per dry ton[4] farm-gate.



1. Compare with 108 million ton baseline which is on an output basis
2. These results are explained in detail in the following slides. Regions are defined by the Regional Biomass Energy Program.
3. Data did not include Hawaii and Alaska
4. The prices in this section are “farm or plantation” gate prices and do not include transportation costs to the processing plant.

Sufficient biomass is available to more than double biomass use but farm-gate prices at high volume are expected to exceed $20/dry ton[1].

- Available literature data indicates that over 600 million dry tons of biomass are available within the United States at farm-gate prices between 0 and 40 $/dry ton (0 to ~$2.3/GJ or $2.4/million BTU):
  - Available biomass is defined as a resource that is currently or potentially collectable and not currently used as energy fuel or any beneficial use and is potentially usable (not contaminated or comingled)
  - Available biomass in significant quantities below $20/dry ton farm-gate are typically heterogeneous wastes (Organic municipal solid waste and urban tree residues)
  - Manure is potentially available in large quantities and at low cost, but off-site applications may be limited due to high transportation costs
  - Based on USDOE ORNL agricultural sector model projections[2], energy crops could be the largest source of biomass at prices in excess of $40/dry ton farm-gate, but energy crops are not currently produced in high volume
- Consistent and homogeneous biomass supplies are only available in large quantities at prices in excess of $20/dry ton farm-gate (e.g. energy crops, corn stover, wheat straw)
- The biomass sources with the highest potential in the 0-40 $/dry ton farm-gate price range are:
  - Corn stover (Great Lakes region: Minnesota, Iowa, Wisconsin, Illinois, Indiana, Ohio and Michigan)
  - Organic municipal solid waste (Northeast: New England, New York, Pennsylvania, New Jersey, and Delaware)
  - Forest residues (Northwest :Washington, Oregon, Idaho, and Montana)
  - Switchgrass (Southeast and West regions: all other states)
- Feedstock cost reductions alone will not enable broader competitiveness for some technologies
- Fuel chain costs include raw biomass transportation costs for 50-mile one way

The biomass resource prices in this section are farm-gate or plantation-gate and do not include transportation cost to the processing plant.

1. For comparison for the industrial sector 2010 reference case: coal $1.3/million BTU; residual fuel oil is $3.4/million BTU; natural gas $3.3/million BTU in the EIA 2001 Annual Energy Outlook. The price of biomass is a farm-gate price; transportation of biomass is included in the fuel chain costs of the various options.
2. Model results were obtained from Ugarte, D., M. Walsh, H. Shapouri, and S. Slinsky (July 2000), "The Economic Impacts of Bioenergy Crop Production on US Agriculture". Additional resource references are in the Data Volume to this report.

Task I, the resource assessment, was based primarily on a literature review and gap analysis.

- ADL performed a resource assessment on unused biomass quantities and prices by reviewing the *existing* literature
  - Food[1], feed, wood, and textile crops were excluded from the analysis since they do not compete with non-biomass resources
  - Unused biomass contributes directly to the aggressive goals
- There exist major areas to better utilize currently used biomass that involve an opportunity cost
  - Black liquor and hogged fuel from pulp & paper industry
  - Traditional agricultural crops (e.g. corn, wheat, soybean, rapeseed)
- The use of traditional agricultural crops was included but a detailed resource assessment was not done
- An opportunity cost analysis of currently used resources was outside the scope of the study

The objective of the resource assessment was to generate supply price curves for a range of biomass resources.

1. However, corn, soybeans, and rapeseeds are included for non-food end uses.

Task I did not include an independent assessment or critique of existing resource data.

- An original resource assessment was beyond the scope of this study
  - Only existing data was used
- We reviewed an extensive list of resource assessments and chose the best data based on this study's requirements
  - Data selection was accomplished with input from outside experts (e.g. DOE, RBEP managers, EPA)
- Some resources were not included due to lack of demand on the end use side of our modeling effort (an artifact of our analysis)

RBEP is the Regional Biomass Energy Program.

The resource assessment used existing data; however, critical information on feedstock quality and composition was not uniformly available.

Review Existing Literature

- Performed literature search
- Gathered published data and information from personal communications with DOE

- Identified gaps in the literature and estimated when appropriate

Build Biomass Supply Database

Fuel	Unit	HHV (GJ)	Density (MT/unit)	HHV (GJ/MT)	Elemental composition C	H	O	S	N	kg/kmol
Anaerobic digester feed	1000 m^3	7,200	800	9						0.00
Bio-diesel	million gallons	140,220	3,311	42	19	36	2	0	0	296.49
Biogas	MMSCF	642	33	20	1	3	1	0		26.09
Biomass - corn	1000 bushels	487	22	22	1	2	1		0	28.49
Biomass - douglas fir	1000 tons	18,480	907	20	1	1	1	0	0	23.69
Biomass - eucalyptus	1000 tons	17,554	907	19	1	1	1	0	0	24.73
Biomass - maple	1000 tons	17,110	907	19	1	1	1	0	0	23.94
Biomass - oil seeds	1000 tons	25,034	907	28	1	2	1		0	28.49
Biomass - ponderosa pir	1000 tons	18,162	907	20	1	1	1	0	0	24.31
Biomass - poplar	1000 tons	17,042	907	19	1	1	1	0	0	24.41
Biomass - rapeseed	1000 tons	17,536	907	19	1	1	1	0	0	24.22
Biomass - rapeseed mea	1000 tons	16,420	907	18	1	2	1	0	0	25.78
Biomass - soybean	1000 bushels	458	27	17	1	2	1	0	0	29.55
Biomass - sugarcane ba	1000 tons	15,722	907	17	1	1	1	0	0	24.15
Biomass - switchgrass	1000 tons	16,602	907	18	1	1	1	0	0	24.27

- Adjusted data to obtain state-level information when necessary
- Adjusted data to obtain available quantities when necessary
- Made assumptions on price when necessary

Segment and Analyze Database

		Quantity (tons/yr)	Price ($/ton)
Geography	Northeast U.S.		
	Mid-Atlantic U.S.		
	Etc.		
Type	Cellulosic		
	Oil seeds		
	Etc.		
source	Marginal cropland		
	Dedicated cropland		
	Etc.		

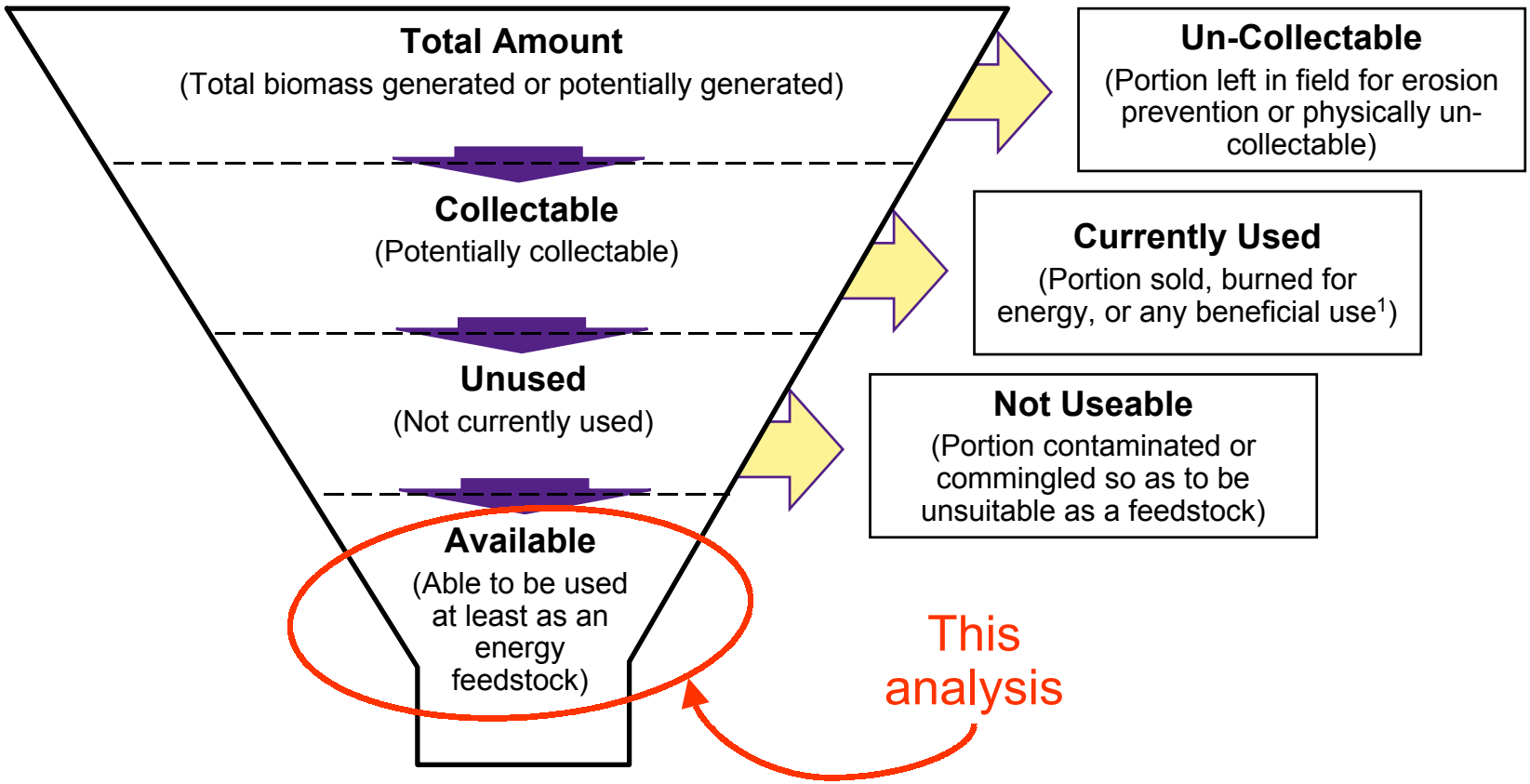
- Segmented the resources by geography, source, type, and availability
- Constructed regional supply curves from price and available quantity information
- Compared data to other sources
- Looked critically at how supply curves may change in the future

A price/supply database on a regional basis was developed using existing data and reasonable assumptions for data gaps.

Where possible, quantity and price data were established by geographic location, so that supply curves could be generated for each region.

- Only existing price and quantity data were used
  - An original assessment was outside the study scope
  - Data sources used included a variety of industry and government studies, reports, and publications (Key references are found in the Data Volume, Section E)
  - Existing farm-gate price data were used when available
  - When farm-gate data was not available, prices were estimated
  - Transportation costs are included in a separate transport module
- Regional supply curves were constructed from state-level quantities and state average prices
  - The United States is split into five regions defined by DOE's Regional Biomass Energy Program (RBEP)
  - Supply curves were constructed from biomass quantities and average prices in the various states
- Corn, soybeans, and rapeseeds were included as model inputs at quantities and prices in current use, but a detailed resource assessment was not performed
  - Supply curves were not generated for these traditional crops
  - Crops are assumed to be available at the commodity market price
  - The potential to increase the use of conventional crops was not examined

Supply curves were based on potentially "available" quantities of biomass.[1]

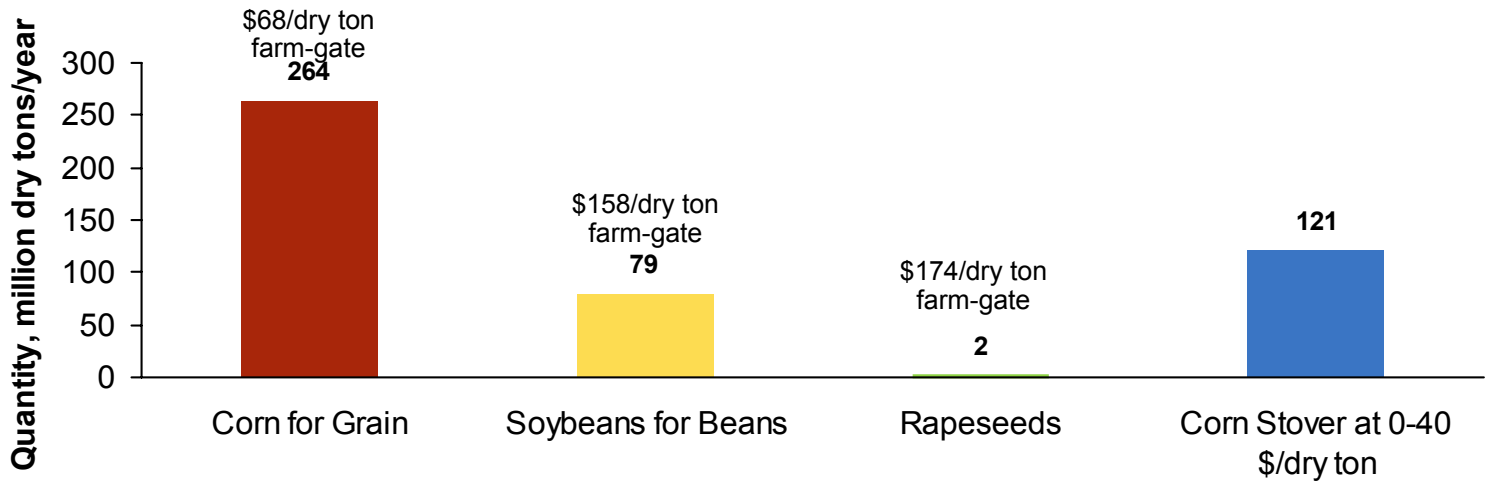


1. "Beneficial use" was determined on a case by case basis.

Corn, soybean, and rapeseed were included as potential feedstocks for fuels and chemical products.

- Corn, soybeans, and rapeseeds were chosen based on their demand as feedstocks for products and fuels
  - Other traditional crops were not in demand for the end uses selected in the model (an artifact of the analysis)
- Rapeseed quantities could dramatically increase if demand was sufficient
- Quantity and price data are from USDA crop production and value data

U.S. Current Production of Selected Traditional Crops, with Comparison to Available Corn Stover at 0-40 $/dry ton Farm-gate (Million Dry Tons per Year)

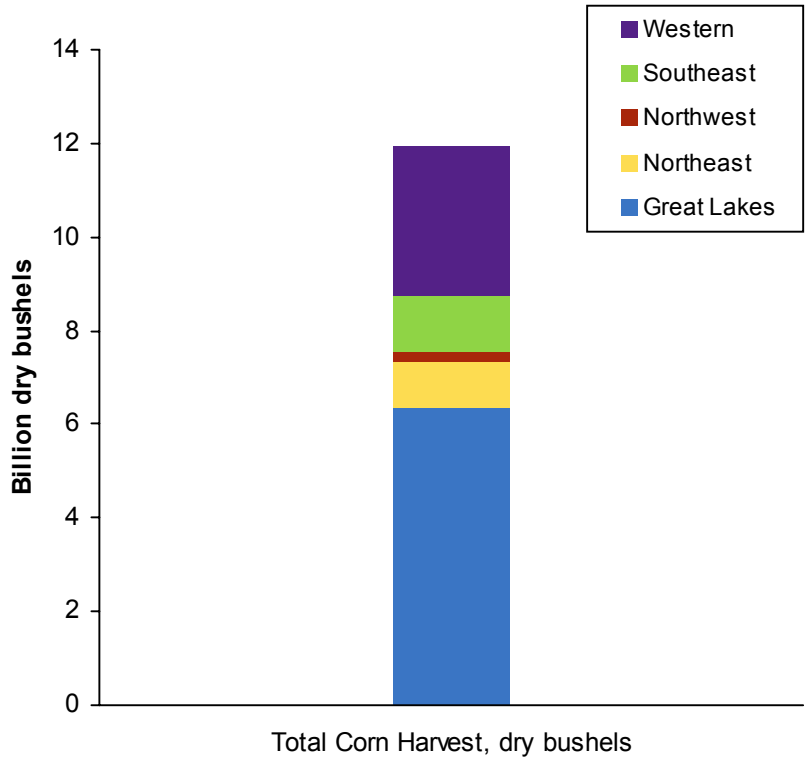


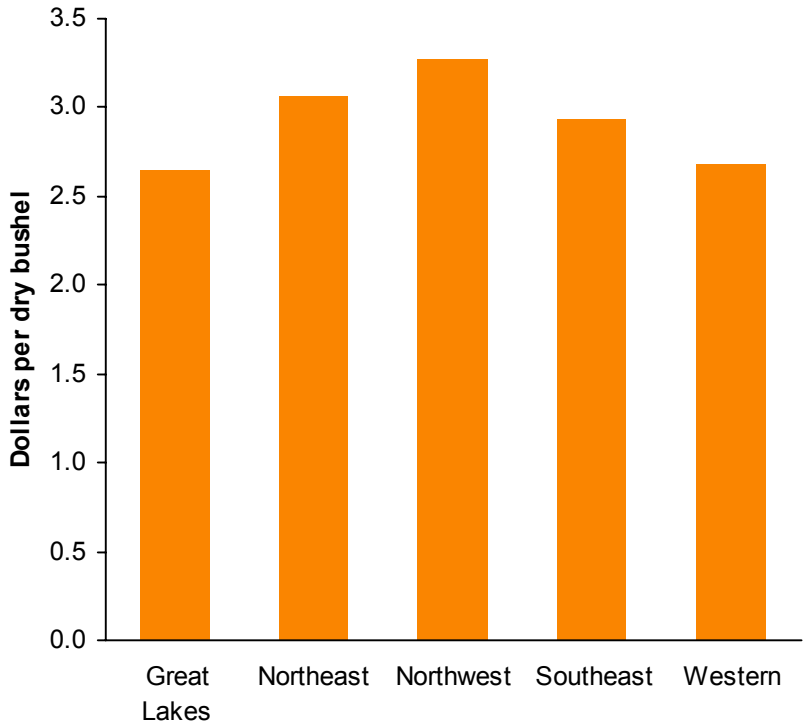
Note: Prices are 1999 marketing year average prices received by the farmer. Assumes 56 lb/bu for corn and 60 lb/bu for soybeans.

Corn, soybean, and rapeseed are not included in the following resource assessment discussion.

Corn prices for selected applications used an average over 1996-1998 prices for bushel (wet basis)

Total Corn Harvest and Corn Prices Used in Model (Billion dry bushels and $/dry bushel farm-gate, respectively)

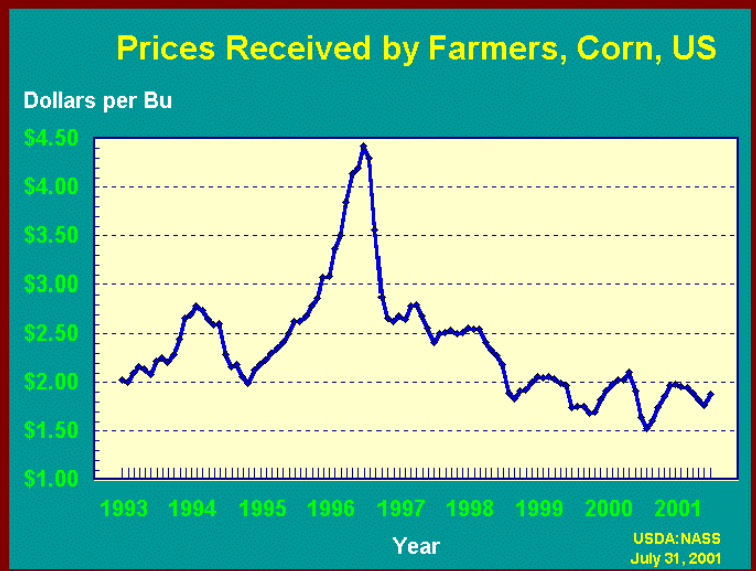


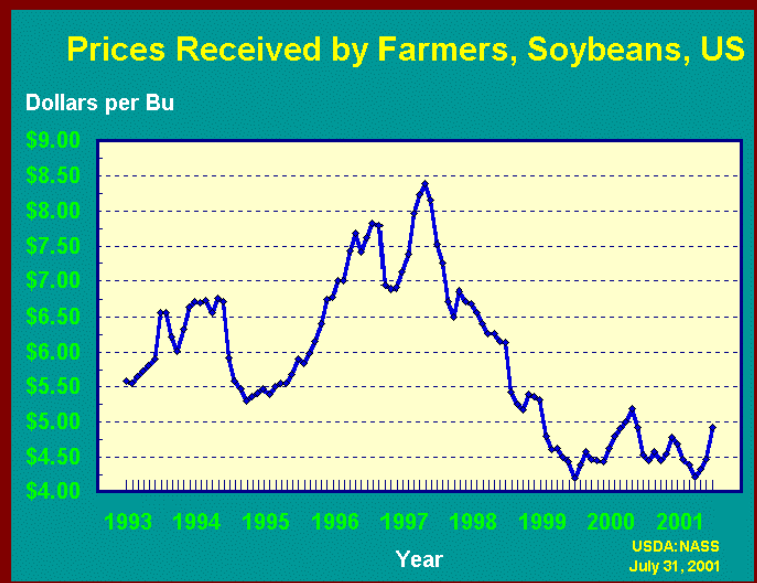


Production data from USDA NASS http://www.usda.gov/nass/pubs/ranking/croprank.htm.
Price data from Agricultural Statistics Board, Crop Values, Feb. 1999 (NASS/USDA) average of 1996, 1997, 1998 values.
Regions are defined by the Regional Biomass Energy Program
A corn density of 56 wet pounds per bushel; corn grain moisture content of 12% and corn grain dry density of 49.3 dry pounds per bushel were used.

Corn and soybean price data are shown from USDA. The study used one set price for the analysis.

Prices Received by Farmers in the United States for Corn and Soybeans
Dollars per bushel





1. Corn price and soy bean data from USDA

Several biomass types have not been considered in this assessment due to a lack of data and/or small available quantities.

Biomass Not Included	Reason
Food[1], feed, wood, and textile crops	Does not compete with non-biomass resources
Silage corn residues, corn mill residues, spent brewers grains, and hay	Most is used as animal feed or bedding
Barley, oats, rye, sorghum, and peanut residues	Low total acreage
Soybean residues	Difficult to collect and decompose rapidly
Sugarcane bagasse	Most is used on-site for heat and power generation[2]
Used pallets	Most are in use (repaired, refurbished, or recycled)
Enteric fermentation	Difficult to collect on a large scale
Cotton gin trash	Lack of demand on the end use side of the model, an artifact of *this* analysis
Secondary mill residues	Most are used or not useable[3]
Greases	Lack of demand on the end use side of the model, an artifact of this analysis. Soybean oils were used to estimate costs associated with biodiesel
Used railroad ties, used utility poles, wood waste, agricultural residues from site conversion, aquatic organisms, wood ash	Lack of data

1. However, corn, soybeans, and rapeseeds are included for non-food end uses such as fuel ethanol or biodiesel
2. Does not represent the same opportunity as pulp & paper waste (which was considered, even though it is all used on-site as well).
3. An NREL report (Rooney, 1998) indicates that 83% of residue are being used as fuel, animal bedding, mulch, pulp, or other use; and 17% are land filled.

Average state quantity and price data were used to construct the resource supply curves.

- Supply curves were generated for all types of biomass (e.g. corn stover, wheat straw, urban tree residues)
  - Assumed that the entire quantity of biomass in each state is available at the average price in that state, an "ALL OR NOTHING" scenario
  - Constructed supply curves from biomass quantities and average farm-gate prices in the various states

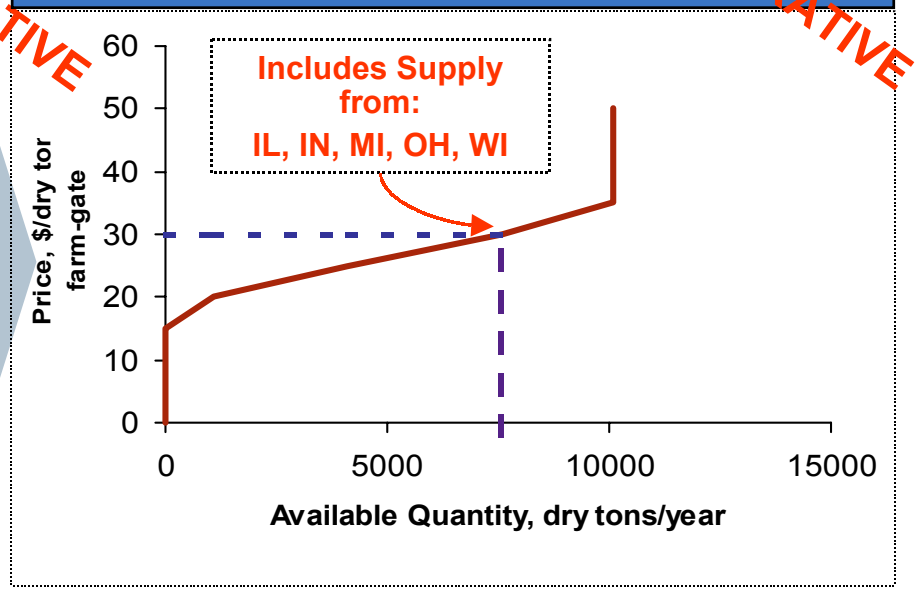
ILLUSTRATIVE

Great Lakes State Level Data

State	Quantity tons/year	Price $/dry ton Farm-gate
IL	2,000	24
IN	1,000	22
IA	500	31
MI	2,000	29
MN	2,000	35
OH	1,100	18
WI	1,500	27

ILLUSTRATIVE

Great Lakes Regional Supply Curve
Available Quantity of X



The availability of published feedstock quantity data varied widely.

Biomass Resource		Level of Data Reported			
		Total	Collectable	Unused	Available
Agricultural Crop Residues	Corn Stover	State	State	Assume All	Assume All
	Wheat Straw	State	State	Assume All	Assume All
	Rice Straw	State	National	Assume All	Assume All
	Cotton Stalks	State	Assume All	Assume All	Assume All
Forest Residues		NA	State	Assume All	Assume All
Primary Mill Residues		No Data	State	State	Assume All
Other Wastes	Urban Tree Residue	State	Assume All	National	Assume All
	C&D Wood	State	Assume All	State	Assume 50%
	Organic MSW[2]	NA	State	State	Assume All
Biogases	Landfill Gas	No Data	State	State	Assume All
	Digester Gas	No Data	State	Assume All	Assume All
	Sewage Gas	No Data	State	Assume All	Assume All
Sludge	Manure	State	State	Assume All	Assume All
	Biosolids	State	Assume All	National	Assume All
Potential Energy Crops[3]		State	Assume All	Assume All	Assume All

1. "State" indicates state-level data or better (county, sub-state) is published, "Region" indicates regional data is published, "National" indicates national (United States total) data is published. "NA" indicates that the category is not applicable, "No Data" indicates that this analysis did not collect data in this category. Assumptions made in this analysis are generally based on published information.
2. Organic MSW is the organic fraction of municipal solid waste as defined by the EPA.
3. Potential energy crops include switchgrass, hybrid poplar, and willow.

Published, state-level data was used whenever possible, otherwise assumptions were made based on ADL and DOE expertise (page 1 of 2).

- Agricultural Crop Residues (corn stover, wheat and rice straw, cotton stalks):
  - Collectable quantity excludes the state-level fractions left on the field to maintain soil quality
  - Assumed all collectable quantities are unused[1]
- Forest Residues:
  - Collectable quantity includes rough, rotten, and salvageable dead wood, and logging residues (from public and private lands)
- Primary Mill Residues:
  - Unused quantity excludes uses as fuel wood, fiber, and miscellaneous by-products
  - Unused quantity may be underestimated by mills
- Urban Tree Residues:
  - Unused quantity excludes the fractions burnt for energy and sold for each type
- Construction and Demolition Wood:
  - Unused quantity excludes wood used for fuel and 20% of compost use[2], but includes cover, other and 80% of compost use
  - Assume 50% is available based on a national estimate that 70% of demolition debris and 24% of construction debris can not be used due to contamination or commingling (Fehrs, 1999)
- Organic Municipal Solid Waste[3]:
  - State population data was used to partition the national quantity generated into state-level quantities

1. Lack of data on the extent to which residues are currently being used.
2. We assumed that 20% of compost in current use is beneficial; based on EPA data (Franklin Associates, 1998) that 18% of compost is sold to nurseries or bagged and sold retail.
3. Organic MSW is the organic fraction of municipal solid waste as defined by the EPA.

Published, state-level data was used whenever possible, otherwise assumptions were made based on ADL and DOE expertise (page 2 of 2).

- Landfill Gas:
  - Unused quantity includes “candidate”, “shutdown”, and “other” landfill gas recovery projects
- Digester Gas:
  - Collectable quantity takes into account current manure management practices in each state
  - It does not include quantities that could potentially be produced if current practices change
  - Digester construction costs are not included
- Sewage Gas:
  - State population data was used to partition the national quantity generated into state-level quantities
- Manure:
  - State livestock population data was used to break down the national quantity generated into state-level quantities
  - Collectable quantity excludes state-level pasture manure management fractions
- Biosolids:
  - State population data was used to break down the national quantity generated into state-level quantities
  - The unused fraction is determined by a national estimate
- Potential Energy Crops (switchgrass, hybrid poplar, and willow):
  - Each compete with existing crops and other energy crops on all crop lands

The energy crop supply curves were derived using a model that assessed the net present value for energy crops versus traditional land uses.

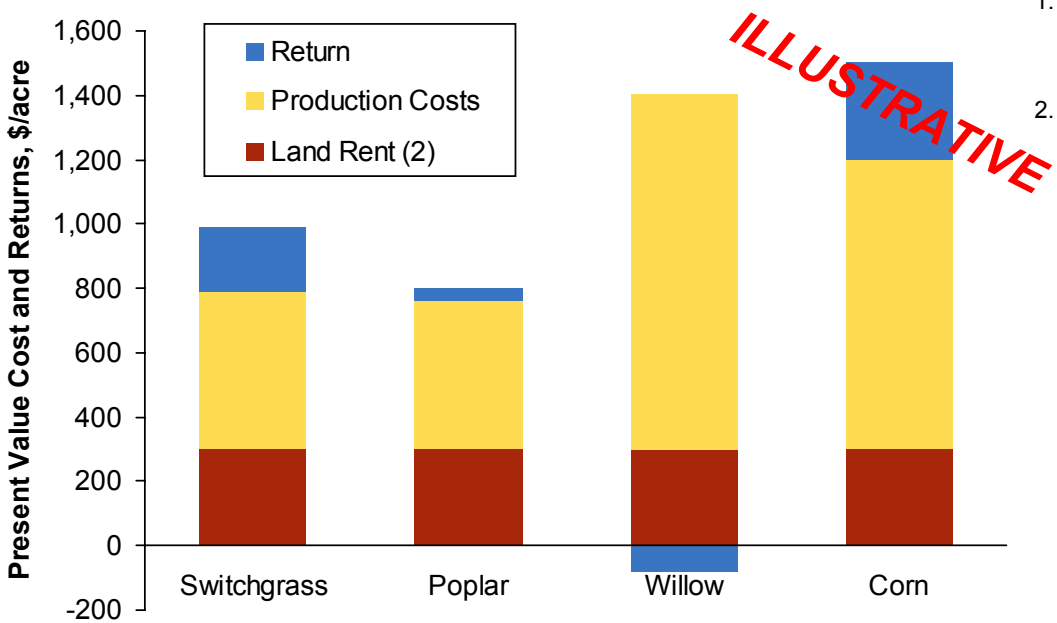
Assumptions and Methodology	• An agricultural sector model (POLYSIS), used by the USDA, has been modified to include switchgrass, hybrid poplar, and willow. • The analysis estimates farm-gate prices required to make bioenergy crops economically competitive with alternative agricultural uses for cropland. It also estimates the potential impact of bioenergy crop production on traditional crop prices and quantities and net farm income. • The model allocates acres to competing crops using a linear programming model that maximizes expected returns using expected crop prices. Expected returns per acre for each crop includes revenues, based on the expected prices and the baseline or hypothesized yield, and a range of expenditures, used to compute the variable and cash costs. • To avoid corner solutions, POLYSIS contains embedded flexibility constraints that limit the acreage that a given crop can lose or gain each year. • The model results used for this project include eight major crops (corn, grain, sorghum, oats, barley, wheat, soybeans, cotton, and rice). • The analysis also evaluates the economic potential of a modified Conservation Reserve Program (CRP) to serve as a land resource for bioenergy crop production.
Comments	• This analysis focuses on switchgrass, hybrid poplar and willow because these crops receive the greatest research funding and their management practices are similar to several of the other potential bioenergy crops being evaluated. Thus, they can serve as a general indicator for many other potential bioenergy crops. • CRP acres which have been identified as most environmentally sensitive are eliminated from consideration from bioenergy crop production.
Conclusions	• Acreage is allocated to each crop (traditional as well as bioenergy crops) based on relative net present value profits subject to flexibility constraints.

Note: The model results were obtained from Ugarte, D., M. Walsh, H. Shapouri, and S. Slinsky (July 2000), “The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture”.

Energy crop data is based on a modified agricultural sector model that allocates acres to competing crops by maximizing expected net returns.

- In this illustrative example, corn gives the highest return on a dollar per acre basis; Therefore, zero corn acres would be converted to energy crops on this category of cropland in this district
- Returns are calculated based on revenues generated from the assumed energy crop price (e.g. $40/dry ton farm-gate) or USDA price projections for traditional crops

Net Present Value[1] for Selective Crops, $/acre



1. Present value of the future cash benefits of the project minus the present value of any cash costs.
2. Land rent is the same for all crops and so is not actually included in the model.

These types of results are constructed for 305 districts in the U.S. for these energy crops and all major traditional crops.

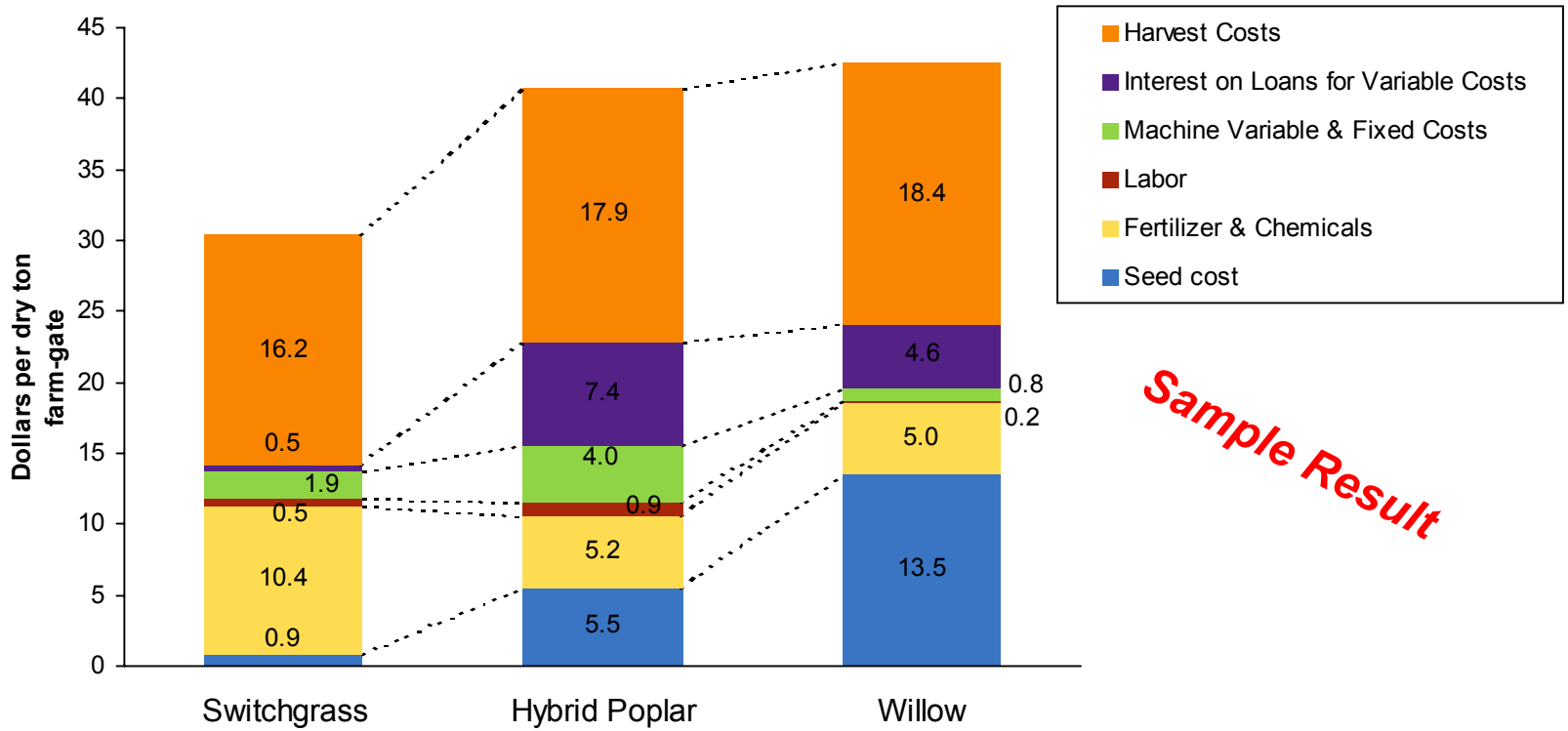
Discounted production costs for energy crops are based on its entire production rotation time for each agricultural statistical district.

Assumptions and Methodology	• Production costs are estimated based on operations schedules (i.e., field-level activities) using the University of Tennessee Agricultural Policy Analysis Center Budgeting System (ABS) or ORNL's BIOCOST budget generator model for each of the 305 Agricultural Statistical Districts (ASDs) contained in POLYSIS, an agricultural sector model used by USDA. • Production costs include variable cash inputs, producer's own labor, and machinery related costs. • Production costs are present value cost (assuming a discount rate of 6.5%) of producing the bioenergy crop for its entire production rotation (10 years for switchgrass, 6-10 years for poplar, and 22 years for willow). • Crop management practices for bioenergy crops produced on cropped, idle, and pasture acres are based on recommendations from an expert panel. For CRP lands, a production management scenario to achieve high levels of biomass production was assumed for this project. • Yields of bioenergy crops on idled and pasture acres are assumed to be 85% of those that can be obtained on acres in crop production.
Comments	• Currently, switchgrass is grown on limited acreage in the Conservation Reserve Program (CRP) and as a forage crop. Hybrid poplar is commercially produced on about 200,000 acres for use by the pulp and paper industry; and willow is being commercially produced for energy in Europe. The lack of large-scale commercial production resulted in the use of research data and expert opinion to determine yields and management practices assumed in the model. • Bioenergy crop yields, by agricultural statistical district, ranged from 2 dt/acre/yr to 6.75 dt/acre/yr depending on crop and location within the United States. Research is on-going to improve yields. • Variation in production practices, yields, and labor and equipment constraints at an individual farm or field level within an agricultural statistical district were not taken into account in this model.
Conclusions	• Switchgrass is relatively the least expensive bioenergy crop to produce per dry ton yield for most agricultural statistical districts. As a result, the POLYSIS agricultural sector model allocates most of the bioenergy crop acres to switchgrass. • Poplar and willow are generally more expensive to produce due to the higher establishment costs and the long period of time before returns from harvest are sufficient to pay for establishment, requiring interest payments to be carried for several years.

Note: The model results were obtained from Ugarte, D., M. Walsh, H. Shapouri, and S. Slinsky (July 2000), "The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture"; dt/acre/yr is dry ton per acre per year.

Production costs are generated for energy crops based on a net present value calculation.

Present Value Production Costs (Adapted from Ugarte et al.), Dollars per Dry Ton, Farm-gate Prices



1. Based on average values for the Northeast region on lands currently producing traditional crops. Based on ORNL yield assumptions and a 6.5% discount rate.

These types of results are constructed for 305 districts in the United States for these energy crops and all major traditional crops.

Feedstock farm-gate prices were determined based on estimated costs of collection or production whenever possible.

Biomass Resource		Price Data Availability	Comments
Agricultural Crop Residues[1]		State	Based on estimated cost of collection and premium to farmer
Forest Residues		State	Based on estimated cost of collection
Primary Mill Residues		State	Based on prices for mill residues currently sold
Other Wastes	**Urban Tree Residue**	State	Assume $10/dry ton, but free for the fraction typically land-filled
	Organic MSW[2] C&D Wood	State	Assume free if state tipping fee is greater than $15/ton, $10/dry ton if state tipping fee is less than $15/ton[6]
Biogas[3]		None	Free, does not include investment required to gather the gas
Sludge[4]		None	Free
Potential Energy Crops[5]		State	Based on estimated profitability relative to alternative agricultural uses

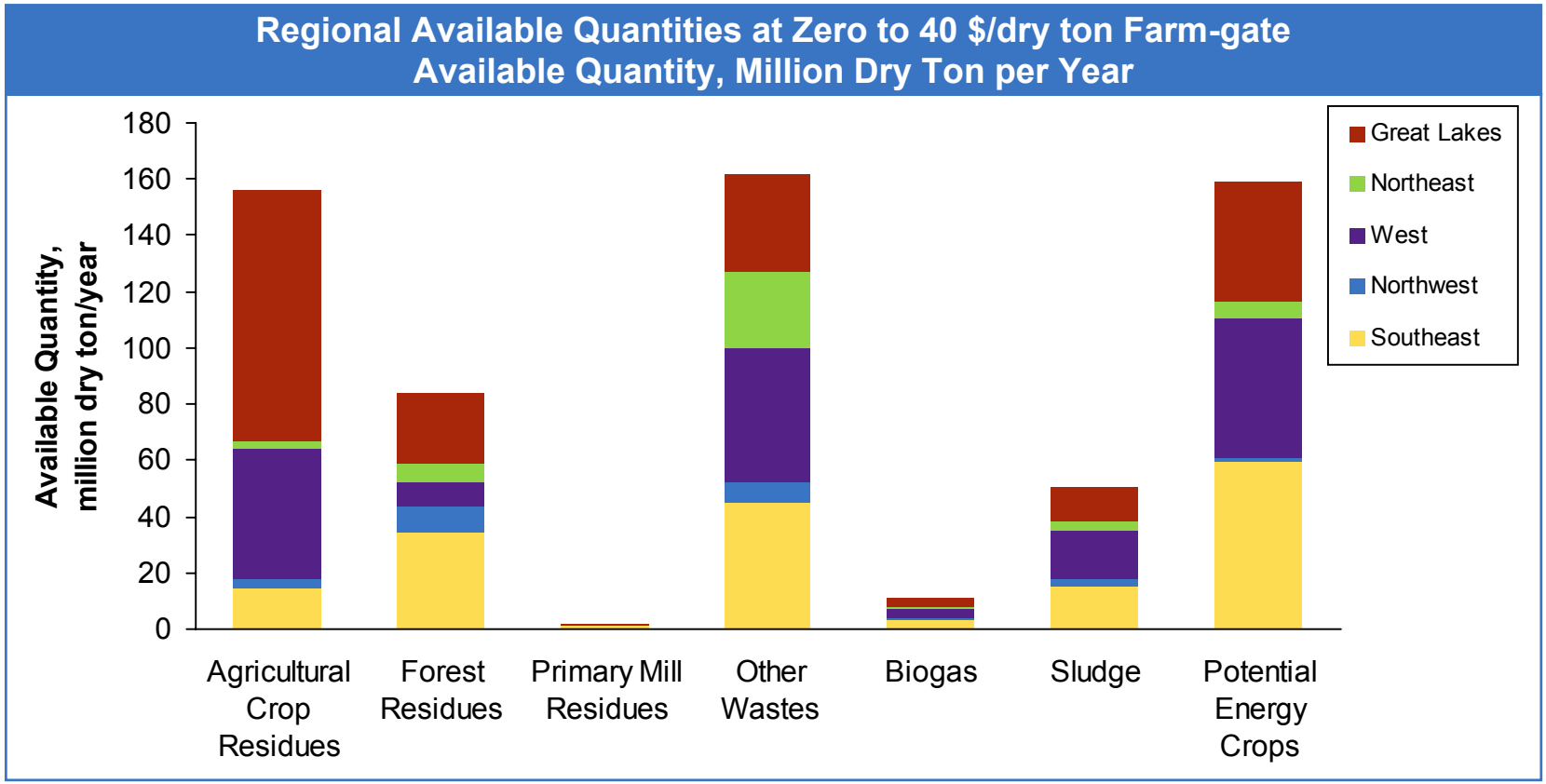
1. Agricultural crop residues includes corn stover, wheat straw, rice straw, and cotton stalks.
2. Organic MSW is the organic fraction of municipal solid waste as defined by the EPA.
3. Biogas includes landfill gas, digester gas, and sewage gas. Quantity data is for current manure management practices only; therefore digester construction costs are not included
4. Sludge includes manure and bio-solids.
5. Potential energy crops include switchgrass, hybrid poplar, and willow.
6. Tipping fee refers to a fee paid by the waste generator to the disposal facility for landfilling, incinerating, or otherwise disposing of the waste. State tipping fee refers to the average tipping fee for MSW and C&D disposal facilities in the state.

Published, state-level data was used whenever possible, but many assumptions were necessary.

- All prices used to generate supply curves are farm-gate prices
  - Transportation costs to the processing facility are calculated as a separate module
- It was assumed that there would be zero negatively priced biomass available
  - Biomass producers may be willing to pay tipping fees[1] to landfill their waste, but it is unlikely that they would pay a third party to use their waste for additional profit
  - In California, when several biomass cofired boilers came online at once, biomass with previously negative or zero value suddenly became a valuable commodity
- It was assumed that some wastes are free if they can be used onsite (e.g. biogas[2], sludge[3]) or if a tipping fee is required (e.g. other wastes[4])
  - Biogas collection costs (e.g. for tarp, gas handling equipment) were not available; we assumed these costs could be relatively low in many cases or required for other reasons, such as odor control[5] and did not estimate these costs
- It was assumed that unused primary mill residues have the same price as the currently used fraction
  - However, the unused fraction may be of poor quality and could be obtained at a lower price
  - There was a lack of data on the unused portion of mill residues

1. Tipping fee refers to a fee paid by the waste generator to the disposal facility for landfilling, incinerating, or otherwise disposing of the waste.
2. Biogas includes landfill gas, digester gas, and sewage gas.
3. Sludge includes manure and bio-solids.
4. Other wastes include the organic fractions of municipal solid waste, urban tree residues, and construction and demolition wood.
5. Quantity data is for current manure management practices only, therefore, digester construction costs were not included.

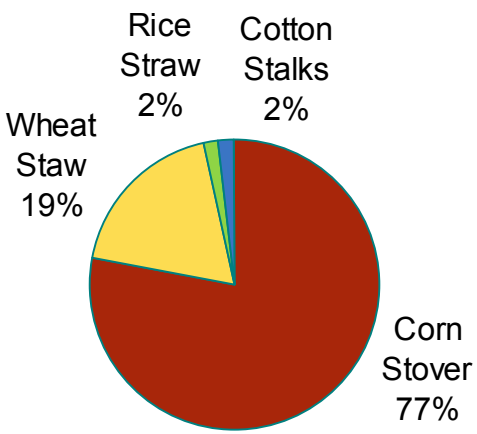
Region specific data were generated for available quantities of all biomass types.



1. The regions are defined by the Regional Biomass Energy Program. Detailed regional data on each major source is found in the Data Volume, Section E
2. Agricultural crop residues includes corn stover, wheat straw, rice straw, and cotton stalks.
3. Other wastes include the organic fraction of municipal solid waste, urban tree residues, and construction and demolition wood.
4. Biogas includes landfill gas, digester gas, and sewage gas.
5. Sludge includes manure and bio-solids.
6. Potential energy crops include switchgrass, hybrid poplar, and willow.

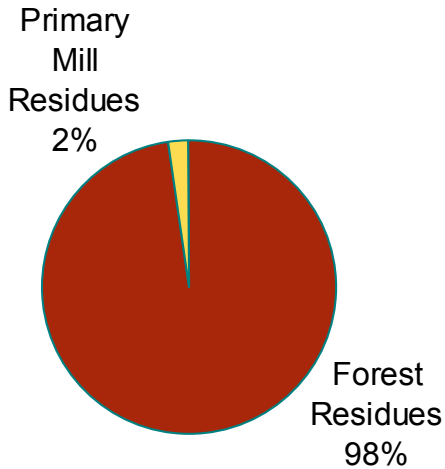
At 0-40 $/dry ton farm-gate, most biomass categories are dominated by a single resource (page 1 of 2).

Agricultural Crop Residues at 0-40 $/dry ton Farm-gate



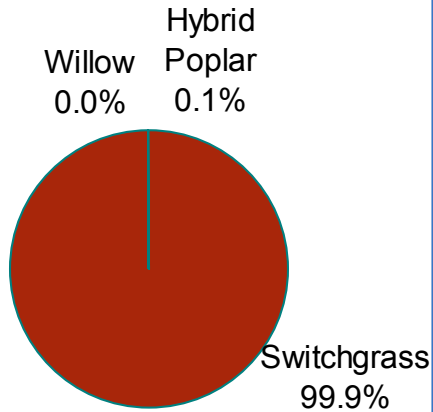
Available Quantity = 156 million dry tons/year

Forest and Mill Residues at 0-40 $/dry ton Farm-gate



Available Quantity = 85.5 million dry tons/year

Potential Energy Crops at 0-40 $/dry ton Farm-gate

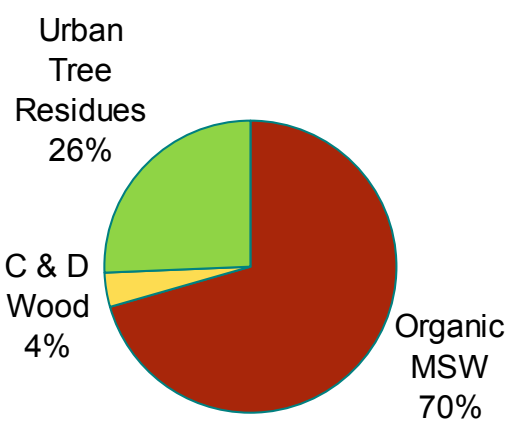


Available Quantity = 159 million dry tons/year

Switchgrass dominates energy crops because it was estimated to be slightly cheaper than hybrid poplar and willow on an energy basis.

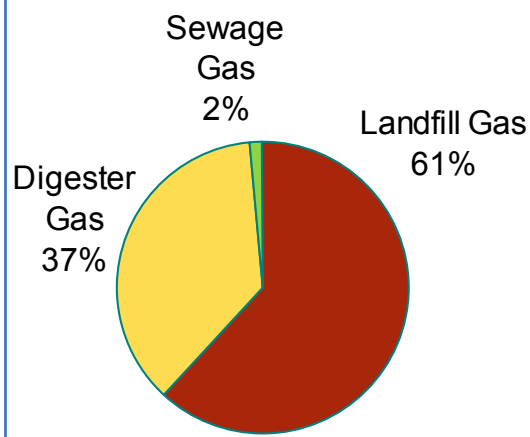
At 0-40 $/dry ton farm-gate, most biomass categories are dominated by a single resource (page 2 of 2).

Other Wastes at 0-40 $/dry ton Farm-gate



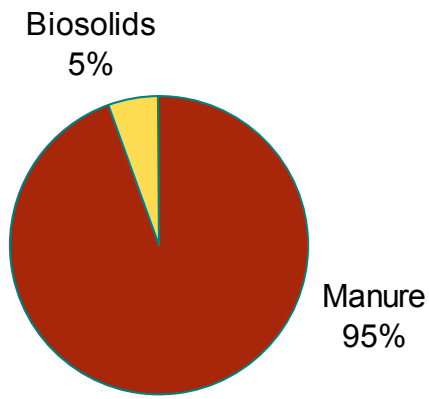
Available Quantity = 161 million dry tons/year

Biogas at 0-40 $/dry ton Farm-gate



Available Quantity = 11.3 million dry tons/year

Sludge at 0-40 $/dry ton Farm-gate



Available Quantity = 50.5 million dry tons/year

1. C&D wood is construction & demolition wood.

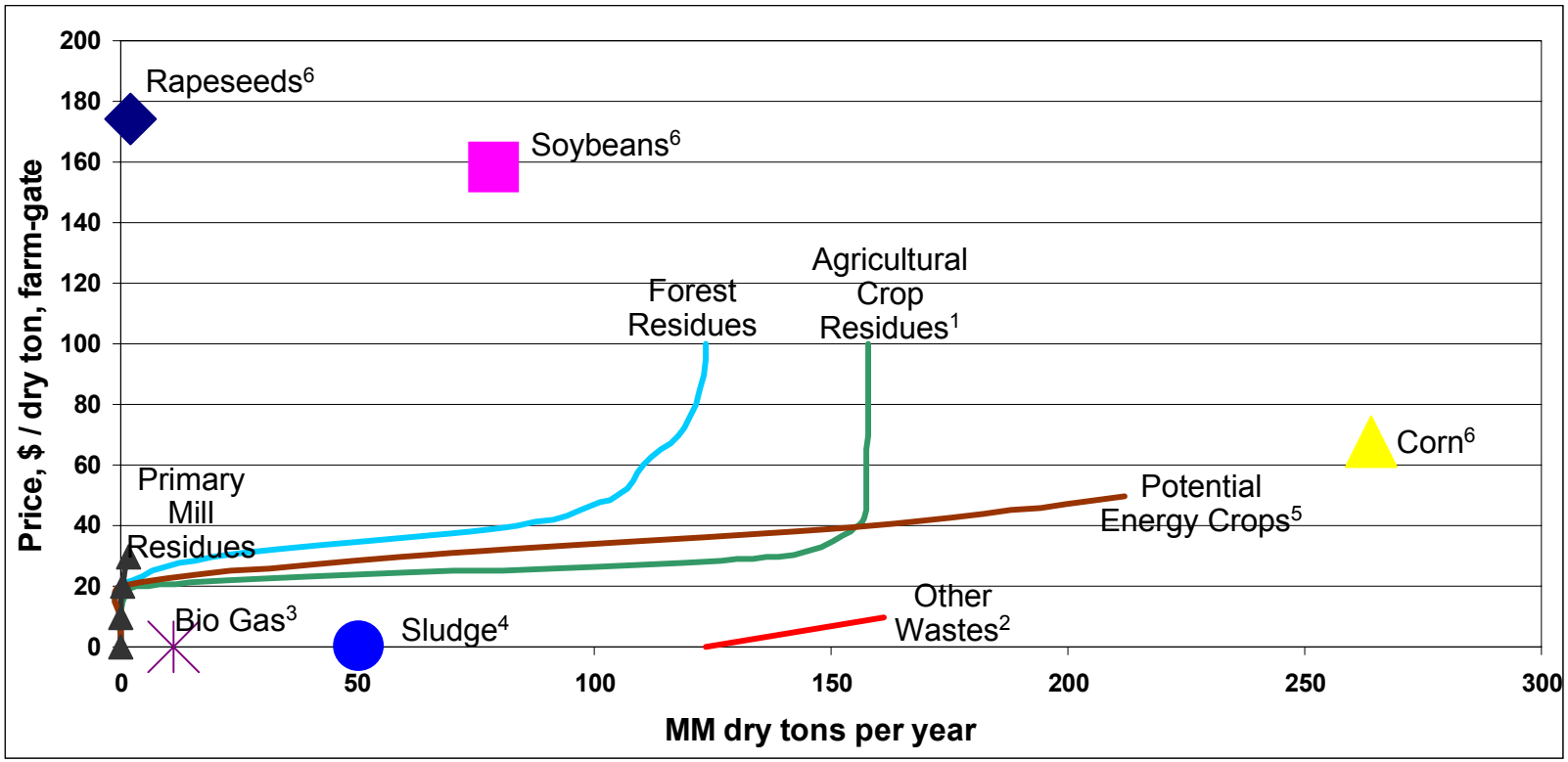
In general the data processed by ADL agrees well with a recent ORNL resource analysis[6].

	U.S. Available Quantity at 0-40 $/dt (farm-gate price), million dt/year		
Biomass Type	**ADL Analysis**	**ORNL[6] Analysis**	**Comments**
Agricultural Crop Residues[1]	156	151	Both analyses used the same source for corn stover and wheat straw. The ADL analysis included rice straw and cotton stalks.
Forest Residues	84	45	Both analyses used the same source. The ADL analysis used updated data.
Primary Mill Residues	2	90	Both used the same source. ORNL data included the currently used portion (for fuelwood, fiber, and misc. by-products). ADL excluded currently used portion of primary mill wastes
Other Wastes[2]	161	37	ORNL included used and unused fractions of MSW wood, yard trimmings, and C&D wood. The ADL analysis included only unused fractions of organic MSW, C&D wood, and UTR.
Biogas[3]	11	NA	
Sludge[4]	50	NA	
Potential Energy Crops[5]	159	188	Both used same source. ADL analysis assumed a linear interpolation of the ORNL data.
Total	**623**	**511**	

1. Agricultural crop residues includes corn stover, wheat straw, rice straw, and cotton stalks.
2. Other wastes include the organic fraction of municipal solid waste, urban tree residues, and construction and demolition wood.
3. Biogas includes landfill gas, digester gas, and sewage gas.
4. Sludge includes manure and bio-solids.
5. Potential energy crops include switchgrass, hybrid poplar, and willow.
6. Based on a presentation given by Marie Walsh of ORNL (Walsh, 2000). Transportation cost assumed to be $10/dt to convert the ORNL data

Some biomass may be available at low cost, but most is expected to command prices in excess of $20/dry ton farm-gate.

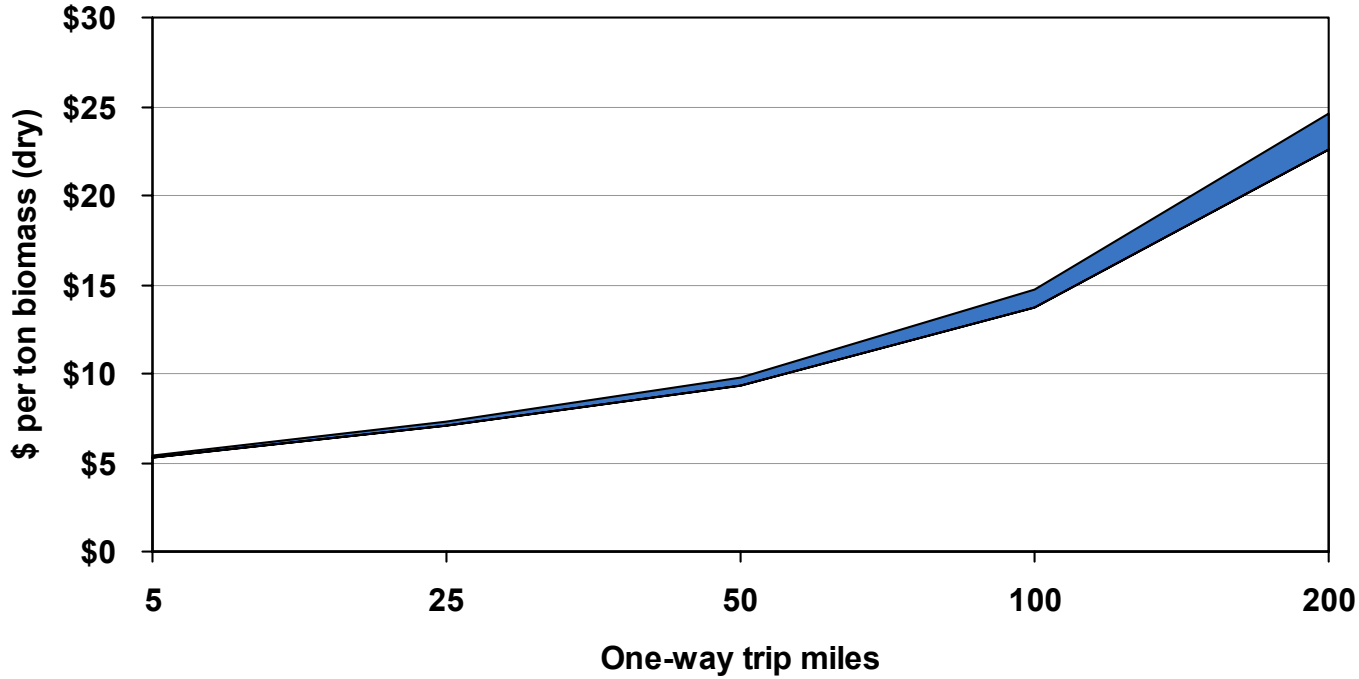
U.S. Available Biomass Supply Curve: Cost per Dry ton vs. Available Quantity Million Dry Tons per Year, Farm-gate Price



1. Agricultural crop residues includes corn stover, wheat straw, rice straw, and cotton stalks.
2. Other wastes include the organic fraction of municipal solid waste, urban tree residues, and construction and demolition wood.
3. Biogas includes landfill gas, digester gas, and sewage gas. This analysis assumes all biogas is available at no cost and is used on-site.
4. Sludge includes manure and bio-solids. We assume that all sludge is free and used on-site.
5. Potential energy crops include switchgrass, hybrid poplar, and willow. Note that production was not evaluated above $50/dt.
6. A supply curve analysis was not done for traditional crops (corn, soybeans, and rapeseeds). Used the national average price and total quantity produced.

Transport of raw biomass to a transport facility is assumed to use a truck travelling 50 miles one-way.

One-way Transportation Costs of Dry Biomass, Dollars per Dry Ton



Assumptions:
6 miles/gallon average fuel economy (from Transportation Energy Databook, volume 19)
$0.92-1.35/gallon diesel fuel
$1,000 maintenance cost per year, + $20 oil change every 5,000 miles
$50,000/year driver salary, + $25,000/year benefits, driver operates truck 3120 hours/year (60 hour weeks)
5 miles of each trip at local speeds, remainder at highway speeds. 2 hours of each trip spent loading/unloading
10 year truck life, lease rate 8% per year with 10% residual value at end of lease (.131 capital recovery factor)
$113,000 truck capital cost, 29 ton capacity

Based on this review of the literature, resource production modules were developed for each of the included biomass resources.

- Biomass resource production modules were estimated for each of the biomass resources
- The modules describe all key technical and economic parameters for each biomass resource:
  - Cost of biomass
  - Use of other feedstocks (e.g. fertilizers)
  - Use of other energy sources in production (i.e. diesel for skidders, etc.)
  - Environmental impacts associated with the above

1. A detailed description of each of the biomass resource production modules can be found in the Data Volume, section C.

The supply curves could change if biomass becomes a traded commodity, similar to corn or soybeans.

- Agricultural crop residue available quantities could increase dramatically if residues are seen as having cash value to the farmer
  - Current agricultural production is optimized to minimize currently worthless residues
  - Production and harvesting methods for the agricultural product could be altered to give twice as much collectable residue if they had sufficient value
  - The potential impact on marginal production cost of the residue is not well understood
- The collection of forest residues could be subsidized for fire safety reasons (to prevent and slow forest fires)[1]
  - A subsidy of $20/dry ton[2] would make forest residues a very attractive biomass source (this is similar in magnitude to the ethanol tax credit)
- Residues that are currently in use were not included in this analysis[3], but would contribute to the total biomass supply, especially in the case of primary mill residues
- This analysis did not take into account the upward price pressure that could result from increased demand for certain biomass resources
  - In California, when several biomass co-fired boilers came online at once, biomass with previously negative or zero value suddenly became a valuable commodity.

1. See "Cost and Benefits of a Biomass-to-Ethanol Production Industry in California, Report for California Energy Commission, Arthur D. Little, 2001
2. Based on a potential target of $300 per acre forest subsidy for fire prevention and assuming 15 dry tons residue per acre.
3. Except in pulp and paper where we considered the potential for improved efficiency and some traditional crops (i.e. corn, soybeans, and rapeseeds).

A standardization of reporting methods would help reduce the severity of gaps in the resource assessment literature.

- No uniform method exists for reporting biomass quantities across the United States
  - Different reporting regions and residue definitions are the most obvious shortcomings
  - Not all information is available on the state level and very little information is available for all counties
  - Finer levels of analysis would provide smoother and more accurate supply curves
  - Price and quantity data on the county level may be necessary to locate end use facilities
- No consistent method exists for slicing the residue quantity and price data
  - Data is not consistently broken out according to collectable/uncollectable, unused/used, and available/unusable fractions
- In general, the quality of biomass residues is not assessed
  - Aside from some estimates for construction and demolition (C&D) wood, the quality of the unused fractions of primary mill residues and other wastes[1] was not available
  - Some unused fractions may be of poor quality (contaminated or commingled) resulting in a lower than expected price or they may be altogether unusable
- Erosion factors are not taken into account for agricultural residues (work in progress)[2]
- Lack of prices for available quantities of other wastes[1], primary mill residues, and digester gas
  - Tipping fees provide the best insight into possible price scenarios for other wastes
  - No prices for available (unused but usable) quantities of primary mill residues[3] and digester gas

1. Other wastes include the organic fraction of municipal solid waste, urban tree residues, and construction and demolition wood.
2. The analysis used excludes land with erodibility index of 8+, but collectable quantities could be even lower if soil erosion factors are taken into account.
3. Available primary mill residue prices were based on the prices of residues currently sold.

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Several biopower options could provide large fossil energy & carbon dioxide reduction benefits in the short to medium term with modest cost. A number of biopower options are commercially available today or can be made available within 1-2 years with minimal technology development. Co-firing of solid biomass in coal plants and utilization of biogas (digester gas, sewage gas and landfill gas) combustion are examples of near term, “low-hanging fruit” options. These technologies also have fairly attractive economics today, particularly when the fuel source is low or zero cost.

In general, biopower options work if capital cost is very low due to the use of existing capacity and infrastructure (example being biomass co-firing with coal) and/or if the feedstock delivered cost is very cheap. Onsite power generation conceivably could use waste streams which have zero or negative value.

Other biopower technologies have the potential for attractive economics ultimately, but technology development is still required to achieve the needed levels of cost and performance. There exists various gasification options (refuse derived fuel, small-scale systems, utility-scale systems, and black liquor). Some of these technologies also face significant non-technical hurdles, such as RDF gasification and black liquor gasification.

Several opportunities for biopower are significant and could independently achieve the aggressive implementation goal for biomass use if fully exploited. While it is unlikely that any one application will achieve its full technical potential, a combination of applications could meet the aggressive goals for biomass use. The fact that biopower utilizes a variety of feedstocks allows for parallel deployment with minimal inter-application competition.

Biopower has the potential to be cost effective at a variety of scales, from less than 1 MW to 100 MW, depending on the application and technology used. This provides the opportunity to utilize feedstocks that might otherwise not be useable for biofuels or bioproducts. Biopower is likely to be part of a biorefinery concept as certain fractions of cellulosic biomass are recalcitrant so as to make power generation a likely end-use (for example, utilization of lignin).

Several biopower options could provide large fossil energy & carbon dioxide reduction benefits in the short to medium term with modest cost.

- A number of biopower options can be made available within 1-2 years or less with minimal or no technology development:
  - Co-firing of solid biomass in coal plants
  - Biogas (e.g. landfill gas, digester gas, sewage gas) combustion
- These technologies also have fairly attractive economics today, particularly when the fuel source is low or zero cost
- Other biopower technologies have the potential for attractive economics ultimately, but technology development is still required to achieve the needed levels of cost and performance
  - Various gasification options (Refuse derived fuel [RDF], small-scale systems, utility-scale systems, black liquor)
  - Some of these technologies also face significant non-technical hurdles, such as RDF gasification and black liquor gasification
- The different opportunities for biopower could each independently achieve the aggressive goals for biomass use if fully exploited
  - While it is unlikely that any one application will achieve its full technical potential, a combination of applications could meet the aggressive goals
  - The fact that biopower utilizes a variety of feedstocks allows for parallel deployment with minimal inter-application competition
  - Many resources, like landfill gas and onsite residues, are not likely to be in demand for other end uses besides electricity generation
- Biopower has the potential to be cost effective at a variety of scales, from less than 1 MW to 100 MW, depending on the application and technology used
  - This provides the opportunity to utilize feedstocks that might otherwise not be useable for biofuels or bioproducts

The following definitions apply to biopower and are used to organize the options being screened.

Technologies	• These are the ways in which biomass can be used, such as **direct combustion**, **gasification**, and **liquefaction**. Direct combustion can be of **solid biomass** or of **biogas or gaseous biomass** (methane derived from the decomposition or anaerobic digestion of biomass by microorganisms). • Technologies can use **biomass only**, or biomass can be **co-fired** with other fuels (e.g., coal or natural gas).
Applications	• These are the situations in which the technologies are used. **Grid power** is the generation of electricity only for sale into the wholesale power market. Owners are typically electric utilities, independent power producers (IPPs) or merchant plant operators (generation companies). – Fuel would generally be purchased on the open market and delivered to the power plant. – For MSW and RDF feedstocks, electricity generation is sometimes accompanied by the production of cogenerated heat if a thermal host is nearby. • **Onsite Power and CHP*** is the production of power only or the co-production of power and heat at facilities that generate biomass residues. Owners are typically IPPs, energy service companies (ESCOs) or industrials. – Generally, the fuel is used where it is generated. – The **heat only** option is captured in both areas, where appropriate.

* Combined heat and power

Growth in biomass power generation will come from three broad options – green-field projects (new capacity), repowering and fuel substitution.

Application		Pathway to Increased Generation		
		Green-field, including cogeneration	Repowering/ Efficiency Increase[1]	Fuel Substitution
Grid Power	Biomass-only power plants (grid power)	●	●	
	Co-firing with coal or other grid power plants	○		●
	Municipal solid waste (MSW) and other urban wastes	●	○	
	Landfill gas	●	○	
Onsite Power & CHP	Other biogas (e.g. anaerobic digestion, sewage or digester gases)	●	○	
	Pulp and paper - Black liquor and other residues	○	●	Will occur due to efficiency increase
	Other forest products or industrial residues	○	●	Will occur due to efficiency increase
	Integration with other bioenergy production[2]	●		

1. Repowering refers to the reuse of an existing site and potentially part of the existing infrastructure and equipment (e.g., conversion of a Rankine cycle plant to a combined cycle plant).
2. Such as ethanol production, bio-chemicals production or bio-refineries.

● Primary pathway
○ Secondary pathway

The key limiting factor for new, grid-sited biomass power plants is likely to be the reliable supply of large quantities of low-cost biomass.

- Today this market is relatively small compared to onsite biomass energy use
  - It developed in part due to favorable power contracts written under the PURPA1 legislation. As these contracts have expired many plants have shut down
  - To ensure future growth, a secure, reliable and cost-effective supply of biomass fuel must be available
  - This requires the availability of appropriate quantities within a reasonable area, to ensure reasonable transportation costs
  - These power plants will generally need to compete at the wholesale level with baseload natural gas-fired GTCC and existing coal and nuclear plants, which generally have low marginal operating costs
  - Pockets of electricity and fuel price volatility, such as in California in 2000-01, may increase the attractiveness of biomass power plants, provided fuel can be procured at a reasonable price and with reasonable guarantees of long-term supply
- Biomass-based grid power flows into a practically unconstrained market: total power demand will not be a limiting factor for biomass-based grid power potential
- Biomass grid power is at worst a completely fungible product with other power, competing on straight economics…
- …but growing interest in green power could actually bolster demand for biopower
  - Customers willing to pay a premium for green power would be able to cover the over-market cost of biomass power versus fossil fuel-fired power
  - Other renewable energy sources are currently exploiting this market, most notably wind and photovoltaics, but also landfill gas and small, low-impact hydro

1. Public Utility Regulatory Policy Act

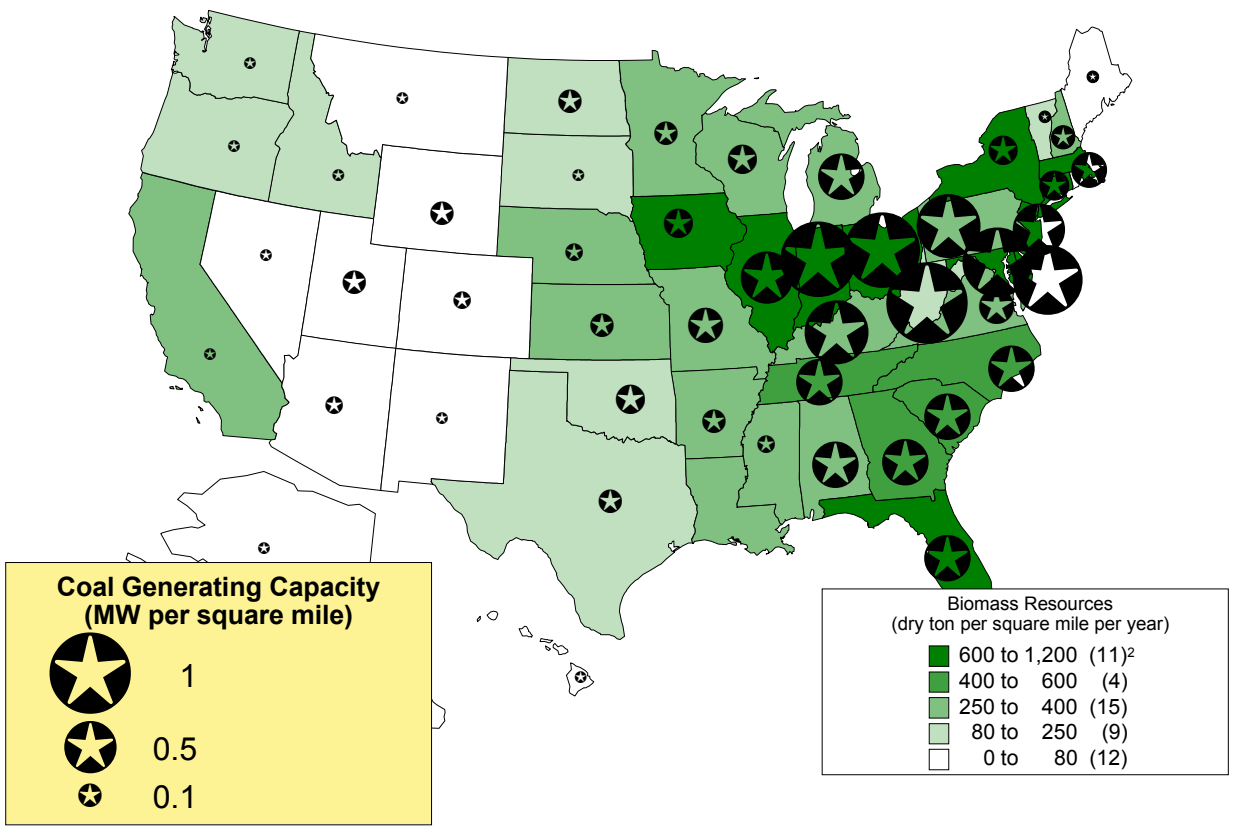
Biomass co-firing at existing coal plants appears to be an attractive near-term option for biomass-based grid power.

Advantages	Barriers
• Much lower marginal capital cost than new biomass-only power plants ($50-500/kW vs. $1,500-$2,000/kW) • Emissions benefits at the coal plant (NOx and SO_2) have real economic value due to emissions trading • Able to take advantage of the higher efficiency of large coal-fired power plants (30-35%) compared to existing biomass-only power plants (15-25%) • Flexibility in biomass firing rates	• Fly ash regulations need to accommodate biomass content • Co-firing may trigger **New Source Review** requirements and may be incompatible with SCR for NOx control • Plant owners may perceive or encounter risks: – Biomass fuel price and availability relative to coal – Technical issues that could impact overall plant reliability and availability • Many coal plants are 30+ years old – the long-term future of these coal plants may be uncertain – Increased future interest in clean-coal technologies has the potential to offset the impact of retirements, at least partially

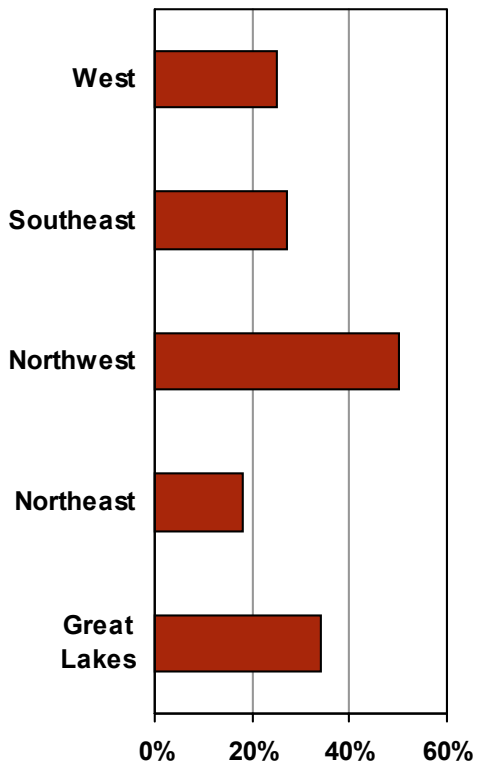
- The United States has an installed coal-fired capacity of approximately 320,000 MW (more than 1,000 individual units)
- Biomass can be co-fired at rates of up to 10-15% on a energy basis, yielding a theoretical market potential for biomass of 32,000–48,000 MW
  - This is likely to be limited by biomass supply and other factors, but the potential is still significant

At least at the state and regional levels, biomass supply does not appear to be a significant barrier to implementing co-firing.

Biomass Resources and Coal Generating Capacity



Available Biomass[1] as a Fraction of Coal Consumption (Energy Basis)



1. Excludes municipal solid waste and sewage sludge. Data are based on the resource assessment conducted for this study
2. Number in parentheses is the number of states (including DC) in this category.

Natural gas-fired gas turbine combined cycle (GTCC) technology currently dominates new capacity additions, creating potentially large future markets for biomass co-firing.

Advantages	Barriers
• Lower capital cost than new biomass-only power plants (~$500/kW vs. $1,500-$2,000/kW) • Able to take advantage of the very high efficiency of large natural gas GTCC plants (50-55%) compared to existing biomass-only power plants (15-25%) • Flexibility in biomass firing rates • Very low emissions inherent in GTCC plants • Partial hedge against natural gas price volatility • If employed as duct firing, may be relatively simple to implement plus provides for added capacity	• Plant owners may perceive or encounter risks: – Biomass fuel price and availability relative to natural gas – Technical issues that could affect plant reliability and availability – Delays in siting and permitting new GTCC plants • Compared to co-firing with coal, this option has not been extensively tested or demonstrated

- New GTCC capacity additions in the 2000-2010 timeframe are estimated at approximately 70,000 MW (DOE/EIA *Annual Energy Outlook 2000*)
- In theory, gasified biomass can be co-fired at any rate, but 10-15% is likely to be a practical limit based on required modifications to the gas turbine and the availability of sufficient quantities of biomass fuel in close proximity to an single power plant
  - This yields a technical market potential of 7,000–10,000 MW, excluding the retrofit of existing facilities
  - Percentages may be higher for duct-firing at smaller GTCC plants, but overall project sizes likely to be limited to 40-50 MW in most cases due to resource availability and transport costs

Roughly 15% of municipal solid waste (MSW) today is combusted in waste-to-energy plants, leaving a large technical market potential untapped.

- There are 103 waste-to-energy (WTE) plants in operation today, with a combined capacity of approximately 105,000 tons per day[1]
  - These plants have a combined power generation capacity of approximately 2,800 MW. The biomass fraction is estimated at approximately 2,400 MW
  - This represents roughly 15% of municipal solid waste generated in the United States, implying an untapped potential of nearly 12,000 MW (total) and 10,000 MW (biomass fraction), after accounting for the 25% of MSW that is currently recycled
- Very few new WTE plans have been built in recent years, due in large part to public opposition
  - Public is concerned about emissions (e.g. dioxin) from WTE facilities
  - However, a lack of new landfill space and high tipping fees in some areas may make it necessary to add WTE capacity in the future
- Conversion technologies that are/appear inherently cleaner or provide additional performance assurance, such as gasification, may be required to make the idea of new WTE capacity acceptable to the public
- Alternative WTE technologies could be more attractive to the public but less practical due to long-term constraints on landfill space:
  - e.g. Landfill + landfill gas utilization

1. Total capacity, not the biomass portion. Data from the Integrated Waste Services Association website (www.wte.org).

Landfill gas and other biogases have low technical barriers to implementation, and could therefore contribute to near-term objectives.

Advantages

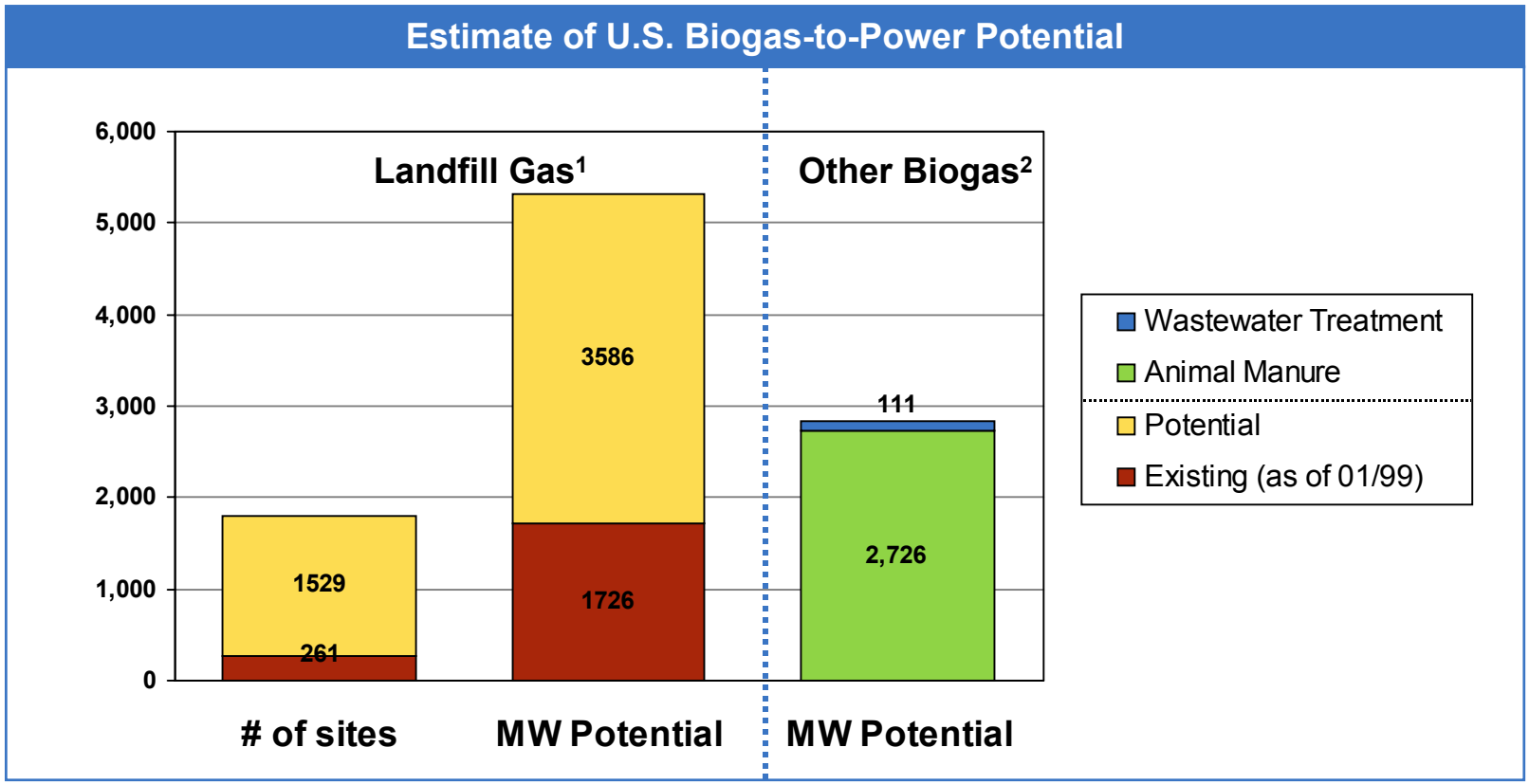
- Readily usable source of "free" methane
- Significant environmental benefits versus flaring or venting
- Utilizes proven technology (IC-engines, gas turbines, steam turbines)
- Emerging technologies (fuel cells[2], microturbines) are also showing good promise and may open up smaller sites to development
- Already accepted by the public as green power (unlike traditional WTE facilities)
- Many projects are generally small (<15MW) and can be developed quickly relative to larger biomass power projects
  - Even the largest landfill gas projects (50-60MW) can be developed relatively quickly

Barriers

- Small plant sizes have historically led to high project development cost ($ per kW), limiting application to only the most desirable locations
- IRS Section 29 Tax Credits are not available to landfill gas collection systems installed after June 1998, which negatively impacts project economics[1]
- Despite essentially free fuel, current projects typically result in electricity costs that exceed wholesale market prices much of the time (can be overcome via green power sales)
- Gas clean-up requirements can significantly impact feasibility of options

1. Under the Climate Change Technology Initiative (CCTI), a 1-1.7¢/kWh production credit is proposed for landfill gas-to-energy projects through 2006.
2. News release on Deer Island Fuel Cell, MWRA, MASSACHUSETTS ELECTRIC TO REDUCE ENERGY COSTS WITH NEW FUEL CELL, MWRA news release, September 22, 1997
3. Biogas includes landfill gas, sewage gas, digester gas and other gases from anaerobic digestion

Landfill gas and other biogases represent an untapped technical market potential of approximately 6,000 MW.



1. Source: US EPA Landfill Methane Outreach Program (www.epa.gov/outreach/lmop/projects.htm). Note that the estimate of existing sites includes all uses of landfill gas converted to a MW equivalent.
2. Source: Inventory of U.S. Greenhouse Gases and Sinks: 1990-1998. (EPA 236-R-00-001), US EPA, April 2000. Note that the EPA considers the data highly uncertain. Moreover, it is not known how much is currently used in power generation. The data represent current estimated production and not the potential production if the organic wastes are deliberately converted to methane for power generation.

The pulp & paper industry is by far the largest user of biomass today for power and heat, with significant long-term potential for growth via efficiency improvements.

Current Situation

- More than 100 million tons of biomass solids[1] are converted to power and heat annually
  - Total existing electric generation capacity is estimated at approximately 7,000 MW
- Being a mature industry, organic growth is unlikely to result in significant new generating capacity or thermal loads
  - Mill efficiency improvements and increased pulp yields will further dampen growth of biomass residues in this industry
- The primary option for increasing the output of biomass-based power in the pulp & paper industry is to increase the efficiency of existing cogeneration
  - Electric generating efficiency today is based on the Rankine cycle and is relatively inefficient where black liquor is the fuel (~12%)

Future Potential

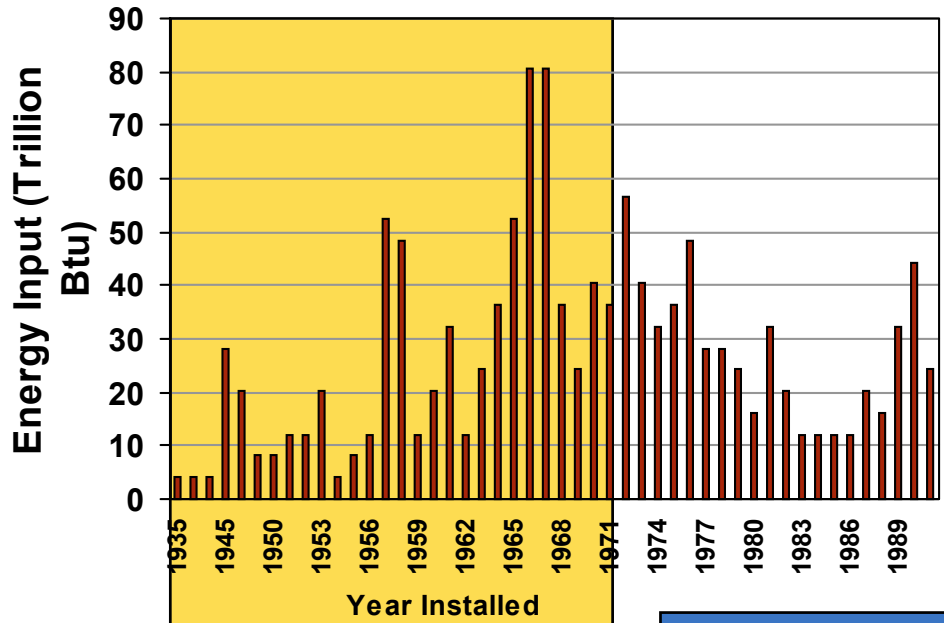
- It is possible to significantly increase black liquor (BL) conversion efficiency to approximately 22%, via replacement of existing BL Tomlinson recovery boilers with black liquor gasification technology
  - This is likely to happen slowly as the fleet of existing recovery boilers turns over
- Black liquor (BL) gasification technology is currently being demonstrated in the United States but is still several years from commercialization
- Even when it is commercially available, BL gasification is most likely to be applied when existing boilers need to be replaced, implying gradual penetration of the market
- Repowering hog fuel and bark boilers with gasification is also possible, with similar efficiency gains

- Since gasification technology has the potential to roughly double the electrical efficiency of current biomass utilization in pulp & paper mills, there is the potential for roughly 7,000 incremental MW, for a total industry potential of approximately 14,000 MW.
- Because the P&P industry has a well developed biomass supply infrastructure, it also has the potential to generate significant additional electricity for export if it chooses to and is able to collect additional biomass for dedicated power generation. This would be necessary to reach the industry's 2020 Vision of generating up to 30,000 MW of electricity from biomass (personal communication with David Freidman, AF&PA, May 2001).

1. Includes spent liquor solids and hogged fuel and bark, which totaled more than 1,500 trillion Btu in 1997.

The number of Tomlinson boilers due for replacement implies a near-term opportunity for increasing generation from black liquor of about 2,600 MW.

Estimated Energy Consumed in U.S. Black Liquor Recovery Boilers



Boilers 40 years or older by 2010

700 Trillion BTU/yr

Black Liquor Recovery Boiler Issues

- By their nature, Tomlinson boilers require extensive and frequent maintenance
- Typical life of Tomlinson boilers is around 40 years
- Around that age, most of their owners will consider complete rebuild or replacement
- In this decade, an unusual number of facilities face this decision

Rankine Cycle (12%) → Power Generation Potential **24,500 GWh**

- or -

IGCC (22%) → Power Generation Potential **45,000 GWh**

Potential **Near-Term** Incremental Generation

20,500 GWh (~2,600 MW)

The long-term opportunity is approximately 5,000 incremental MW from black liquor and approximately 2,000 additional MW from existing hog fuel and bark.

Collectively, other solid biomass residues (outside of the P&P industry) likely represents a small (<1,000 MW) opportunity for power generation.

- Industries include food processing, secondary mills (forest products), and furniture manufacture, which total many thousands of sites across the United States
  - Generally, facilities produce enough biomass residues to generated several hundred kW to a few (<10) MW each
- Detailed data on how much solid residues are generated and used are not readily available, making it difficult to estimate market potential
- Most food processing residues are currently used and are relatively valuable
  - Brewers grains, distillers dried grains, and corn fiber have high value as animal feeds, with almost all of the 9 million dry tons per year in use and valued upwards of $100/dry ton[1]
  - Sugarcane bagasse is already combusted to provide energy and heat used to process sugarcane[1], so that repowering with IGCC, as in the pulp & paper industry, could increase the estimates
- It is estimated that most secondary mill residues are either being used or are not suitable for use
  - An estimated 83% of residues are being used as fuel, animal bedding, mulch, pulp, or other use; and 17% are landfilled[1]
  - Only about 50% of unused residues are available for energy uses, reflecting residue quality and recoverability[1]
  - If these estimates are correct, only one million dry tons per year are available (unused and usable) for use as an energy feedstock, representing approximately 200 MW of potential capacity
  - However, 3 to 4 million dry tons per year go to marginal uses (animal bedding and mulch) that could be used more productively, representing approximately 600-800 MW of potential capacity

1. T. Rooney (NEOS Corporation), Lignocellulosic Feedstock Resource Assessment, NREL report, September 1998.

In addition to the stand alone systems evaluated in this section, biopower is expected to be a part of any other biofuel/product facility.

- Production of fuels, chemicals or other products from biomass almost always results in some residual biomass fraction that has value only for its energy content
  - This is already the case in the pulp & paper and cane sugar industries, and will be the case in the cellulosic ethanol industry
  - This will also be true whether the facility produces a single product or multiple products
- The power will most likely be used to meet onsite requirements, but if there is sufficient capacity, power can also be exported (i.e., it becomes another product)
- The ability to export power will depend on
  - The type of biopower technology (efficiency)
  - The absolute scale of the plant (efficiency)
  - The quantity of residues produced relative to onsite power demands
- While it is difficult to estimate the market potential for this biopower application, it could become significant in the long term (beyond 2010)

Initially, 60 distinct, technically-feasible biomass power, CHP, and heat-only fuel chains were identified for further evaluation.

Technology		Grid Power					Onsite Power & CHP				
		Agricultural residues & energy crops	Municipal Solid Waste (MSW	Refuse Derived Fuel (RDF)	Sewage Sludge	Biogas - Landfill gas	Biogas - Sewage Treatment	P&P - Black Liquor	P&P - Hogged Fuel & Bark	Other Solid Biomass Residues	Biogas - Other Residues
Direct Combustion (solid biomass)	Biomass-only Rankine Cycle	X	X	X	X			X	X	X	
	Co-firing Rankine Cycle (coal)	X									
	Biomass-only Direct-Fired GT									X	
	Biomass-only Heat Only		X	X	X			X	X	X	
Gasification (solid biomass)	Biomass-only Rankine Cycle	X		X	X					X	
	Biomass-only GT/IGCC	X		X	X			X	X	X	
	Biomass-only ICE				X					X	
	Biomass-only Fuel Cell	X		X	X					X	
	Co-firing (coal or NG Rankine, IGCC, GTCC)	X		X	X						
Liquefaction (solid biomass)	Biomass-only Pyrolysis (Rankine, GT, ICE)	X		X	X				X	X	
	Co-firing with oil (Rankine, GT, ICE)	X		X	X				X	X	
Direct Combustion (gaseous biomass)	Biomass-only Rankine Cycle					X	X				X
	Co-firing Rankine Cycle (with natural gas)					X	X				X
	Biomass-only GT, GTCC, ICE					X	X				X
	Co-firing GT, GTCC, ICE (with natural gas)					X	X				X
	Biomass-only Fuel Cell					X	X				X
	Co-firing Fuel Cell (with natural gas)					X	X				X

1. Agricultural residues & energy crops includes woody and other biomass fuels purchased through existing channels

The technical market potential for biopower is generally, but not always, limited by the availability of fuel rather than demand for the final product.

Market Screen

Do the products have markets that are large enough to contribute measurably to an aggressive increase of bioenergy use (more than double) and/or do the feedstocks allow for significant markets?

NO

- Biomass-only direct-fired gas turbine
- All biogas-natural gas co-firing technologies
- Biomass/coal co-gasification for IGCC co-firing
- Biomass gasification co-firing with natural gas Rankine
- Biomass only heat only

YES

- **All other options**

Rationale

- The direct-fired gas turbine (GT) is currently limited to very clean sawdust fuel. While other technologies, especially small-scale gasification systems, also require clean fuel, their restrictions are generally less stringent and can apply across a variety of wood, wood wastes, and agricultural residues
- While technically straight-forward, co-firing of biogas with natural gas is not expected to significantly impact either the market for biogas power or the benefits derived therefrom. Most biogas (including landfill gas) is expected to be used in stand-alone applications. Note that for the market screening, all biogas markets are considered together, as the application requirements and technologies are similar
- Biomass/coal IGCC co-firing is limited by the availability of coal IGCC plants and the likelihood of significant, new coal IGCC capacity being built in the next 10 years in the United States is considered relatively low.
- Biomass gasification for co-firing in natural gas Rankine plants is likely to be a niche application, limited by the number of suitable locations and the willingness of plant owners to invest/take on the risk. Other gasification co-firing options (coal/Rankine, gas GTCC) are retained due to the large technical potential
- Biomass only-heat only requires a thermal host. For the most part, these are probably met already (e.g., P&P) and so would require a significant increase in thermal needs in industries where biomass residues are produced. In cases where additional thermal loads can be met with biomass, then the more likely/desirable scenario is to use CHP. As such, the heat-only option is not carried forward.
- Heat-only production is also possible with technologies other than direct combustion, but are likely to be limited in scope and application. The more likely use of gasification is for power only or CHP, which has been included in the screening.

The following stages of product development were used to describe the status of biopower technologies.

	Research & Development			Demonstration			Market Entry	Market Penetration
	Concept	Bench	Pilot	Initial System Prototypes	Refined Prototypes	Commercial Prototypes		
Description of Typical Activities	• Concept, bench and pilot scale activities • 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	• Initial 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
Key for following slides	**R&D**			**D**			**E**	**P**

Based on these evaluations, the maturity of each option has been ranked.

Technology P = Technology that has achieved market **P**enetration E = Technology in the market **E**ntry phase D = **D**emonstration phase - not commercially available R&D = **R&D** phase - not yet demonstrated		Grid Power					Onsite Power & CHP				
		Agricultural residues & energy crops	Municipal Solid Waste (MSW	Refuse Derived Fuel (RDF)	Sewage Sludge	Biogas - Landfill gas	Biogas - Sewage Treatment	P&P - Black Liquor	P&P - Hogged Fuel & Bark	Other Solid Biomass Residues	Biogas - Other Residues
Direct Combustion (solid biomass)	Biomass-only Rankine Cycle	P	P	P	E/P			P	P	P	
	Co-firing Rankine Cycle (coal)	E									
	Biomass-only Direct-Fired GT									---	
	Biomass-only Heat Only		---	---	---			---	---	---	
Gasification (solid biomass)	Biomass-only Rankine Cycle	D		D	D					E	
	Biomass-only GT/IGCC	R&D/D		R&D	R&D			R&D/D	R&D	R&D	
	Biomass-only ICE				R&D					D/E	
	Biomass-only Fuel Cell	R&D		R&D	R&D					R&D	
	Co-firing (coal or NG Rankine, IGCC, GTCC)	R&D/D		D	?						
Liquefaction (solid biomass)	Biomass-only Pyrolysis (Rankine, GT, ICE)	R&D		D	R&D				D	R&D	
	Co-firing with oil (Rankine, GT, ICE)	R&D		R&D	R&D				R&D	R&D	
Direct Combustion (gaseous biomass)	Biomass-only Rankine Cycle					P	?				?
	Co-firing Rankine Cycle (with natural gas)					---	---				---
	Biomass-only GT, GTCC, ICE					P	E/P				D/E
	Co-firing GT, GTCC, ICE (with natural gas)					---	---				---
	Biomass-only Fuel Cell					D/E	D/E				R&D
	Co-firing Fuel Cell (with natural gas)					---	---				---

1. Agricultural residues & energy crops includes woody and other biomass fuels purchased through existing channels

Direct combustion technologies are relatively mature and in most cases, widely applied today.

Technology	Rationale
Biomass-only Rankine Cycle	• The technology is mature and widely applied using multiple fuels and boiler types/sizes • Today, this is the primary use of biomass for power generation, cogeneration and heat • Some sewage sludge is incinerated today (alone or with other fuels) but the extent to which it is also used for energy recovery is not known
Co-Firing Rankine Cycle	• Solid biomass co-firing with coal has been successfully demonstrated and is in limited commercial application in the United States (approximately 10 total sites) • Works better with woody biomass versus herbaceous or grassy biomass, but both are possible • It is possible to co-fire conventional fuels (coal, natural gas) with MSW, RDF or sludge, but using the conventional fuel as the co-fired fuel (and not the main fuel) does not increase the utilization of biomass and has therefore not been considered here
Biomass-only Direct-Fired GT	• Extended demonstration via EUA Bioten Partnership, but not in commercial use • The Bioten technology (equipment and IP) was put up for sale in early 2000 (*Bioenergy Update,* March 2000*)*
Biomass-only Heat-only	• The technology is mature and widely applied using multiple fuels • A major use of biomass, especially in pulp & paper, forest products and MSW/RDF incineration • Other technologies (i.e., gasification, utilization of biogas) can also be used to generate heat only, but these are likely to be limited relative to their use for power and CHP, going forward • This application in residential use is also an important source of biomass use today

Biomass gasification technologies are maturing, but have yet to be applied on a wide scale.

Technology	Rationale
Biomass-only Rankine Cycle	• There is some commercial application of gasification to produce substitute fuel for boiler/steam turbine plants (e.g., PRM Energy Systems in the Unites States, TPS in Greve in Chianti, Italy, using RDF) • Primarily used for onsite power today (<10 MW) – while technically feasible for larger scales consistent with utility, grid-only applications (50-100 MW), it is more likely that if this technology were widely deployed at these larger scales, that it will be used in IGCCs vs. Rankine cycle plants
Biomass-only GT/IGCC	• There are several demonstrations in operation/construction/development (Europe, U.S., Brazil). These operate on "clean" biomass fuels (e.g., woody residues) • Use of "dirty" biomass fuels has been limited to pilot scale and demonstrations
Biomass-only ICE	• Several technologies available in limited commercial use (e.g., BG technologies) • Tends to be limited to "clean" wastes like wood chips and sawdust • Good for the utilization of onsite biomass residues but not likely to be applied at utility scale
Biomass-only Fuel Cell	• Fuel Cell Energy working on a demonstration project with DOE support (clean coal program) • No commercialization-stage activity at present
Co-firing	• Can co-fire biomass syngas with gasified coal, into a coal boiler or with natural gas in a GTCC • Limited demonstrations and early commercial examples, such as: – Lahti, Finland - Lahden Lampovoima Oy using a Foster Wheeler CFB gasifier to process MSW, shredded tires and wood waste. Syngas is then co-fired in a PC boiler (*Power Magazine*, May/June 2000) – Zeltweg, Austria - Verbund-Austrian Hydro Power AG is co-firing low-BTU gas into an existing PC boiler (*IEA Bioenergy Annual Report 1999*)

Biomass liquefaction is under development, but is not receiving the same attention as gasification.

Technology	Rationale
Biomass-only Pyrolysis (Rankine, GT, ICE)	• Some development activity going on today (e.g., several companies in Canada) • Pre-commercial demonstrations are planned • Technology has yet to be demonstrated at commercial scales
Co-firing with Oil (Rankine, GT, ICE)	• Similar issues apply to co-firing as biomass-only operation

Liquefaction is more likely to be attractive in applications other than power-only or CHP – applications where the liquid pyrolysis product has value beyond simply its heat (BTU) content.

Gaseous biomass (biogas) is in commercial use today, primarily in landfill gas applications.

Technology	Rationale
Biomass-only Rankine Cycle	• Technology is mature and straight-forward to apply but limited to the largest landfill sites and therefore not widely used • e.g., Puente Hills Landfill, Los Angeles, CA, generates about 60 MW, the largest landfill gas project in the United States
Biomass-only GT, GTCC, ICE	• Most common use of biogas for power • Products are commercially available from multiple vendors • ICEs used most often due to good size fit (<5MW) • GTs and GTCCs used on larger projects (>5MW) • Microturbines are emerging as potential biogas conversion technology with very low emissions (Capstone and Honeywell have demonstrated microturbine operation on landfill gas with good initial results)
Biomass-only Fuel Cell	• Several successful demonstrations of ONSI's PC25 on landfill gas and digester gas but no significant commercialization activity
Co-firing	• Limited application, although the technology is straight-forward. Most biogas installations are stand-alone • Assuming the biogas would be used in any event, this option does not increase the use of biomass. Therefore the impacts of using biogas can be effectively captured without requiring additional analysis of co-firing

Based on these rankings, gasification/fuel cell and large-scale pyrolysis technologies were eliminated from further consideration.

Technology Screen

Can the products be produced with technologies that could be commercially viable by 2010?

NO

- Utility-scale liquefaction technologies/applications
- Liquefaction/co-firing opportunities
- Gasification/fuel cell applications
- Direct combustion of gaseous biomass in Rankine cycles and GTCCs for onsite power

YES

- **All other options**

Rationale

- Liquefaction does not appear to be receiving the same level of attention as gasification, is less mature and will likely progress more slowly. Small (<10 MW) technologies could be commercially available by 2005. Co-firing with oil does not increase the use of biomass
- For straight power generation or cogeneration applications, there do not appear to be compelling advantages for liquefaction over gasification (however, this may not be true for a bio-refinery or similar multiple product facility where liquefaction is used to create higher-value products)
- Although gasification has received much attention, the timeline for demonstrating a fuel cell with gasification is not likely to lead to significant markets through 2010. Nevertheless, gasification applications as a whole could contribute significantly over the next 10 years and it is clearly a critical technology for biomass power
- Rankine cycle and GTCC technologies do not lend themselves well to the relatively small-scale application of the onsite use of gaseous biomass

Heat and power are completely fungible products and hence no options were removed in the infrastructure screen.

Infrastructure Screen

Is the product fungible with existing products and processes?

NO

- None

YES

- **All options pass the infrastructure screen**

Rationale

- No biomass power application requires significant changes to existing infrastructure, and obviously, the product is the same as with any power generation technology
- For some applications, significant investments would be required, but these are not required because of infrastructure fungibility, but because biomass is a dispersed resource and requires a well developed infrastructure to collect it in large quantities. These investments would include:
  - Biomass energy plantations
  - Biomass transportation from plantations to power plants

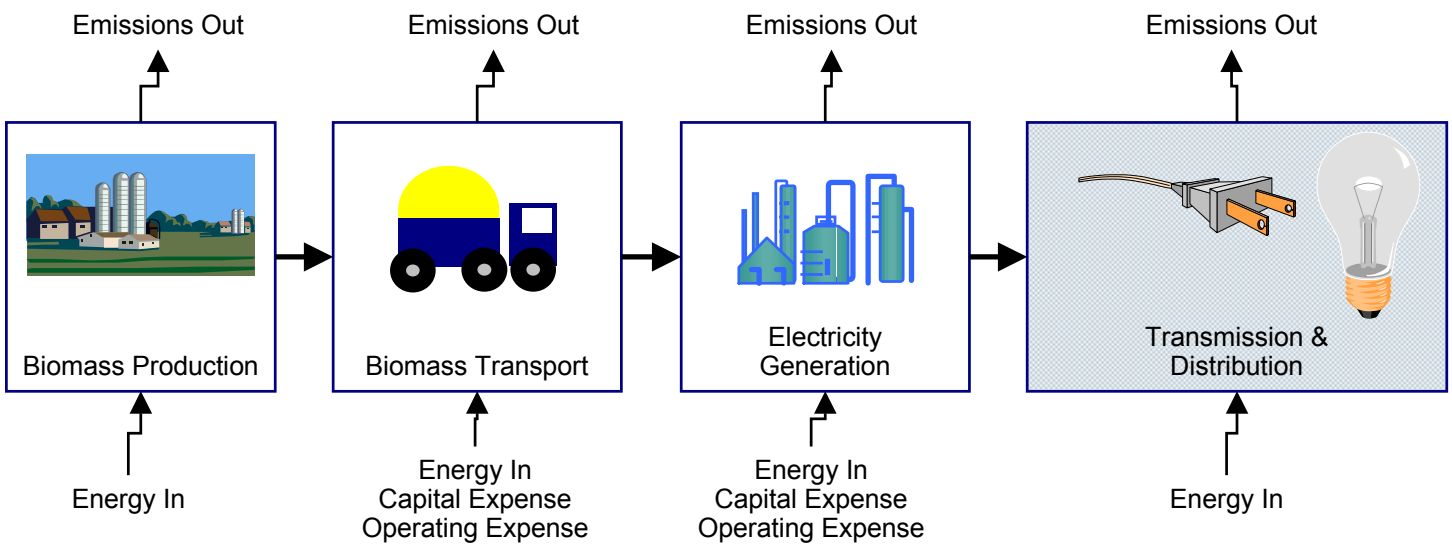
The economic and environmental impacts of the following 32 options were retained for the economic screen.

Technology
P = Technology that has achieved market **P**enetration
E = Technology in the market **E**ntry phase or in limited use
D = **D**emonstration phase - not commercially available
R&D = **R&D** phase - not yet demonstrated

		Grid Power					Onsite Power & CHP				
		Agricultural residues & energy crops	Municipal Solid Waste (MSW	Refuse Derived Fuel (RDF)	Sewage Sludge	Biogas - Landfill gas	Biogas - Sewage Treatment	P&P - Black Liquor	P&P - Hogged Fuel & Bark	Other Solid Biomass Residues	Biogas - Other Residues
Direct Combustion (solid biomass)	Biomass-only Rankine Cycle	P	P	P	E/P			P	P	P	
	Co-firing Rankine Cycle (coal)	E									
	Biomass-only Direct-Fired GT									---	
	Biomass-only Heat Only		---	---	---			---	---	---	
Gasification (solid biomass)	Biomass-only Rankine Cycle	D		D	D					E	
	Biomass-only GT/IGCC	D		R&D	R&D			R&D/D	R&D	R&D	
	Biomass-only ICE				R&D					E	
	Biomass-only Fuel Cell	R&D		R&D	R&D					R&D	
	Co-firing (coal or NG Rankine, IGCC, GTCC)	D/E		D	?						
Liquefaction (solid biomass)	Biomass-only Pyrolysis (Rankine, GT, ICE)	R&D		D	R&D				D	R&D	
	Co-firing with oil (Rankine, GT, ICE)	R&D		R&D	R&D				R&D	R&D	
Direct Combustion (gaseous biomass)	Biomass-only Rankine Cycle					E	?				?
	Co-firing Rankine Cycle (with natural gas)					---	---				---
	Biomass-only GT, GTCC, ICE					P	E/P				D/E
	Co-firing GT, GTCC, ICE (with natural gas)					---	---				---
	Biomass-only Fuel Cell					D/E	D/E				R&D
	Co-firing Fuel Cell (with natural gas)					---	---				---

1. Agricultural residues & energy crops includes woody and other biomass fuels purchased through existing channels

The cost of electricity was estimated from biomass production to electricity generation including energy losses of transmission and distribution.



Key Artifacts and Assumptions of the Methodology

- The costs associated with biomass production (e.g. land, labor, seed, fuel, capital recovery) are assumed to be reflected by the price ($ per dry ton farm-gate) of the biomass. Emissions associated with biomass production are included (from fertilizer, petroleum fuel use) in the benefits and impact analysis.
- Biomass transport costs are associated with a 50-mile one way by truck
- Cases using biomass co-firing include only the cost associated with implementing the biomass
- Energy losses of 7.2% are included for transmission and distribution but not the associated investment costs

While this approach captures many of the associated costs and emissions, it is not a full lifecycle analysis, and should not be interpreted as such.

Typical cost and performance parameters were assigned to each of the chains, with net electrical efficiency being one example.[1]

Net Electrical Efficiency – Biomass-Only Options		Grid Power					Onsite Power & CHP				
		Agricultural residues & energy crops	Municipal Solid Waste (MSW	Refuse Derived Fuel (RDF)	Sewage Sludge	Biogas - Landfill gas	Biogas - Sewage Treatment	P&P - Black Liquor	P&P - Hogged Fuel & Bark	Other Solid Biomass Residues	Biogas - Other Residues
Direct Combustion (solid biomass)	Biomass-only Rankine Cycle	27%	19%	27%	27%			12%	27%	24%	
Gasification (solid biomass)	Biomass-only Rankine Cycle	27%		27%	27%					27%	
	Biomass-only GT									26%	
	Biomass-only IGCC	39%		39%	39%			22%	39%		
	Biomass-only ICE				32%					31%	
Liquefaction (solid biomass)	Biomass-only Pyrolysis (GT)									17%	
	Biomass-only Pyrolysis (ICE)									23%	
Direct Combustion (gaseous biomass)	Biomass-only Rankine Cycle					23%	23%				
	Biomass-only (GT)					26%	26%				26%
	Biomass-only (GTCC)					40%	40%				
	Biomass-only (ICE)					35%	35%				35%
	Biomass-only Fuel Cell					40%	40%				40%

Note: Efficiency assumptions are a function of both the technology type and the unit size.
1. For the complete set of assumptions, please refer to the Data Volume.
2. Agricultural residues & energy crops includes woody and other biomass fuels purchased through existing channels

Co-firing with coal performance parameters vary somewhat by region, based on the mix of coal plant types and ages.[1]

Net Electrical Efficiency – Co-firing Options		Grid Power					Onsite Power & CHP				
		Agricultural residues & energy crops	Municipal Solid Waste (MSW	Refuse Derived Fuel (RDF)	Sewage Sludge	Biogas - Landfill gas	Biogas - Sewage Treatment	P&P - Black Liquor	P&P - Hogged Fuel & Bark	Other Solid Biomass Residues	Biogas - Other Residues
Direct Combustion (solid biomass)	Co-firing (coal) Rankine Cycle (Northeast)	33.5%									
	Co-firing (coal) Rankine Cycle (Southeast)	33.6%									
	Co-firing (coal) Rankine Cycle (Great Lakes)	32.5%									
	Co-firing (coal) Rankine Cycle (Northwest)	31.8%									
	Co-firing (coal) Rankine Cycle (West)	32.0%									
Gasification (solid biomass)	Co-firing (coal) Rankine Cycle (Northeast)	33.1%		33.1%	33.1%						
	Co-firing (coal) Rankine Cycle (Southeast)	33.2%		33.2%	33.2%						
	Co-firing (coal) Rankine Cycle (Great Lakes)	32.0%		32.0%	32.0%						
	Co-firing (coal) Rankine Cycle (Northwest)	31.3%		31.3%	31.3%						
	Co-firing (coal) Rankine Cycle (West)	31.5%		31.5%	31.5%						
	Co-firing (natural gas) GTCC	52.9%									

Note: These efficiencies are for the entire plant, not the biomass portion. For direct combustion, the biomass conversion efficiency is assumed to be 31.2%. For gasification, the overall biomass conversion efficiency is assumed to range from 25.5-26.9%.

1. For the complete set of assumptions, please refer to the Data Volume.
2. Agricultural residues & energy crops includes woody and other biomass fuels purchased through existing channels

The levelized[1] cost of electricity (COE) varies widely depending on the application and the fuel cost.

Assumptions and Methodology	• The costs shown represent the levelized (all-in) costs for all the options retained for the economic screening • The range in levelized costs is due mainly to a range of feedstocks costs • The annual capital charge rate used is 15% per year • Results are expressed per kWh delivered. For grid-sited, this includes transmission and distribution energy losses of 7.2 percent, but not the actual costs of delivering the power • For options employing biomass co-firing, the economic calculations *are for the biomass portion only*
Comments	• For grid-sited power plants utilizing solid biomass feedstocks, the cost of the biomass feedstock is an important component of total levelized costs • For biogas options, the cost of generating and collecting the biogas is assumed to be accounted for outside the cost of power. – A nominal cost range of $ 0-0.50/GJ ($0.0-0.53/million BTU) is used – For landfills, the trend is to require methane collection for flaring – For sewage treatment plants, the methane is produced as part of the core activity – For other biogas (e.g., methane from animal wastes), it is assumed that the trend will be to require systems that reduce wastes, mitigate odors, and generally reduce environmental impacts. This would include using anaerobic digestion systems
Conclusions	• The range in levelized cost of electricity is from slightly negative for RDF and sewage sludge co-firing with coal to approximately 12 ¢/kWh for the pyrolysis options • New, grid-based biomass-only power falls in the 7-11 ¢/kWh range for feedstock costs of $30-60/dry ton farm-gate • Landfill gas and other biogas options appear to fall in the 3-5 ¢/kWh range, driven in part by very low fuel costs • Co-firing options appear the most attractive, due to low capital costs and in the case of coal, emissions credits

1. Levelized cost is the “all=in” cost of generated power, including fuel, operations, maintenance, and capital, expressed in ¢/kWh.

The levelized cost of biomass power ranges from less than zero to more than 12 ¢/kWh, depending on the fuel, technology, and the ability to capture emissions credits.

		Grid Power (¢/kWh)					Onsite Power & CHP (¢/kWh)				
		Agricultural residues & energy crops	Municipal Solid Waste (MSW	Refuse Derived Fuel (RDF)	Sewage Sludge	Biogas - Landfill gas	Biogas - Sewage Treatment	P&P - Black Liquor	P&P - Hogged Fuel & Bark	Other Solid Biomass Residues	Biogas - Other Residues
Direct Combustion (solid biomass)	Biomass-only Rankine Cycle	8.0-10.3	7.5-8.3	5.3-6.2	5.1-6.0			4.8-6.9	4.9-5.7	6.4-8.1	
	Co-firing Rankine Cycle (coal)	2.2-4.1									
Gasification (solid biomass)	Biomass-only Rankine Cycle	8.4 -10.7		5.7-6.6	5.5-6.4					6.8-8.3	
	Biomass-only GT									6.7-8.3	
	Biomass-only IGCC	7.1-8.6		5.4-6.0	5.2-5.8			4.6-5.8	5.0-5.5		
	Biomass-only ICE				4.5-5.2					5.2-6.5	
	Co-firing NG GTCC	5.2-6.6		3.1-3.7							
	Co-firing coal Rankine	2.7-5.1		-0.6-0.4	-0.2-0.8						
Liquefaction (solid biomass)	Biomass-only Pyrolysis, GT									8.7-11.2	
	Biomass-only Pyrolysis, ICE									7.7-9.5	
Direct Combustion (gaseous biomass)	Biomass-only Rankine Cycle					3.4-4.2	3.1-3.4				
	Biomass-only GTCC					3.9-4.4	3.6-4.0				
	Biomass-only GT					3.0-3.7	2.8-3.1				2.8-3.1
	Biomass-only ICE					3.8-4.3	3.5-3.9				3.5-3.9
	Biomass-only Fuel Cell					4.6-5.1	4.3-4.7				4.3-4.7

Agricultural residues & energy crops includes woody and other biomass fuels purchased through existing channels
Note: includes T&D losses (7.2%) for grid power options.

Three different conventional power baselines were required to adequately assess the wide variety of biopower options.

	Economic Comparison Basis	
	Grid Power	**Onsite Power & CHP**
Co-firing of solid biomass or of gasified biomass with coal	• Baseload power cost of 2.7¢/kWh • Biomass co-fired at rate of 10 percent based on heating value	• N/A
Co-firing of gasified biomass with natural gas	• Levelized cost[1] of a new natural gas-fired GTCC power plant of 3.2 - 3.6 ¢/kWh[1] • Biomass co-fired at rate of 10 percent based on heating value	• N/A
Direct combustion or gasification of biomass for grid power generation	• Levelized cost of a new natural gas-fired GTCC power plant of 3.2 - 3.6 ¢/kWh[1] • Includes agricultural residues & energy crops (e.g. corn stover, wood/poplar, switchgrass & wheat straw), MSW, RDF, sludge, landfill gas	• N/A
Direct combustion, gasification or liquefaction of biomass process wastes for onsite power	• N/A	• Industrial sector rates of 3.6 - 4.5 ¢/kWh (EIA *Annual Energy Outlook 2001*, Base Case price in 2010)
All biogas combustion options	• Landfill gas compared to levelized cost of a new natural gas-fired GTCC power plant (3.2 - 3.6 ¢/kWh[1])	• Digester and sewage gas were compared to industrial sector rates of 3.6 - 4.5 ¢/kWh (EIA *Annual Energy Outlook 2001*, Base Case price in 2010)

1. Using natural gas prices for 2010 as reported in the DOE/EIA Annual Energy Outlook 2001 Base Case scenario.

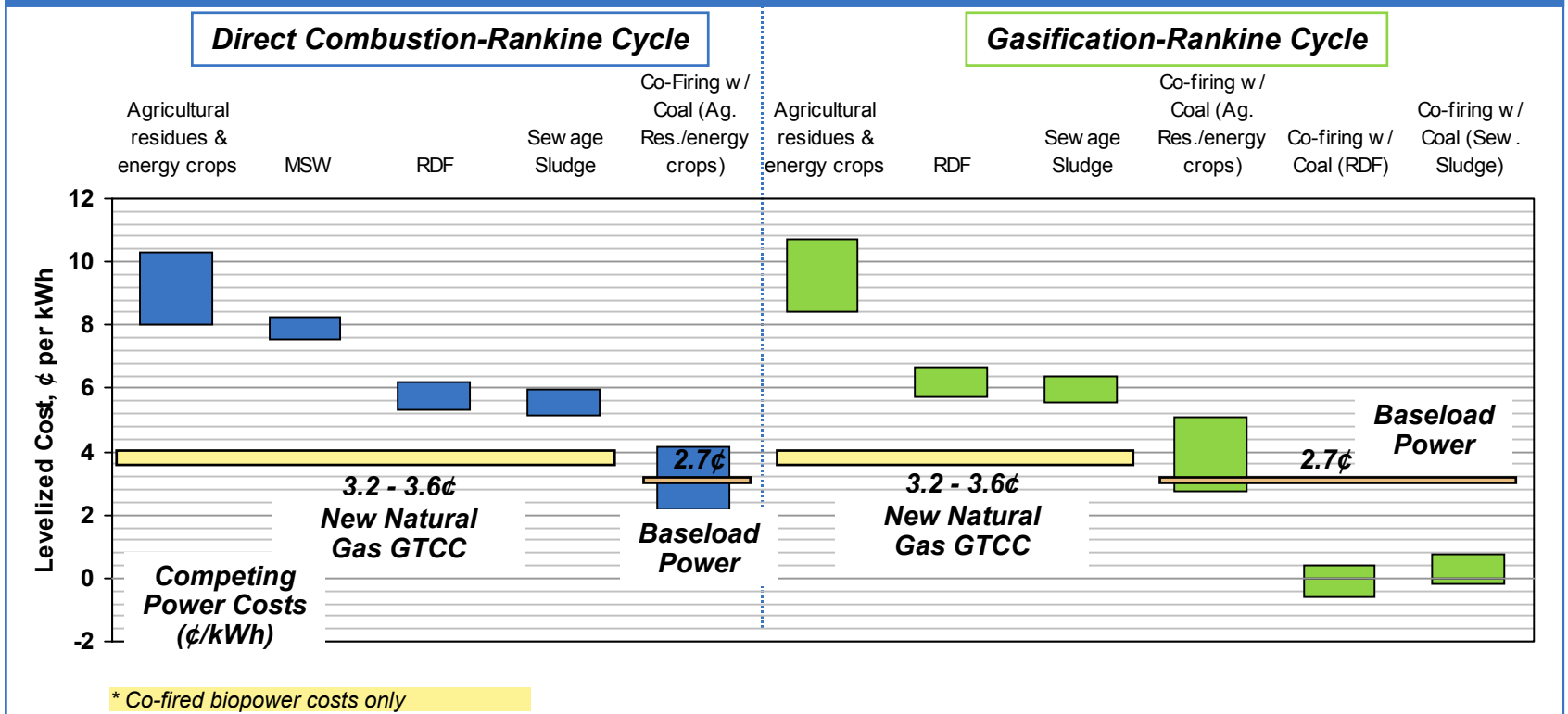
Rankine cycle grid-power options appear to be competitive, provided either low feedstock costs or low capital costs are achievable (2.2 - 6.4 ¢/kWh).

Assumptions and Methodology	• The range in levelized costs for a given application is due mainly to a range of feedstock costs. Agricultural residues & energy crops ($30-60/dry ton, farm-gate) and wastes (RDF, MSW, sludges, $0-10/dry ton, "farm-gate") • The annual capital charge rate used is 15% per year • Results are expressed per kWh delivered. For grid-sited options, this includes transmission and distribution energy losses of 7.2 percent, but not the actual costs of delivering the power • For options employing co-firing, the economic calculations are *for the biomass portion only*
Comments	• Coal plants were assumed to be fully depreciated so that the cost of power from coal plants is effectively the marginal cost only. In order to better compare the levelized COE of biomass co-firing options to a similar grid option, data for electricity futures contacts were reviewed. Based on these data, 2.7¢/kWh was determined to be a reasonable cost for grid baseload power • Biomass co-firing has the potential to significantly reduce NOx emissions from coal plants, in addition to SO_2 reductions. These reductions were included in the levelized COEs, based on futures prices for NOx credits , and current prices for SO_2 credits
Conclusions	• Biomass-only power plants require COE of 8-11¢/kWh at feedstock costs of $30-60/ dry ton farm-gate using agricultural residues or energy crops • Conventional waste-to-energy plants, as represented by the MSW case, are not competitive, even with zero-cost fuel, due to high capital and non-fuel operating costs (COE of greater than 7 cents per kWh) • RDF and sewage sludge options appear reasonably competitive, provided that fuel is available at low cost (<$10/ton), and that capital costs are comparable to those for plants using agricultural residues or energy crops (5.3-6.9 ¢/kWh) • Co-firing with coal looks very competitive with baseload wholesale power – even for feedstocks costing $30-60/ton (farm-gate), levelized costs are 2.2 - 4 cents per kWh for the incremental biopower – Unlike all other biopower options, capital cost is a relatively minor component of the levelized COE – The ability to monetize NOx and SO2 credits results in negligible net non-fuel operating costs – If co-firing can be accomplished with "waste" fuels via gasification, the economics appear more favorable than conventional baseload power

1. as reported in the DOE/EIA *Electric Power Annual 1999.*

Co-firing and waste utilization could be very competitive options once biomass markets are established and the technology is proven.

Levelized Cost for Solid Biomass Power Using Rankine Cycle Technology (¢ per kWh)



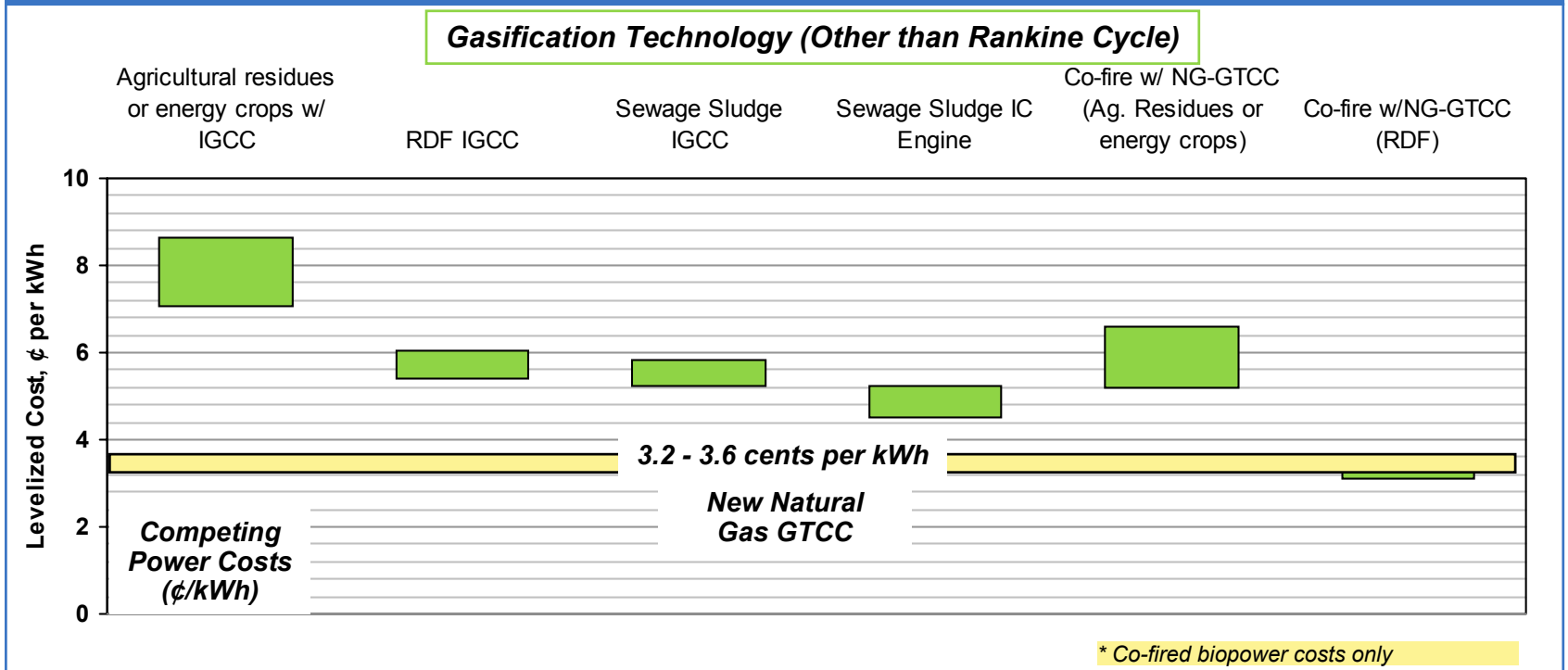
1. For the co-firing cases, the biomass is co-fired at a rate of 10 percent based on heating value.
2. Co-firing with coal cases were compared to an estimated baseload wholesale power cost of 2.7 ¢/kWh. All other cases were compared to new capacity natural gas-fired combined cycle levelized cost of 3.2-3.6 ¢/kWh.
3. The ranges represent a range of fuel costs for agricultural residues & energy crop options ($30-60/ton farm-gate) and for MSW, RDF, and sewage sludge ($0-10/ton gate).
4. Natural gas was assumed to cost $2.90-3.47/MSCF.
5. The analysis includes transmission and distribution energy losses of 7.2 percent but not the actual electricity delivery costs.

The cost issues are similar for gasification-based biopower options.

Assumptions and Methodology	• The costs shown are based on the levelized (all-in) cost of electricity • The range in costs for a given technology/application is due mainly to a range of feedstocks costs. Agricultural residues & energy crops ($30-60/dry ton, farm-gate) and wastes (RDF, MSW, sludges ($0-10/dry ton, farm-gate) • The annual capital charge rate used is 15% per year • Results are expressed per kWh delivered. For grid-sited options, this includes transmission and distribution energy losses, but not the actual costs of delivering the power • For options employing co-firing, the economic calculations *are for the biomass portion only*
Comments	• Economic assumptions for all IGCC options are similar, regardless of the fuel type – For "dirty" fuels like RDF and sewage sludge, capital costs are assumed to be approximately 20% higher than for agricultural residues & energy crops – The key differentiator is the fuel cost • Unlike co-firing with coal, co-firing in a natural gas GTCC does not produce emissions savings (other than CO_2), so there are no monetized credits for NOx or SO_2 included in the analysis
Conclusions	• Biomass-only IGCC technology is expected to require a COE of approximately 7.1-8.6¢/kWh at feedstock costs of $30-60/ton farm-gate using agricultural residues & energy crops • RDF and sewage sludge options appear reasonably competitive, provided that fuel is available at low cost, and that capital costs are not too much higher than those for plants burning agricultural residues or energy crops – Note that the "low-tech" but lower efficiency IC engine option has the potential to be quite competitive because the lower efficiency is less important for low-cost feedstocks (4.9-5.7 cent per kWh) • Co-firing in a natural gas GTCC looks reasonably competitive with baseload wholesale power – even for feedstocks costing $30-60/ton farm-gate with a COE of 5.2-6.6 ¢/kWh – RDF co-firing looks very attractive but because gas turbines are much more sensitive to contaminants than coal-fired boilers, the ability to implement this option is uncertain

Stand-alone biomass IGCC is expected to require a significant premium but co-firing with natural gas using low-cost feedstocks appears attractive.

Levelized Cost for Solid Biomass Power Using IGCC and Gasification-IC Engine Technology (¢ per kWh)



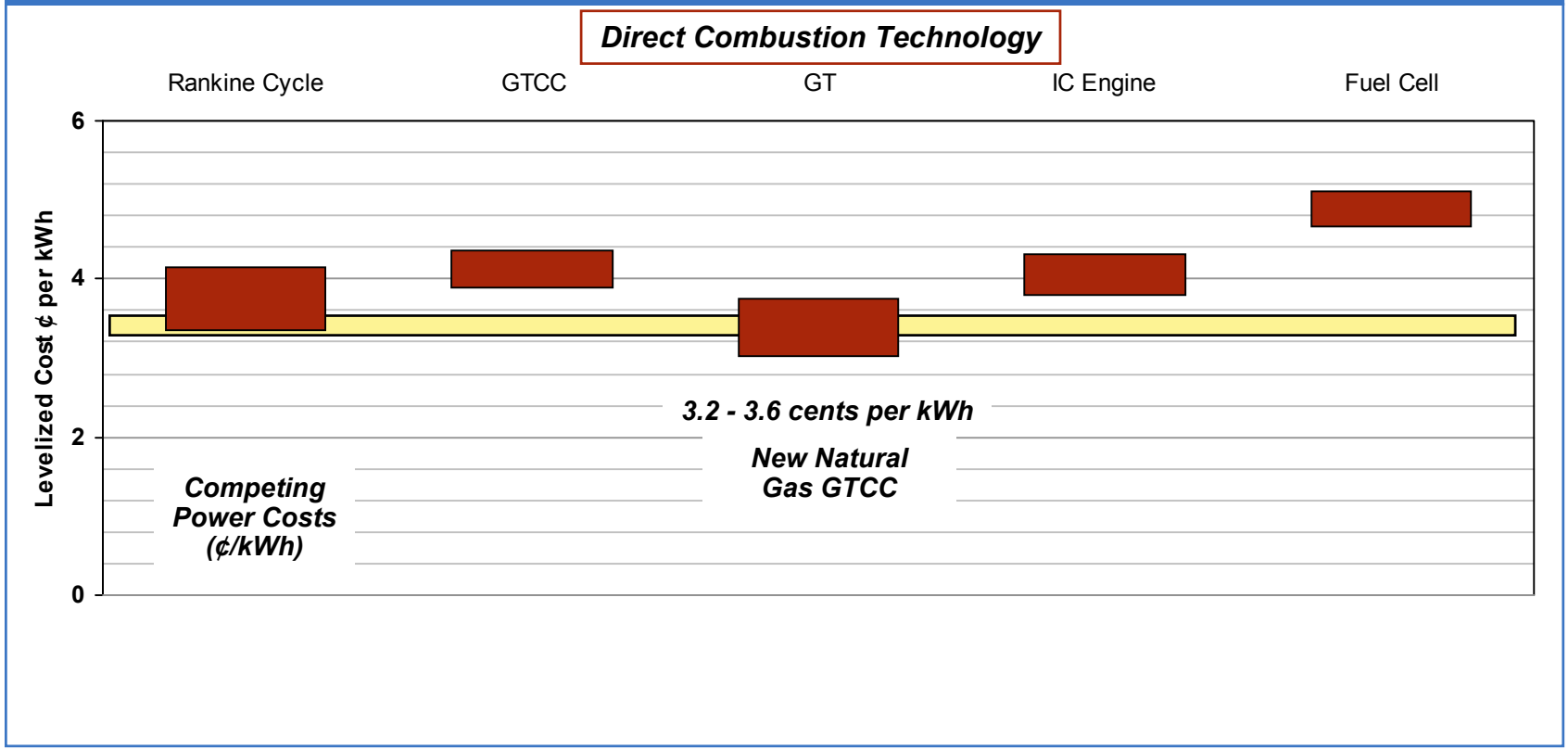
1. The efficiency of a NG-fired GTCC plant is 54.0% (HHV). For biomass co-firing cases with natural gas, the biomass is co-fired at a rate of 10 percent based on heating value. Natural gas was assumed to cost $2.90-3.47/MSCF.
2. All cases were compared to natural gas combined cycle levelized cost of 3.2-3.6¢/kWh.
3. The ranges represent a range of fuel costs for agricultural residues & energy crops options ($30-60/ton) and for MSW, RDF, and sewage sludge ($0-10/ton).
4. The analysis includes transmission and distribution energy losses of 7.2 percent but not the actual electricity delivery costs.
5. Sewage sludge is assumed to be used on-site to generate electricity so that the cost does not include transport costs.

Landfill gas appears to offer very attractive economics regardless of the technology used (3.0 - 5.1 ¢/kWh).

Assumptions and Methodology	• The cost of electricity shown are based on the levelized (all-in) cost of electricity • The range in cost of electricity for a given technology/application is due mainly to a range of feedstocks costs (essentially 0-0.50 $/GJ) • The annual capital charge rate used is 15% per year • Results are expressed per kWh delivered. For grid-sited options, this includes transmission and distribution energy losses, but not the actual costs of delivering the power • The costs for gathering the gaseous biomass was not included in the cost of electricity
Comments	• The cost of collecting the landfill gas is assumed to be accounted for outside the cost of power, as the trend is to require methane collection for flaring anyway – A nominal cost range of $ 0-0.50/GJ ($0-0.53/million BTU) is used to cover any costs than may be more directly associated with the power plant (e.g., gas cleanup not required for a flare) • Fuel cell capital costs are based on expected costs of approximately $1,500/kW, and not on current prices for low-volume production fuel cells, such as the available PAFC technology, even though these fuel cells are the ones currently running on landfill gas
Conclusions	• All options, even the fuel cell, offer the potential cost competitiveness (3.0 to 5.1 cents per kWh) – Some options appear to not require a premium at all over the baseline • The main differentiator between options is the capital cost – higher efficiency, higher cost options, like the GTCC are not favored due to low fuel costs – The low-cost simple cycle gas turbine appears to be the most attractive option • Given the potential for attractive economics, the non-technology barriers are likely to be the ones needing attention, including project development costs and effort for small projects, interconnection, and ownership

With total installed costs in the $1,100-1,800/kW range, landfill gas appears competitive with the cost of new GTCC power generation (3.0-5.1¢/kWh) .

Levelized Cost for Landfill Gas Power Generation (¢ per kWh)



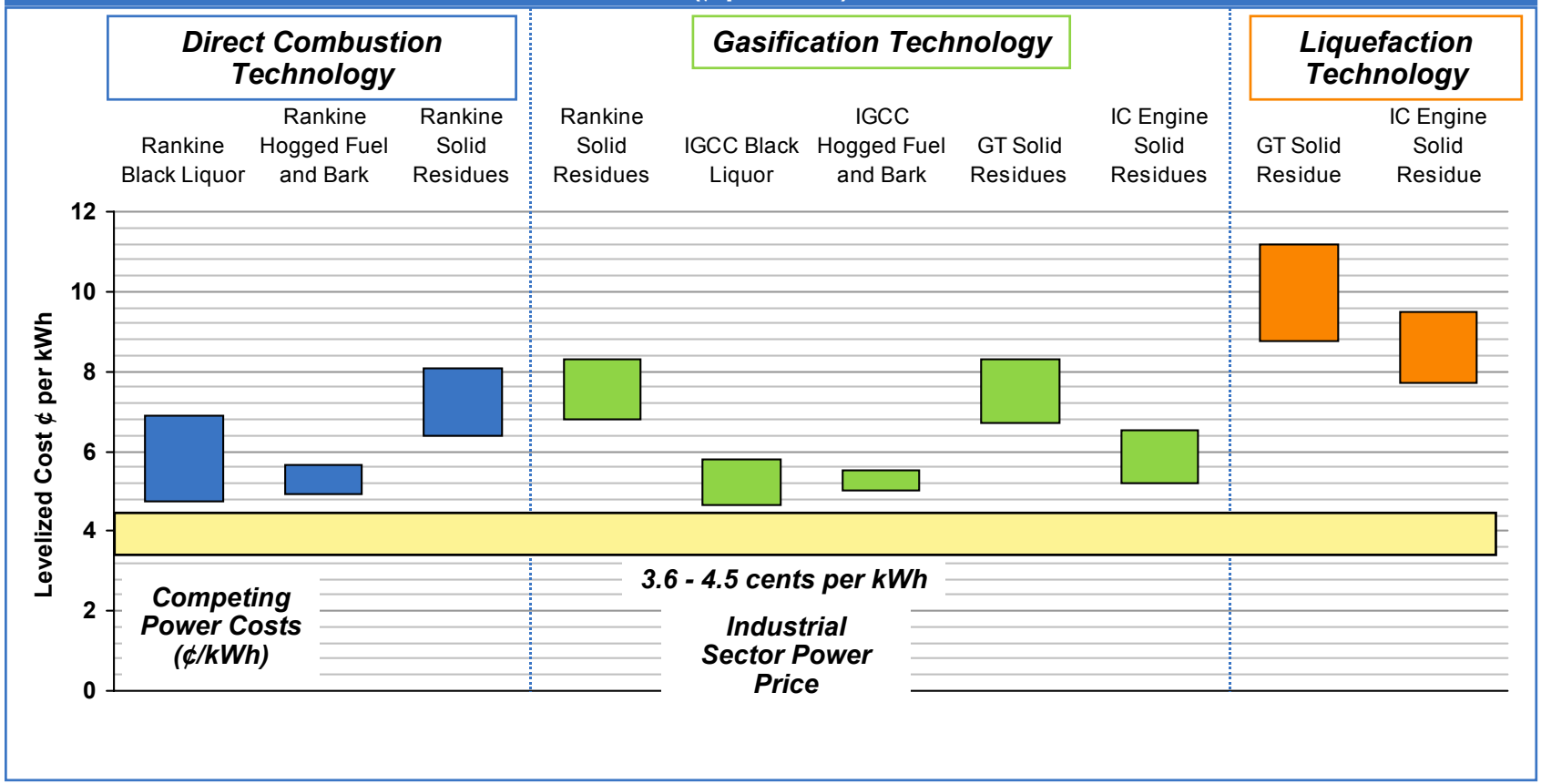
1. All cases were compared to natural gas-fired combined cycle levelized cost of 3.2-3.6¢/kWh.
2. Natural gas is assumed to cost $2.90-3.47/MSCF (for the calculation of the baseline GTCC costs).
3. The analysis includes transmission and distribution energy losses of 7.2 percent but not the actual electricity delivery costs.
4. Landfill gas costs are assumed to range in price from 0-0.50 $/GJ.

Onsite conversion of solid biomass via combustion or gasification could be competitive in areas with high industrial electric rates (COE 4.6- 8.3 ¢/kWh).

Assumptions and Methodology	• The cost of electricity shown is based on the levelized (all-in) cost of electricity • The range in COE for a given application is due mainly to a range of feedstocks costs. Hogged fuel, black liquor ($0-10/dry ton farm-gate) and solid residue wastes ($10-30/dry ton farm-gate) • The annual capital charge rate used is 15% per year • The power is assumed to be generated and used onsite. No credits are taken for electricity export • Because the biomass is generated and used onsite, feedstock costs are generally lower than for grid-power options using agricultural residues or energy crops. Onsite wastes are assumed here to be $0-30/ton)
Comments	• Although today some residues may have negative cost, for this analysis the minimum cost is assumed to be zero, a general assumption made throughout the study, consistent with the concept that as biomass utilization increases, residues that were once thought of as liabilities now have market value • Consistent with other analyses in this study, forecasts of average industrial rates were used for the comparison (EIA 2001 projected industrial sector rates in 2010) • Industrial rates actually vary much more significantly than the 3.6-4.5¢/kWh range used, and not only vary significantly from state to state but also within a state for different size industrial customers • If more detailed data on actual industrial rates for a given site are available, the reader can adjust the COE calculation by comparing that rate to the range used here for the appropriate application • For some industries, most notably pulp & paper, residues are utilized for power and heat regardless of the power economics, because their use is integral to the core industrial process
Conclusions	• Scale is an important consideration in overall economics as it affects capital costs – Pulp & paper industry applications are generally large 30-80 MW, whereas the size of installations in other industries is typically much smaller (<1-10 MW) • COE range from 4.6-8.3¢/kWh for combustion and gasification – Pulp & paper options generally appear the most attractive – Rankine cycle and small gas turbines (under 1 MW) require the highest premiums • Liquefaction options appear the least attractive – A substantial portion of the biomass is converted to char and gases, which do not contribute to power output, resulting in higher per kW capital costs and low electrical efficiencies – Liquefaction is likely to be more attractive in applications where higher values can be obtained for the liquid, solid and gaseous products

Cost of electricity ranges from 4.6 to 8.3 ¢/kWh for direct combustion and gasification options. Liquefaction is likely to be an unattractive option.

Levelized Cost for Solid Biomass Power Generation for Onsite Power, Excluding Cogeneration Credits (¢ per kWh)



* Note that industrial rates vary widely by state and by industrial sector. For example, the pulp & paper industry and other large end-users enjoy some of the lowest rates in the country.

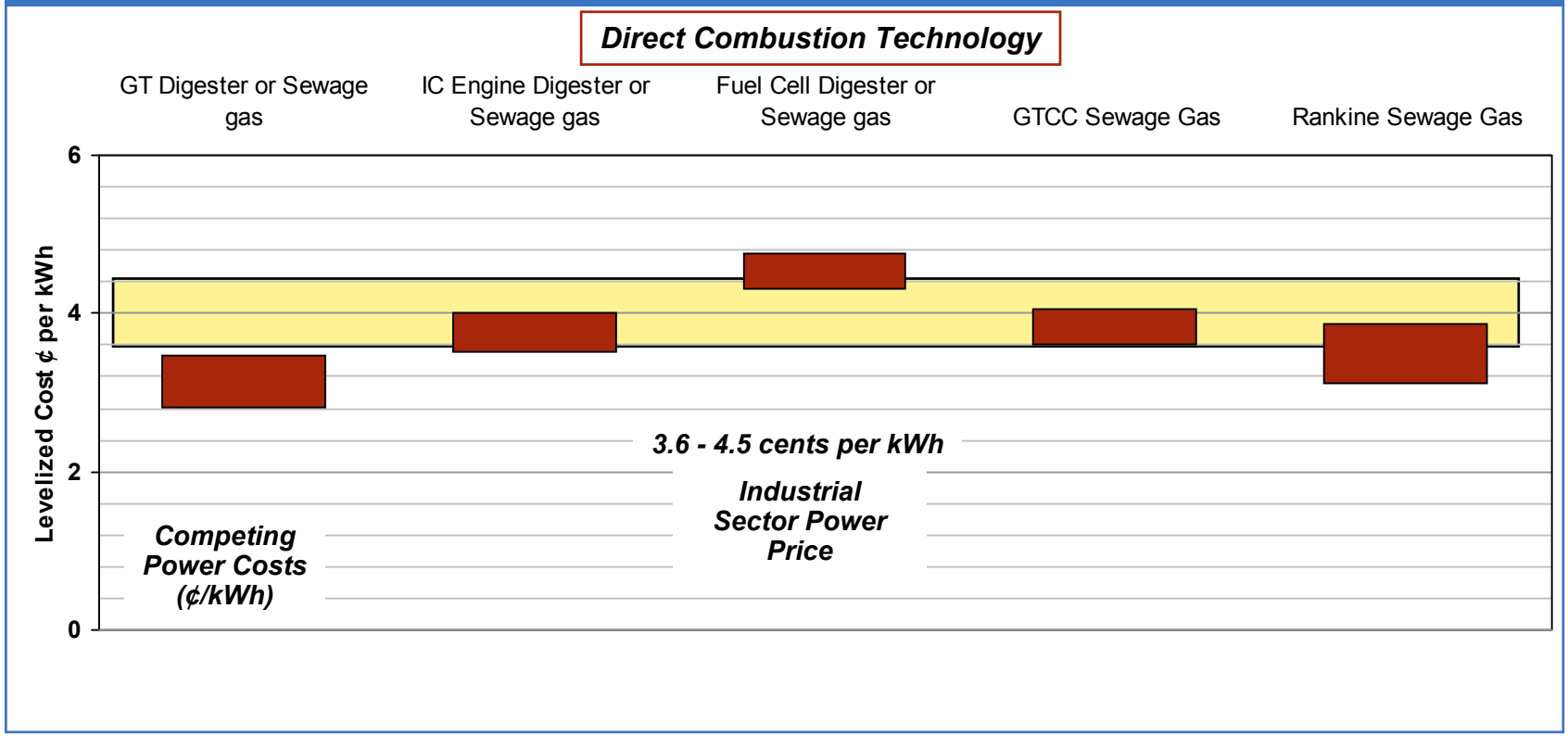
1. The range in electricity generation costs represents a feedstock cost range of $0-10/ton.
2. All cases were compared to industrial sector rates of 3.6 to 4.5¢/kWh (EIA Annual Energy Outlook 2001, Base Case price in 2010).

The conversion of biogas appears very attractive relative to industrial power rates, provided that fuel costs are very low.

Assumptions and Methodology	• The costs of electricity shown are based on the levelized (all-in) cost of electricity. The range in COE for a given application is due mainly to a range of feedstocks costs (0-0.50 $/GJ) • The annual capital charge rate used is 15% per year • The power is assumed to be generated and used onsite. No credits are taken for electricity export • Because the biomass is generated and used onsite, feedstock costs are generally lower than for grid-power options using agricultural residues or energy crops
Comments	• The cost of generating the biogas is assumed to be accounted for outside the cost of power – For sewage treatment plants, the methane is produced as part of the core activity – For other biogas (e.g., methane from animal wastes), it is assumed that the trend will be to require systems that reduce wastes, mitigate odors, and generally reduce environmental impacts. This would include using anaerobic digestion systems – A nominal cost range of $ 0-0.50/GJ ($0-0.53/million BTU) is used to cover any costs than may be more directly associated with the power plant (e.g. gas cleanup) • Fuel cell capital costs are based on expected costs of approximately $1,500/kW, and not on current prices for low-volume production fuel cells, such as the available PAFC technology, even though these fuel cells are the ones currently running on biogas in selected locations • Consistent with other analyses in this study, forecasts of average industrial rates were used for comparison • If more detailed data on actual industrial rates for a given site are available, the reader can adjust the COE calculation by comparing that rate to the range used here for the appropriate application
Conclusions	• All options, even the fuel cell, offer the potential for competitive COE, indicating that this is a potentially very exciting, yet under-exploited opportunity (COE of 2.8 - 4.3 ¢/kWh) • This conclusion is predicated on the availability of low to zero cost methane – While this is a reasonable assumption for sewage treatment plants, it may not be for other applications, where methane production is not part of the core activity – For these other applications, methane generation costs may be necessary for environmental compliance, or could be offset by other factors such as the sale of fertilizer, which have not been included here • The main differentiator between options in the capital cost – higher efficiency, higher cost options, like the GTCC are not favored due to low fuel costs • The low-cost simple cycle gas turbine appears to be the most attractive option

COE range from 2.8 to 4.3 cents per kWh, highly competitive with projected EIA 2001 Outlook industrial sector rates in 2010.

Levelized Cost for Biogas Power Generation for Onsite Power, Excluding Cogeneration Credits (¢ per kWh)



* Note that industrial rates vary widely by state and by industrial sector. For example, the pulp & paper industry and other large end-users enjoy some of the lowest rates in the country.

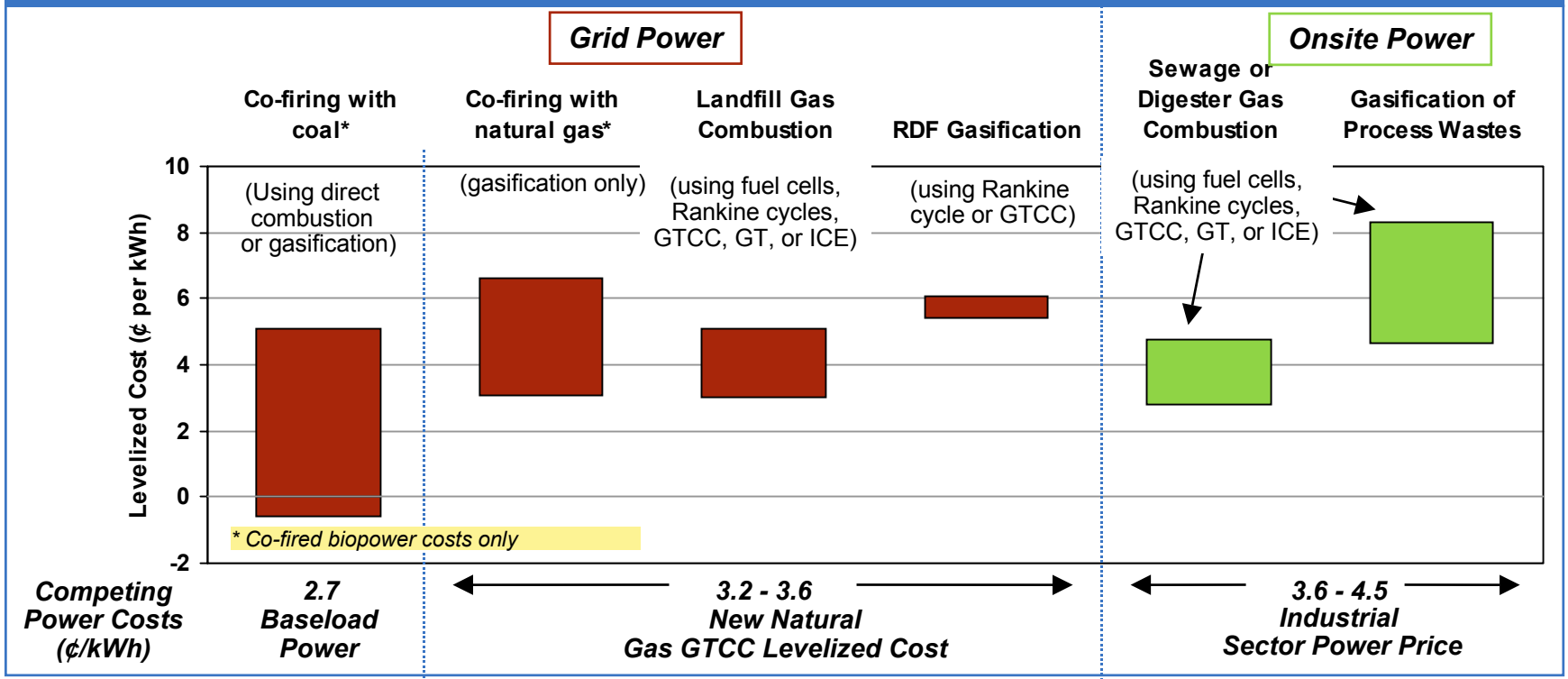
1. The range in electricity generation costs represents a feedstock cost range of $0-10/ton. This assumes the cost of biogas production and gathering is not included in the cost of power, but that it is required for other reasons, like environmental compliance and odor control.
2. All cases were compared to industrial sector rates of 3.6 to 4.5¢/kWh (EIA Annual Energy Outlook 2001, Base Case price in 2010).

Co-firing with coal and utilization of biogas appear very attractive relative to grid and industrial power rates, provided that fuel costs are very low.

Assumptions and Methodology	• The costs shown are based on the levelized (all-in) cost of electricity (COE) • The range in COE for a given application is due mainly to a range of feedstocks costs ($30-60/dry ton farm-gate for agricultural residues or energy crops; 0 to $30/dry ton farm-gate for process wastes; $0 - 0.50/GJ farm-gate for gaseous biomass) • Results are expressed per kWh delivered. For grid-sited, this includes transmission and distribution energy losses of 7.2 percent, but not the actual costs of delivering the power • For options employing biomass co-firing, the economic calculations *are for the biomass portion only*
Comments	• For biogas options, the cost of generating and collecting the biogas is assumed to be accounted for outside the cost of power • Coal plants were assumed to be fully depreciated so that the cost of power from coal plants is effectively the marginal cost only. In order to better compare the levelized COE of biomass co-firing options to a similar grid option, data for electricity futures contacts were reviewed. Based on these data, 2.7¢/kWh was determined to be a reasonable cost for grid baseload power • Biomass co-firing has the potential to significantly reduce NOx emissions from coal plants, in addition to SO_2 reductions. These reductions were included in the levelized COEs, based on futures prices for NOx credits , and current prices for SO_2 credits. Co-firing in a natural gas GTCC does not produce emissions savings (other than CO_2), so there are no monetized credits for NOx or SO_2 included in the analysis • Although today some residues may have negative cost, for this analysis the minimum cost is assumed to be zero, a general assumption made throughout the study, consistent with the concept that as biomass utilization increases, residues that were once thought of as liabilities now have market value • For some industries, most notably pulp & paper, residues are utilized for power and heat regardless of the power economics, because their use is integral to the core industrial process
Conclusions	• For grid-sited power plants utilizing solid biomass feedstocks, the cost of the biomass feedstock is an important component of total levelized costs • The range in levelized cost of electricity is from slightly negative for RDF and sewage sludge co-firing to approximately 8-11 ¢/kWh biomass only Rankine cycle power for grid applications using agricultural residues or energy crops • New, grid-based biomass-only power falls in the 7-11 ¢/kWh range for feedstock costs of $10-60/dry ton farm-gate using Rankine or IGCC technology • Landfill gas and other biogas options appear to fall in the 3-5 ¢/kWh range, driven in part by very low fuel costs • Co-firing options appear the most attractive, due to low capital costs and in the case of coal, emissions credits

The lowest cost biopower options are co-firing with coal (due mainly to low capital costs) and biogas combustion (due mainly to low fuel costs).

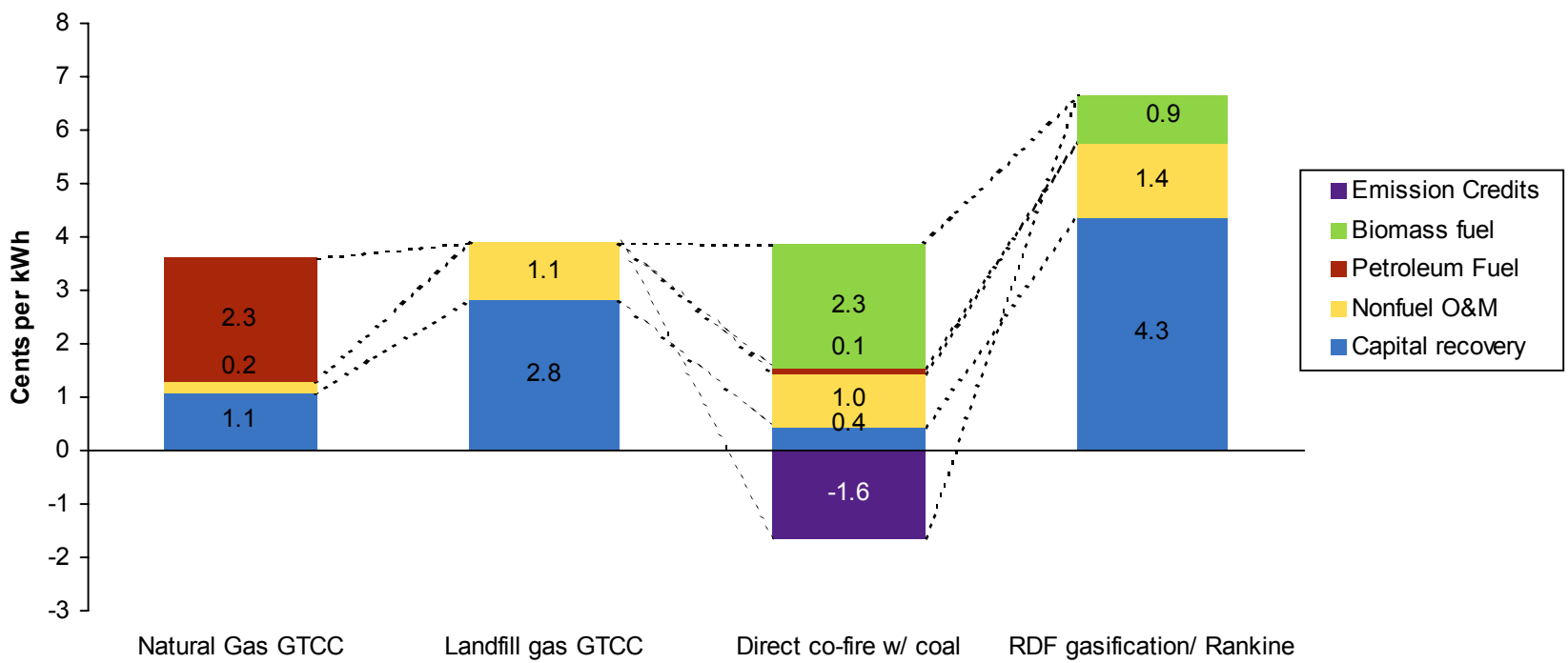
Summary of Levelized Costs for Biomass Power Generation Options (¢ per kWh)



1. For co-firing cases, biomass is co-fired at a rate of 10 percent based on heating value. Natural gas is assumed to cost $2.90-3.47/MSCF. The bar for co-firing with coal includes RDF, corn stover, wheat straw, poplar & switchgrass. The cases with co-firing with natural gas includes corn stover, wheat straw, poplar, & switchgrass
2. Landfill gas, sewage gas and other digester gases and process wastes are generated and used onsite.
3. Co-firing with coal cases were compared to an estimated baseload wholesale cost of 2.7 ¢/kWh. All other grid power cases were compared to a natural gas combined cycle levelized cost of 3.2-3.6 ¢/kWh. Onsite power options were compared to industrial sector rates of 3.6-4.5 ¢/kWh (EIA Annual Energy Outlook 2001, Base Case price in 2010).
4. The analysis includes transmission and distribution energy losses of 7.2 percent for the grid power options, but not the actual electricity delivery costs.
5. Biogas costs are assumed to range in price from 0-0.50 $/GJ; RDF and process wastes from $0-10/ton; agricultural residues or energy crops from $30-60/ton.

Both capital recovery cost and biomass feedstock cost are key cost drivers for levelized cost of electricity.

Summary of Levelized Costs for Biomass Power Generation Options (¢ per kWh)



Note: For co-firing cases, biomass is co-fired at a rate of 10 percent based on heating value; a biomass price of $30/dry ton farm-gate was used for co-firing case. Natural gas is assumed to cost $3.47/MSCF. Landfill gas was used onsite and considered zero cost. RDF was considered to be used onsite and had a cost of $10/dry ton farm-gate. The analysis includes transmission and distribution energy losses of 7.2 percent for the grid power options, but not the actual electricity delivery costs.

Feedstock cost has been and will continue to be a major driver for the economics of biomass power.

- Every $10/ton paid for agricultural residues or energy crop-based fuel (e.g., wood, hybrid poplar, corn stover, sugar bagasse) adds approximately 0.5¢/kWh to the levelized cost of power
  - For agricultural residue or energy crop feedstocks, the economic analysis assumed feedstock costs of $30-60/dry ton farm-gate, equivalent to roughly $1.70-4.00/million BTU, depending on the type of biomass
  - If instead, these feedstocks could be procured for $10-30/dry ton farm-gate ($0.85-2.00/million BTU), this would reduce the levelized cost of electricity by approximately 1.0-1.5 ¢/kWh
  - While this would measurably improve the economics, the COE for new, biomass-only grid power would still be the highest among the grid power options
  - Biomass co-firing in natural gas-fired GTCCs could be very attractive at these lower feedstock costs
- For the remaining feedstocks like RDF, landfill gas and onsite residues, (i.e., other than what is termed agricultural residues or energy crops) the economic analysis conducted here already assumed a low-cost feedstock, so that there is little opportunity for lower prices to impact the cost of power
  - Although today some residues may have negative cost (e.g., because they are currently landfilled at a cost), as markets develop for biomass as an energy feedstock, residues that were once thought of as liabilities will have market value. In such circumstances it is not appropriate to assign them a negative cost

The following options have been retained for further analysis of benefits and impacts.

All biogas combustion options	• While the technical market potential is modest in size, the economic attractiveness of most options suggests that this "low-hanging fruit" is cost competitive now and should be developed wherever possible
Co-firing of solid biomass and of gasified biomass	• The economics are nearly competitive with wholesale power (but typically not with the marginal cost of coal-based power) • The large market potential could significantly contribute to the aggressive goals • This also retains utility-scale gasification technology in the mix of options
RDF Gasification	• Because the feedstock is potentially available at low to zero cost, the economics can be attractive • Because only a small fraction (~15%) of municipal waste is combusted for energy today, this leaves a very large untapped potential market • There are likely to be hurdles with respect to permitting and public resistance
Gasification of process wastes	• Where onsite waste fuels are available, gasification technology could be cost competitive, and have modest near-term market impact and significant long-term impact – Successful deployment of IGCC in the pulp & paper industry is critical to making this a high-impact option. • The cost of stand-alone biomass IGCC power for sale into the wholesale market is expected to be well above the cost of competing conventional technologies, but represents an enormous long term opportunity – Gasification, which will enable the long-term viability of new, biomass-only grid power, was retained for analysis in applications with better near-term economics.

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Biofuels, either as a straight fuel replacement, as a blend stock, or as an additive, represent very large fuel markets for increasing the use of biomass-derived materials. Market value of biofuels as blend stock or as additives have commanded premiums over its energy content value (using the example of ethanol). Ethanol's value has ranged from its oxygenate content value, its octane value, low-sulfur and low-aromatics, volume extending value, to its energy content value. Next generation cellulosic ethanol (e.g. advanced SSCF technology) could be close to cost-competitive when valued as an oxygenate additive. Current technology corn ethanol (both from wet and dry corn mills) offers a current and near term option for increased demand of ethanol for oxygenate additive applications if oxygenate requirements in reformulated and oxygenated gasoline remain. Other biofuel options carry a considerable cost premium (especially when valued solely on energy content).

As a straight replacement of conventional petroleum fuels in terms of energy content, the cost premium of biofuels (ethanol and FT-diesel) over conventional fuels exceeds 100% and presents the most important barrier to the broader implementation of biofuels as a neat fuel. As a fuel additive, we estimate that current corn ethanol (wet mill and dry mill) and next generation SSCF bioethanol could be produced for a very modest cost-premium over MTBE; the current ethanol tax credit bridges that gap. This, together with the alternative fuel tax credits available in some states and the planned phase-out of MTBE make bioethanol a plausible biofuel option for blending. Use of ethanol for ETBE as an oxygenate is likely to meet similar resistance as for MTBE.

Other fuels could be considered but are likely to face much higher barriers as those discussed, especially if the fuel will solely be valued on energy content. Other fuels such as mixed alcohols could fulfill similar applications as ethanol once the technology and cost competitiveness is proven. Other fuels such as biodiesel from agricultural seed crops and waste and animal fats continue to find application in niche markets. Broad application of biodiesel is hampered by its feedstock cost and the disposition of co-products such as glycerol and food by-products which likely have to command premium values in order for the economics to work.

Biofuels have significant potential as additive alternatives for conventional petroleum fuels, provided current tax credits are continued.

- Today's biofuel options are technically feasible based on fermentation, low-temperature processing and gasification technology
- Due to the huge market potential, biofuels can offer significant potential impact
  - The most likely continued growing market for biofuels is as blending agents (including additives)
  - Neat fuels are currently a niche option
- Ethanol looks particularly attractive as a desirable gasoline additive:
  - Additive markets (as an MTBE replacement) for ethanol would provide ~50% higher value than neat fuel markets primarily due to its oxygenate value on a dollar per gallon basis
  - A progressive reduction in cellulosic ethanol cost is projected down to about two times the cost of gasoline on a volume basis
  - Wet mill and dry mill corn ethanol provides a current and near-term options for increased oxygenate demand for MTBE replacements
  - The ethanol tax credit aids the economics so that today corn ethanol can be competitive with MTBE
- Other fuels could be considered, but they will face much higher barriers than the ones selected
  - Bio-FT-diesel appears to offer another plausible combination of cost and environmental benefits:
  - Bio-FT-diesel is considerably more expensive than ethanol. FT-diesel is projected to be at about 2.5 times the price of conventional diesel* (on a energy basis)
  - Bio-FT-diesel could help to meet new diesel specifications, but it will face tough competition from natural gas-based FT-diesel
  - Extending ethanol tax credits to Bio-FT-Diesel would reduce the price differential to 50-100%

*Based on $21/b oil prices projected by EIA for 2010 reference case, for comparison assume price of conventional fuels is roughly proportional to crude oil prices

The following categories apply to biofuels and are used to organize the options being screened.

Technologies	• **Fermentation:** Conversion of the feedstock to produce a fuel using microorganisms (or portions of microorganisms) • **Pyrolysis or Thermal Treatment:** Pyrolysis involves high-temperature thermal conversion of the feedstock in the absence of free oxygen to form a broad product slate, many of the products of which could be used as chemicals or possibly as fuels • **C_1 chemistry (syngas based):** High temperature conversion of the feedstock to a mixture of permanent gases (usually syngas) and then subsequent conversion of the syngas into a liquid or gaseous fuel. May also provide co-products • **Low temperature chemical processing:** Chemical processing (usually enzyme, acid or base-catalyzed) to break the biomass into sub-species and subsequent recovery of the product from the resulting mixture (includes oil splitting of lipids to make liquid fuels) • **Physical separation:** Separation of a component from the feedstock. Minor chemical modification to form the product
Applications	These are the situations in which the technologies are used. • **Transportation** – Internal Combustion Engine – Fuel Cell Vehicle • **Nonvehicle applications**
End-Use	• **Blending agent (**Includes additive for oxygenates for a MTBE replacement for gasoline, blend stock for octane enhancement, diesel oxygenate, blend stock for gasoline volume extender, low-sulfur blend stock; and low aromatic blend stock) • **Pure or Neat Fuel**

Transportation applications will be discussed in this section.

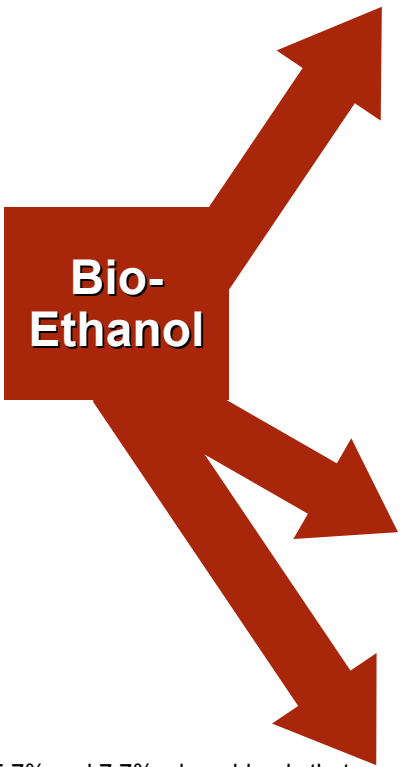
Increased growth in biomass fuels will come from use as a blending agent with existing petroleum-based fuels and as a pure or neat fuel.

Application		Pathway to Increased Biofuel Use	
		Pure Transportation Fuel	Blending Agent / Additive
Fermentation	Ethanol	○	●
	Mixed alcohol fuel	○	●
Pyrolysis or Thermal Treatment	Pyrolysis Oil	○	●
	HTU Diesel	○	●
C_1 chemistry Gasification/ Syngas	Hydrogen	●	
	Dimethyl ether	●	
	Dimethyoxymethane	●	○
	Methanol (MeOH)	●	
	Fischer-Tropsch diesel	○	●
	Synthetic Natural Gas	●	
	MT Gasoline (from MeOH)	○	●
	Fischer-Tropsch Gasoline	○	●
	Mixed alcohol fuel	○	●
Low Temperature Chemical Process	Biodiesel	○	●

● Primary pathway

○ Secondary pathway

Ethanol is being used in three different modes, with different market sizes and economic implications.



Gasoline Additive or Blend Market (Primary existing market with significant potential for near-term expansion)

- Current regulations limit blends to 10 percent by volume ethanol
- Higher concentration ethanol blends (likely up to 20%) are technically feasible
- Blended at 5 to 10% in gasoline by volume (typically 5.7, 7.7, 10%*)
- Works in conventional vehicles without any adjustments
- Provides octane improvement, emissions reduction, and a near-zero sulfur blend stock

Conventional Gasoline

- Ethanol value based on gasoline price with a premium based on ethanol's octane value
- Historically, ethanol is used as an octane enhancer and gasoline extender
- Suboctane gasoline for ethanol blending is now being produced in areas with high ethanol use
- E10 has an RVP waiver to compensate for its RVP increase in gasoline blends

Reformulated Gasoline (RFG) and Oxygenated Gasoline

- Clean Air Act requires a minimum oxygen content (Primary oxygenates are ethanol and MTBE; public acceptability of use of ethanol as ETBE is questionable)
- Value is based on oxygenate content (based on MTBE); minimum is based on competing MTBE prices
- Ethanol market will likely expand with an extended MTBE ban and continuation of oxygenate use in RFG
- Higher premium is possible if MTBE is phased-out suddenly resulting in an effective ethanol mandate
- Requires adjustment of summer RFG gasoline blend stocks to produce low vapor pressure gasoline
- May require more gasoline blend-stock; and may put more pressure on gasoline supply

Neat fuel (Existing, small market with largest potential size; least potential for expansion in near to mid term)

- Denatured with gasoline (e.g. Ed-85 in U.S.; Ed-95 in Europe); requires modest modifications to some vehicles, though new vehicles sold in the U.S. are increasingly fuel flexible, requires slightly increased maintenance
- Receives no premium over super premium gasoline (value based on heat content)

E-diesel

- Ethanol may also be used as a diesel oxygenate in e- diesel or oxydiesel (~10% vol ethanol; 5-10% other additives)

*5.7% and 7.7%vol are blends that correspond to the oxygen content standards for gasoline sold in ozone nonattainment and carbon monoxide nonattainment areas under the CAAA. Higher volume percentages needed for MTBE

The value of ethanol as a blending agent involves its use as a low-sulfur, low-aromatic, high-octane, oxygenate blend stock, and as a diluent.

- The value of ethanol potentially serves several functions for the refiner:
  - Ethanol serves as an oxygenate for RFG and oxygenated gasoline
  - As an octane booster, ethanol displaces the need for petroleum fractions such as benzene, toluene, and xylene (BTX) and other petroleum high octane fractions
    - With low grade gasolines, ethanol can displace other petroleum feedstocks used to enhance octane
  - Ethanol is essentially sulfur free (except for the denatured gasoline used) and serves as a low sulfur blend stock
  - Ethanol also serves as an aromatic free blend stock for volume extending
- The properties of ethanol also pose challenges to the refiner
  - The higher Reid vapor pressure (RVP) of conventional ethanol/gasoline blends restricts ethanol's use in gasoline in order to meet overall RVP fuel specifications (especially in summer months)
    - Neat ethanol has a lower RVP than gasoline
  - E10 has a RVP waver (10 percent volume ethanol blends)
  - Requires more gasoline blend-stock (different from that used in MTBE based RFG); puts more pressure on gasoline supply
  - Ethanol's water hygroscopic nature precludes distribution in existing petroleum pipeline infrastructure (including gasoline blended with ethanol)
    - Drying out the the existing pipeline system makes sense only if the volume of ethanol to be transported is sufficient
  - Blending would occur at distribution depots with additional infrastructure required
- The energy content and combustion characteristics of ethanol have implications in fuel use and associated emissions
  - Ethanol's energy density is 2/3 that of gasoline on a volume basis
  - Ethanol's higher Reid vapor pressure is associated with higher evaporative emissions
  - Ethanol's properties may result in higher NOx emissions
  - CO and hydrocarbon emissions are reduced with gasoline/ethanol blends due to ethanol's oxygen content and the dilution of aromatics present in the gasoline

There are several studies of ethanol demand and value as an additive or blending agent; sample studies are summarized below.

	Sample Ethanol Demand Projection Studies		
	Center for Transportation Analysis Oak Ridge National Laboratory	**California Energy Commission**	**California Energy Commission**
Study	Ethanol Demand in U.S.: Regional Production of Oxygenate-Limited Gasoline G. R. Hadder August 2000 (Report no. ORNL/TM- 2000/165) ORNL 6926 Ethanol Demand in U.S. Gasoline Production, November 1998	Evaluation of Biomass-to-Ethanol Fuel Potential in California" December, 1999 Data Volume VII-C Update on Ethanol Market: Current Production Capacity, Future Supply Prospects, and Cost Estimates for CA: Energy Security Analysis, Inc.	Cost and Benefits of a Biomass-to-Ethanol Production Industry in California Report No. P500-01-002 March 2001 Arthur D. Little Jack Faucett Associates
Value of Ethanol in Blending Applications	The value of ethanol is determined by optimal refinery blending. Ethanol price is based on its octane value relative to gasoline	The price at which ethanol was sold in California was estimated to be its value as a gasoline blending component plus the $0.54/gal federal tax credit plus transport costs from out-of-state. Three tiers of value were used, energy (BTU) content, octane value, oxygenate value	Study was for California ethanol demand when MTBE is phased out. The value of ethanol was taken for the scenario in which MTBE is banned in California and is based on a subsidized production cost of ethanol
Federal Excise Tax Exemption	Partial excise tax exemption of 54 cents per gallon of ethanol. In this ethanol demand study, it is assumed that the partial excise tax exemption is available for ethanol blended at 5.7, 7.7 or 10 percent	Blenders income tax credit for ethanol, cent per gallon of 53 cents in '01-'02; 52 cents in '03-'04; 51 cents in '05-'07 The tax exemption is available for ethanol blended at 5.7, 7.7 or 10 percent.	Blenders income tax credit for ethanol, cent per gallon of 53 cents in '01-'02; 52 cents in '03-'04; 51 cents in '05-'07
MTBE Price	MTBE $35.47/B; $0.844/gal (Summer conditions)	Baseline gasoline wholesale price $0.62/gal (89 octane) MTBE price of $0.85/gal	Not applicable, analysis in context of MTBE ban in California
Ethanol Value or Price	Annual ethanol demand with reduced MTBE in PADD I+III gasoline type production Yr-2006 - 3% max MTBE - 30 ppm sulfur: Ethanol value up to 1 billion gallons/y ethanol, ~¢108 to 90cent/gal ('97$)	Not including transportation costs: range for oxygenate value was ¢87.8 - 104.8 cent/gal ethanol Octane blending value in range of ¢65.9 to 80.8 cent/gal ethanol	Target Ethanol Prices ¢164 to ¢173 cent per gallon near-term; ¢123 to ¢139 cent per gallon mid-term (ProForma Systems, Inc., 1999 from CEC 1999)

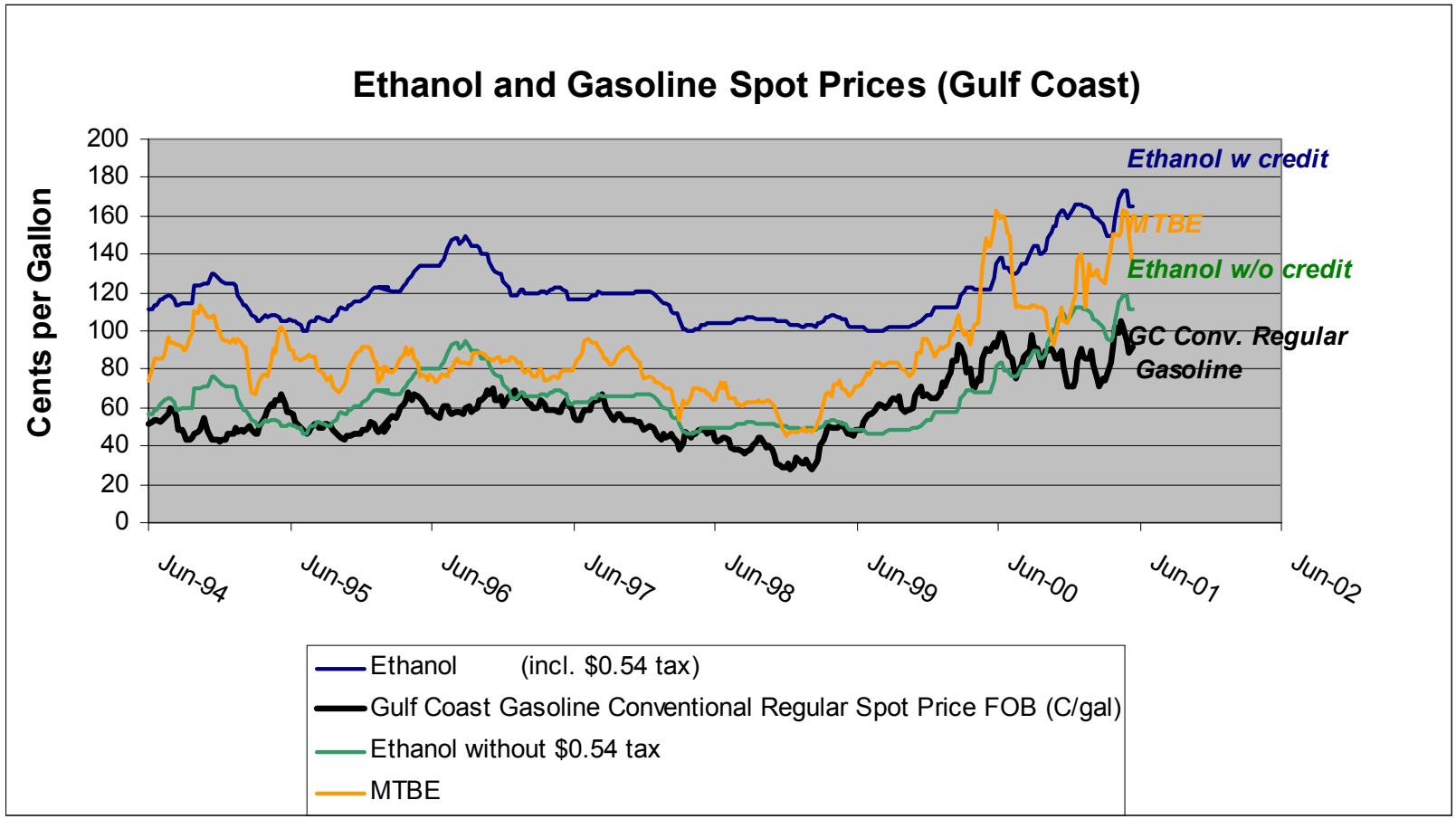
Ethanol as a blending agent commands on average, 4-tiers of value.

	Value of Ethanol Scenarios
Value Based on Energy Content*	• The value of ethanol is based solely on its energy content. Neat fuels such as Ed85, Ed95 would be valued on the same energy basis as gasoline, i.e. on a dollar per BTU or MJ basis • Ethanol has a lower energy density than gasoline (129.1 MJ/gal for gasoline versus 88.6 MJ/gal for ethanol) • Value of ethanol may be impacted (favorably) by efficiency improvements in engine designs for neat ethanol use
Value Based on Octane Value	• The value of ethanol as a volume extender and octane enhancer (for blends of typically 10% by volume ethanol) is based on its octane value (Ethanol 115, Rack gasoline stock 89) • Value is based on rack gasoline price, retail gasoline price, octane price, and price of blend stock to make blended gasoline with ethanol • Costs associated with separate infrastructure for blending ethanol fuels will also contribute to the value of ethanol (Blended gasoline with ethanol cannot use existing petroleum pipelines)
Value Based on Oxygenate Value*	• Value of oxygenate for blends that correspond to the oxygen content standards for gasoline sold in ozone nonattainment and carbon monoxide nonattainment areas under the CAAA (~5.7 and 7.7% by volume) • Value is based on MTBE (if there is a choice between the two) with corrections to account for Reid vapor pressure (RVP) differences and differences in gasoline blend stock required for each of the two additive agents • Costs associated with separate infrastructure for blending ethanol fuels will also contribute to the value of ethanol
Value Based on Partial or Total MTBE Ban	• In scenarios where a partial or total ban of MTBE is in place (and the oxygenate requirement is maintained resulting in shortages for oxygenate additives); the value of ethanol as an oxygenate will depend upon competing agents • Other ethers are likely to have the same resistance as MTBE (e.g. ETBE or TAME) • Tertiary butyl alcohol (TBA) is a candidate but is likely to have volume constraints • Ethanol could command what the market will bear in that full production costs could be recovered

* valuations considered in this study

Precise pricing of ethanol as an blending agent involves complex regional refinery linear programming methods that is beyond the scope of this study.

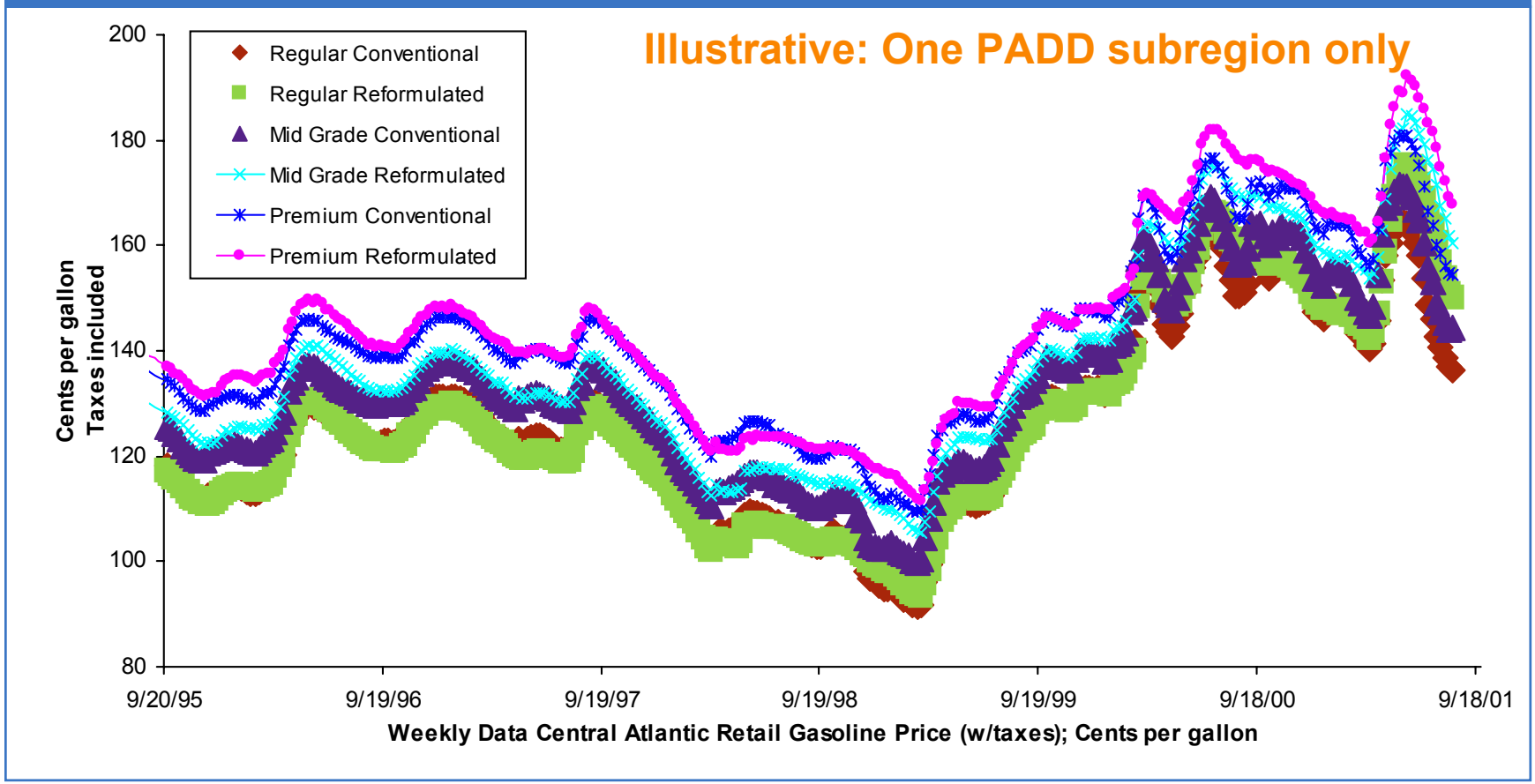
Over the last 5 years, ethanol (without the tax credit) has commanded spot price value between conventional regular gasoline and MTBE on a volume basis.



Series compiled by USEIA from data reported by Octane Week

The difference between octane grades of conventional gasoline and between reformulated versus conventional grade can serve as proxies for octane and oxygenate value, respectively.

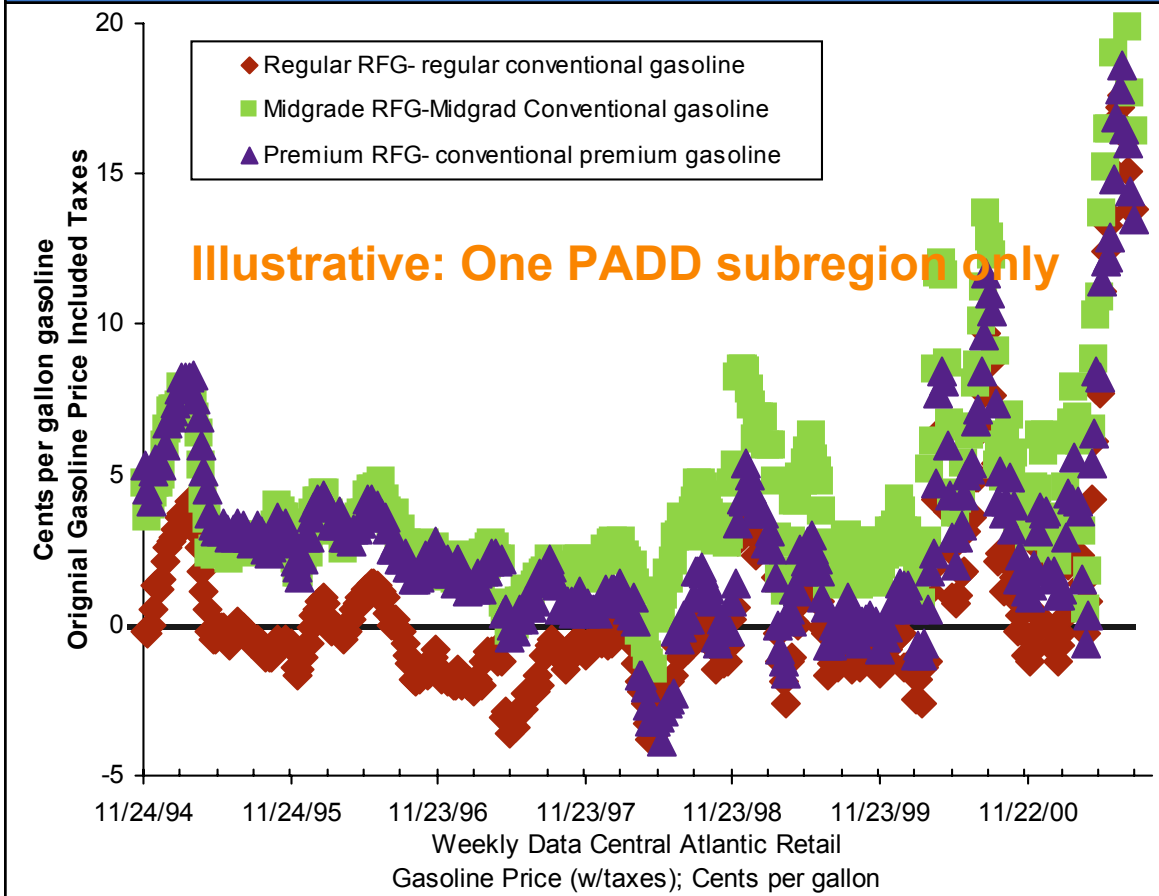
Weekly Gasoline Retail Price Data with Taxes: All Grades Central Atlantic



Source USEIA Petroleum Weekly Statistics

Although not solely attributed to oxygenate content, the difference in value of reformulated versus conventional gasoline within a grade is an indicator of value of oxygenate.

Proxy for Oxygenate Value using Weekly Central Atlantic Gasoline Retail Price Data (that included taxes)

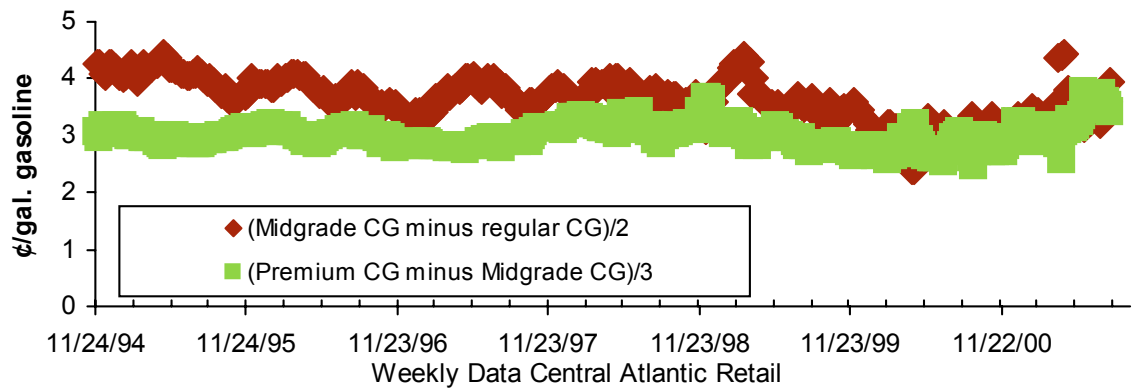


Comments

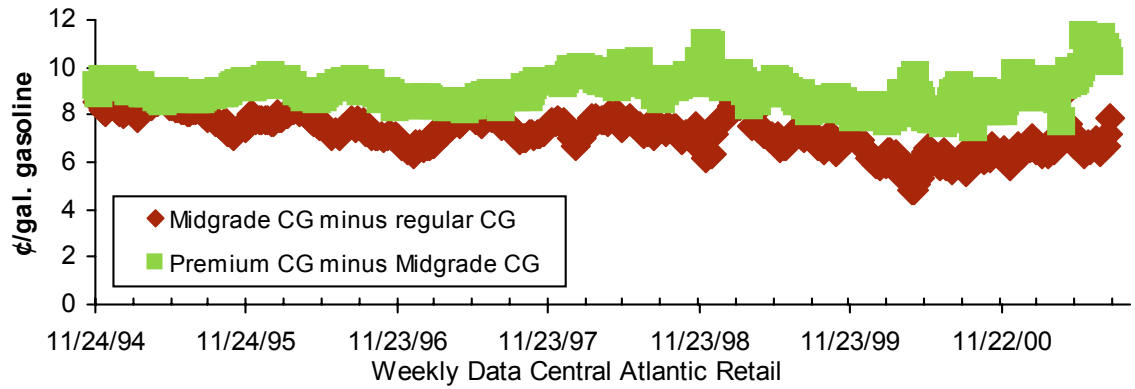
- Weekly data were obtained from USDOE EIA for Central Atlantic retail gasoline prices with taxes for all grades and formulations
- Within each grade, the price for reformulated gasoline was subtracted from the price of gasoline for conventional gasoline to obtain a proxy on the value of oxygenate in cents per gallon gasoline
- The value difference is not solely attributed to oxygenate content since gasoline formulation is also different from that used in conventional gasoline

As an illustration using Central Atlantic weekly data, the value of octane ranges from 3 to 4 cents per gallon gasoline per octane point.

Proxy for Octane Value using Weekly Central Atlantic Gasoline Retail Price Data (that included taxes)



Illustrative: One PADD subregion only

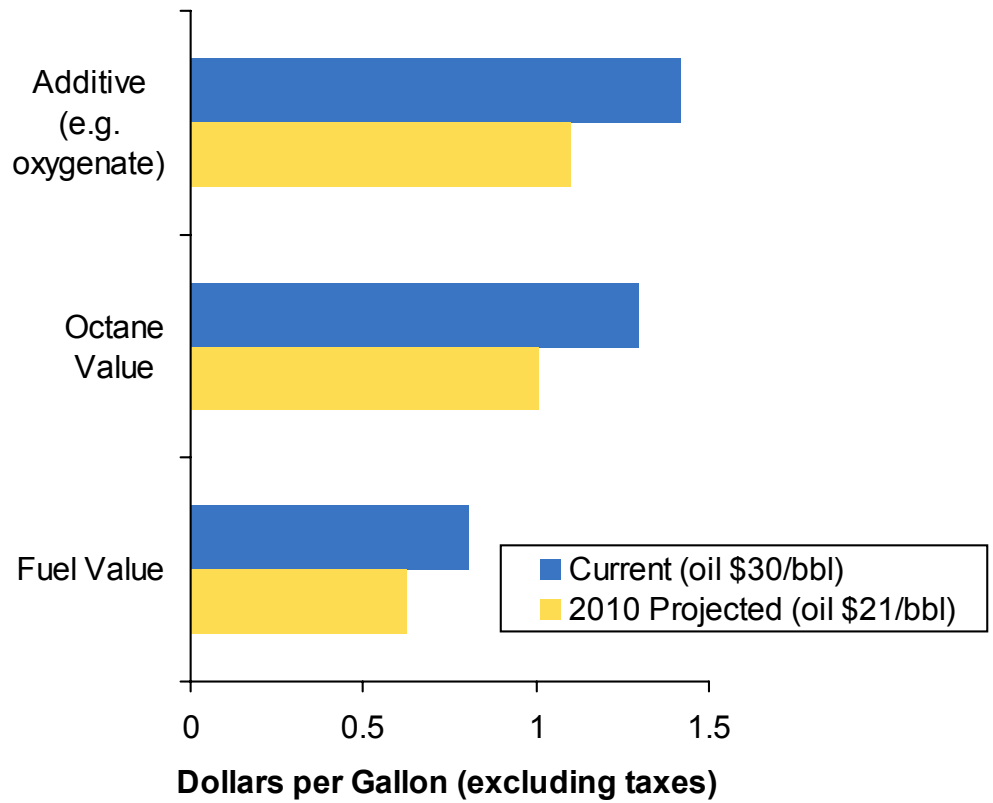


Comments

- Weekly data were obtained from USDOE EIA for Central Atlantic retail gasoline prices with taxes for all grades and formulations
- Conventional gasoline grades were analyzed assuming an average octane of 87 for regular gasoline; 89 for midgrade and 92 for premium
- The top graph is an indicator in cents per gallon gasoline of a single octane point but taking the difference between (midgrade and regular) and (premium and midgrade)
- The bottom graph is the absolute difference in price between the grades of conventional gasoline

Ethanol's valuation is complex and driven by the individual refiner's demands; however, in general, value for oxygenate use commands highest value.

Value Commanded by Ethanol



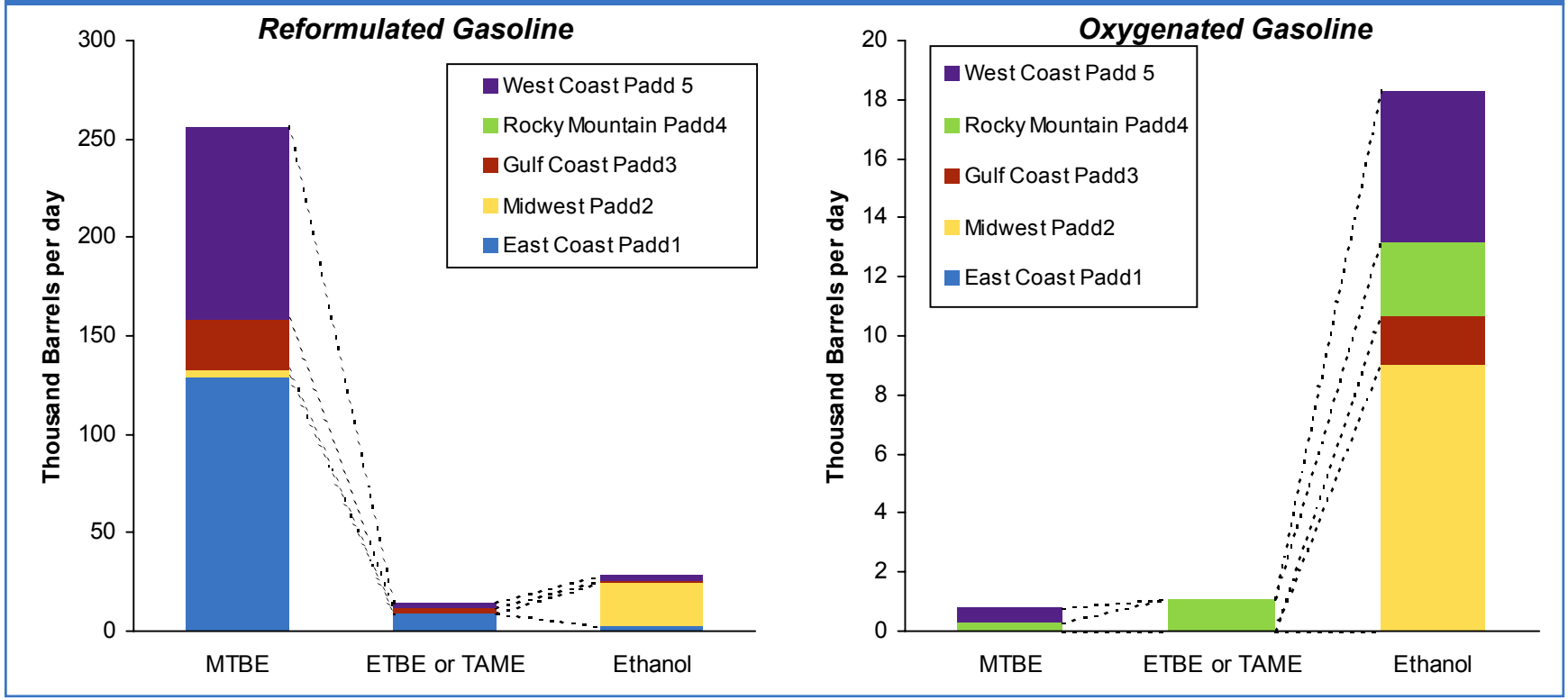
Ethanol credit is $0.54 per gallon

Comments

- The 2010 projections are based on EIA 2001 Annual outlook with a reference case oil price of $21.4/barrel
- Fuel value is based solely on energy content with no premium over super premium gasoline; assumed equivalent of average motor gas from EIA 2001 Outlook projects for 2010
- Today's gasoline price was Midgrade NE average conventional of $1.554 pre gal (with taxes of ~$0.38/gal)
- Octane value is based on the premium over regular gasoline. Used an octane value of $0.28/octane point per barrel
- Additive value commands premium over octane value; during last 5 year period MTBE commanded ~11% over its octane value
- Ethanol oxygenate value was taken as equivalent to MTBE on a gallon basis

Currently about 55 percent of total fuel ethanol goes into reformulated and oxygenated gasoline blends.

1997 Oxygenate Demand in Reformulated and Oxygenated Gasoline Control Areas: Thousand Barrels per Day

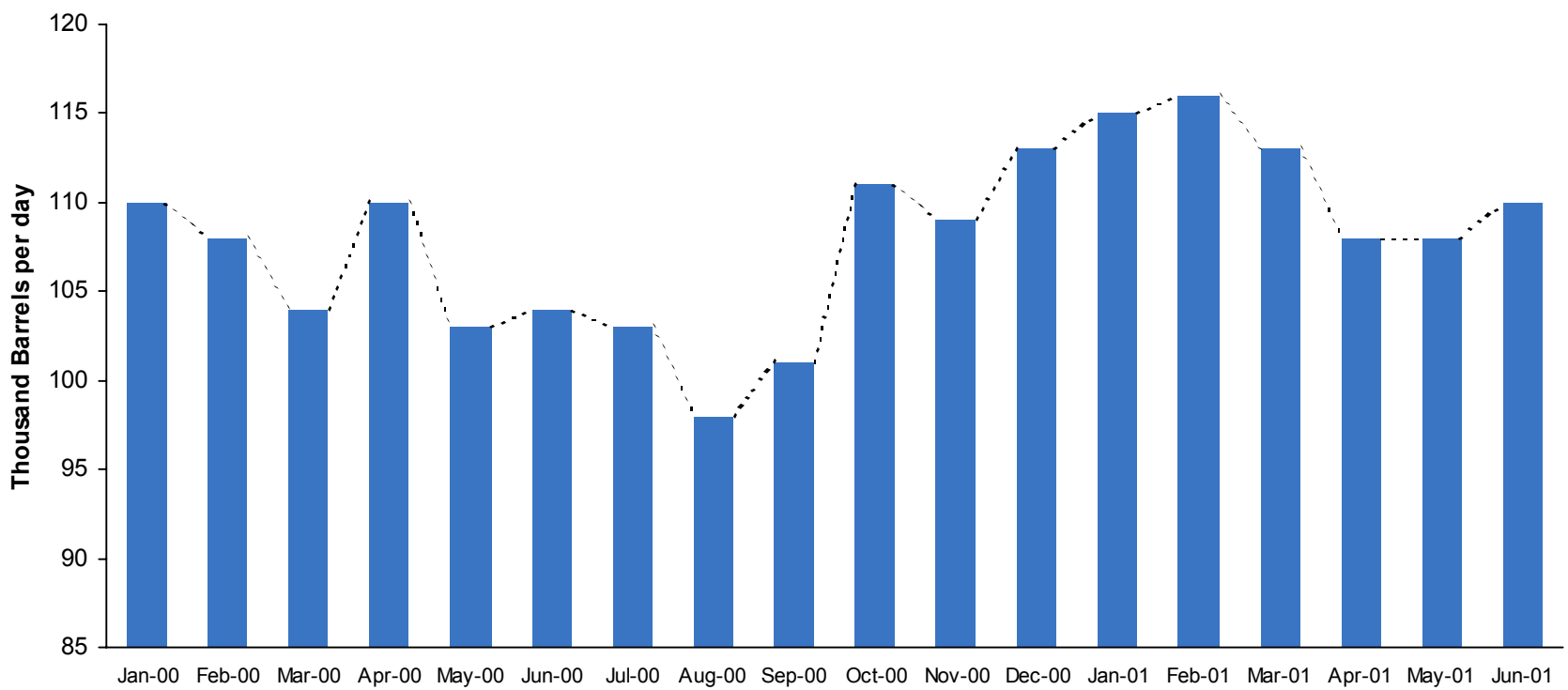


Source: USEIA, (T. Litterdale and A. Bohn), "Demand and Price Outlook for Phase 2 Reformulated Gasoline, 2000, August 1999; http://www.eia.doe.gov/emeu/steo/pub/special/rfg4.html. Demand for oxygenated-reformulated gasoline is lumped into reformulated gasoline (less than 10% of reformulated gasoline). One U.S. barrel contains 42 U.S. gallons.

The remaining 45% of fuel ethanol is blended into conventional gasoline (~37,000 barrels per day).

Over the last eighteen months, over 100 thousand barrels per day fuel ethanol is produced monthly, approximately 1.4 billion gallons per year.

Total U.S. Monthly Production of Fuel Ethanol:Thousand Barrels per Day



Source: USEIA Weekly Petroleum Status Report; Table B2; fuel ethanol has been denatured with gasoline, typically 5 volume% gasoline.

This fuel ethanol is predominately from starch based feedstocks.

Ethanol production is the most mature technology using fermentation and could replace gasoline for spark ignition engine vehicles.

- Technically, ethanol is suitable for use in spark ignition engines
  - Regulations limit mixing with gasoline up to 10% by volume (up to 20% technically feasible with modest modifications)
  - Many new vehicles already offer 100% ethanol capability, although some impact on maintenance cost may result from high concentration ethanol blends
  - Pure use (typically as Ed85: 85% ethanol denatured with 15% gasoline in U.S. and Ed95 in Europe) requires some modifications for some engines (which will also realize the benefit of higher octane)
- Limited experiments in Brazil indicate that very small concentrations may be blended with diesel up to 10 percent by volume with 5-10% additives (e-diesel)
- A range of production technologies are available
  - The most widely used technology uses relatively expensive sugar or starch feedstocks (typically sugar beet, sugar cane, corn, wheat, or sugar or starch-containing waste streams)
    - Volume of ethanol production may be tied to feedstock cost and price/market for by-products (e.g. feed, feed by-products, and oils)
  - Emerging technology is based on cellulosic feedstocks such as energy crops or crop residues
    - Use of cellulosic feedstocks has the potential to decouple markets of ethanol versus other by-product markets
    - Conventional technology uses thermochemical hydrolysis and has a potential, modest cost-advantage over sugar / corn-based process (e.g. wet or dry milling)
    - The current state-of-the-art is SSCF (simultaneous saccharification and co-fermentation), which provides more significant cost reduction possibilities
    - An emerging technology is CBP (Consolidated/integrated biochemical hydrolysis and fermentation) which could reduce the cost of production somewhat further but is still in the bench-scale research stage
- The existing gasoline infrastructure can be used with some restrictions
  - Dedicated fuel transportation will be required for ethanol to distribution and blending stations
- Ethanol has close to zero sulfur; high octane; and high oxygenate on a percentage basis
- Mixed alcohol technology offers similar benefits but the technology is not as well developed

Although ethanol is largely compatible with gasoline in pure or blended form, there are some limitations in its use.

- Ethanol's hygroscopic characteristic and its solubility in water restrict the modes of fuel transportation, distribution and storage that can be used:
  - Ethanol is hygroscopic (attracts water) and is 100% soluble in water
  - Gasoline is hydrophobic (repels water) and completely immiscible with water
  - Pipelines and some storage tanks have accumulated significant amounts of moisture
  - If ethanol cannot be transported or stored in these media it will need to be separately trucked to terminals and blended at the terminal
  - For the same reasons, there is a concern over tampering at the pump (diluting the ethanol with water)
- Ethanol has several very desirable properties as a gasoline blending agent:
  - It is an oxygenate (with a high percentage of oxygen on a weight basis) and can be used to meet RFG oxygenate requirements and for oxygenated gasoline
  - Because it has a higher oxygen content by mass percent, less of it is required compared with MTBE
  - It has very high octane and can be used as an octane booster
  - Ethanol also is used as a volume extender and diluent (low sulfur and zero aromatic blend stock)
- However, using ethanol instead of MTBE for RFG has some less desirable consequences:
  - Ethanol raises the vapor pressure of the mixture significantly, which will require balancing it by blending in less light ends and more heavies (mostly likely alkylate):
    - This could cause an imbalance in many refineries, making them short on alkylate and long on light ends
    - Ethanol can negatively impact the cold-start properties of the blended fuel
  - Because less ethanol is blended, more petroleum-based stock is required, again causing potential imbalances in refineries
  - High concentrations of ethanol may have negative consequences on gaskets, seals, etc. resulting in possible increased maintenance costs

Pyrolysis oil and Hydrothermal Upgrading (HTU) oil have similar characteristics and might be used in similar applications

Pyrolysis Oils

Diesel additive
- Blended at low levels as diesel oxygenate (~5-10% volume)
- Currently, there are no oxygenate requirements planned for diesel
- Would require no special vehicle technology
- Several complications must be dealt with:
  - ➢Would likely only be attractive if diesel oxygenate standards were implemented
  - ➢Requires stabilization of pyrolysis or HTU oil
  - ➢Would require extensive testing

Use of raw, straight, untreated pyrolysis oil or HTU oil
- Significant concerns over fuel stability may limit implementation
- Likely to require vehicle modifications

Use of treated stabilized product
- Would require extensive stabilization and upgrading
- Currently only proven option is expensive hydrotreating
- Would make product more or less fungible with conventional diesel

Pyrolysis oil diesel could replace petroleum derived diesel for compression ignition engine vehicles.

- Pyrolysis oil may be used in compression-ignition engines[1]
  - Extensive testing has occurred with stationary engines
  - Experience with vehicles is limited
- Once upgraded, pyrolysis-oil has diesel-like quality
  - The presence of oxygenates and possible solids (alkali, ash and char) and acids requires careful removal
- Pyrolysis oil production for transportation applications requires several steps:
  - Pyrolysis of biomass to raw pyrolysis oil
    - Oil is unstable and cannot be used directly for transportation applications
    - Some foreign technologies have been further developed (e.g. Ensyn)
  - Significant hydrotreating is required to achieve acceptable fuel stability and quality; zeolite-based technology may allow use of other feedstocks for stabilization and partially replace this
  - Char (and possibly gas) are utilised internally for power and heat generation
  - Although the pyrolysis process produces some hydrogen, most hydrogen for hydrotreating must be produced purposely from fossil sources (e.g. natural gas) or from biomass gasification
- Pyrolysis technology could use a variety of biomass feedstocks (such as crop residues or energy crops) but dry feedstocks are preferred
- Some synergy with chemicals production might exist for pyrolysis technology
- Pyrolysis technology is in the pilot-scale testing stage

1. S. Czernik, R. Maggi, G. Peacocke, Biomass Conference of the Americas, Oakland, CA, 1999

Hydrothermal Upgrading (HTU) technology was originally developed for coal liquefaction but is now considered for application to biomass.

- HTU involves a high-pressure, intermediate temperature steam treatment (hydrolysis) of the biomass followed by purification and possibly hydrotreating
- The HTU process was developed by Shell among others, but is currently not being pursued aggressively by Shell
- HTU fuels may be used in compression-ignition engines[1]
  - Some testing has occurred with laboratory engines
  - No experience with vehicles exists today
- Once upgraded, HTU-oil has diesel-like quality
  - The presence of oxygenates and possibly solids (alkali, ash and char) and acids requires careful removal
  - Currently the only technology available is hydrotreating and extensive filtering
- HTU technology could use a wide range of biomass feedstocks (such as crop residues or energy crops) and can easily use wet feedstock
- HTU technology is at the pilot scale testing stage (pilot plant in the Netherlands)

1. S. Czernik, R. Maggi, G. Peacocke, Biomass Conference of the Americas, Oakland, CA, 1999

Biomass gasification and further chemical processing can be used to produce a variety of liquid or gaseous fuels.

- The first step is the production of a suitable synthesis gas:
  - Gasification produces a crude synthesis gas (syngas is a mixture of carbon monoxide and hydrogen)
  - The crude syngas is then further processed/conditioned to produce a suitable syngas mixture:
    - Gas clean-up technology to remove tar, ash, carbon, metals, sulfur, halogens and possibly other contaminants from crude syngas (technology is in pilot-scale development stage)
    - Existing steam reforming and water-gas-shift technology to convert residual hydrocarbons and balance CO and H_2 for the required ratio
    - CO_2 removal if necessary
- Fuels production would utilize gasification and cleanup technology similar to that needed for gasification-based power generation, but will likely need to achieve a higher level of purity of syngas
- Liquid fuel technologies will require an additional chemical synthesis step
  - Fischer-Tropsch synthesis to produce naphtha, gasoline, or diesel
  - Synthetic gasoline (via methanol production in a zeolite-based conversion process like ExxonMobil MTG)
  - Methanol synthesis
  - One or two-step synthesis to produce Dimethyl ether (DME)
  - One or two-step synthesis to produce Dimethoxymethane (Dmillion)
  - Water gas shift to produce hydrogen
  - Methanation to produce synthetic natural gas
- All fuels will require additional product recovery, purification, and processing steps
- Feedstocks could include low-cost cellulosics such as crop residues or energy crops
- Although large-scale pilot facilities have been operated to demonstrate key new technology components, significant challenges in system integration still remain
- Integrated plant demonstrations based on biomass have not occurred at demonstration scale

Methanol from biomass could replace gasoline for spark ignition engine vehicles.

- Methanol is produced from syngas and requires at least one stage distillation purification
- Methanol can be mixed with gasoline or used as a neat fuel:
  - Both require specially designed infrastructure and vehicles (due to fuel corrosivity and hygroscopticity)
  - Some new flexible fuel vehicles already offer 100% methanol capability, although minor impact on maintenance cost may result from high concentration methanol blends
  - Pure use offers greater performance benefits from high octane
  - Methanol might be a premium fuel for fuel cell vehicles
  - Methanol fuel is sulfur-free and aromatic-free in its neat form
- Significant concern exists of the behavior of methanol in the environment:
  - Low vapor pressure compared with gasoline (requires sealed tanks)
  - Vapor is odorless and toxic (significant danger for neurological damage) will require special handling and safety procedures
  - 100% miscible with water represents a potential ground-water (and dilution tampering) problem and would require specially designed, dedicated storage and handling systems
  - Although public might make connection between methanol and MTBE, water pollution risk from methanol is significantly lower than that for MTBE:
    - Methanol is not a carcinogen, MTBE is
    - Methanol is biodegradable, MTBE is not
- Synthesis technology is mature, but production of suitable syngas from biomass is in the pilot-scale testing stage

FT-diesel with its low sulfur and aromatics and high cetane (both bio- and natural-gas-derived) can be used in three broad use categories.

FT-Diesel

Current Diesel Blending Market

- Sold as blend stock
- Possibly demands premium over regional high quality diesel grade
- Current Low-sulfur (LS) diesel market (45 Cetane)

High Grade Diesel Blending Market

- FT-diesel sold to refineries as blend stock
- LS 55 cetane diesel launched in environmentally sensitive regions
- Demand premium over current LS diesel sold at the pump

Niche bio-FT-Diesel Market–70 Cetane

- Sold at the pump as environmentally friendly fuel

Most Likely

Least Likely

Fischer-Tropsch (FT) diesel from biomass could replace diesel for compression ignition engine vehicles.

- Biomass FT-diesel requires gasification of biomass and low-temperature FT synthesis using syngas
  - Most efficient FT route produces minimal by-products (20% of product slate is naphtha)
  - Significant experience with natural gas and coal-based FT technology (Shell and SASOL)
- FT-diesel can be used to replace conventional diesel:
  - No aromatics lead to lower soot (particulate matter) and NOx
  - FT-diesel is essentially sulfur-free
  - FT-diesel has a very high cetane number (>70 compared to 35 - 45 for conventional diesel) that could lead to advantages in efficiency with minor engine adjustments
  - FT-diesel can be used to upgrade poor-quality conventional diesel
  - Requires no special infrastructure and is fully miscible with conventional diesel
- Co-products are high-quality naphtha (for steam cracker feedstock) and kerosene
- Conversion technology is mature (starting from coal-based SASOL technology), but production of suitable syngas from biomass is in the pilot-scale testing stage

Bio-FT-diesel production could be integrated with gas to liquids (GTL) conversion, but is not likely to be applicable in the United States

- Technically, there are some benefits to integrating bio-FT-diesel production with GTL:
  - The most efficient form of natural gas reforming is steam reforming; but it produces syngas with a H_2 to CO ratio that is too high (typically around three, instead of two which is desired)
  - Biomass gasification produces a syngas that typically has a H_2 to CO ratio that is too low
  - Combining syngas from the two could lead to a process that is overall, more efficient
  - The use of natural gas could enable better economy of scale for the FT conversion and product upgrading sections of the plant, thus reducing the marginal cost per barrel of the bio-FT-diesel
  - Some improved system integration could provide additional benefits
  - Product water from FT could be used for biomass irrigation for plantations that could also help with water treatment (in some cases additional fresh water could be produced by using low-temperature waste heat for desalination of sea-water)
- However, the drivers that motivate interest in GTL might not be compatible with bio-FT
  - Interest in GTL is driven by two principal interests: monetizing large stranded gas reserves and avoiding flaring of associated gas
  - Both cases are only attractive where the natural gas has no practical local use, which is generally not the case in developed nations with a natural gas infrastructure
  - In the U.S., the marginal value of gas is generally in excess of $1.00/million BTU which exceeds the level needed for economic GTL production*
- Shell has carried out pre-feasibility studies of this option for several locations

Although outside of the study scope, this option should be considered.

*Thijssen, J. H. J. S. and N. Godley (2000). Gas to Liquids Update. Sixteenth World Petroleum Congress, Calgary, Canada.

Fischer-Tropsch (FT) gasoline could partially replace gasoline for spark ignition engine vehicles.

- The high-temperature FT process required for reasonable gasoline yields is likely to be economically problematic and possibly impractical:
  - Produces a very broad range of gaseous and liquid co-products, which have to be used locally for high-value chemical applications (not power generation) to make economics reasonable
  - Broad product slate requires very large scale and tremendously costly plants (e.g. SASOL II and III plants in Secunda, South Africa)
  - Required scale cannot be supported by local biomass resources, thus necessitating hybrid approach or costly long-range biomass transport
- Gasoline product from FT process has very low octane (~ 40)
  - High concentration of normal alkanes and alkenes (inherent to the chemistry of the process)
  - Limits use to very low concentration when mixing with gasoline pool
  - Upgrading of the product will be required to increase octane level
- Most natural gas-based FT processes currently under consideration focus on producing FT-diesel rather than gasoline due to better economics
- Conversion technology is technically mature (starting from coal-based SASOL technology) but economically not viable
- As with other biomass gasification-based biofuels, the production of suitable syngas is in the pilot-scale testing stage

Dimethyl ether (DME) or Dimethoxymethane (Dmillion) from biomass could replace diesel for compression ignition engine vehicles.

- Fuel Production requires biomass gasification, liquid synthesis, and product recovery steps
  - Single-step DME synthesis (Haldor Topsoe / Amoco demonstration plant) or two-step DME technology (Lurgi)
  - Two-step Dmillion synthesis via methanol
- DME and Dmillion require slightly modified engines
- DME requires pressurised tanks (like LPG, liquefied petroleum gas)
- Dmillion can be used in a conventional LPG infrastructure
- LPG is not widespread in the United States hence a new infrastructure would be required
- Demonstration studies have used Dmillion as a blending agent with petroleum diesel fuel
- The use of DME as a blending agent is likely to be not technically feasible
- Conversion technology is in the semi-works/demonstration stage; production of suitable syngas from biomass feedstocks is in the pilot-scale testing stage

Biodiesel from rapeseed or soybean oil could replace petroleum diesel for compression ignition engine vehicles.

- Biodiesel is produced in a two-step process:
  - Vegetable oil is pressed from rapeseed or soybean (or other oil-containing crops), both of which are expensive feedstocks
  - Feedstocks such as animal fats and waste grease have also been demonstrated
  - Simple transesterification technology allows production of diesel-like fuel
  - Alcohols used for transesterification are largely recycled
  - Further processing may be required for fuel stability (unsaturate and oxygen content)
- Biodiesel can be used pure or mixed in compression ignition engines
  - Miscible with conventional diesel (blends of 10 and 20 percent have been piloted)
  - Pure use is feasible with modified engines
  - Use avoids typical diesel smell
  - Concerns about fuel stability limits mixing with existing petroleum infrastructure
  - Stabilization would require similar upgrading as for pyrolysis oil
- Large quantities of by-product (glycerol and feed by-product) are produced
  - They must be sold for high-value applications for economic viability (due to less than 50% oil yield)
  - The only high-value markets are in animal feed or other food and specialty applications, limiting market volume

Gaseous transportation fuel chains could also be considered.

- Compressed synthetic natural gas (SNG) from biomass
  - Fossil-based CNG has had some success as a fleet fuel (buses, delivery vehicles) in environmentally sensitive areas
  - Requires expansion of CNG infrastructure
  - SNG could be produced via thermochemical or biochemical routes
- Hydrogen
  - Requires completely new infrastructure and vehicle technology, possibly including fuel cell engines (e.g. demonstrations by California Fuel Cell Partnership)
  - On-board storage technology options are still in development stage:
    - Compressed gaseous storage
    - Cryogenic liquid storage
    - Metal hydride storage
- All gaseous fuels will most likely be derived via gasification of crop residues or energy crops

Over 170 fuel chains, including neat fuels and blending agents, were considered for internal combustion and fuel cell vehicles. (page 1 of 2)

Technology		Pure Fuel					Blending Agent				
		Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils & Greases	Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils& Greases
Fermentation	Corn Ethanol (or other sugar feedstocks)	X					X				
	Cellulosic Ethanol from TVA process		X	X				X	X		
	Simultaneous saccharification (SSCF) & co-fermentation;		X	X	X			X	X	X	
	Consolidated bio-processing		X	X	X			X	X	X	
	Syngas fermentation		X	X	X			X	X	X	
	Algal hydrogen production				X						
Pyrolysis & Thermal Treatment	Thermal pyrolysis oils		X	X	X			X	X	X	
	HTU oils		X	X	X			X	X	X	
C1 Chemistry	Gasification and hydrogen synthesis	X	X	X	X						
	Gasification and synthetic natural gas synthesis	X	X	X	X						
	Gasification and methanol synthesis	X	X	X	X		X	X	X	X	
	Gasification and dimethyl ether synthesis	X	X	X	X						

1. Note: "Cellulosics" is used generically to describe cellulose-rich dedicated energy feedstocks that are amenable to each biomass-conversion technologies (poplar, switchgrass, homogeneous agricultural wastes etc.).
2. TVA is Tennessee Valley Authority process

Selected

Over 170 fuel chains, including neat fuels and blending agents, were considered for internal combustion and fuel cell vehicles. (page 2 of 2)

Technology		Pure Fuel					Blending Agent				
		Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils& Greases	Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils& Greases
C1 Chemistry	Gasification and dimethoxymethane synthesis	X	X	X	X		X	X	X	X	
	Gasification and Fischer-Tropsch diesel synthesis	X	X	X	X		X	X	X	X	
	Gasification and Fischer-Tropsch Gasoline synthesis	X	X	X	X		X	X	X	X	
	Gasification and MTG synthesis	X	X	X	X		X	X	X	X	
	Gasification and Mixed Alcohol Synthesis	X	X	X	X		X	X	X	X	
Low Temperature Processing	Methyl esters(Biodiesel) from seed oils & greases				X	X				X	X

Selected

1. Note: “Cellulosics” is used generically to describe cellulose-rich dedicated energy feedstocks that are amenable to each biomass-conversion technologies (poplar, switchgrass, homogeneous agricultural wastes etc.).
2. MTG is methanol to gasoline process

No fuel chains were rejected in the market screen, as all could have a potentially large impact.

- In theory, all fuels could address mass markets:
  - Some would require vehicle modifications
  - Covers light duty vehicle (LDV) and heavy duty vehicle (HDV) markets
  - Some fuels would clearly be better suited to fleets than mass markets
- There were a total of 2.56 trillion vehicle miles driven in the U.S. in 1997.[1]
  - At an average fleet fuel economy of 18.9 miles/gallon, this is equivalent to 135 billion gallons of fuel per year
  - Cars and light trucks (the dominant users of gasoline) contribute approximately 87% of this total fuel consumption, with the balance due to heavy single-unit and combination trucks (which predominantly use diesel fuel)
  - While some fuels could only displace a specific fraction of this market (e.g., FT-diesel will be used in compression ignition engines rather than spark-ignition engines), there is no technical reason why more vehicles designed for this fuel could not be rolled out if the fuel was available
- Blended biofuels, with their lower levels of biomass-derived material could still lead to significant markets, and often present a reduced infrastructure barrier to implementation

1. All transportation-related data shown here from Davis, Stacey, Transportation Energy Data Book, Edition 19 (ORNL 6958). DOE Office of Transportation Technologies, 1998.

All biofuel options have the potential for large market impacts.

Market Screen

Do the products have markets that are large enough to contribute measurably to an aggressive increase in biomass use (more than doubling) and/or do the available feedstocks allow for significant markets?

NO

- None

YES

- All options

Rationale

- All fuels could be made to work to meet current and future customer needs though some would require vehicle modifications
- Biofuels for blending applications represent an avenue with reduced infrastructure barriers for expanded use

The following stages of product/technology development were used to describe the status of biofuel technologies.

	Research & Development			Demonstration			Market Entry	Market Penetration
	Concept	Bench	Pilot	Initial System Prototypes	Refined Prototypes	Commercial Prototypes		
Description of Typical Activities	• Concept, bench and pilot scale activities • 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	• Initial 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
Key for following slides	**R&D**			**D**			**E**	**P**

Most of the biofuel options were screened out due to the status of the technology (1 of 2).

Technology P = Technology that has achieved market **P**enetration E = Technology in the market **E**ntry phase D = **D**emonstration phase - not commercially available R&D = **R&D** phase - not yet demonstrated		Pure Fuel					Blending Agent				
		Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils & Greases	Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils& Greases
Fermentation	Corn Ethanol (or other sugar feedstocks)	E					P				
	Cellulosic Ethanol from TVA process		D	D				D	D		
	Simultaneous saccharification (SSCF) & co-fermentation;		D	R&D	R&D			D	R&D	R&D	
	Consolidated bio-processing		R&D	R&D	R&D			R&D	R&D	R&D	
	Syngas fermentation		R&D	R&D	R&D			R&D	R&D	R&D	
	Algal hydrogen production				R&D						
Pyrolysis & Thermal Treatment	Thermal pyrolysis oils		R&D	R&D	R&D			R&D	R&D	R&D	
	HTU oils		R&D	R&D	R&D			R&D	R&D	R&D	
C1 Chemistry	Gasification and hydrogen synthesis	D*	D*	R&D	R&D						
	Gasification and synthetic natural gas synthesis	D*	D*	R&D	R&D						
	Gasification and methanol synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and dimethyl ether synthesis	D*	D*	R&D	R&D						

* Components have been demonstrated with syngas obtained from natural gas or coal. Gasification of biomass has been demonstrated. Integrated demonstration of a gasification and syngas conversion process (e.g. to hydrogen or methanol or DME or FT-diesel) has not been demonstrated.

1. "Cellulosics" is used generically to describe cellulose-rich dedicated energy feedstocks that are amenable to each biomass-conversion technologies (poplar, switchgrass, homogeneous agricultural wastes etc.).
2. TVA is Tennessee Valley Authority process

Selected

Most of the biofuel options were screened out due to the status of the technology (2 of 2).

Technology		Pure Fuel					Blending Agent				
		Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils& Greases	Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils& Greases
C1 Chemistry	Gasification and dimethoxymethane synthesis	R&D	R&D	R&D	R&D		R&D	R&D	R&D	R&D	
	Gasification and Fischer-Tropsch diesel synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and Fischer-Tropsch Gasoline synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and MTG synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and Mixed Alcohol Synthesis	R&D	R&D	R&D	R&D		R&D	R&D	R&D	R&D	
Low Temperature Processing	Methyl esters(Biodiesel) from seed oils and greases				R&D	D				R&D	E

Selected

* Components have been demonstrated with syngas obtained from natural gas or coal. Gasification of biomass has been demonstrated. Integrated demonstration of a gasification and syngas conversion process (e.g. to hydrogen or SNG or methanol or DME or FT-diesel) has not been demonstrated.

1. Note: “Cellulosics” is used generically to describe cellulose-rich dedicated energy feedstocks that are amenable to each biomass-conversion technologies (poplar, switchgrass, homogeneous agricultural wastes etc.).
2. MTG is methanol to gasoline process

Options that have been proven at least at the initial demonstration stage of development were retained.

Technology	Rationale
Fermentation	• Simultaneous saccharification (SSCF) & co-fermentation of organic municipal solid wastes and other wastes has not been demonstrated at least at a semi-works scale • Ethanol production via consolidated bio-processing is still a concept to bench-scale technology, and will not be ready for commercialization by 2010 • Ethanol production via fermentation of syngas (from biomass gasification) is at an bench to pilot level of demonstration and will not be ready for commercialization by 2010 • Algal hydrogen production is still a concept to bench-scale technology, and will not be ready for commercialization by 2010
Pyrolysis & Thermal Treatment	• Fuels derived from pyrolysis oils and HTU are unstable and corrosive because of its oxygenate, olefinic, metal and ash content. Long term demonstration of the fuel stability has not yet been shown
C_1 Chemistry	• C_1 chemistry (gasification) will use the same technology components being developed for power generation although there is likely to be stricter specifications for the quality of the syngas • Components have been demonstrated with syngas obtained from natural gas or coal. Gasification of biomass has been demonstrated. Integrated demonstration of a gasification and syngas conversion process (e.g. to hydrogen or SNG or methanol or DME or FT-diesel) has not been demonstrated • Gas cleanup processes for biomass gasifiers are still being refined; in the near term, developers are expected to focus on simple feedstocks and avoid MSW and other solid wastes • Gasification and mixed alcohol synthesis has not been demonstrated at least at a semi-works scale. In addition, the long-term stability of the fuel has not yet been demonstrated • Dmillion production technology from syngas from coal or natural gas is at an earlier stage of development compared to DME or methanol
Low temperature processing	• The use of waste greases and other animal wastes have not been demonstrated at a demonstration/semi-works scale

Technologies for pure fuels and blending agents that have not reached the demonstration stage of development have been removed.

Technology Screen

Can the products be produced with technologies that could be commercially viable by 2010?

NO

YES

- All other options

Rationale

- Vehicle developers have not yet made any significant effort to develop fuel cell vehicle technology for operation on any fuel other than gasoline, hydrogen, methanol, and FT-diesel. Fuel cell vehicles (FCVs) designed for gasoline are expected to be capable of operation on ethanol as well. The California Fuel Cell Partnership plans to demonstrate hydrogen-fueled FCVs first, then optionally methanol-fueled FCVs, and finally optionally gasoline-fueled FCVs
- Of the technologies that passed through the technology screen, they have either already been fully commercialized (e.g., corn-ethanol), will soon be demonstrated (e.g., BCI's SSF ethanol facility, Masada/TVA's MSW-ethanol facility) or have already had their key technology components demonstrated (e.g., gasification, methanol synthesis, FT-diesel synthesis, etc.), and could potentially be combined into integrated plants by 2010
- Several of the screened-out technologies should be tracked and supported, since, even though they are not expected to materialize during the period of interest of this study, they could have a breakthrough impact on viability of biofuels

- Processing of MSW and other wastes by SSF process technology for pure fuels and blending agents
- Ethanol via consolidated bio-processing
- Ethanol via fermentation of syngas
- Algal hydrogen production
- HTU and Pyrolysis oil fuels
- Options involving the gasification of MSW
- Gasification and mixed alcohol synthesis for pure fuels and fuel blending agents
- Gasification and Dmillion synthesis for pure and blended fuels
- The use of waste greases and other animal wastes for biodiesel as a fuel or a fuel blending agent
- Fuel cell vehicles for any fuel other than hydrogen, methanol, ethanol, FT-diesel or gasoline

A structured screening approach was used to rank the infrastructure requirements of each of the remaining fuel chains.

Rank	Definition
1	The existing infrastructure can be used without or with minor modification
2	Some of the existing infrastructure can be used and/or the existing infrastructure will require minor modifications and new construction
3	A complete new infrastructure is required

- Each component of each fuel chain was ranked
  - Biomass production (biomass growth & harvesting)
  - Biomass transportation
  - Fuel processing
  - Fuel distribution
  - Fuel marketing
  - Vehicle end use
- Fuel chains receiving a score of “3” for all components were removed from this screen
  - Such chains require retrofits to the entire fuel infrastructure and are unlikely to contribute significantly to increased biomass utilization by 2010
- Fuel chains receiving a score of “3” for all components other than biomass production and biomass transportation were removed from further consideration
  - Since downstream operations are larger in number and more disperse, they will require the largest investment in capital and time to build up

Ethanol appears reasonably compatible, but only marketing and end use of blends appears fully compatible without modifications.

Selected		Biomass Production	Biomass Transport	Fuel Processing	Fuel Distribution	Fuel Marketing	Vehicle End Use
Ethanol[1]	SSF, blended	2	2	3	2	1	1
	SSF, neat	2	2	3	2	2	2
	Corn, blended	2	2	2	2	1	1
	Corn, neat	2	2	2	2	2	2
	TVA, blended	2	2	3	2	1	1
	TVA, neat	2	2	3	2	2	2
Methanol[1]	Starch-based feedstocks	2	2	3	3	3	3
	All other feedstocks	2	2	3	3	3	3
Hydrogen[2]	ICE vehicles	2	2	3	3	3	3
	FCV vehicles	2	2	3	3	3	3
	Non-vehicle applications	2	2	3	2	1/2	1/2
DME[1,3]	Starch-based feedstocks	2	2	3	3	3	3
	All other feedstocks	2	2	3	3	3	3

1. Values shown are for ICE-based fuel chains. Fuel chains with fuel cell vehicles would receive scores of "3" for end-use infrastructure.
2. Values shown are for gasification-based production of hydrogen only, as algal-based hydrogen production was removed from further consideration in the technology screen. 1/2 scores for non-vehicle applications reflect the fact that hydrogen could be produced to compete directly with applications for pure hydrogen as an industrial gas (1), or could compete with natural gas, either in pure or blended form as a fuel.
3. DME could use some of the existing infrastructure for LPG, which has similar handling requirements to DME.

Shaded chains have been selected for further consideration.

FT-diesel distribution, marketing and end use are largely compatible with existing infrastructure without the need for modifications.

Selected		Biomass Production	Biomass Transport	Fuel Processing	Fuel Distribution	Fuel Marketing	End Use
FT-diesel[1]	Starch-based, blended	2	2	3	1	1	1
	Starch-based, neat	2	2	3	1	1	1
	Other feedstocks, blended	2	2	3	1	1	1
	Other feedstocks, neat	2	2	3	1	1	1
FT-gasoline[2]	Starch-based, blended	2	2	3	3	3	3
	Starch-based, neat	2	2	3	3	3	3
	Other feedstocks, blended	2	2	3	3	3	3
	Other feedstocks, neat	2	2	3	3	3	3
SNG	ICE vehicles	2	2	3	3	3	2
	FCV vehicles	2	2	3	3	3	3
	Non-vehicle applications	2	2	3	1	1	1
MTG-gasoline	Neat fuel	2	2	3	3	3	3
	Blended with gasoline	2	2	3	3	3	3
Biodiesel	From, seed oils, blended	1	2	2	3	3	3
	From seed oils, neat	1	2	2	3	3	3

Selected

1. FT-diesel can be blended directly with conventional diesel, and can thereby use the same distribution and marketing infrastructure.
2. New distribution, marketing and end use technologies are needed due to FT-gasoline's low octane rating, which effectively requires wholly separated fuel supply networks.

Eight distinct classes of fuel options have been removed from further consideration in the infrastructure screen.

Infrastructure Screen

Is the product fungible with existing products and processes?

NO

- Hydrogen transportation options
- Fischer-Tropsch gasoline
- MTG-gasoline
- Methanol
- DME
- Biodiesel from seed oils
- Synthetic natural gas for fuel cell vehicles
- Synthetic natural gas for ICEs

YES

- Fermentation-derived ethanol
- Fischer-Tropsch diesel
- SNG for non-transportation uses
- Hydrogen for non-transportation uses

Rationale

- Massive investments in a hydrogen and/or SNG distribution infrastructure are required in order to achieve measurable National benefits; early configurations of the technology will likely favor natural gas and/or electricity as a raw material rather than biomass
- FT-gasoline's low octane rating will require wholly new investments in a parallel distribution infrastructure so as not to contaminate conventional gasoline. The MTG process also requires that the finished fuel be blended with alkylate to raise its octane rating to an acceptable level
- Methanol's corrosiveness and toxicity will require that the gasoline distribution infrastructure be entirely retrofit with corrosion-resistant materials. While not an insurmountable task, the petroleum industry disfavors the use of methanol which is more soluble in groundwater than MTBE
- The long-term stability of Biodiesel from seed oils has not been demonstrated. Biodiesel that has been sufficiently chemically upgraded may still be corrosive (residual oxygenates) and may require a retrofit of the existing diesel distribution infrastructure. Blends of biodiesel have been demonstrated in fleet tests.
- Ethanol can be used in the existing gasoline distribution infrastructure with minor modifications
- SNG could be used in the existing natural gas distribution infrastructure
- FT-diesel can be used in the existing diesel distribution infrastructure without modifications
- DME could be built up rapidly in countries where LPG infrastructure exists; but LPG use is rare in the United States

Ethanol and FT-diesel were retained for the economic screening analysis. (page 1 of 2)

Technology P = Technology that has achieved market **P**enetration E = Technology in the market **E**ntry phase D = **D**emonstration phase - not commercially available R&D = **R&D** phase - not yet demonstrated		Pure Fuel					Blending Agent				
		Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils	Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils
Fermentation	Corn Ethanol (or other sugar feedstocks)	E					P				
	Cellulosic Ethanol from TVA process		D	D				D	D		
	Simultaneous saccharification (SSF) & co-fermentation;		D	R&D	R&D			D	R&D	R&D	
	Consolidated bio-processing		R&D	R&D	R&D			R&D	R&D	R&D	
	Syngas fermentation		R&D	R&D	R&D			R&D	R&D	R&D	
	Algal hydrogen production				R&D						
Pyrolysis	Thermal pyrolysis oils		R&D	R&D	R&D			R&D	R&D	R&D	
C1 Chemistry	Gasification and hydrogen synthesis	D*	D*	R&D	R&D						
	Gasification and synthetic natural gas synthesis	D*	D*	R&D	R&D						
	Gasification and methanol synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and dimethyl ether synthesis	D*	D*	R&D	R&D						
	Gasification and dimethoxymethane synthesis	R&D	R&D	R&D	R&D		R&D	R&D	R&D	R&D	

* Components have been demonstrated with syngas obtained from natural gas or coal. Gasification of biomass has been demonstrated. Integrated demonstration of a gasification and syngas conversion process (e.g. to hydrogen or methanol or DME or FT-diesel) has not been demonstrated.

1. Note: "Cellulosics" is used generically to describe cellulose-rich dedicated energy feedstocks that are amenable to each biomass-conversion technologies (poplar, switchgrass, homogeneous agricultural wastes etc.).
2. TVA is Tennessee Valley Authority process

Selected

Ethanol and FT-diesel were retained for the economic screening analysis. (page 2 of 2)

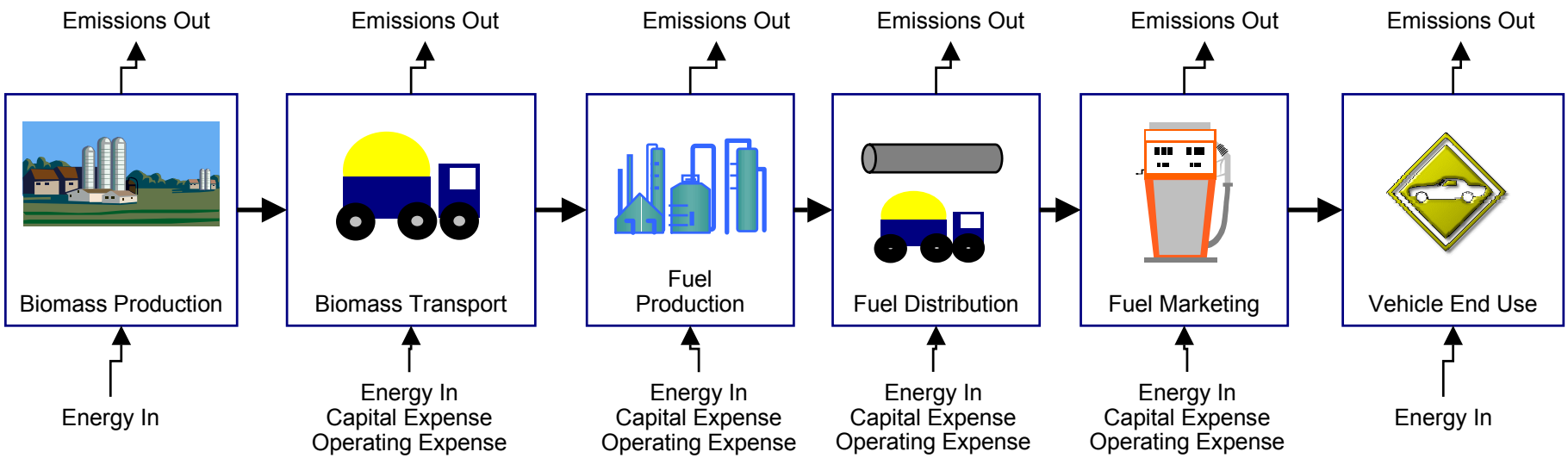
Technology		Pure Fuel					Blending Agent				
		Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils	Starch/Sugar Crops	Cellulosics	Municipal Solid Waste (MSW	Other Wastes	Seed Oils
C1 Chemistry	Gasification and Fischer-Tropsch diesel synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and Fischer-Tropsch Gasoline synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and MTG synthesis	D*	D*	R&D	R&D		D*	D*	R&D	R&D	
	Gasification and Mixed Alcohol Synthesis	R&D	R&D	R&D	R&D		R&D	R&D	R&D	R&D	
Low temperature Processing	Methyl esters(Biodiesel) from seed oils				R&D	D				R&D	E

Selected

* Components have been demonstrated with syngas obtained from natural gas or coal. Gasification of biomass has been demonstrated. Integrated demonstration of a gasification and syngas conversion process (e.g. to hydrogen or SNG or methanol or DME or FT-diesel) has not been demonstrated.

1. Note: "Cellulosics" is used generically to describe cellulose-rich dedicated energy feedstocks that are amenable to each biomass-conversion technologies (poplar, switchgrass, homogeneous agricultural wastes etc.).
2. MTG is methanol to gasoline process

The cost of fuels was estimated from biomass production to vehicle end use not including the cost of any necessary vehicle modifications.



Key Artifacts and Assumptions of the Methodology

- The costs associated with biomass production (e.g. land, labor, seed, fuel, capital recovery) are assumed to be reflected by the price ($ per dry ton farm-gate) of the biomass. Emissions associated with biomass production are included (from fertilizer, petroleum fuel use) in the benefits and impact analysis.
- Biomass transport costs are associated with a 50-mile one way by truck
- Vehicle end use includes the efficiency of the vehicle with the fuel (Costs associated with vehicle modifications are not included)
- While this approach captures many of the associated costs and emissions, it is not a full lifecycle analysis, and should not be interpreted as such.

The economic screen uses the relative cost of production as opposed to the price (or value) in the market place for a yardstick.

The economic screen compared the cost of production of biofuels to the value as a neat fuel (energy content) and value as an oxygenate for blends.

- We used existing studies where available to estimate the cost of production of the biofuels (complete references and detailed assumptions are in the data volume)
- We compared the cost of production to a likely value in the market place to see if the cost of production could be recovered (without the use of any tax credits)

	Economic Comparison Basis: Assumptions Used for Values of Ethanol	
	Pure Fuels	**Blended Fuels**
Ethanol	• 2010 projected transportation sector average price for motor gasoline $0.85 per gallon (excluding taxes and distribution costs; weighted average of all grades, all regions)	• Comparison of biomass portion (ethanol) with MTBE value range of $42.4 to $46.0 per barrel MTBE. Ethanol could command a value of $42.4 per barrel of EtOH based on its octane value. However costs associated with its higher Reid vapor pressure and blending requirements could lower value
FT-diesel	• 2010 projected transportation sector average price for diesel fuel (distillate) $0.69/gallon (excluding taxes and distribution costs; weighted average of all grades, all regions)	• Not shown

* Energy Information Administration 2001 Energy Outlook. 2010 Average transportation sector petroleum product prices in 2010 for the reference oil price scenario excluding state & federal taxes and distribution costs. The prices are in 1999 dollars. The oil price is $21.4 per barrel (1999 dollars).

The oxygenate value ethanol is keyed to that of MTBE on the basis of oxygen content.

	Economic Comparison Basis: Assumptions for Value of Ethanol	
	MTBE	**Ethanol**
R+M/2 Octane Value	109.5 (MON of 101; and RON of 118)	113 (MON of 96; and RON of 130)
Value of Octane	$0.28 per octane point per barrel	$0.28 per octane point per barrel
Premium over Octane Value	11 percent	Premise: Up to that of MTBE
Value of 89 Octane Gasoline	$0.85 per gallon	$0.85 per gallon
Weight % O in Agent	18.1 percent	34.7 percent
Specific gravity	0.7405	0.7893
Octane Value Reference Oil Price	$46.0 per barrel $1.095 per gallon	$42.4 - 47.1 per barrel $1.01 to $1.12 per gallon

1. Energy Information Administration 2001 Energy Outlook. 2010 Average transportation sector petroleum product prices in 2010 for the reference oil price scenario excluding state and federal taxes. The prices are in 1999 dollars. The oil price is $21.37 per barrel (1999 dollars).
2. The value of octane-barrel was based on the average over the period of 1998 to 2000; the premium of MTBE over gasoline was estimated over the same period.

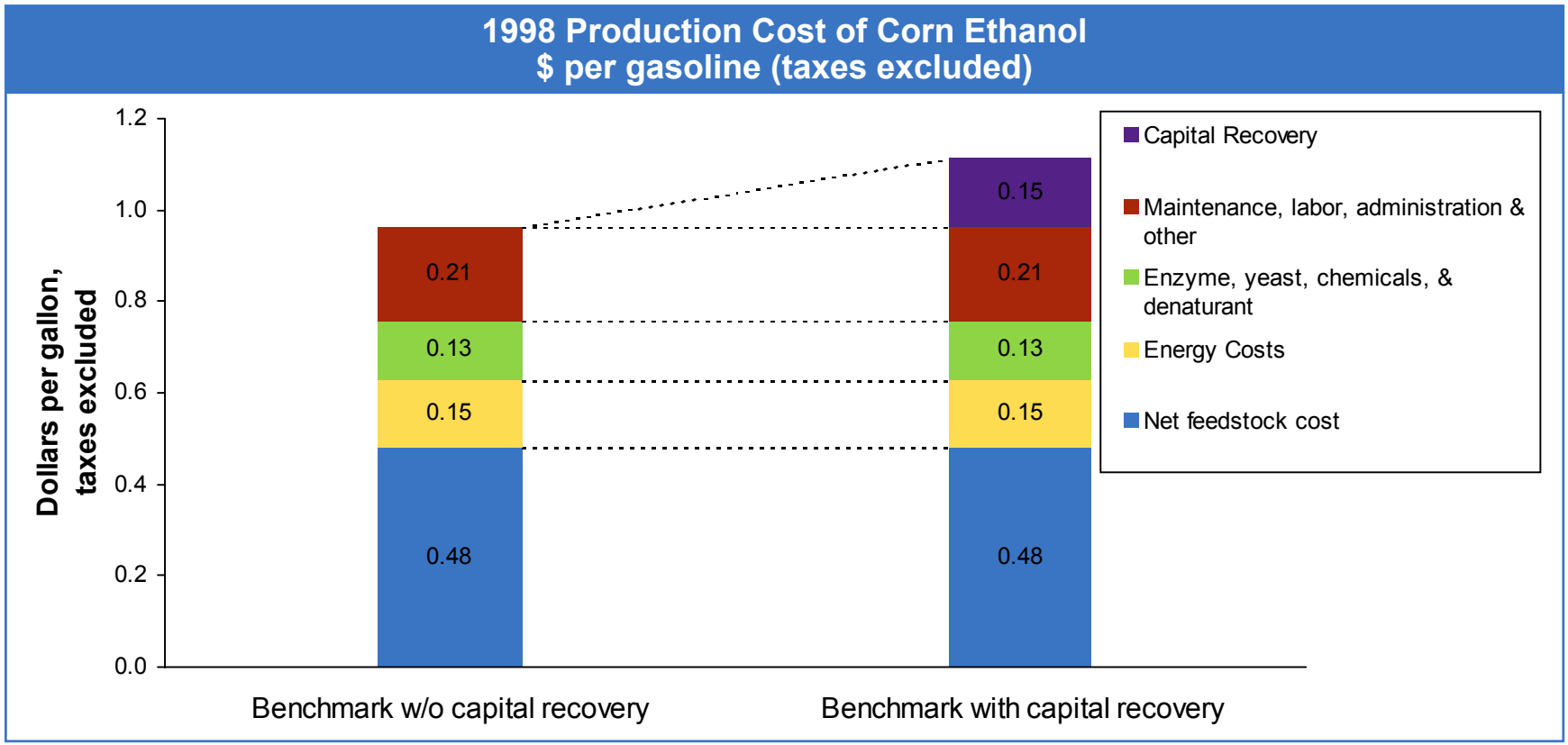
The value of MTBE was estimated based on its octane value relative to regular gasoline plus a premium.

The cellulosic fuel plants were limited in capacity by the amount of biomass that could be economically delivered to the plant.

Plant Size Used in Economic Calculations		
Corn Ethanol	100 million gallons per year	• Dry corn mill process, 2.5 to 2.7 gal. ethanol per bushel of corn processed (104 to 112 gal/dry ton)
Current SSCF ethanol technology	• Corn stover 46 million gal per year 826 thousand dry tons per year stover • Poplar 52 million gal per year 772 thousand dry tons per year poplar • Switchgrass 60 million gal per year 962 thousand dry tons per year switchgrass • Wheat straw 50 million gal per year 772 thousand dry tons per year wheat straw	• Additional biomass was used in the corn stover and switchgrass cases to account for the lignin content of the feedstock which is required for internal power production • The additional biomass required for the corn stover and switch grass cases was gasified and then fired in a gas turbine for internal power production • Ethanol yields: corn stover 57 gal per dry ton; poplar 68 gal per dry ton; switchgrass 64 gal per dry ton; wheat straw 67 gal per dry ton
Next Generation SSCF ethanol technology	• Corn stover 62 million gal per year 826 thousand dry tons per year stover • Poplar 72 million gal per year 772 thousand dry tons per year poplar • Switchgrass 75 million gal per year 962 thousand dry tons per year switchgrass • Wheat straw 66 million gal per year 772 thousand dry tons per year wheat straw	• Additional biomass was used in the corn stover and switchgrass cases to account for the lignin content of the feedstock which is required for internal power production. • The additional biomass required for the corn stover and switch grass cases was gasified and then fired in a gas turbine for internal power production • Ethanol yields: corn stover 77 gal per dry ton; poplar 93 gal per dry ton; switchgrass 81 gal per dry ton; wheat straw 88 gal per dry ton
FT Diesel	• 35-37 million gallons per year total product • 24-26 million gallons per year of diesel • 606 thousand dry tons per year biomass	• The variations in product input are a result of heating value of the feedstock. The gasifier efficiency was assumed to be the same for each feedstock

Economy of scale for fuel manufacture was not achieved due to feedstock capacity limitations.

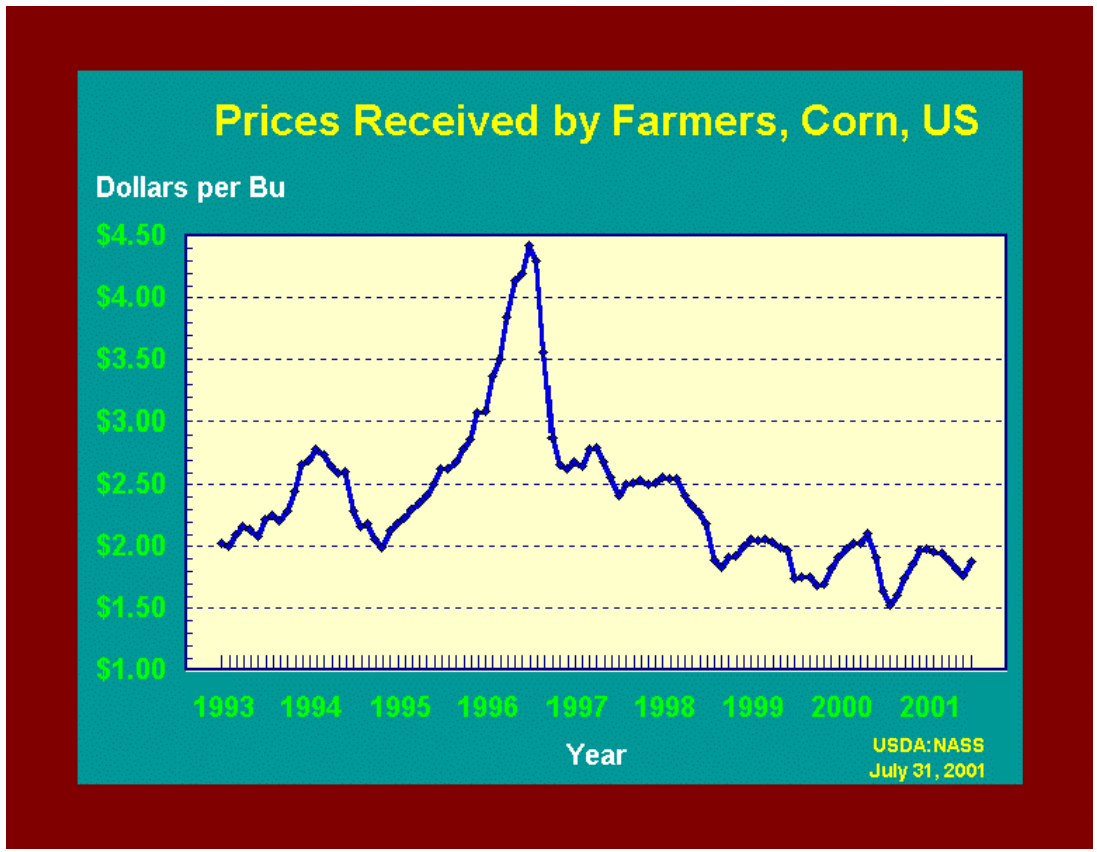
A recent USDA benchmark study estimated a ~$1.0 per gallon production cost for corn ethanol not including capital recovery costs.



1. "Overview of the First Ethanol Industry Bench Marking Survey", H. Shapouri, USDA, Office of the Chief Economist, Office of Energy Policy and New Uses; Presentation at 2000 International Fuel Ethanol Workshop & Trade Show, Windsor, Ontario, Canada, Jun 200-23, 2000. Also in "The USDA 1998 U.S. Ethanol Cost of Production Survey", H. Shapouri, P. Gallagher, and M. S. Graboski, USDA Office of Energy Policy and New Uses.
2. The survey included both wet and dry mills; 28 plants with over one billion gallons production. Plant sizes ranged from 1 million to 50 million gallons per year
3. Survey estimated that total capital investment at start up ranged from $1.07 to 2.38 per gallon; Cost of expansion ranged from $0.33 to 0.88 per gallon

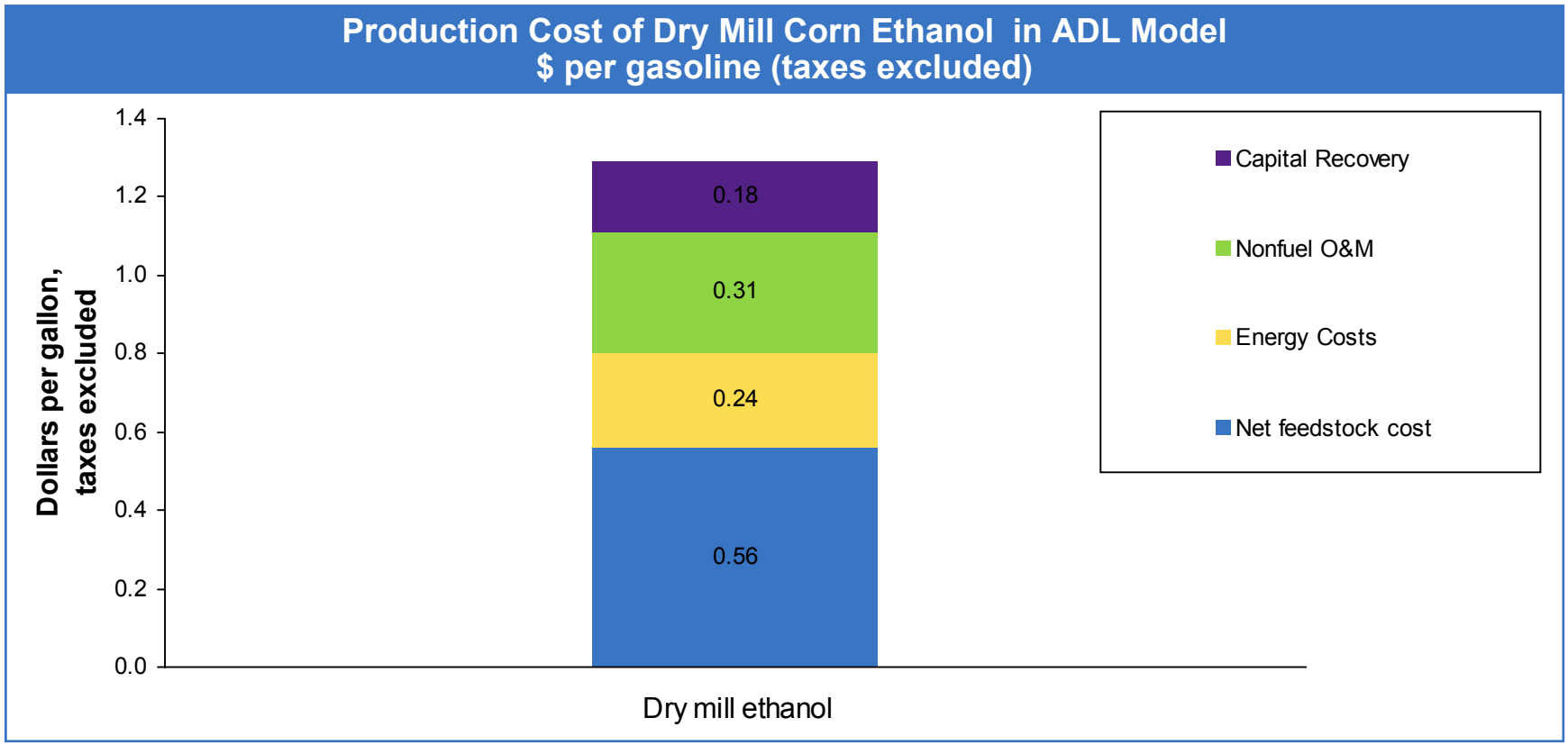
Depending on wet mill or dry mill manufacture, the degree of production cost volatility of ethanol will continue to be heavily dependent on corn price.

Prices Received by Farmers in the United States for Corn, Dollars per bushel



1. Corn price data from USDA

A dry mill production cost was used for corn ethanol cost comparisons including capital recovery costs.



1. Using a corn price of $2.9 per dry bushel and DDS price of $0.151/kg. Used a ethanol yield of 2.7 gal ethanol per bushel corn and 3.6 kg DDG per gal EtOH.
2. Did not take credit for carbon dioxide co-product.
3. Corn price is based on average of 1996-1998 regional corn prices across U.S.
4. Used a capital investment of $1.55 per gallon of ethanol

The range reflects the range of feedstocks analyzed ($30 to 50 per dry ton; $50 to 60 per dry ton for woody biomass; all farm-gate prices).

	Pure Fuel						Additive Agent					
	Starch/Sugar Crops	Corn Stover	Wheat Straw	Switchgrass	Woody Biomass	Municipal Solid Waste (MSW	Starch/Sugar Crops	Corn Stover	Wheat Straw	Switchgrass	Woody Biomass	Municipal Solid Waste (MSW
Dollar per Gallon, Gasoline Equivalent (Taxes Excluded)												
Corn Ethanol	2.1						Not Applicable					
Current SSCF Ethanol		3.1-3.6	2.7-3.1	2.6-3.0	2.8-3.0							
Next Generation SSCF Ethanol		2.0-2.4	1.8-2.2	1.8-2.2	1.9-2.1							
Fischer-Tropsch diesel		2.2-2.6	2.2-2.6	2.2-2.5	2.4-2.6							
Dollar per Gallon (Taxes Excluded)												
Corn Ethanol	1.4						1.3					
Current SSCF Ethanol		2.1-2.5	1.8-2.1	1.8-2.1	1.9-2.1			1.9-2.3	1.6-2.0	1.6-1.9	1.8-1.9	
Next Generation SSCF Ethanol		1.4-1.7	1.3-1.5	1.2-1.5	1.3-1.4			1.2-1.5	1.1-1.3	1.1-1.3	1.1-1.2	
Fischer-Tropsch diesel		2.4-2.8	2.4-2.8	2.3-2.7	2.6-2.8		Not Analyzed					

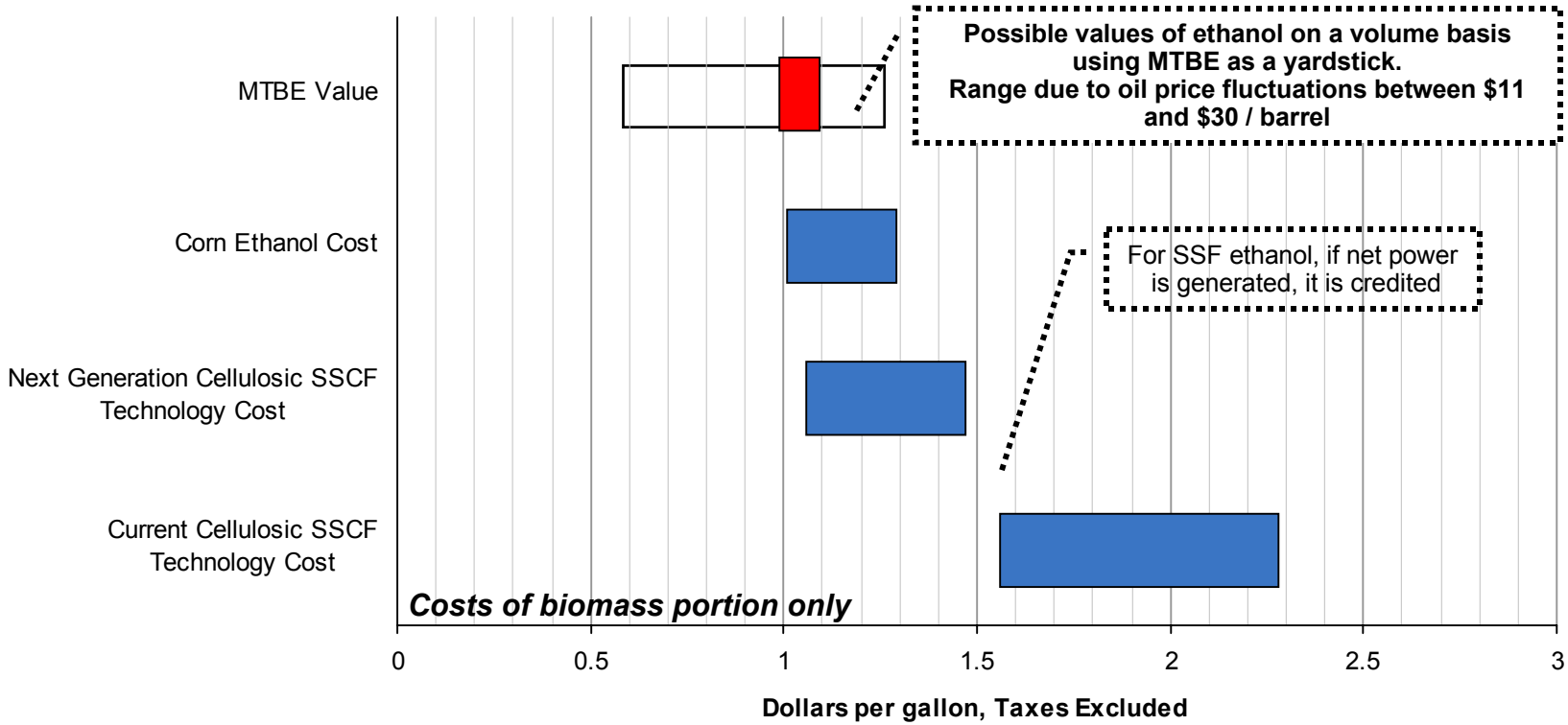
1. Using a corn price of $2.9 per dry bushel and DDS price of $0.151/kg. Used a ethanol yield of 2.7 gal ethanol per bushel corn and 3.6 kg DDG per gal EtOH.

Ethanol use as a additive is by far the most plausible biofuel option, despite the high current projected production cost of cellulosic ethanol.

Assumptions and Methodology	• Bars represent range of feedstock costs ranging from waste-type feedstocks to energy crops ($30 - 60/dry ton, farm-gate) • We used EIA price projections for regular gasoline for 2010 and estimated MTBE prices based on these prices and the current premium of MTBE over regular gasoline (octane 89) • Plant sizes varied by fuel type. feedstock delivery capacity limits plant sizes • Bioethanol is transported by truck, train, or barge (not pipeline) to blending terminals • Assumed no vehicle modifications. Assumed no engine efficiency impact of biofuels
Comments	• Opportunity for increased use of ethanol as an additive is created by MTBE ban in California and other states • Discussions on MTBE appear to have several possible outcomes currently: – MTBE is allowed to continue to be used in certain areas – MTBE is banned, oxygenate requirement is dropped – MTBE is banned, oxygenate requirement stays, allowing various options (TBA, Ethanol, ETBE, TAME) – It is likely the other ethers such as ETBE and TAME will have the same resistance as MTBE – MTBE is banned, oxygenate requirement effectively turned into ethanol requirement • The value of ethanol as an oxygenate additive is not purely comparable to MTBE on a volume basis. However, it is useful to compare cost of ethanol and price of MTBE on a volume basis. Ethanol has roughly twice the oxygen content as MTBE on a weight basis. Different blend stocks of gasoline are required in each resulting oxygenated gasoline product however, which may impact the value of ethanol
Conclusions	• With the current ethanol tax treatment provided in farm states, cost could drop to within 25% of competitive prices • If MTBE is outlawed, ethanol is one of the few short-term solutions. If near-term market prices spike, causing inflation of fuel prices, it could create a large market for bioethanol • Use of ethanol in ETBE as an oxygenate additive is likely to have similar resistance as for use of MTBE • Current starch / sugar-based ethanol provides a competitive MTBE alternative under modest to high oil price scenarios with a tax credit • Developmental SSF technology could reduce the price differential in high volume so that bioethanol could be cost-competitive with MTBE over a range of oil prices without a tax credit

The competitiveness of ethanol as a gasoline oxygenate depends heavily on the outcome of the MTBE debate.

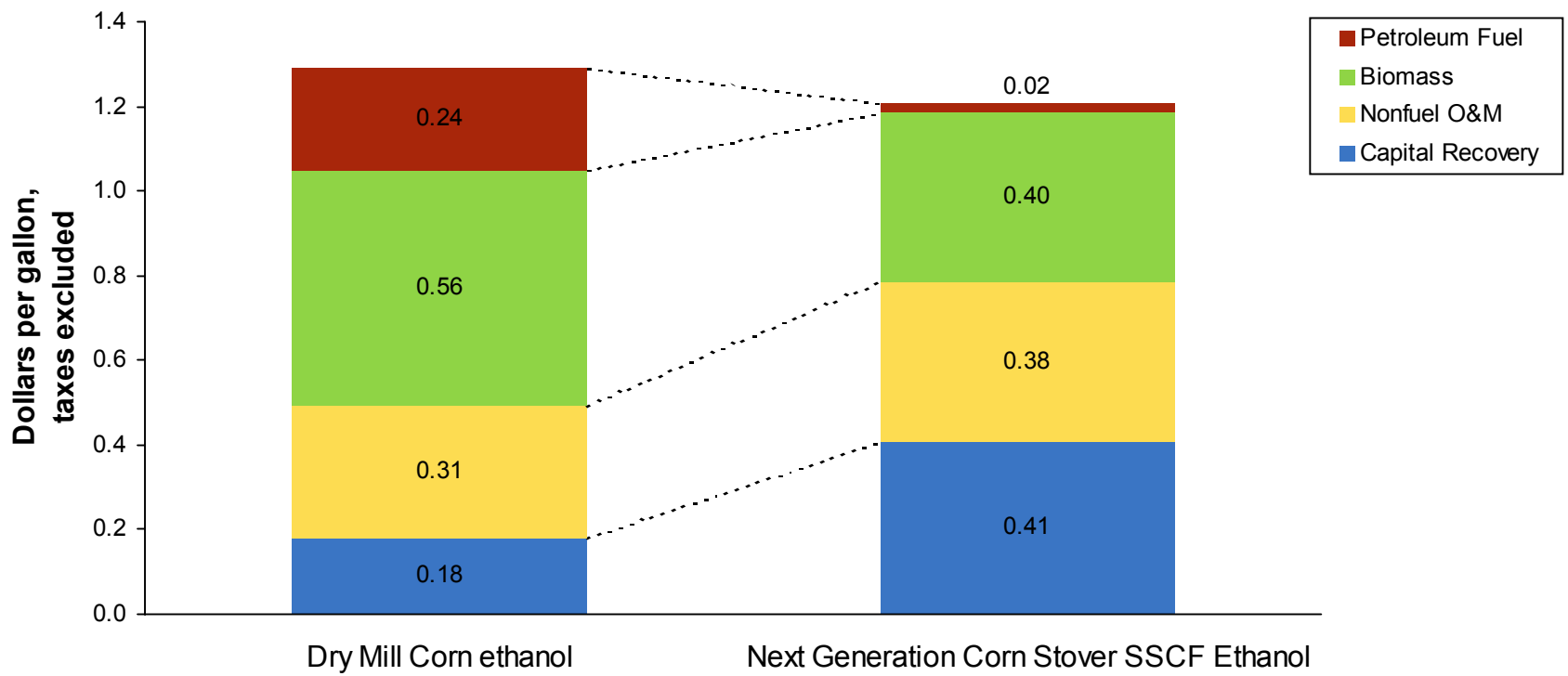
Levelized Cost of Ethanol as an Additive , $ per Gallon (Taxes excluded)



1. The bar range represents the spread of feedstock cost.
2. Corn ethanol price is based on ($1.5/bu with 2.8 gal ethanol yield per bushel corn) to ($2.9 per dry bushel corn with 2.7 gal ethanol per bushel); total chain cost.
3. The blended fuels are blended at a level of 10 percent by volume. The costs represented are for the biomass-derived fuel portion
4. The bar range of the SSCF options reflects feedstock cost of $30 to 60 per dry ton; farm-gate
5. SSCF is simultaneous saccharification and co-fermentationtechnology that utilizes cellulosics as the feedstock

... Eliminating feedstock cost completely would reduce cellulosic ethanol cost to about $0.8 per gasoline (taxes excluded).

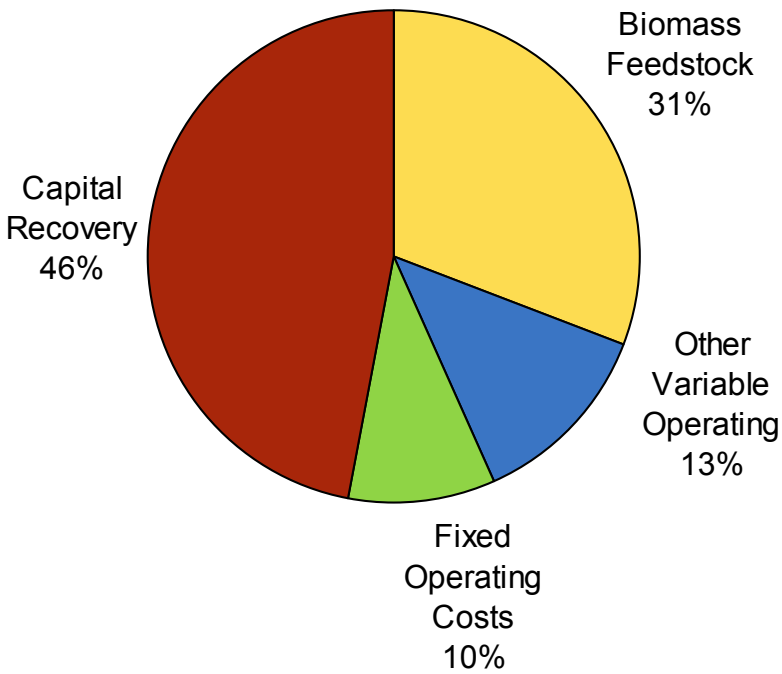
Levelized Cost of Fermentation Derived Blended Fuels, $ per gasoline (taxes excluded), Costs Apportioned by Product Slate



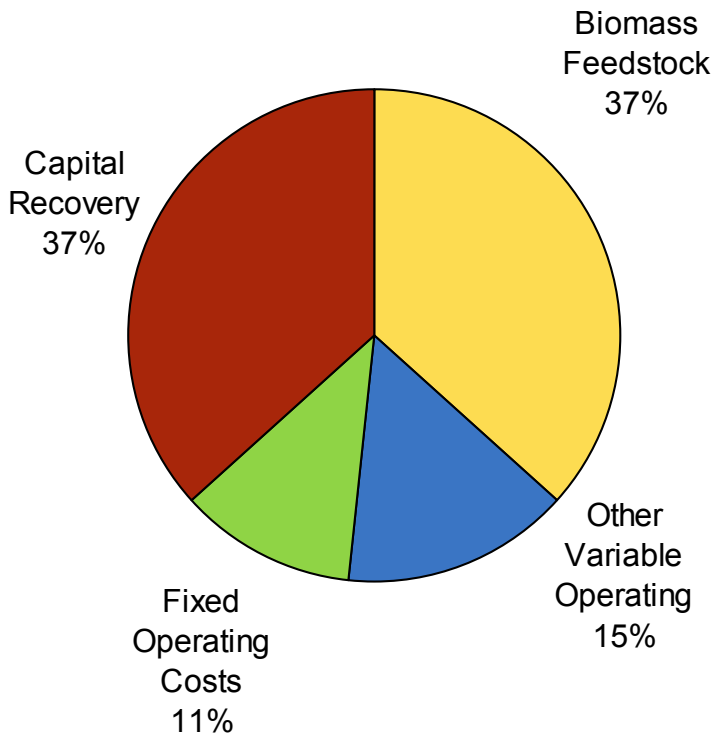
1. Biomass feedstock cost used is $30 per dry ton farm-gate. Corn ethanol price is based on $2.9 per dry bushel corn farm-gate and DDS price of $0.151/kg. Used a ethanol yield of 2.7 gal ethanol per bushel corn and 3.6 kg DDG per gal EtOH.
2. The gasoline and diesel prices are based on a $21.4 per barrel crude oil price which is the reference oil price in 2010 in the EIA 2001 Energy Outlook. The prices do not include state or federal taxes.
3. The SSCF ethanol fuel costs are proportioned by energy value. Cases using poplar and wheat straw have power export. Those fuel costs have been proportioned as follows: for SSF with wheat straw, 97.9% of the cost is attributed to ethanol for the 2010 case and 97.2% in the base case. For Poplar, 95.1% of the cost is attributed to ethanol in the 2010 case and 93.3% in the base case.

Cost reductions in SSCF ethanol technology are focussing on capital investment and on yield improvement (reduced feedstock costs).

Current SSCF Ethanol Cost: $1.44 per gal: 52 million gallon plant



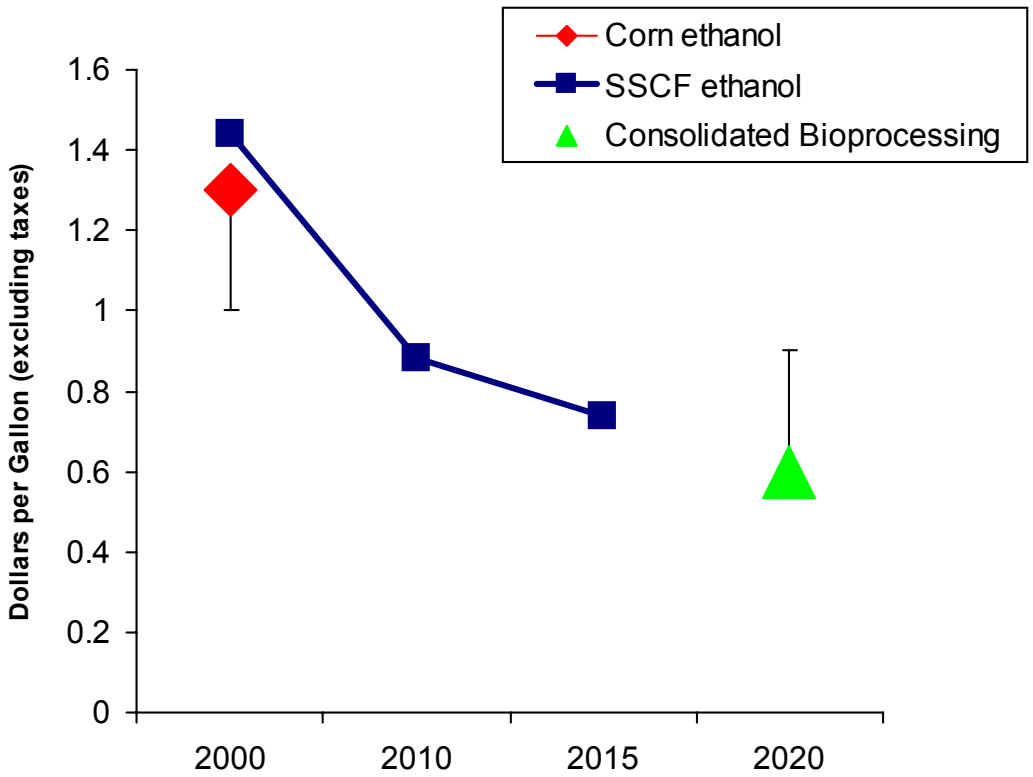
Next Generation SSCF Ethanol Cost: $0.88 per gal: 72 million gallon plant



SSCF is simultaneous sacchrefication co-fermentation using a feedstock cost of $30 per dry ton
Not including electricity credits; Taxes excluded

With advanced SSCF technology (and even with consolidated bioprocessing); projected production costs may not enable cost parity with gasoline on a energy basis (with projected oil prices of $15-21/B).

Current Production Cost Projections of Ethanol



Comments

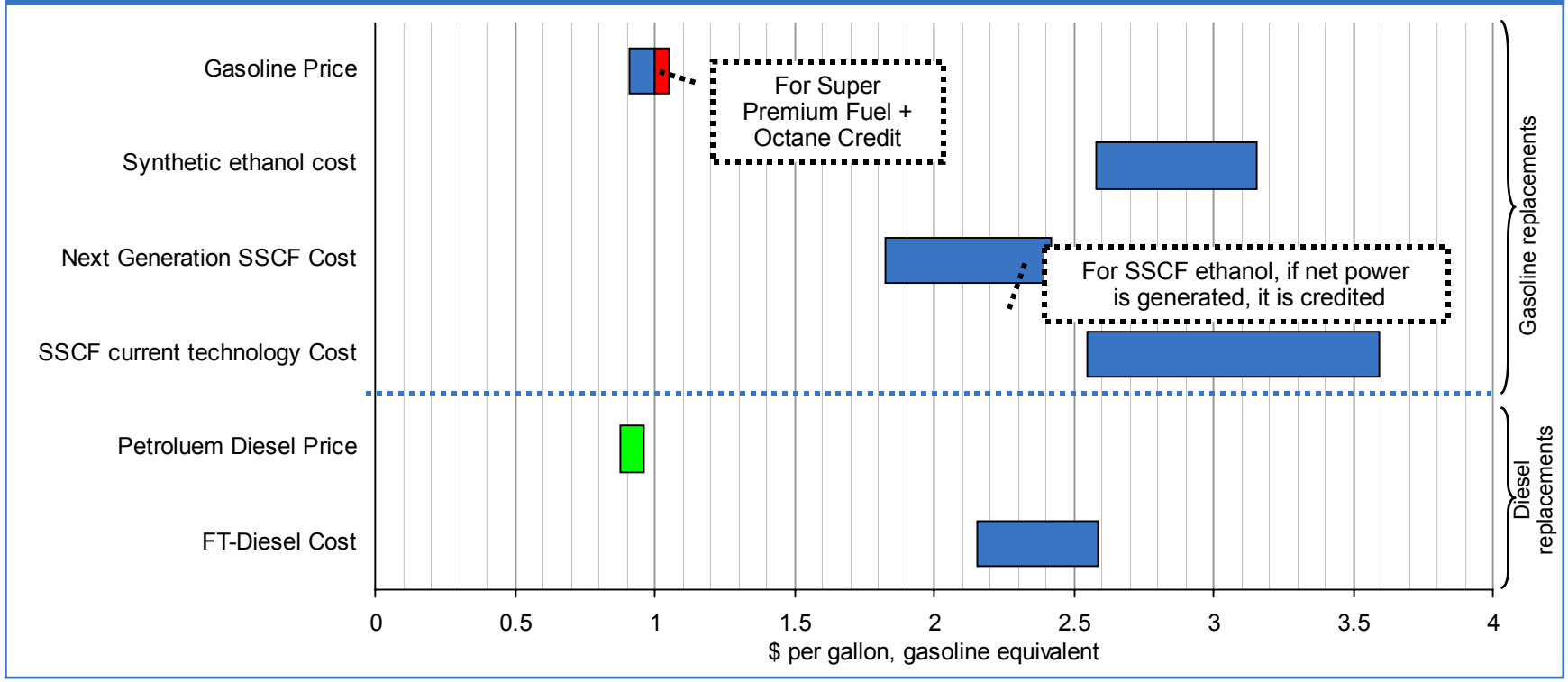
- Cost improvements for SSCF technology are focusing on capital cost reductions and yield improvement
- Additional cost reductions are in operating cost for decreased cost of enzymes for cellulose digestion
- Assumptions are that the microorganisms can be developed to digest a wider variety of sugars (e.g. 5 and 6-carbon sugars)
- Consolidated processing assumes that the cellulase enzymes, hydrolysis of biomass fiber and fermentation of sugars occurs in 1 step
- Capital costs and improved yield are projected by using a single microbial community in consolidated processing
- Limits in yield are an economic trade-off of yield versus power production costs

The use of neat ethanol (e.g. Ed-85 or Ed-95) faces significantly higher cost hurdles than its use as an additive...

Assumptions and Methodology	• Bars represent range of feedstock costs ranging from waste-type feedstocks to energy crops • We used EIA price projections for super premium gasoline and high-grade diesel for 2010 • Plant sizes varied by fuel type. Feedstock delivery capacity limits plant sizes • Bioethanol is transported by truck, train, or barge (not pipeline) to blending terminals • Assumed no-cost vehicle modifications • Assumed no net efficiency impact of biofuels
Comments	• Current use of ethanol as a neat fuel or as a volume extender, could be seriously disrupted by rapid popularization of ethanol as a gasoline additive for oxygenate and octane purposes. Such a scenario could be expected if a sudden ban on MTBE would effectively mandate the use of ethanol in the large gasoline market where oxygenates are required. The result from a national benefits point of view would be no net increase in biofuel use as it would simply transfer existing use to new use
Conclusions	• Given the current situation, there appears little benefit to using ethanol as a neat fuel instead of as a gasoline additive, except if the markets for oxygenates were to be decimated • Ethanol cost exceeds conventional competing gasoline prices by more than 100%, even for the most attractive technology-feedstock combinations • With the current ethanol tax treatment provided in farm states, the cost penalty could drop to within around 75% of competitive prices • Current ethanol use as gasohol or neat fuel in farm states may be compromised if ethanol becomes the standard oxygenate, thus limiting the net effect

... with ethanol production cost exceeding 100% of current competing product prices.

Levelized Cost of Pure Fuels, $ per Gasoline Equivalent (Taxes excluded)



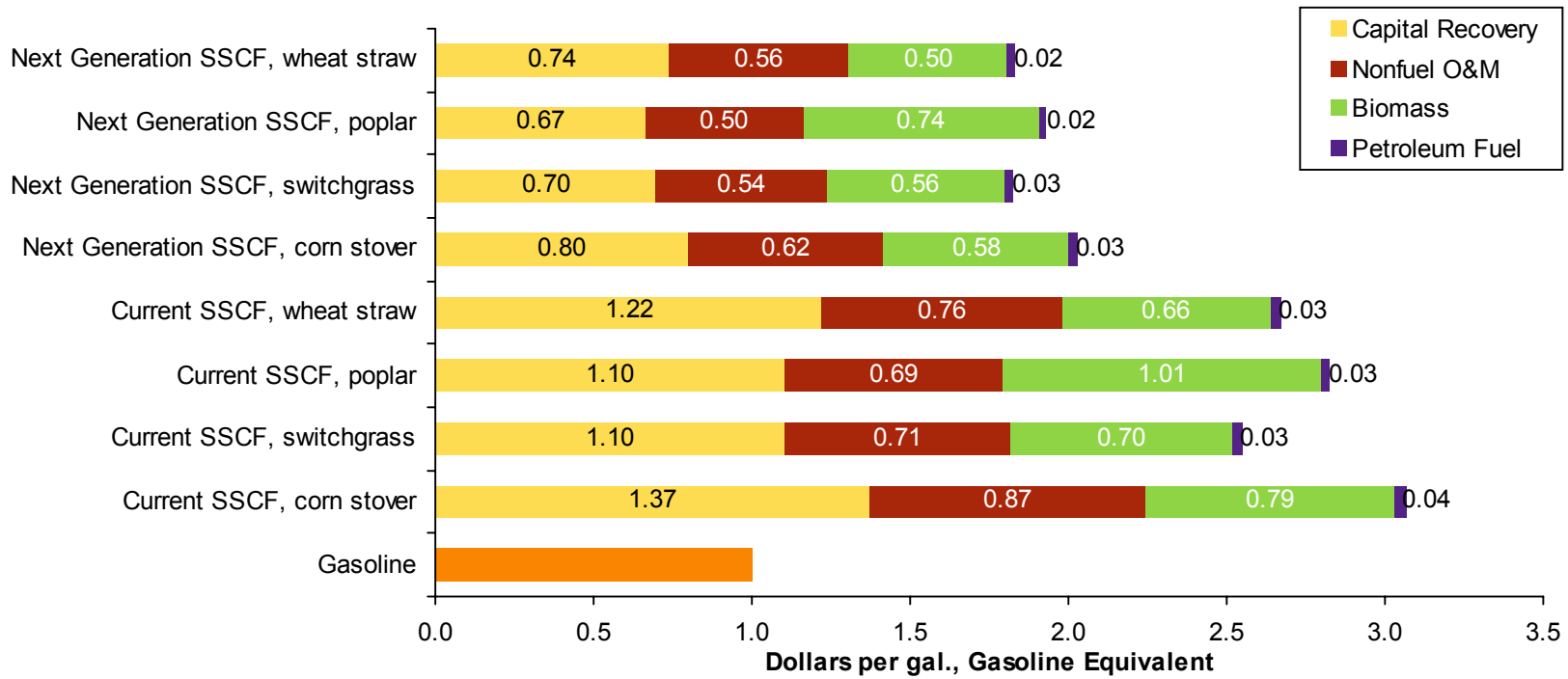
1. The bar range represents the spread of feedstock cost of $30 to 60 per dry ton, farm-gate.
2. Reformulated gasoline contains 11 percent MTBE by volume and is assumed to cost $0.04 to.08 more per gallon than gasoline for phase II RFG which includes $0.01 per gallon for the use of ethanol from EPA estimates.
3. The gasoline and diesel prices are based on a $21.4 per barrel crude oil price which is the reference oil price in 2010 in the EIA 2001 Energy Outlook. The prices do not include state or federal taxes.

While choosing the lowest-cost feedstock can have a significant impact on produced ethanol costs, feedstock cost is not the dominant cost...

Assumptions and Methodology	• The biomass feedstock cost shown is $30 per dry ton farm-gate except for poplar which is $50/dry ton farm-gate. • We used EIA price projections for super premium gasoline and high-grade diesel for 2010 • Plant sizes varied by fuel type. Feedstock delivery capacity limits plant sizes • Bioethanol is transported by truck, train, or barge (not pipeline) to blending terminals • Assumed no-cost vehicle modifications • Assumed no net efficiency impact of biofuels • Feedstock costs used are explained in the Resource Assessment section [Section 3, part 2]
Comments	• SSCF processes were chosen as examples • As shown earlier, impact of feedstock cost on corn-based process is significant (50% of cost), while impact on cellulosics-based SSF process is balanced also with capital recovery and nonfuel operating costs • As an aside, available low-cost starch-based feedstocks may be used preferentially for chemicals production in the future • In limited markets early on, some feedstocks could be used of which the use provides additional benefits (e.g. using forest trimmings); this could make such projects economically more attractive in the short run
Conclusions	• Given the current situation, there appears little benefit to using ethanol as a neat fuel instead of as a gasoline additive, except if oxygenate requirements for RFG are abandoned • Ethanol cost exceed conventional competing gasoline costs by more than 100%, even for the most attractive technology-feedstock combinations • With the current ethanol tax treatment provided in farm states, the cost premium could drop to within around 75% of competitive prices • Current ethanol use as gasohol or neat fuel in farm states may be compromised if ethanol becomes the standard oxygenate, thus limiting the net effect

... Eliminating feedstock cost completely would reduce cellulosic ethanol cost to about $1.2 to $2.3/gallon gasoline equivalent.

Levelized Cost of Fermentation Derived Pure Fuels, $ per gasoline equivalent (taxes excluded), Costs Apportioned by Product Slate



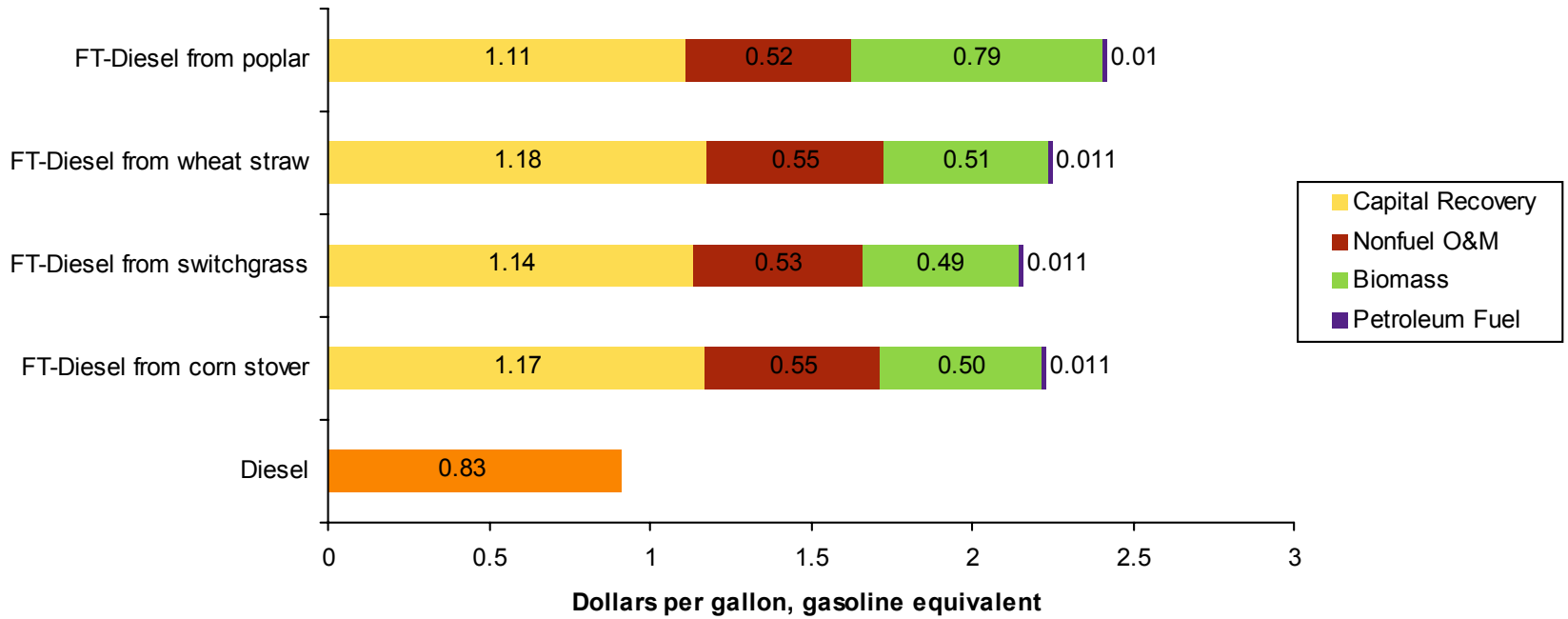
1. Biomass feedstock cost used is $30 per dry ton farm-gate except for poplar which is $50 per dry ton farm-gate.
2. The gasoline and diesel prices are based on a $21.4 per barrel crude oil price which is the reference oil price in 2010 in the EIA 2001 Energy Outlook. The prices do not include state or federal taxes.
3. The SSF ethanol fuel costs are proportioned by energy value. Cases using poplar and wheat straw have power export. Those fuel costs have been proportioned as follows: for SSF with wheat straw, 97.9% of the cost is attributed to ethanol for the 2010 case and 97.2% in the base case. For Poplar, 95.1% of the cost is attributed to ethanol in the 2010 case and 93.3% in the base case.

Bio-FT-diesel could achieve a similar cost structure as bioethanol, but because its value will be lower, it will face higher cost barriers than ethanol.

Assumptions and Methodology	• The biomass feedstock cost shown is $30 per dry ton farm-gate except for poplar which is $50/dry ton farm-gate • We used EIA price projections for super premium gasoline and high-grade diesel for 2010 • Plant sizes were assumed to be 606,000 tons per year cellulosics for all FT technologies • Assumed no-cost vehicle modifications • Assumed no net efficiency impact of biofuels • feedstock costs used are explained in the Resource assessment section [Section 3, part 2]
Comments	• FT-diesel is a high-grade diesel, with some desirable and some not so desirable properties: – Zero sulfur, zero aromatics, high cetane number – Lubricity issues and incompatibility with conventional seals and gaskets if used in high concentrations • Nevertheless, based on our analyses it will not likely receive significant product premium over conventional high-grade diesel: – Might help to meet product specs as a blend stock to meet demands petroleum-based solutions will have to be found. Once capital investments are made premiums will evaporate – GTL diesel will also compete with bio-FT-diesel and drive prices down to conventional diesel levels • feedstock costs have only a minor impact on Bio-FT-diesel cost • In the case of bio-FT production, integration with other FT-facilities (esp. overseas) or the use of idled paper mills or biopower plants could significantly reduce capital cost and thus reduce product cost
Conclusions	• Bio-FT-diesel might achieve similar cost to bioethanol, especially when produced overseas together with GTL diesel • Product market value is expected to equal that of conventional diesel • Cost premium of 140-200% over conventional diesel represents a significant barrier to implementation

Bio-FT-diesel costs are estimated to be 140-200% higher than conventional diesel prices; and $1.6 to 1.7 a gallon gasoline equivalent with zero feedstock cost.

Levelized Cost of C_1/Syngas Derived Pure Fuels, $ per gasoline equivalent (taxes excluded), Costs Apportioned by Product Slate



1. All cases shown did not produce power for export.
2. The gasoline and diesel prices are based on a $21.4 per barrel crude oil price which is the reference oil price in 2010 in the EIA 2001 Energy Outlook. The prices do not include state or federal taxes.
3. The FT-diesel is proportioned by energy value. The cost attributed to FT-diesel is 71-72% of the total cost to take into account the production of the co-product naphtha.
4. Biomass feedstock cost used is $30 per dry ton farm-gate except for poplar which is $50 per dry ton farm-gate.

From an initial list of over 100 biofuel options, ethanol is the economically most attractive option for broader application.

- Currently, all biofuels are significantly more expensive to manufacture than petroleum fuels on an energy basis
- Corn ethanol continues to be a key current and near term option for oxygenates for MTBE replacement and octane blend stock
- Ethanol offers additional value in use as an additive and blend stock, respectively
  - Ethanol offers additive qualities which can increase its value far beyond its energy value, and can be cost-competitive, especially when considering the current ethanol fuel tax credit
- Bioethanol can be used as a blend stock in the existing fuel infrastructure
- Other fuels could be considered, but they will face much higher barriers than the ones selected
  - Bio-FT-diesel appears to offer another plausible combination of cost and environmental benefits:
  - Bio-FT-diesel is considerably more expensive than ethanol. FT-diesel is projected to be at about 2.5 times the price of conventional diesel* (on a energy basis)
  - Bio-FT-diesel could help to meet new diesel specifications, but it will face tough competition from natural gas-based FT-diesel
  - Extending ethanol tax credits to Bio-FT-Diesel would reduce the price differential to 50-100%

Ethanol	• Ethanol is attractive as an alternative additive to MTBE in reformulated gasoline or as an octane booster • Ethanol comes closest to cost-competitiveness with conventional fuels and there is significant experience with its use • Current and near-term demand is likely to be fulfilled by corn ethanol; cost projections of next generation SSCF cellulosic ethanol technology may make that technology competitive in mid around 2010

Ethanol could be close to cost-competitive as an oxygenate additive, but other biofuel options carry a considerable cost premium when valued solely on energy content.

- Biofuels, either as a straight fuel replacement, as a blend stock, or even as an additive, represent very large potential markets for biobased products
- As a straight replacement of conventional fuels, the cost premium of biofuels over conventional fuels exceeds 100% and presents ***the*** most important barrier to the implementation of biofuels as a neat fuel and volume extender
- As a fuel additive, we estimate that bioethanol could be produced for a very modest cost-premium over MTBE; the current ethanol tax credit bridges that gap
- This, together with the alternative fuel tax credits available in some states and the planned phase-out of MTBE make bioethanol a plausible biofuel option for blending for oxygenate applications
- It is unclear whether ethanol is as competitive when just valued on its octane value (compared to its oxygenate value) excluding any tax credits
- The tax credit could be reduced further if aggressive R&D&D on cellulosic ethanol technology reduces costs associated with feedstock, capital, and non-fuel operating
- In niche applications, where advantage can be taken of other benefits of bioethanol production, lower-overall-cost solutions could be found now:
  - Production of bioethanol from waste-streams while recovering other valuables from these stream
  - Use of forest residues for ethanol production that must be utilized (e.g. in California)
  - Use of existing infrastructure (e.g. use of idled paper mills or biomass power plants)

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Our analysis indicated that several bioproduct options produced via fermentation, pyrolysis, and low-temperature processing, appear to offer attractive opportunities.

Based on an extensive literature survey (see bibliography in references section: Data Volume) and limited discussions with experts, we identified over eighty products that can be made from biomass. The review identified all biomass products that had been suggested or are being studied. Some of the products are produced as single products, such as many of the fermentation-based products, while others are produced in processes that inherently co-produce other chemicals (e.g. pyrolysis processes), fuels (e.g. FT-naphtha), or food products. As mentioned earlier, all pharmaceuticals, pharmaceutical ingredients, food products, and paper and timber products were removed from consideration per definition of the scope of this study.

Most of the products thus identified are fine or specialty chemicals, some with quite small potential markets. Given the focus of this study on significant environmental and economic impacts, we screened out these low-volume applications. In fact, in order for chemicals to have a significant impact, they would preferably be targeted to the polymer or commodity chemical category. Also screened out were some chemicals for which substantial excess production capacity already exists, as well as products that are still in the concept generation or bench-scale R&D stages, as these options would unlikely have a significant impact in the time horizon chosen for this study. After that, no products were actually screened out based on economic viability.

The resulting list of chemicals can be roughly categorized into four categories:

- Lipids (e.g. fatty alcohols, esters) derived from seed-oils via low-temperature chemicals processing (oil splitting/transesterification). Though lipids do not offer the largest possible market potential (compared to some polymers), the technology is available now and could eventually produce cost-competitive products based on our analysis. Particularly attractive markets serve surfactant and lubricant applications. Additional large-volume applications include feedstocks for polyurethane foam and coatings applications.
- New “biomonomers” produced from sugars or starch via fermentation-based processes. While such processes are currently still in the pilot-scale testing phase significant interest has arisen in their development and potential (e.g. Cargill-Dow LLC and DuPont). Two chemical entities currently targeted include lactic acid and 1,3-propanediol. The cost of producing these chemicals might eventually be competitive with that of their petroleum-based counterparts.
- Phenolics, and possibly some other niche chemicals, produced from wood or wood-waste via pyrolysis technology has the potential to make competitive products for applications in medium-size markets. The example of phenolics may be cost-competitive with petroleum-based phenolics for phenol-formaldehyde adhesive applications based on technology that is available currently.
- Syngas based technology (e.g., FT-naphtha) appears too capital intensive to compete with much larger-scale fossil fuel alternatives. Hence we do not see it as one of the most attractive options for chemical applications on a stand alone basis. However, if its use for fuel production (notably diesel) would drive its application, the potential impact of the naphtha co-product in chemical applications would be considerable, and would be straightforward. It is worth noting that unlike in other processes, in the case of FT the chemical products actually have a lower value than the fuel products (about a forty percent difference in value)

Despite the current use of relatively costly feedstocks, this is often not the largest cost factor - capital and non-fuel operating & maintenance (O&M) appear significant, particularly for fermentation-based products.

Several bioproducts appear to be able to approach cost and performance competitiveness with conventional products.

- Fermentation-based polymer building blocks can offer cost-competitive routes to commodity plastics provided key technology challenges are met
- Selected pyrolysis-based and low-temperature processing based products (using woody biomass and lipids) may be competitive in medium to large markets
- Bioproducts derived by C_1-chemistry do not appear to come close to being cost-competitive on a stand alone basis because of lack of economy of scale in the processing steps
- Biotechnology could lead to a broader range of products that could be produced through physical separation, low-temperature processing or fermentation
- Further development is required for large scale energy efficient reactors, that allow easy and flexible operation and integration in “bio-refineries”, especially for fermentation processes
- For commodity markets, availability of the desired feedstock at low cost and in sufficient quantities is critical

Commodity scale production technology for high-volume chemicals from biomass is in the early stages of technology development...

- Current technology for bioproducts is mainly used for pharmaceutical and specialty chemicals markets
  - Direct transfer of this typically small-scale, batch technology (although proven) to commodity scale chemical manufacture is not cost effective
  - Current niche markets using biomass derived materials can sustain high feedstock, capital, and operating costs due to the high market price of the product
- Current demonstrated bioprocessing technology utilizes convenient yet relatively expensive feedstocks (e.g. sugar feedstocks for fermentation; processed seed oils)
- Demonstration scale production of bioproducts derived from cellulosics has not yet been achieved (similar to biomass-derived fuels)
- Data on product processing schemes for commodity products using feedstocks such as cellulosics or sugars are, in general, closely held trade secrets
- As a result, much less data is available about the performance and cost of bioproduct processes than about biofuels and biopower
- The degree of process integration for some of the fermentation processes, in particular, is not widely published

… requiring that the bioproduct options analysis combine example analyses with a more generic analysis of the cost drivers for commodity chemical production.

Recent developments in biotechnology and bioengineering may enable a gradual shift from niche into high-volume markets.

Current Situation

- Biomass is currently used only in niche chemical applications (e.g. natural rubber, industrial starch, cellulose) and for production of traditional biomass-derived products such as lumber and paper
- The chemical applications are typically high-value specialty chemicals and are sometimes integrated with paper production
- Approximately 6-8 million tons per year volume for production of biomass derived products, not including paper and lumber
- Less than 5% of annual U.S. organic chemicals production

- Advanced bio-tech (e.g. genetic engineering) enables improved production of chemicals and fuels from biomass feedstocks
- Public interest in sustainability improves market conditions for biobased products
- Major chemical and agricultural companies are entering field (e.g. Cargill Dow LLC, DuPont, Genencor) and new industrial alliances are forming

Future Vision

- Biobased chemicals are competitive with major petrochemical intermediates and plastics
- Penetration in both the commodity and specialty chemical markets
- Wide range of chemicals ranging from specialties to plastics are produced from biomass
- Biobased materials may be favored by end-users (by green positioning and advanced properties)

Currently, biomass is predominantly used as a feedstock for traditional products (starch, paper, lumber, grain processing).

The following categories apply to bioproducts and are used to organize the options being screened.

Technologies	• **Fermentation:** Conversion of the feedstock to produce a product using microorganisms (or portions of microorganisms) • **Pyrolysis:** High temperature thermal conversion of the feedstock to form a product • **C_1 chemistry:** High temperature conversion of the feedstock to a mixture of permanent gases (usually syngas, CO & H_2) and then subsequent conversion of the syngas into a product • **Low Temperature Chemical Processing:** Chemical processing (usually enzyme, acid, or base-catalyzed) to break the biomass into sub-species and subsequent recovery of the product from the resulting mixture (includes oil splitting of lipids) • **Physical separation:** Separation of a component from the feedstock. Minor chemical modification to form the product
Type of Product	This is the position of the product in the value chain • **Primary Product** – Product is derived directly from biomass resource. Product can then be used as is without further modification or combined with other materials to make a derivative product (e.g. acetic acid as is or for acetic anhydride manufacture) • **Derivative Product** – Product uses a bioderived material to make the final product (e.g. polyethylene from ethylene which in turn is derived from ethanol). The derivative product may contain petroleum derived feedstocks in addition such as in polytrimethylene terephthalate (PTT) polymers
End-Use	This is the end-market for the product or derivative, for example: • Human/Animal Food by-products and Nutraceuticals • Commodity Chemicals • Polymers and Fibers • Specialties

A range of production technologies have been proposed and are under development.

Physical Separation	When feasible, there may be a component that can be derived from feedstock by simple physical processes (e.g. extraction). Provisions must be made for utilizing the rest of the unused resource. Use of residuals for power generation may be limited by the local market demand for power. The scale may be limited by the market demand for the product or the ability to use or to dispose of the residual materials.
Fermentation	Currently, fermentation based products are limited to a few products that are biochemically feasible to produce using simple sugar-based feedstocks and known metabolic pathways. The more traditional microbial fermentation processes using “designer” feedstocks could lead to success for a much wider spectrum of potential products. The scale may be limited by the market demand for the product or the scale at which the microorganisms can sustain sufficient yield and productivity.
Low Temperature Processing	Low temperature processing employs an agent to break down the feedstock into its constituent parts (e.g. cellulose, hemicellulose, and lignin) which are then further processed. Market demand for the product (or co-products) may limit the scale of production. If high-volume markets are addressed, the scale at which biomass gathering and processing is feasible may limit the volume that can be manufactured in a single plant. Provisions for utilizing all product fractions must be made for cost effective production. Low temperature processing includes oil splitting of lipids.
Pyrolysis	Pyrolysis technology produces a complex liquid/gas/solid mixture from which products are recovered. The flexibility towards feedstock type is medium to high. Pyrolysis technology may make products for medium-size markets which may limit the scale of the plant. If market volumes are sufficient, the scale at which biomass gathering and processing is feasible, may limit the product volume that can be manufactured in a single plant.
C_1 Chemistry	C_1 chemistry via gasification and reforming completely break down the biomass. The resulting “syngas” mixture is then used to build custom products. Thus flexibility towards feedstock type is high. The scale at which biomass gathering and processing is feasible limits the product volume levels that can be manufactured in a single plant. Advances made in gasification technology for power generation can be adapted although there will likely be more stringent specifications for the syngas produced.

Trade-offs between the different types of process technologies are based on their inherent processing characteristics.

Physical Separation	Fermentation	Low Temperature Processing	Pyrolysis	C_1 Chemistry

Increasingly takes advantage of biomass' inherent chemical structure. This typically helps the economics of the plant provided all fractions of the biomass (and co-products) have an end disposition

Increasing flexibility in product slate that can be produced. Therefore, increasingly likely to be able to cover large potential markets

Increasing impact of genetic engineering developments on process performance and product features

Increasing importance of system thermal integration for process performance and cost

Current bioproducts currently used are derived from starch and lipids. Future growth may be through the use of cellulosics.

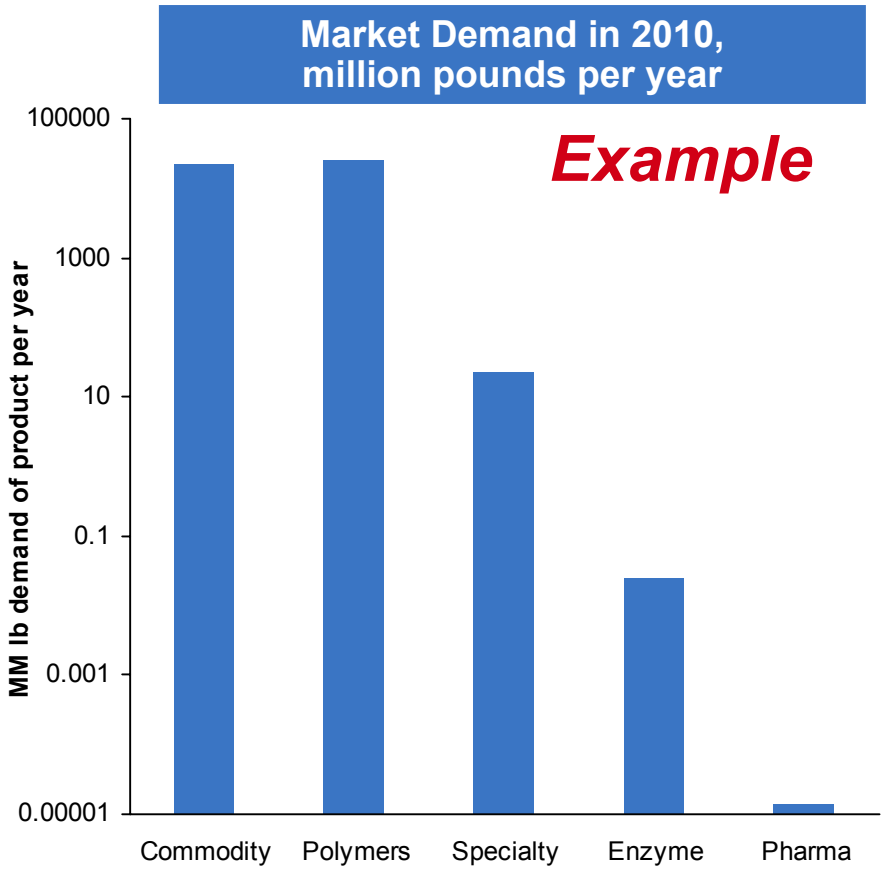
Starch & Sugars	Most current activity, especially for fermentation based processes, uses simple carbohydrates such as glucose as feedstock to make specialty chemicals and new polymer building blocks. The feedstocks are derived from food processing waste streams and pre-processed starches and are generally high in cost. For future high growth scenarios, research and development will be required to utilize more complex (and cheaper) feedstocks such as cellulose and hemicelluloses from cellulosic biomass
Lipids	Lipids are oils derived from plant and animal fats. Products have been used that incorporate the lipid as is but are limited in application. Typically the lipids are further processed by oil splitting and transesterification to produce glycerol, fatty acids,esters and alcohols. The ultimate market volume for lipid derived products may be limited by the supply of seed oils so that large scale application in some segments of the lubricant and surfactant market may be resource limited
Cellulosics	Cellulosics represent the feedstock with the largest potential volume for use for power generation, fuels production and chemicals production. For chemicals production, a key hurdle is using all constituents of the biomass (e.g. cellulose, hemicellulose, and lignin fractions). Research using the tools of biotechnology may enable broader use of the more recalcitrant fractions of the biomass (hemicellulose and lignin) for markets other than for power generation.

Historically, biomass is used in starch based products, paper (outside scope), and lipid based products which cover a wide range of markets.

Functionalized Monomers for Polymers	Functionalized monomers for high volume polymer applications include lactic acid, 1,3-propanediol, and succinic acid using fermentation technology. Lipids based on plant oils and animal fats can be used (with chemical modification) to produce polyols for urethanes for rigid and flexible foam applications. Urethanes for CASE (coatings, adhesives, sealants, and elastomers) applications are also being developed
Solvents/ Cleaning Agents	Fermentation based solvents such as lactate esters and lipid based solvents such as methyl esters are being piloted and demonstrated as halogen free, biodegradable, low-toxic alternatives to conventionally used solvents. Wood and citrus terpenes also find use as cleaning agents and solvents
Lubricants & Surfactants	Lipid based products (fatty acids and their derivatives) are being piloted and demonstrated for this application. There has been activity combining genetic engineering and processing to produce seed oils for application in the markets of hydraulic fluids, engine oils, penetrating oils, & cutting fluids. Genetic engineering is being used to “design” the carbon number product spectrum of the vegetable base oil
Inks/Paints	Soy based inks have already found application in this area.
Specialty Chemicals	Work is continuing to develop low cost routes to produce antifreeze replacements for petroleum derived ethylene glycol. Propylene glycol could be produced by a number of routes using fermentation and subsequent conventional chemical conversion technologies. Routes which produce ethylene (for ethylene glycol among other derivatives) and propylene glycol from thermochemical conversion of C_6 and C_5 sugars
Composite Applications	Biomass materials such as plant fibers have historically found use as fillers and fiber material for material such as concrete-based products. Work is continuing on finding new applications as fillers and/or fibers for thermoset applications particularly for automotive applications and less demanding commodity applications.

To achieve significant impact in biobased products, either commodities or polymers must be addressed.

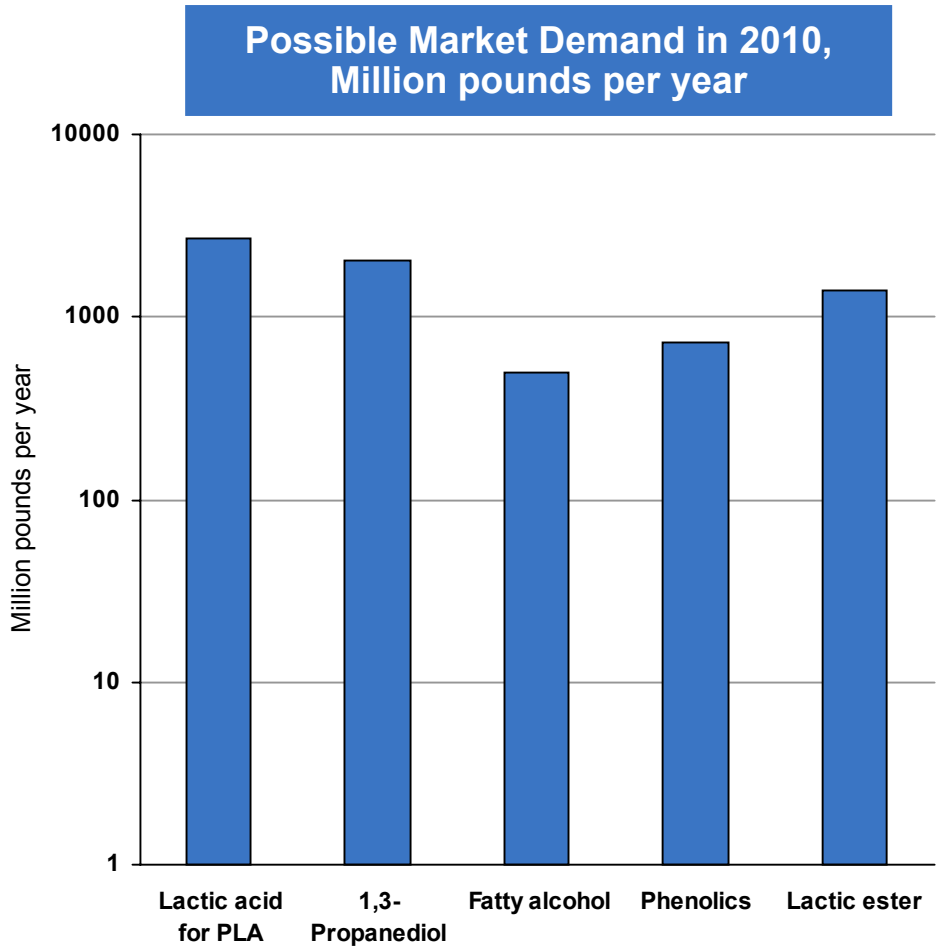
- High volume polymers or substitutes into this segment represent the greatest volume opportunity for bioproducts
- Routes which make key monomers (e.g. ethylene or propylene) are also large volume targets
- Specialty chemicals represent at least two order of magnitude less volume
- Niche markets such as enzymes or pharmaceutical ingredients are at least an order of magnitude below specialties



Note: polymers include HDPE, PP, PET, and polystyrene.
Commodities include ethylene and propylene (double counting since ethylene and propylene are used to make HDPE and PP)
Specialty is a 10,000 MT/y organic acid
Enzyme market is approximately 10MT/y
Pharma market is an antibody, 1 kg/y

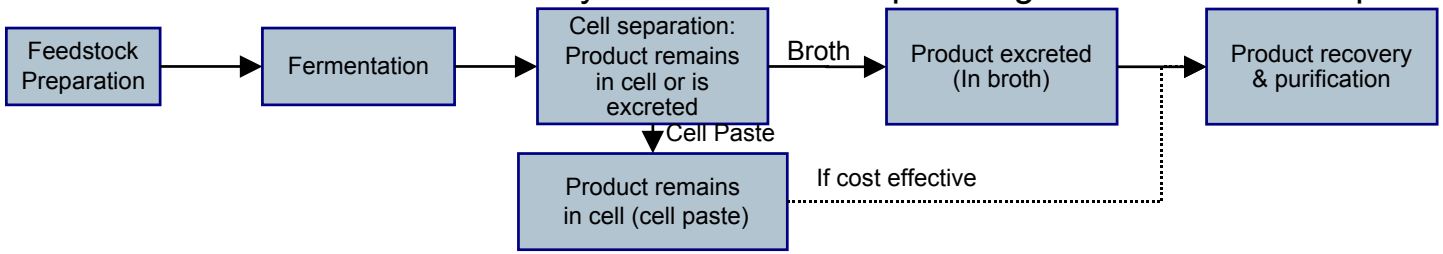
Polymers (and their monomers) may represent the largest volume opportunity for biomass use.

- Polylactic acid (PLA) demand was estimated with the total polystyrene market and 15% of the HDPE market
- 1,3-Propanediol for PTT polymer demand was estimated with the caprolactam market demand
- Fatty alcohol demand is also predicated on the demand for glycerol (co-product) and is a slow growing market
- Phenolics demand was taken as the demand of phenol for phenol-formaldehyde resins
- Lactic ester demand was taken as the sum of demand for (acetone, THF, 2-ethyl hexanol, DMSO, and acetate solvents)

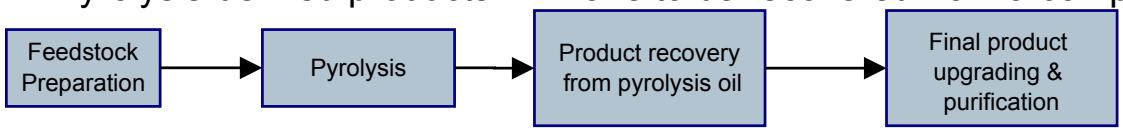


Due to stringent product requirements, the technology for bioproducts is generally more complex compared to that required for fuels production.

- Fermentation-derived commodity chemicals will require large-scale continuous process technology:

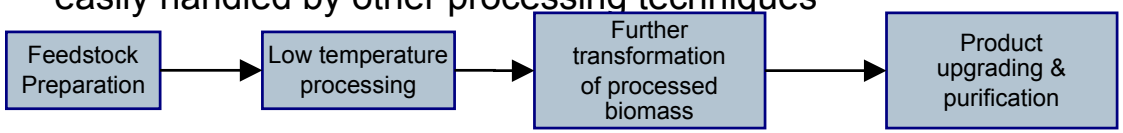


- Pyrolysis-derived products will have to be recovered from a complex gas/solid/liquid mixture

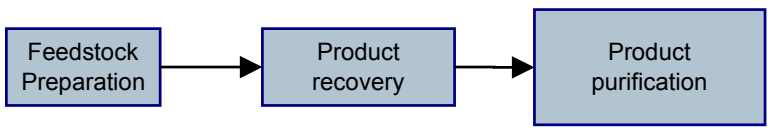


- C_1-chemistry can be used to tailor products using syngas produced from gasification of the biomass

- Low-temperature processing can be used to convert the biomass into a form which is then more easily handled by other processing techniques



- Extraction processing may be used when a chemical entity can be separated without significant further chemical processing of the biomass



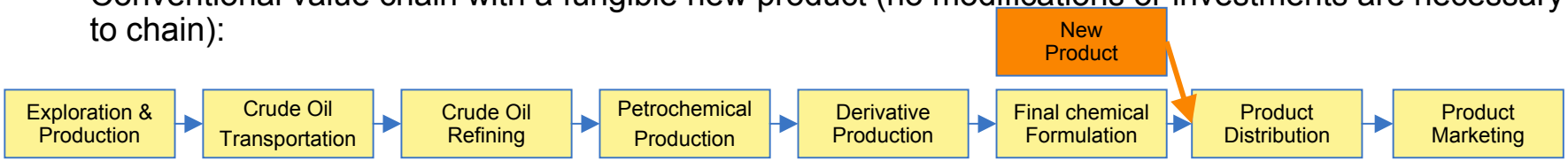
Compared to producing electricity or fuels, most bioproducts will not be completely fungible with currently used competitive products...

- Commercialization of bioproducts may require several steps of development in addition to the necessary process technology development efforts
- Bioproducts that can serve as “drop-in” replacements may use existing infrastructure such as distribution and marketing channels with the associated investment savings
  - These opportunities are likely to be limited
- It is likely that “drop-in” replacement applications may be limited, therefore additional investments may be required for application & market development efforts and distribution & marketing channels
- New products for existing applications such as blow-molded plastics may use existing infrastructure elements
  - However, investments may be required to demonstrate the feasibility of using the “new” bioproduct” in existing equipment
  - Investments may be required to retrofit existing equipment to use the new bioproduct
  - New distribution investments may be required
- New products for new developing markets may require additional investments to cover product, application & market development and distribution & marketing channels

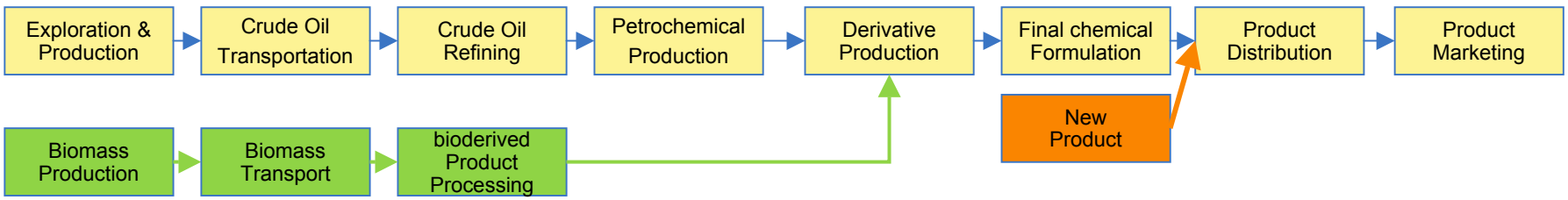
… requiring that the bioproduct options analysis address what pieces of the value chain are likely to require new investments.

Our methodology identified the possible need to make new investments in the value chain that are required to enable bioproduct use.

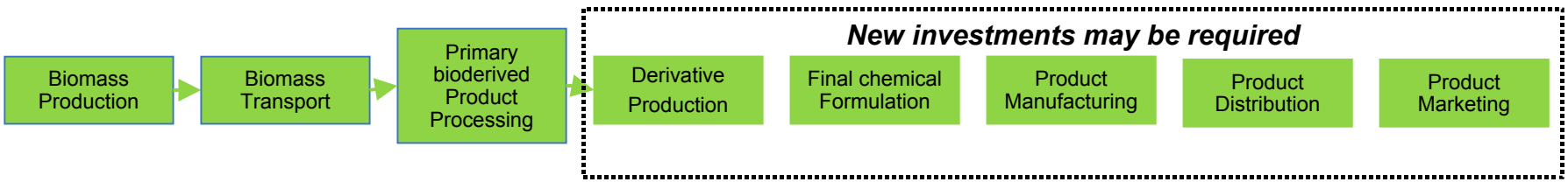
- Conventional value chain with a fungible new product (no modifications or investments are necessary to chain):

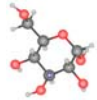


- For a biobased route providing an indistinguishable intermediate product which can "piggy-back" on existing infrastructure only the first part of the value chain need be considered



- For a biobased route providing a new product with new applications and new markets, additional value chain components must be considered.





All biomass-derived chemical species under development were identified and classified into the four broad market segments.

Currently Used as Primarily Food By-products	• Acetic acid • Amino acids • Ascorbic acid • Citric acid • Ethanol • Fumaric acid	• Gluconic acid • Glutamic acid • Itaconic acid • Lactic acid • Mannite • Propionic acid	• Sorbit • Sterols • Vanillin • Vitamin E • Xylitol • Xanthan gum		
Commodity Chemicals	• Acetates • Acetic acid • Acetone • Acrylic acid and esters • Adipic acid	• N-Butanol • 1,4- Butanediol • Butadiene • BTX • Bisphenol A replacement	• Carbon black /activated carbon • Ethanol • Ethylene • Ethylene glycol • Lipids (Fatty acids/alcohols)	• Formaldehyde • Isopropanol • Methanol • Naphtha • Pentanes/Pentenes • Phenol	• 1,2-Propanediol (1,2-propylene glycol) • Propylene • Syngas • Tetrahydrofuran
Polymers & Fibers	• CAB • Cellulose • Cellulose acetates • Cellulose ethers • Cellophane	• Epoxidized soybean oil • Nitrocellulose • Polyethylenes • Polyhydroxy Alkanoates	• Polylactic acid polymers • Polypropylenes • Rayon • Starch-based polymers • Other functionalized seed oils		
Specialties	• Acetol • Acetaldehyde • Anthraquinone • Gamma butyl lactone • Catechol	• DALA • DMSO • Erythritol • Furfural • Furfuryl alcohol • Glycerol/glycerin	• Lactic acid • Lactic esters • Levulinic acid • Levoglucosan • Methyl-THF • Nonyl phenol • Propionic acid	• 1,3-propanediol • Lipid-based lubricants • Resorcinol • Rosins and rosin esters • Sugar esters	• Succinic acid • Terpenes • Vegetable oils for hydraulic fluids, engine oils, penetrating oils, & cutting fluids

We then identified whether the product is directly obtained from biomass or is a derivative.

Fermentation-based products find applications across all major product categories.

Chemical Entity	Selected	Primary Product				Derivative Product			
		Food By-product	Commodity	Polymer/ Fiber	Specialty	Food By-product	Commodity	Polymer/ Fiber	Specialty
Fermentation	Acetic acid	X	X		X				
	acetic anhydride from acetic acid						X		X
	acetates from acetic acid						X		X
	Acetone		X		X		X		X
	Amino acids, e.g. lysine	X			X	X			X
	N-Butanol		X		X		X		X
	butyl acetates from n-butanol						X		X
	Citric Acid	X			X				X
	Ethanol	X	X		X		X	X	X
	Ethylene from ethanol						X	X	X
	polyethylenes from ethylene							X	X
	ethylene glycol from ethylene						X	X	X
	ethyl acetate from ethanol								X
	Fumaric Acid	X							
	Gluconic acid	X							
	Glutamic acid	X							
	Itaconic acid	X							

There is significant emphasis in industry on the use of fermentation to produce monomers for polymer production.

Chemical Entity	Selected	Primary Product				Derivative Product			
		Food By-product	Commodity	Polymer /Fiber	Specialty	Food By-product	Commodity	Polymer Fiber	Specialty
Fermentation	Isopropanol		X		X		X		X
	propylene from isopropanol						X	X	X
	polypropylene from propylene							X	
	Lactic acid	X			X			X	X
	Lactate esters from lactic acid								X
	Polylactic acid from lactic acid							X	
	Acrylic acid and esters from lactic acid						X		X
	1,2-propylene glycol from lactic acid						X		X
	Mannite	X							
	Methanol		X		X		X		X
	Propionic acid		X		X		X		X
	1,3-propanediol (and PTT polymers)				X			X	X
	Succinic acid				X				X
	Gamma butyl lactone								X
	Tetrahydrofuran						X	X	X
	1,4-butanediol						X	X	X
	Adipic acid						X		X
	Xanthan gum	X			X				

Most of the potential products derived from pyrolysis processes are aimed at specialty niche markets.

Chemical Entity	Selected	Primary Product				Derivative Product			
		Food By-product	Commodity	Polymer/Fiber	Specialty	Food By-product	Commodity	Polymer/Fiber	Specialty
Pyrolysis	Acetaldehyde								X
	Acetic acid						X		X
	Acetol								X
	Anthraquinone								X
	Bisphenol A replacement							X	X
	Butadiene							X	X
	BTX (benzene, toluene, xylene) replacements						X	X	X
	Carbon black, activated carbon								X
	Catechol								X
	Formaldehyde						X	X	X
	Levoglucosan								X
	Nonyl phenol								X
	Pentanes/pentene						X		X
	Phenol replacements						X	X	X
	Resorcinol								X

Raw pyrolysis oil will likely only find limited direct applications; further processing is required of the initial product.

While C_1 chemistry can be used to produce a broad suite of chemicals, low temperature processes yield mostly food by-products and specialties.

Chemical Entity	Selected	Primary Product				Derivative Product			
		Food By-product	Commodity	Polymer /Fiber	Specialty	Food By-product	Commodity	Polymer /Fiber	Specialty
C1 chemistry (Based on Syngas)	Acetic acid						X		X
	Methanol						X		X
	Fischer-Tropsch Naphtha		X				X	X	X
	Syngas feedstock						X		X
Low temperature chemical processing	CAB (cellulose acetate butyrate)							X	X
	Cellulose							X	X
	Cellulose acetate fiber							X	X
	Cellulose acetate tow							X	X
	Cellulose acetate flake							X	X
	Cellulose ethers							X	X
	Cellophane							X	X
	Dimethyl sulfoxide (DMSO)								X
	Erythritol	X							
	Epoxidized soybean oil							X	X
	Ethylene						X	X	X
	Furfural								X
	Furfuryl alcohol, THF								X
	Lipids (Fatty acids,alcohols, & esters), from oil splitting & tall crude oil						X		X

Low temperature processes yield mostly food by-products and specialties.

Chemical Entity	Selected	Primary Product				Derivative Product			
		Food By-product	Commodity	Polymer/ Fiber	Specialty	Food By-product	Commodity	Polymer/ Fiber	Specialty
Low temperature chemical processing	Glycerol							X	X
	Levulinic acid								X
	DALA								X
	Methyl-tetrahydrofuran								X
	Nitrocellulose							X	X
	Plant-based lubricants								X
	1,2 propylene glycol						X		X
	Rayon							X	X
	Rosins and rosin esters								X
	Sorbit (and ascorbic acid from sorbitol)	X			X				X
	Starch based polymers							X	X
	Sterols and steroid precursors					X			X
	Simple sugars (glucose, sucrose, fructose)	X			X				X
	Sugar esters								X
	Vanillin					X			X
	Vitamin E (d alpha tocopherols)					X			X
	Xylitol	X			X				X

Physical separation and extraction of biomass products usually yields specialty products and food by-products.

Chemical Entity	Selected	Primary Product				Derivative Product			
		Food By-product	Commodity	Polymer/Fiber	Specialty	Food By-product	Commodity	Polymer/Fiber	Specialty
Physical Separation or Extraction	Polyhydroxy Alkanoates e.g. Polyhydroxybutyrate				X			X	X
	Rubber			X				X	X
	Terpenes				X				X
	Vegetable oils, seed oils	X			X			X	X

Products used for exclusively for food, food by-products and food ingredients were screened out since they were outside the scope of the analysis.

Food, Food-byproducts, Food ingredients, and pharmaceuticals Outside scope of analysis
• Amino Acids • Erythritol • Simple sugars (e.g. glucose, sucrose, fructose) • Glutamic acid • Mannite • Sterols and steroid precursors • Vanillin • Ascorbic acid • Vitamin E (d alpha tocopherols) • Vegetable oils and seed oils for food consumption • Xylitol

Screened out

Both existing and potential markets for bioderived products were assessed.

- The existing markets for bioderived products other than paper/lumber or food products are generally small in volume
  - The focus was on U.S. markets, but if U.S. data were not readily available, world demand was used
  - Demand data was extrapolated to 2010 using projected individual market growth rates
- Also included were markets for existing petroleum based products which could be substituted with bioderived products
  - The potential future growth of bioderived products appears to be as substitutes for key petroleum intermediates
- If the product was also used for food applications, this demand was subtracted out
  - Food/flavor ingredients and nutritional supplements were also subtracted out

The difference between projected 2010 demand and present existing capacity was used to screen out those products with medium markets.

- The current markets for most chemicals under consideration are relatively mature (growth rate less than 5%)
- For most of the chemicals considered, production capacity nearly meets current demand (if not excess capacity)
- Substitution for biomass-derived products may require competing with existing products on a cash-cost basis
- Therefore, it is most likely that bioderived products could capture the market corresponding to demand growth
  - This scenario is possible if the capital investment and operating cost of the bioderived product is competitive to new plant construction and/or expansion cost
  - In reality, the market for each chemical is susceptible to market saturation since most markets considered are relatively mature
  - In order for accelerated demand of biomass products to occur, new products & applications will be required for new expanding markets

About a dozen options were screened out because of expected over-capacity. Many more were eliminated because the markets are small.

Food By-products	***Over Capacity*** • Fumaric acid	***Less than 200 million pounds/y demand*** • Citric acid • Gluconic acid • Itaconic acid • Sorbit	• Xanthan gum
Commodity Chemicals	***Over Capacity*** • Acetates (ethyl & butyl) • N-Butanol • Carbon black / activated carbon • Isopropanol • Methanol	***Less than 200 million pounds/y demand*** NONE	
Polymers & Fibers	***Over Capacity*** • Cellulose acetate tow • LDPE	***Less than 200 million pounds/y demand*** • CAB • Cellulose ethers • Cellulose acetate flake • Cellulose acetate fibers • Cellulose in insulation	• Cellophane • Nitrocellulose • Polyhydroxy Alkanoates • Rayon • Rubber • Starch-based polymers
Specialties	***Over Capacity*** • Furfural • Propionic acid • Resorcinol	***Less than 200 million pounds/y demand*** • Acetaldehyde • Acetol • Anthraquinone • Catechol • DMSO • Furfuryl alcohol • Glycerol	• Lactic acid (current uses) • Levulinic acid • Levoglucosan • Nonyl phenol • Rosins and rosin esters • Succinic acid • Sugar esters • Terpenes

These products can still be considered as part of a biorefinery concept, if appropriate.

Those bioproducts that have potentially high growth rates and a large potential addressable market were retained for the technology screen.

Market Screen

Do the products have markets that are large enough to contribute measurably to a tripling of bioproduct use and/or do the feedstocks allow for significant markets?

YES

- **All other options**

NO

- Fumaric acid
- Carbon black/activated carbon
- Low density polyethylene (LDPE)
- Resorcinol
- Ethyl acetate
- Butyl acetates
- Propionic acid
- Nonyl phenol
- n-Butanol
- Isopropyl alcohol
- Furfural
- Acetic anhydride
- Methanol
- Cellulose acetate tow
- Glycerol
- Rayon
- Cellulose ethers
- Cellulose acetate flake
- Terpenes
- Sorbit
- Cellophane
- Citric acid

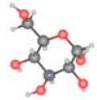
- Itaconic acid
- CAB
- Nitrocellulose
- Succinic acid
- Lactic acid
- Xanthan gum
- Cellulose acetate for fibers
- DMSO
- Gluconic acid
- Rosin acid/esters
- Anthraquinone
- Natural rubber
- Catechol replacement
- Polyhydroxy Alkanoates
- Furfuryl alcohol
- Cellulose in insulation
- Sugar esters
- Acetaldehyde
- Acetol
- Starch-based polymers

Rationale

- The projected 2010 market for existing petroleum-based products is large in absolute volume. However, there exists existing petroleum-based capacity that may be used. The markets for most products analyzed are mature (growing at less than 5 percent per year).
- We projected the market demand for products to 2010 using chemical industry literature estimated growth rates for each individual product.
- We made a first preliminary screen which identified those products with excess capacity (defined as projected 2010 market volume minus existing ('97-'00) U.S. capacity data.
- We then made a secondary screen to identify those products with medium markets (defined as less than 200 million pounds per year taking into account the level of existing capacity).

Approximately 15 chemicals have expected demand in 2010 that is more than 1 billion pounds per year higher than current production capacity.

2010 Market over existing cap. 200-500 million lb	2010 Market over existing cap. 500-1000 million lb	2010 Market over existing cap. >1000 million lb
• 1,2-Propylene glycol • Adipic acid • Tetrahydrofuran • 1,4-Butanediol • Lactic esters • Epoxidized soybean oil • Gamma butyl lactone	• Fatty acids/esters • Acetone • Polylactic acid • Vegetable based lubricants	• Propylene • Ethylene • Polypropylene • High density polyethylene (HDPE) • Formaldehyde • Butadiene • Phenol • Ethylene glycol • BTX • Acetic acid • Bisphenol A • Acrylic acid/esters • Nylon replacement (1,3-propanediol also called 1,3-propylene glycol) for PTT polymers • Naphtha • Syngas feedstock



A potential avenue for accelerated bioproduct market growth is through the use of bioderived intermediates or "building blocks".

- Several products under consideration could function as novel intermediates or "building blocks" for commodity chemicals:
  - Lactic acid
  - Levulinic acid
  - Levoglucosan
  - Succinic acid
  - Sorbitol
- "Bioengineered" polymers, which could be made directly in the cells could simplify processing requirements
  - Polyhydroxy Alkanoates, e.g. Polyhydroxybutyrate
- These products will be taken forward to the next screening
  - Markets are potential large volume commodity chemical and polymer markets

Among fermentation products, only acetic acid can be considered to be in the market penetration phase of product development.

Technology P = Technology that has achieved market **P**enetration E = Technology in the market **E**ntry phase D = **D**emonstration phase - not commercially available R&D = **R&D** phase - not yet demonstrated		**Primary Product**	**Derivative Product**
Fermentation	Acetic acid	P	
	Acetone	E	
	Ethanol	P (corn ethanol)	
	Ethylene from ethanol		R&D
	polyethylenes from ethylene (conventional process)		P*
	ethylene glycol from ethylene (conventional process)		P*
	Isopropanol	R&D	
	propylene from isopropanol		R&D
	polypropylene from propylene		P
	Lactic acid	D	
	Lactate esters from lactic acid		D
	Polylactic acid from lactic acid		D
	Acrylic acid and esters from lactic acid		R&D
	1,2-propylene glycol from lactic acid		R&D

Selected

*The technology to produce polymers such as polyethylene and polypropylenes is in place using ethylene and propylene, respectively. If ethylene could be made via ethanol or via another biobased route, it could conceivably be used to make polyethylene using existing polymer production infrastructure.

Most pyrolysis products are in the R&D phase of product development.

Technology P = Technology that has achieved market **P**enetration E = Technology in the market **E**ntry phase D = **D**emonstration phase - not commercially available R&D = **R&D** phase - not yet demonstrated		**Primary Product**	**Derivative Product**
Fermentation	Succinic acid	R&D	
	Gamma butyl lactone		R&D
	Tetrahydrofuran		R&D
	1,4-butanediol		R&D
	Adipic acid		R&D
	1,3-propanediol (also known as 1,3 propylene glycol)	R&D/D	
	PTT poly(trimethylene)terephthalate		D
Pyrolysis	Acetic acid		R&D
	Bisphenol A replacement		R&D
	Butadiene		R&D
	BTX (benzene, toluene, xylene) replacements		R&D
	Formaldehyde		R&D
	Levoglucosan		R&D
	Pentanes/pentene		R&D
	Phenol replacements		D

Selected

C_1 chemistry and low-temperature chemical processing options are also generally at early stages of the product development cycle.

Technology P = Technology that has achieved market **P**enetration E = Technology in the market **E**ntry phase D = **D**emonstration phase - not commercially available R&D = **R&D** phase - not yet demonstrated		**Primary Product**	**Derivative Product**
C1 chemistry (Based on Syngas)	Acetic acid	D*	
	Fischer-Tropsch Naphtha		D*
	Syngas feedstock		D*
Low temperature chemical processing	Epoxidized soybean oil		D
	Lipids (Fatty acids (from oil splitting and tall crude oil)		P
	Levulinic acid		R&D
	DALA		R&D
	Methyl-tetrahydrofuran		R&D
	Plant-based lubricants		E

Selected

*Components have been demonstrated with syngas obtained from natural gas or coal. Gasification of biomass has been demonstrated. Integrated demonstration of a gasification and syngas conversion process (e.g. to methanol or FT-Syncrude) has not been demonstrated. Methanol from biomass was considered for fuel use.

Approximately 15 options were retained in the technology screen.

Technology Screen

Can the products be produced with technologies that could be commercially viable by 2010?

NO

- Acrylic acid/esters from lactic acid
- 1,2-propylene glycol from lactic acid
- Ethylene from ethanol (and its derivatives)
- Succinic acid and its derivatives
- Propylene from bioderived isopropanol (and propylene's derivatives)
- Formaldehyde from pyrolysis products
- Pentanes/pentene from pyrolysis products
- Levoglucosan from pyrolysis products
- Acetic acid from pyrolysis products
- Bisphenol-A replacements from pyrolysis products
- Butadiene from pyrolysis products
- BTX from pyrolysis products
- Levulinic acid (and its derivatives)

YES

- Lipids: Fatty acids/alcohols/esters
- 1,3-propanediol for polymers
- Lactic esters
- Commodity scale Lactic acid for Polylactic acid
- Phenol replacements

- Acetic acid
- Acetone
- Ethanol
- Syngas feedstock
- Epoxidized soybean oil
- FT-naphtha
- Plant-based lubricants

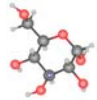
Rationale

- We used a metric of demonstration maturity of the technology by 2005 to meet the technology filter.
- Fermentation technology to produce commodity chemicals at large scale (at least 250 million pounds per year per plant) is at a late R&D to demonstration level of maturity. Commodity lactic acid manufacture is currently under demonstration by Cargill Dow LLC. Du Pont and Genencor have announced a demonstration plant for 1,3-propanediol from biomass for 2003. Other products derived from fermentation are in an earlier R&D stage of development (for large-scale commodity production).
- Pyrolysis technology produces a complex mixture from which products are recovered. Phenolics for wood-glue resins has been demonstrated at a late R&D, early demonstration scale. Other products from pyrolysis processing have not been demonstrated at a scale sufficient for commodity scale production.
- The technology components for gasification of biomass and subsequent conversion of the syngas into products are at a demonstration level of maturity. Although integrated demonstration has not yet occurred.
- Products such as seed oil derivatives have been shown at a demonstration scale of production. Low temperature processing of cellulosic biomass to recover levulinic acid is at a late R&D stage of development. The derivatives from levulinic acid are at an earlier R&D phase of development.

In addition to technology development, application & market development must occur in parallel so that the necessary infrastructures are in place.

Technology *(basic materials, working principles)*	First Evidence	Technology Viability	Technology Verification	Advanced Development	Commercialization
	8-15 years	5-10 years	3-8 years	1-4 years	0-2 years
Production Process *(process to manufacture technology)*	First Evidence	Proof of Principles	Unit Operation Development	Process Integration & Demonstration	Commercialization
	8-15 years	5-10 years	3-8 years	1-4 years	0-2 years
Product *(Product incorporating technology)*	First Evidence	Product Concept Viability	Product Design	Advanced Development	Commercialization
	2-15 years	2-15 years	1-4 years	0-1 years	0-0.5 years
Market *(Customers that want to buy products)*	Customer Need	Product Idea Development	Product Concept Development	Product Refinement	Initial Product Launch
	2-6 months	1-6 months	1-6 months	2- 12 months	2-8 months

Some of the products based on biological processes can take somewhat longer to mature.

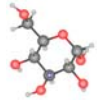


The infrastructure requirements for solvents provide an example of the application and market development that is required for new products.

The following success criteria must be met by bio-solvents:

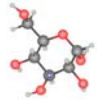
- Satisfy existing and new environmental regulations
- Performance (e.g. solvency, evaporation rate)
  - Equal to or better than the traditional solvent
  - Equal to or better than other competing technologies
- Cost (e.g. price, longevity, disposal, special equipment requirements)
  - Value-in-use
  - Price-per-pound considerations
  - New equipment costs
- Ease of Use
  - Solvent system stability/maintenance
  - Equipment maintenance
  - Operator training/reformulation
- Safety

The "Holy Grail" of solvent substitutes is the "drop-in" replacement: easy to use, works in current equipment, inexpensive, and safe.



Established solvent distribution networks grew up around a few major products and key suppliers.

- Standard processes
  - Simple equipment that is widely available
  - Little technical support for current solvent systems
- Standard products
  - Interchangeable products
  - Consistent quality among suppliers
  - High turnover of inventory
- Sales driven by
  - Relationships
  - Price
  - Service
  - Brand Loyalty

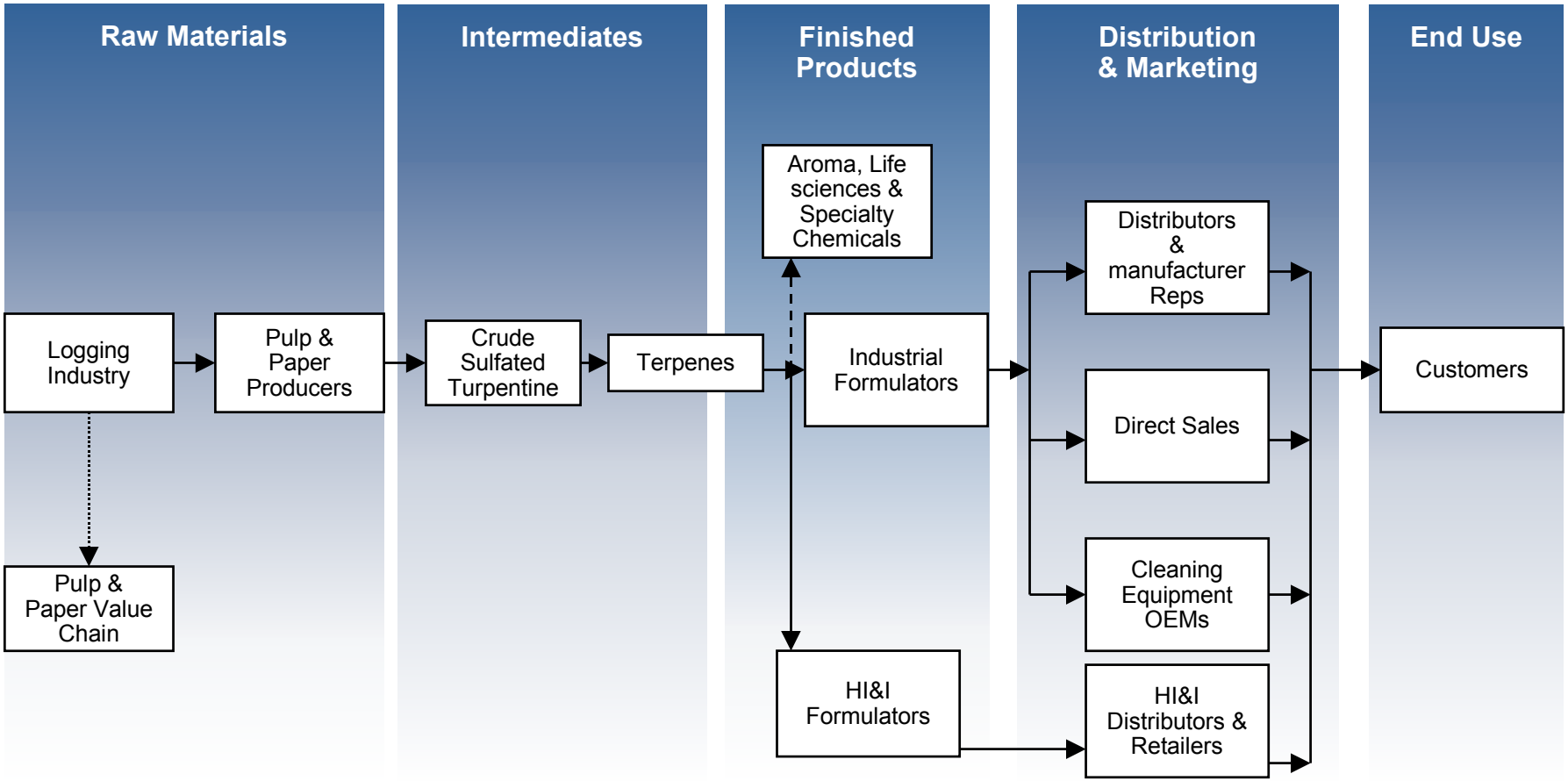


Introducing alternative bio-solvents presents new challenges to the solvents distribution network.

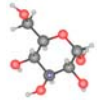
- Technology-driven sales
  - Multiple choices in chemistry
  - Multiple choices in process
  - Requires highly trained sales force
  - Results in highly fragmented market
- New capital requirements
  - Technical support becomes critical
  - Equipment often presents limiting step
- Nonstandard products
  - Niche products for each application
  - More products to inventory
- Processes designed to be less-consumptive
  - Lower sales volumes
  - Higher inventory costs

High costs, long lead-times, and low sales volumes present significant obstacles for producers and distributors.

For example, the value chain for pine terpenes for solvent use links raw material resources, specialty chemicals, distributors, sales, and retailers.



All pieces of the value chain must be in place in order for significant market penetration of the product to be achieved.



Bio-solvents have both benefits and limitations not common to synthetic chemicals used as solvents.

Benefits	Limitations
• "Green" image • Generally lower toxicity levels – Safer handling – Lower cost of disposal – Less difficult remediation • Some advantage with environmental regulations • Usually readily biodegradable	• Variability in color and odor – Seasonality among lots – Creates quality concerns with QC inspectors and operators • Strong or unusual odors – Any unfamiliar odor raises issues with operators, even if benign • Instability. Usually oxygenated and/or unsaturated bio-solvents often have issues with: – Hydrolytic stability – Oxidative stability • Large price swings with agricultural commodities – e.g. d-limonene – High near $2.50/lb in 1995 – Low near $0.20/lb in 1998 • Co-produced with other materials (e.g. food, and pharmaceuticals) – Output capped by demand for unrelated products

New product applications and investments in market development may be required for a product that is not a exact "drop-in" replacement.

A structured screening approach was used to rank the infrastructure requirements of each of the remaining bioproduct options.

Rank	Definition
1	The existing infrastructure can be used without modification or significant new construction. All suitable markets are known and the product is fungible or a “drop-in” replacement in those markets.
2	Some of the existing infrastructure can be used and/or the existing infrastructure will require minor modifications and new construction. The product represents a new product in the chemical pool; applications for the product may need development.
3	A complete new infrastructure is required. The product represents a new market which needs to be developed (both applications and market for applications).

- There are a number of additional infrastructure issues for chemicals
  - Chemicals are not as fungible as fuels and electricity
  - Trace new impurities of a existing chemical can impact performance in downstream existing derivatives (e.g. new source of butanediol with new impurity)
  - New polymers, for example, require R&D time and resources for application development (and market identification/development)

Each chain was ranked using these criteria.

- Each component of each chain was ranked
  - Biomass production
  - Biomass transportation
  - Primary Bioproduct processing/manufacture
  - Derivative product processing if applicable
  - Application Development if applicable
  - Market Development if applicable
- Chains receiving a score of “3” for all components were removed from this screen
  - Such chains require retrofits to the entire infrastructure, and are unlikely to contribute significantly to increased biomass utilization by 2010
- Chains receiving a score of “3” for all components other than biomass production and biomass transportation were removed from further consideration
  - Since downstream operations are larger in number and more diverse, they will require the largest investment in capital and time to build up

Only fatty acids/alcohols appear fully compatible with existing infrastructure, but several options are moderately compatible.

Screened Option / *Selected*	Biomass Production	Biomass Transport	Primary Bioproduct Processing	Derivative Product Processing	Application Development	Market Development
Acetic acid	1	2	1	3	3	3
Acetone	1	2	1	3	3	3
Ethanol	1	1	2 (from cellulosic)	3	3	3
Epoxidized soybean oil	1 (not including GMO)	2	2	3	3	3
Fatty Acids/alcohols/esters	1	1	1	1	1	1
FT-naphtha	1	2	3	1	1	1
Lactic esters	1 (sugar feedstock only)	2	2	2	3	3
Lactic acid for polylactic acid	1 (sugar feedstock only)	2	2	2	2	3
Phenolics	1 (woody feedstocks)	2	2	2	2	3
Plant-based lubricants	1	2	2	3	3	3
1,3-propanediol	1 (sugar feedstock only)	2	2	2	2	3
Syngas	1	2	3	3	3	3

Legend:
1: The existing infrastructure can be used without modification or significant new construction. All suitable markets are known and the product is fungible in those markets.
2: Some of the existing infrastructure can be used and/or the existing infrastructure will require minor modifications and new construction. The product represents a new product in the chemical pool; applications for the product need development.
3: A complete new infrastructure is required. The product represents a new market which needs to be developed (both applications and market for applications).

Most bioproducts will not be "drop-in" replacements for currently used chemicals and thus may require application and market development.

Rationale

- Fatty acids, alcohols, and esters derived from both tall oil and vegetable oils are a mature industry with established distribution and marketing channels. Marketing of glycerol co-product from fat/oil splitting may limit the market volume achievable using splitting processes.
- 1,3-Propanediol is seen as a key monomer for PTT (polytrimethylene terephthalate) which may have applications similar to polyester and other synthetic fibers with more favorable properties. The product and application development could piggy-back onto existing infrastructure for polymer application development, distribution and marketing. Feedstock infrastructure investments for raw material delivery, especially if technology using complex feedstocks such as cellulosics are used.
- Lactic esters are seen as a possible "green solvent". The value chain for the solvents is relatively fragmented with several steps that need to be addressed simultaneously before significant market penetration can occur. This may require both capital and time investments.
- Cargill Dow LLC has announced a commercial plant for lactic acid for polylactic acid polymers. A pilot plant has been in production producing samples for application testing. The product and application development could leverage existing infrastructure for polymer application development, distribution and marketing. The current feedstock (sugars) could use existing channels. Complex feedstocks such as cellulosics may require infrastructure investments.
- Phenolics derived from pyrolysis processing of biomass have found application as wood adhesives. Other applications are under development.
- Acetic acid is currently derived mostly through synthetic routes based on fossil feedstocks. bioderived acetic acid is a mature technology but is currently not cost competitive for commodity scale manufacture.
- Applications and markets for polymers and oil derived lubricants derived from seed-oils such as canola or soybean are in an early stage of development. Additional investments both in technology and market development may be required.
- The production of levoglucosan by pyrolysis processing has been demonstrated at the pilot level, for example by RTI in Ontario, Canada. The derivatives for levoglucosan are at an conceptual or bench stage of development in addition to the development of possible applications and suitable markets. Levogluosan could serve as a carbohydrate feedstock for a fermentation process.
- The production of levulinic acid by low temperature processing has been demonstrated at the pilot level, for example by Biofine. The proposed derivatives for levulinic acid, DALA and methyl-THF are at a conceptual or bench scale of development. DALA has promise for a biodegradable insecticide. Methyl-THF is a possible oxygenate fuel additive. Both derivative products and their applications and markets are at an early stage of development.
- A technology for succinic acid is available for licensing (MBI). The technology is at a pilot scale of development with the large volume process technology at an earlier stage of development. Application and market development is also required for the derivatives which may contain new impurities which would be introduced into the chemical pool.

Overall, half of the remaining options were considered sufficiently compatible with existing product chains to pass the infrastructure screen.

Infrastructure Screen

Is technology and markets for both the product and key derivatives in place?

NO

- Acetic acid
- Acetone
- Ethanol for chemicals
- Seed Oil based polymers
- Levoglucosan
- Levulinic acid
- Plant based lubricants
- Syngas as product

YES

- Fatty acids/alcohols from vegetable oils
- FT-naphtha
- 1,3-propanediol for polymers

- Phenolics
- Lactic esters
- Commodity scale lactic acid for PLA polymers

Rationale

- The main criteria were the state of development of derivative product processing, product applications and markets for the applications.
- Chemicals are not as fungible as fuels and power since new (to the chemical pool) trace impurities may influence performance in downstream products and applications.
- New polymers, for example, require R&D time and resources for application development, market identification and market development.

The screen-out chemicals will still be considered in the scenario analysis.

There is insufficient publicly available information for some of the potentially most attractive bioproduct options.

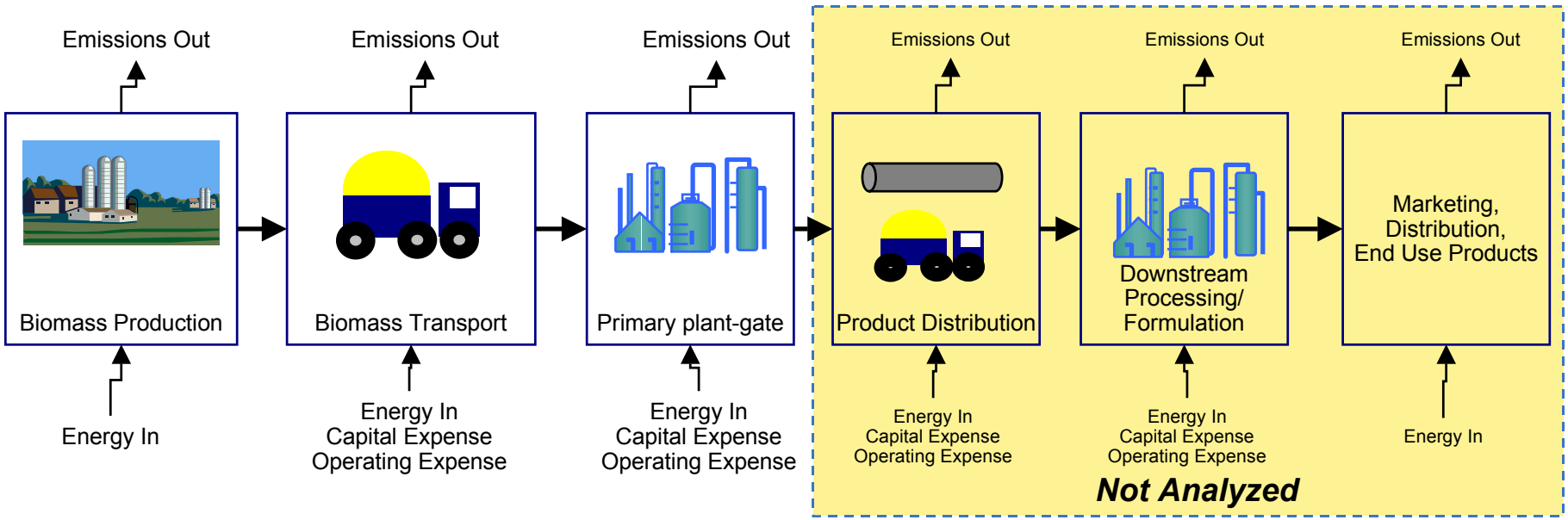
- The economics of bio-chemicals produced by chemical and thermal methods can be estimated with the same methodologies used for fuels and power:
  - Reasonable detail about the technology performance is available
  - Reasonable cost estimates have been made and are in the public domain
  - Examples include oil splitting and C_1 chemistry derived products
- Significant uncertainty exists surrounding the economics of fermentation-based bioproducts now receiving significant industrial attention:
  - Aggressive but not very specific claims are made by developers regarding process economic viability
  - Scant information is available publicly on the technology performance and cost structure, making it impossible to assess the claims
  - Confidentiality concerns make developers leery of divulging key technical and cost information
- The following pages show:
  - Cost estimates of non-fermentation-based technologies based on independent review of cost assessments of specific production technologies
  - Best estimates of the cost and performance of two specific fermentation-based technologies
  - A more detailed analysis of the cost and performance parameters critical for economic fermentation-based technology based on generic technology considerations

The economics of specific examples within each of the selected bioproduct option categories were evaluated.

Low Temperature Processing	Low temperature processing employs an agent to break down the feedstock into its constituent parts (e.g. cellulose, hemicellulose, and lignin) which are then further processed. Example: Oil splitting of seed oils for fatty alcohol synthesis and glycerol recovery
Fermentation	Fermentation is being used by major chemical companies as a key technology platform to make monomers for performance polymers. Examples: lactic acid, 1,3-propanediol
Pyrolysis	Pyrolysis technology can convert a wide variety of biomass into a liquid oil. Products could then be recovered from that complex mixture. Examples: phenolics, sugars (levoglucosan) as a product or for further fermentation processing
C_1 Chemistry	C_1 chemistry via gasification and reforming. The resulting syngas is then used as a “building block” to build chemical products. Example: Naphtha from Fischer-Tropsch synthesis chemistry. This option is worth analyzing as it is a natural co-product from the production of bio-FT-diesel fuel

These examples include some of the most potentially attractive bioproduct options.

The cost of products was estimated from biomass production to primary product manufacture and ended at the primary plant-gate.



Key Artifacts and Assumptions of the Methodology

- The costs associated with biomass production (e.g. land, labor, seed, fuel, capital recovery) are assumed to be reflected by the price ($ per dry ton farm-gate) of the biomass. Emissions associated with biomass production are included (from fertilizer, petroleum fuel use) in the benefits and impact analysis.
- Biomass transport costs are associated with a 50-mile one way by truck

The available data used for the cost estimates varied in the level of detail.

Lactic acid 1,3-Propanediol	• Literature sources for substrate yield and likely product recovery losses. • Data was based on process equipment costs with a factored analysis to estimate necessary investment for installation. A range of technologies was used from batch to large scale continuous processing • NREL data from cellulosic ethanol production was used for the offsites requirements. • The chains used likely yields of glucose from corn to estimate the equivalent cost of corn for making the product. However, the cost of making the glucose from the corn (associated capital, operating, and fuel costs were not included).
Phenolics Levoglucosan (sugars)	• The analysis used a detailed equipment estimate and operating cost estimate for a commercial process for phenolics recovery from woody feedstocks. • For levoglucosan production, the phenolics process equipment estimate was modified to include additional equipment for chemical recovery of the sugars from the oil intermediate. Data on process conditions that optimized levoglucosan and sugar yield was used. Co-products were recovered and sold (primarily low- BTU gas and char)
FT-Naphtha	• Data was based on a detailed analysis of a green field biomass to methanol plant. Modifications were made to account for process efficiency differences. The capital and operating cost was apportioned by product heating value split so that the FT-naphtha carried a portion of the total cost.
Fatty alcohols	• Capital and operating cost data from a commercial oil splitting plant was modified to produce fatty alcohols by partial hydrogenation of the split oils. Glycerol was recovered as a co-product. • The cost of seed oil was used as the feedstock cost. The cost of processing the grain or seed to make the oil (i.e. Capital, operating, and fuel costs) were not included.

Consistent levels of contingency, working capital, owners cost, and engineering and planning were applied to all modules.

The following assumptions were made for all specific examples.

Capital Cost	Operating Cost
Costs based on total fixed capital investment in equipment • Contingency 25 percent of equipment • Owners cost and profit 10 percent of equipment • Working capital 10 percent of equipment • Engineering and planning 18 percent of equipment • 15 percent capital recovery rates for processing investments	**Costs based on equipment investment and direct labor estimates** • Maintenance 3 percent of total equipment investment • General overhead: 65 percent of (maintenance and direct labor) • Direct overhead: 45 percent of direct labor • R&D and GSA costs were *not* included
Assignment of Cost to Products	
• With the exception of FT-naphtha, all products shown are assigned the full capital recovery, fuel, operating, and biomass feedstock costs. Co-products are then credited. • For FT-naphtha, a co-product of FT-diesel, the capital recovery, fuel, operating, and feedstock costs were split by the energy split of the product slate.	

Economy of scale of large scale manufacturing (especially for fermentation based processes) was not accounted for due to lack of data.

The specific options were compared to appropriate conventional counterparts.

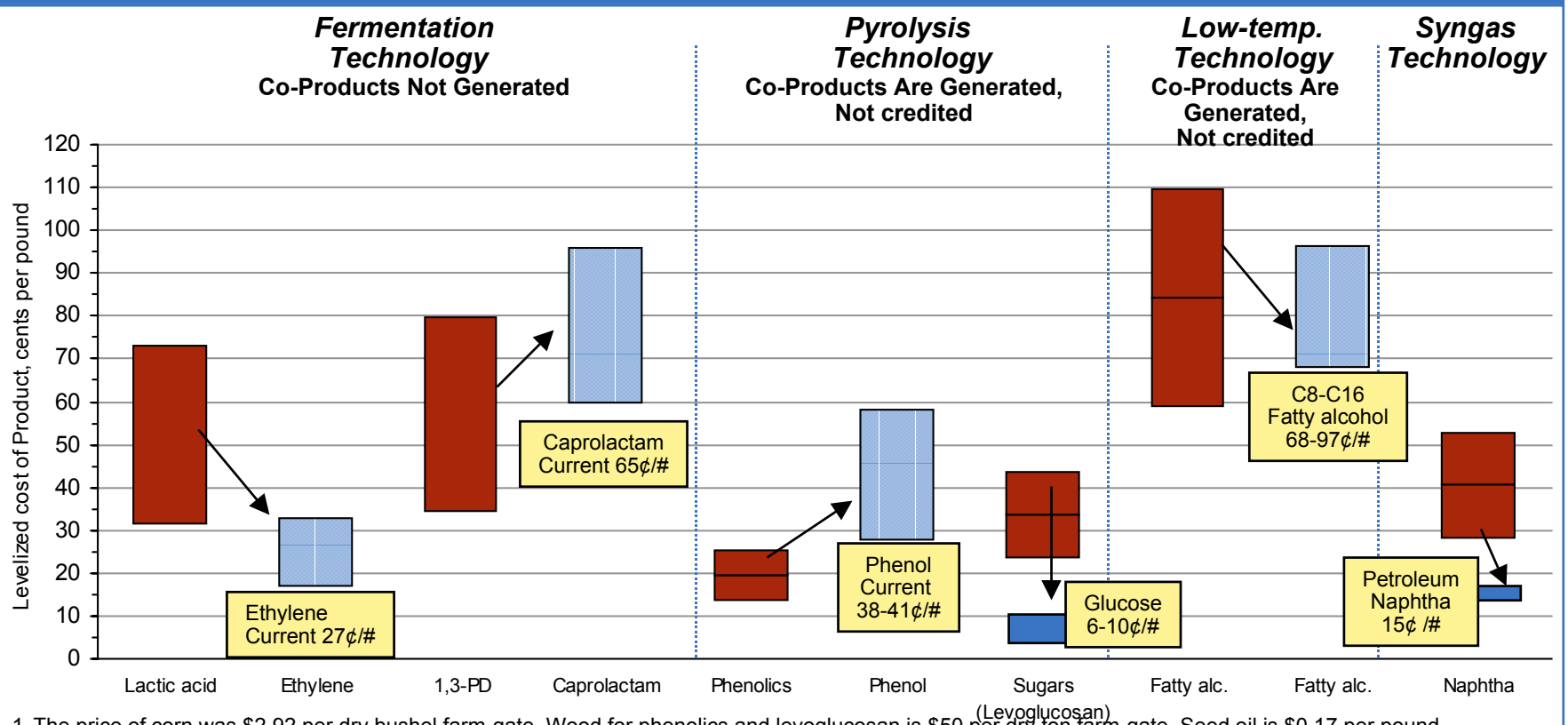
Lactic acid	Lactic acid is compared to the price of ethylene. Polylactic acid may be used in similar applications as low density polyethylene.
1,3-Propanediol	1,3-Propanediol is compared to the price of caprolactam used in Nylon manufacture. Polytrimethylene terephthalate (PTT), using 1,3-propanediol, may compete with Nylon
Phenolics	Phenolics made from pyrolysis processing of woody biomass may be used as a substitute for petroleum-derived phenol in phenol-formaldehyde resins.
Levoglucosan (sugars)	The market for levogluocosan itself (or its possible derivatives) has not been developed. Sugars obtained from pyrolysis processing may be used as a feedstock for fermentation for further processing to make products. It is compared to the price of low grade glucose feedstocks
Fatty alcohols	Fatty alcohols are already made via natural oil splitting in addition to those obtained via petroleum feedstocks. The price range shown is using capryl and cetyl alcohol (C8 and C16)
FT-Naphtha	FT-naphtha is an excellent feedstock for steam cracking for ethylene and propylene manufacture. Shown is a typical price for petroleum naphtha.

Fermentation based products for biomonomers appear promising if large scale continuous commodity processing can be achieved.

Assumptions and Methodology	• The plant-gate levelized product costs shown include the cost of the biomass feedstock, biomass transportation and primary product manufacture. Further costs for product transportation and distribution & marketing of the product or derivative manufacture/formulation are not included; it is a primary plant-gate cost. • The range in the bioproduct costs reflect: for fermentation products the range of likely technologies used (batch and continuous bubble column technology); for pyrolysis products, plus/minus 30 percent of the plant-gate estimated cost; for low temperature process products, plus/minus 30 percent of the plant-gate estimated cost; for syngas derived products, plus/minus 30 percent of the plant-gate estimated cost • The range of comparative prices for ethylene, caprolactum, and phenol reflect historical prices ~1990 to present with the current prices shown • Green field plants are assumed. Plants using existing infrastructure were not analyzed
Comments	• The level of offsite investments has been estimated for each technology. Especially for fermentation based products, the level of infrastructure required for large scale commodity manufacture is an unknown. For example, investments for water treatment and investments required for microorganism containment should be further investigated • The extent of economy of scale savings for fermentation based processes has been estimated for continuous processes using scaling methodology. The likely impact of increased scale on the total investment cost of the entire plant is an area of necessary attention since it will impact the viability of green field “biorefineries” which share infrastructure costs and produce a slate of products
Conclusions	• Fermentation processing for “biomonomers” appears promising if large scale continuous processing can be achieved which delivers cost savings from economy of scale • Pyrolysis technology may be used to produce products for medium-size markets cost effectively (even at an advantage compared to petrochemicals). Additional costs may accrue from investments in product application & market development. Products such as sugars will likely be too expensive to be used as a fermentation feedstock • Low temperature processes such as oil splitting are a mature technology and may be limited due to raw material availability and marketing of glycerol co-product • Syngas processes based on biomass are likely to be too capital intensive for broad application on a stand alone basis even though it promises high flexibility towards the product slate

Bioproducts particularly using fermentation technology have potential to cost effectively compete as monomers.

plant-gate Levelized Cost of Products, Cents per pound, Co-products Not Credited

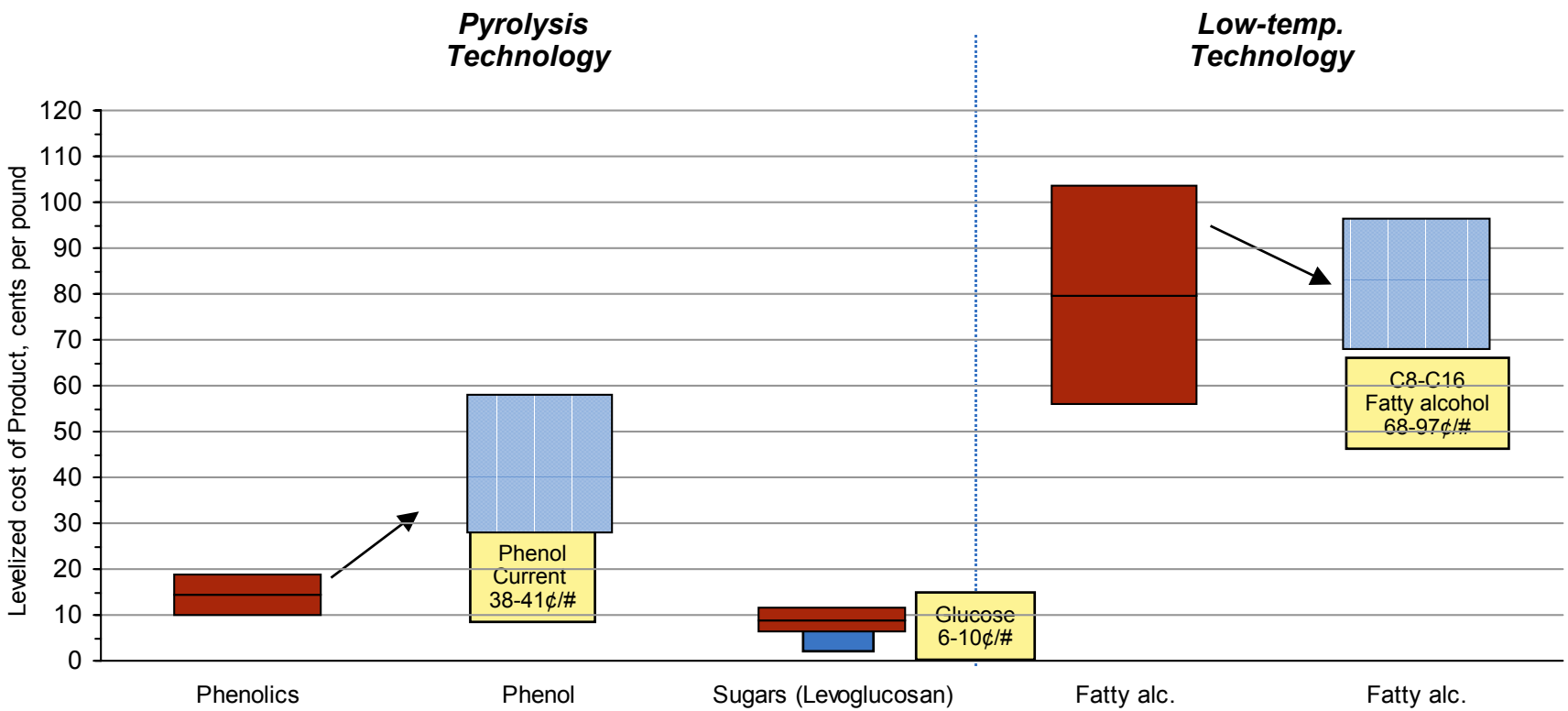


1. The price of corn was $2.92 per dry bushel farm-gate. Wood for phenolics and levoglucosan is $50 per dry ton farm-gate. Seed oil is $0.17 per pound. Cellulosics were $30 per ton farm-gate.

Products using pyrolysis and low temperature (oil-splitting) are competitive today with sufficient raw material cost; market may be resource limited.

The economics for those processes producing a slate of products is improved if all small-volume co-products are recovered and sold.

plant-gate Levelized Cost of Products, Cents per pound, Co-products Credited

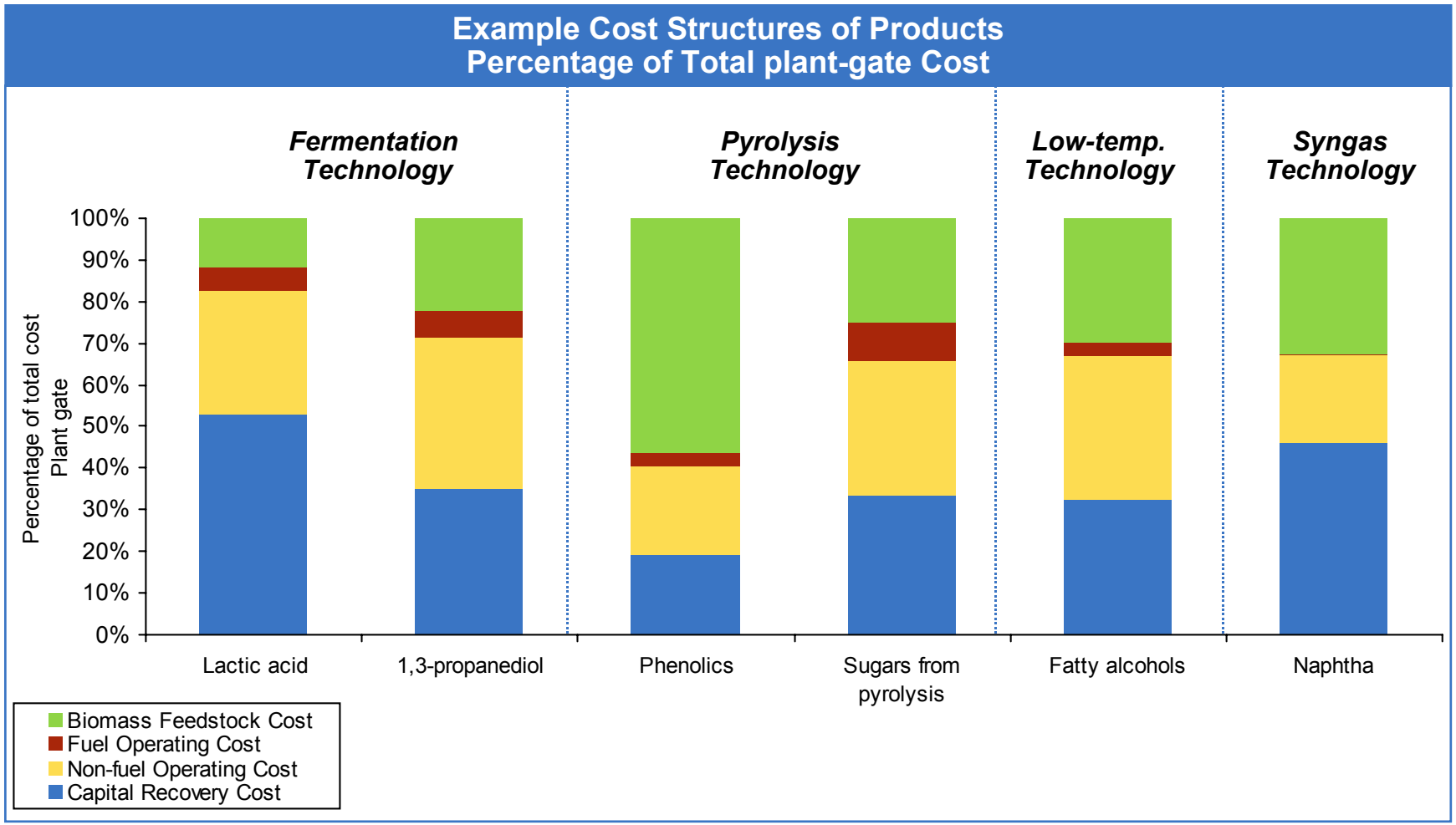


1. The price of corn was $2.92 per dry bushel farm-gate. Wood for phenolics and levoglucosan is $50 per dry ton farm-gate. Seed oil is $0.17 per pound. Cellulosics were $30 per ton farm-gate.

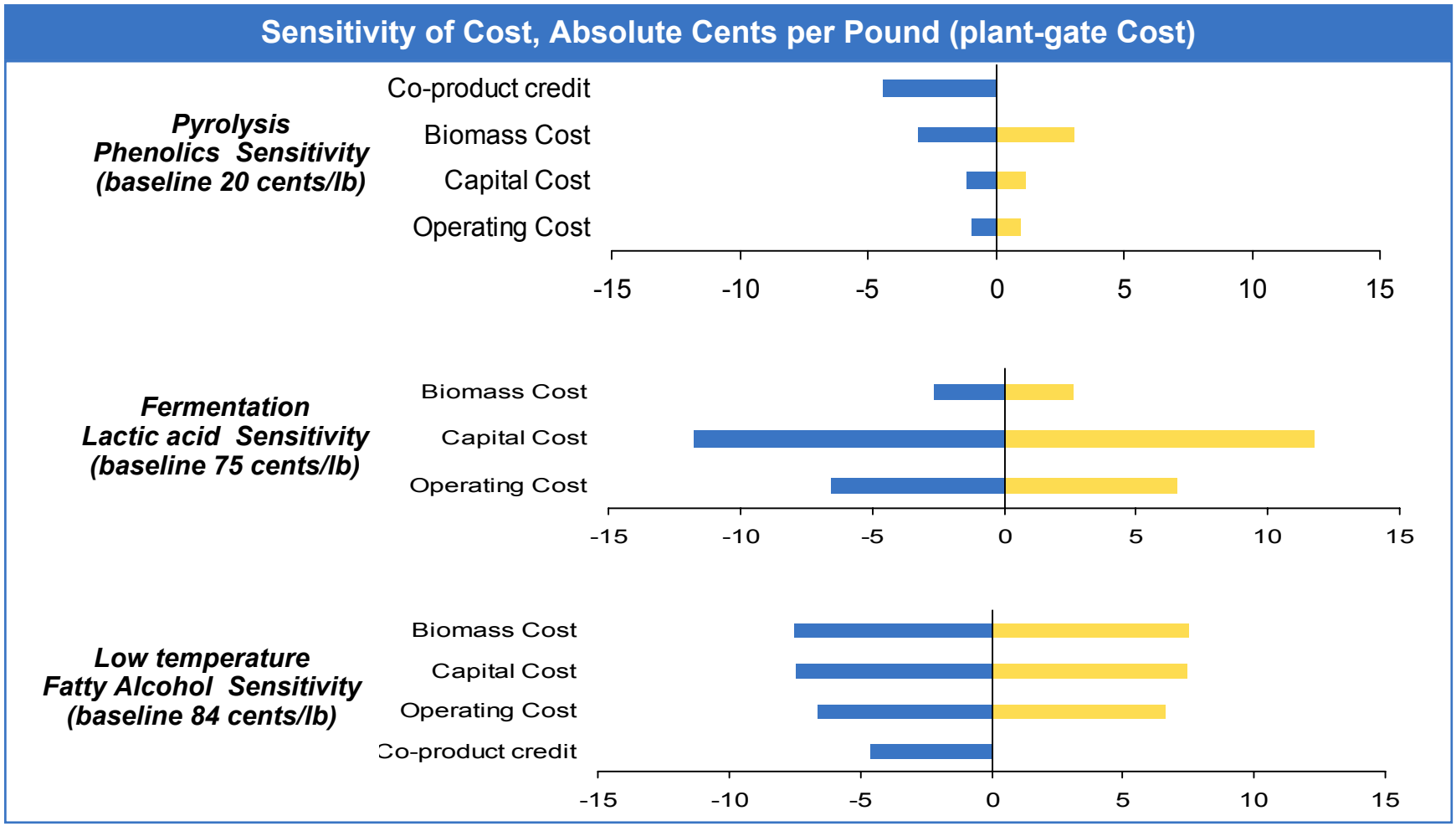
Capital and non-fuel operating costs remain an important factor in the cost structure of potential bioproducts.

Assumptions and Methodology	• The total capital, operating, fuel, and biomass costs are assigned solely to the products shown with the exception of naphtha. In the case of naphtha, the costs are split between FT-diesel and naphtha by energy value split of the product slate. The cost structure shown does not reflect credit of co-products. Process plant recovery rates were 15 percent. Recovery rates for transportation investments were 13 percent. • Biomass feedstock includes the cost of the biomass only. Fuel operating costs include petroleum fuels and electricity cost s for the entire chain. • The fermentation chains used likely yields of glucose from corn to estimate the equivalent cost of corn for making the product. However, the cost of making the glucose from the corn (associated capital, operating, and fuel costs were not included). • The cost of seed oil was used as the feedstock cost for fatty alcohols. The cost of processing the grain or seed to make the oil (i.e. Capital, operating, and fuel costs) were not included.
Comments	• The cost structure shown for lactic acid used the high end of estimated product cost using a batch process technology which results in higher inside battery limit equipment costs (and thus capital investment). • The cost structure shown for 1,3-propanediol used the high end of product costs which was estimated from literature data for a medium scale (10,000 MT/y) continuous process. The low cost shown previously for 1,3 propanediol uses a large scale (500,000 MT/y) continuous process.
Conclusions	• The products shown, particularly the fermentation products, use expensive feedstocks such as corn. Even with the relatively expensive feedstocks, the cost structure of fermentation products is equally impacted by capital and non fuel operating cost. • The low capital cost of phenolics for adhesives results in a high proportion of the total cost for biomass costs. • The capital intensive nature of syngas based processes is reflected in the cost structure shown for naphtha. It must be noted that the costs shown are approximately 30 percent of the costs of the total plant which are assigned to the naphtha. • The impact of by-products especially high-value, low volume will increase the attractiveness of the plant.

Despite the use of relatively costly feedstocks, this is not typically the largest cost factor – capital and non-fuel operating costs are significant.



Sensitivity analyses confirm that by-product credits and capital cost are at least as important as feedstock cost for bioproducts production.



Sensitivity is in absolute cents per pound from baseline, plus/minus 30%.

Several bioproduct options appear to approach cost and performance parity with conventional petroleum-derived products.

Fermentation-Based Polymer Building Blocks	• Could offer cost-competitive routes to commodity plastics provided key technology challenges are met: – High primary product yield from substrate and high concentration in broth – Large-scale, continuous-reactor fermentation production technology – Ability to use low-cost feedstock (i.e. waste or inexpensive feedstock) – Offsite (e.g. Outside battery limit infrastructure) requirements that are similar to conventional petrochemicals
Pyrolysis- & Low-Temperature Processing-Based Products	• May be competitive in medium-sized markets: – Phenolics from wood pyrolysis for resin applications – Fatty alcohols from seed oils – Other lipid based products for lubricant & surfactant applications
C1-Chemistry (Syngas) Based Products	• Do not appear to come close to being cost-competitive on a stand-alone basis • Even though it is less attractive, there might be a need to consider it as a technology to produce co-products as part of a bio-refinery concept (e.g.in FT-diesel or dimethyl ether production) • May require similar market premium or subsidy as current biofuels

One key driver for the cost of bioproducts is the degree of downstream processing and recovery operations required for the final product.

- Pyrolysis technology has the potential to make competitive products for applications in medium sized markets
  - Phenolics have been demonstrated for wood resin applications
    - Minimal processing of the product oils are required once the oil is formed; the "oil" is the product
  - Sugars from pyrolysis would require further fermentation processing or subsequent chemical modifications to form "the product", with additional associated expense
- Gasification-based processes use syngas as the "building block" but are very capital intensive
  - Data for natural gas/syngas based processes have shown that capital and feedstock costs are key drivers in cost structure
  - Biomass based processes are limited in feedstock delivery scale which limits the economy of scale achievable in the expensive syngas generation, conditioning and synthesis train operations
- Low temperature technologies such as oil splitting involve mature technologies which have reduced risk
  - Mature oil splitting and oil recovery technologies will probably generate co-products which have to be considered
  - Low temperature technologies which treat cellulosics will have to find a suitable use for all fractions of the feedstock in order to achieve competitiveness
- Fermentation based processes are being used to produce new "biomonomers"
  - Continuous large scale processing will be required for cost competitiveness
  - The degree of product recovery and purification required may have a large impact on cost

Because very little information is available on up-to-date fermentation-based bioproducts technology, a review based on fundamentals was in order.

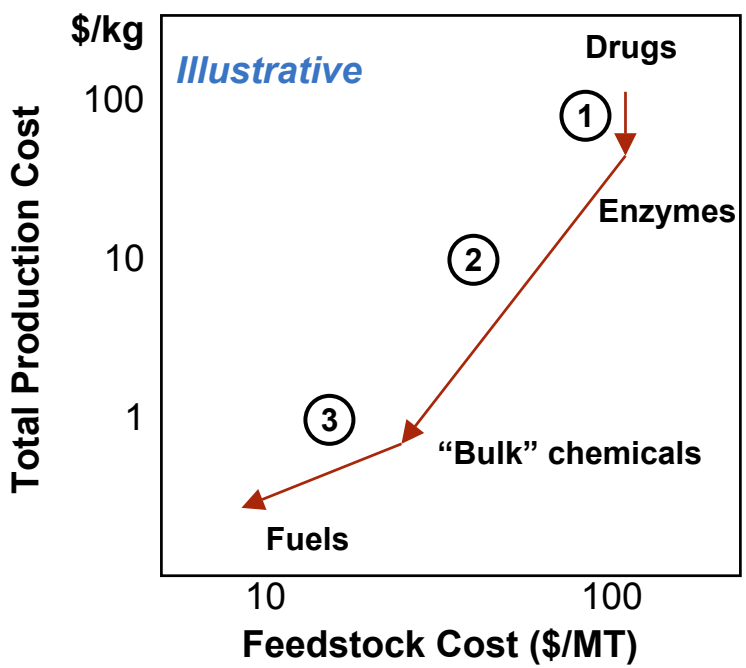
- Specific data on technology performance and critical performance parameters on Cargill-Dow LLC and DuPont programs is not publicly available
- Both of these programs have been received with considerable excitement
- Given the importance of these efforts to the whole bioproducts arena, it is important for DOE to have a more detailed perspective on the key parameters
- A generic analysis was performed on fermentation-based processes to get a perspective on critical developments and performance parameters
- The following pages contain the results of this analysis

Current markets for bioproducts cover a wide range of production scales and market prices driven by each of the applications.

	Antibody	Enzyme	Organic acid
Product type (Target market)	Pharmaceutical	Pharma-chemical	Specialty chemical
Yearly production	10 kg	10 MT	10,000 MT
Production Limit	Process limited	Process/Market	Market limited
Market Price	~ $ 100's per microgram (10^{-6} g)	~ $ 100's per gram	~ $ 1 per kilogram

Reduction of production cost through cuts in feedstock cost, improvements in primary conversion, and success in scale-up are all key to mass market penetration.

Required Production Cost Reduction

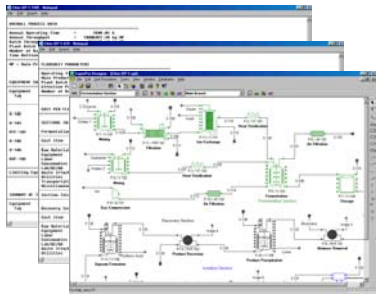


1. Reduction of cost by scale-up of existing processes is required to minimize capital and operating costs (e.g. ADM world-scale corn mills)
2. Fundamental primary conversion process improvement is the most critical step (e.g. Cargill-Dow LLC lactic acid development):
   - Improved product yield
   - Higher product concentration
   - Higher selectivity
   - Increased feedstock flexibility
3. Additional reductions in feedstock cost will be required to meet cost-targets for fuels and certain high-volume chemicals (e.g. possibly through genetically engineered crops)

Processing in a "biorefinery" may reduce the overall production cost and allow for the production of "premium" products with high value but small market volume.

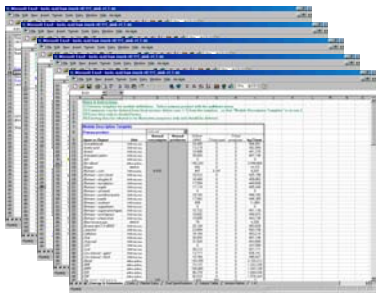
Bioprocess analysis was carried using three levels of process modeling

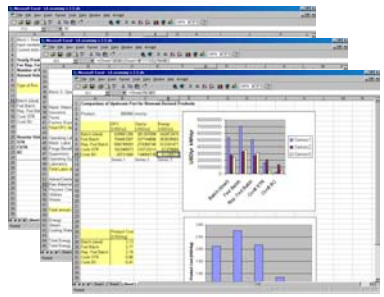
Literature
Engineering methodology
Price indices



Flow sheets
Process Simulations
Process Design

1. Process Simulation
Set up process model to obtain data

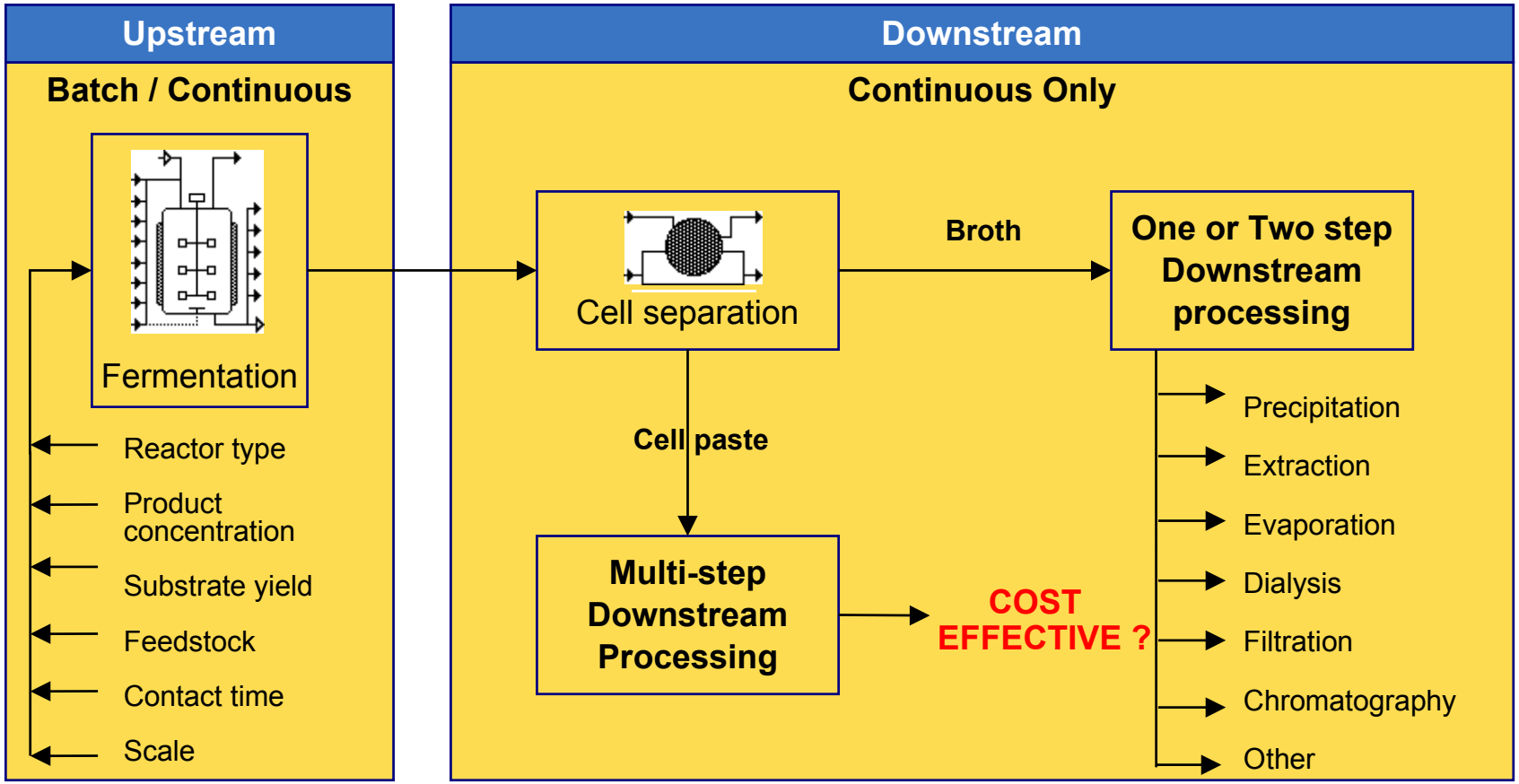




2. Environmental Impact & Cost Estimates
Detailed Process Analysis
to investigate:
– Economical Impact
– Environmental Impact
– Energy Impact

3. Process Parameter Analysis
Scaled back model to investigate
– Scale impact on cost
– Yield impact on cost

To understand the process economics for fermentation-based biomonomers, costs were divided into upstream (production) & downstream (recovery) costs.



For example, in fermentation, the fate of the product remaining inside the cell or excreted into the broth has implications in required recovery costs.

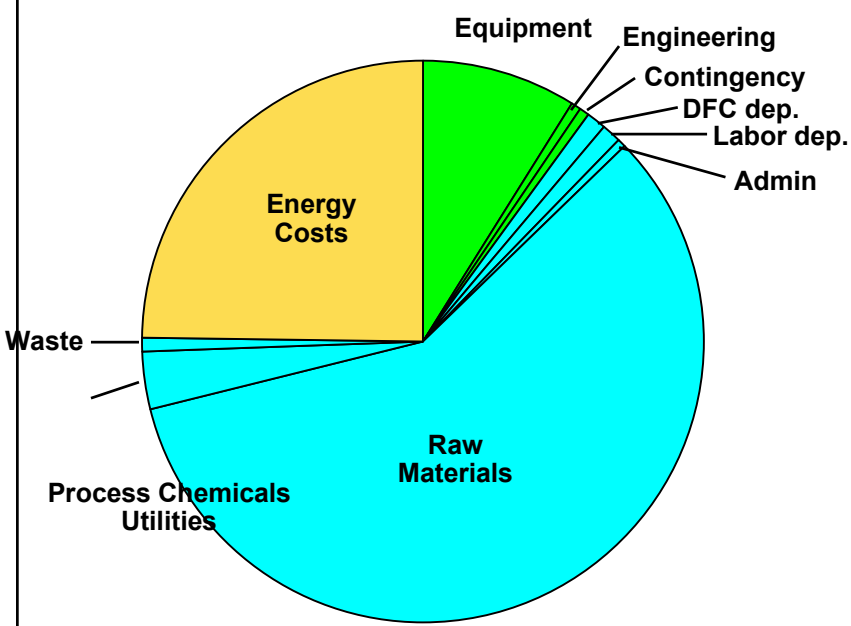
A generic process cost model of a commodity fermentation-based bioproduct was constructed to assess the impact of key process parameters.

Base Case Model: Parameters and Assumptions
1. Lactic Acid was used as a model product with a 500,000 MT/yr target (plant capacity, not single train capacity) 2. The reaction train consisted of 5 airlift bubble column reactors with 1,500 m^3 design volume • Reactor costs are based on a power scaling law • Direct fixed capital costs and operating costs are based on literature data • Energy and raw material cost are based on literature data and simulated process data 3. The reaction trains operate continuously for 8000 hrs/yr 4. A 2-step purification scheme with efficiencies of greater than 95 percent was employed 5. The base case scenario uses the following operational parameters: • Dilution rate, 0.2 hr^{-1} • Product yield on substrate, 0.55 • Product concentration in fermentation reactor, 50 gm/liter • Costs: Raw material (glucose): 133 $/MT — Process Chemicals: 150 $/MT Energy: 0.28 $/kWh — Disposal Costs: 5 $/MT 6. The costs shown are for the upstream processing equipment only (energy costs, labor, capital, installation, maintenance, and raw material costs associated with the fermentation step).

The costs shown do *not* include offsites, downstream purification (and their associated contingency), working capital, or owners cost.

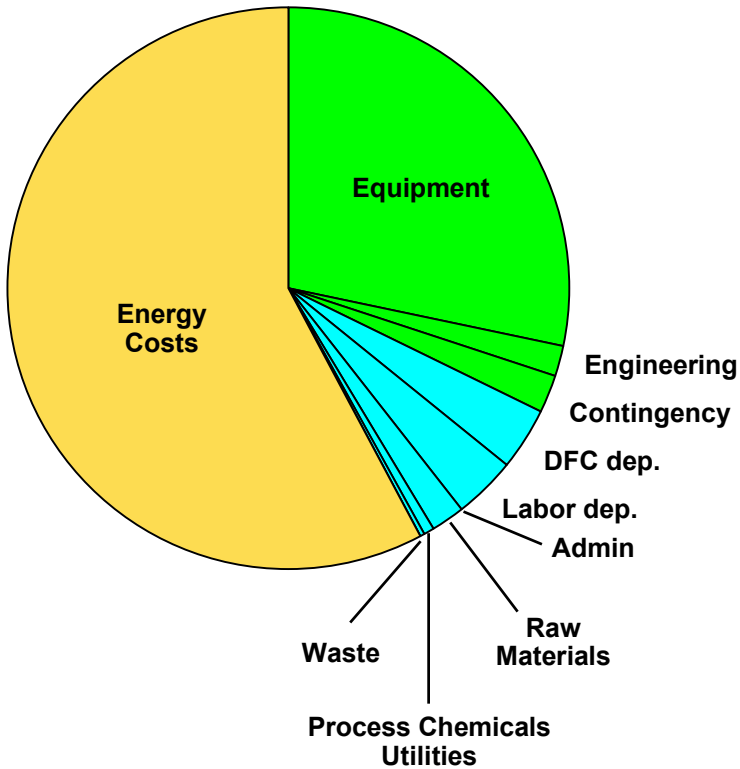
The generic process cost model (using the example of lactic acid production) included the following cost factors:

Base Case Scenario, 0.42 $/kg



DFC is direct fixed cost dependent costs.
Labor dep. is labor dependent costs.

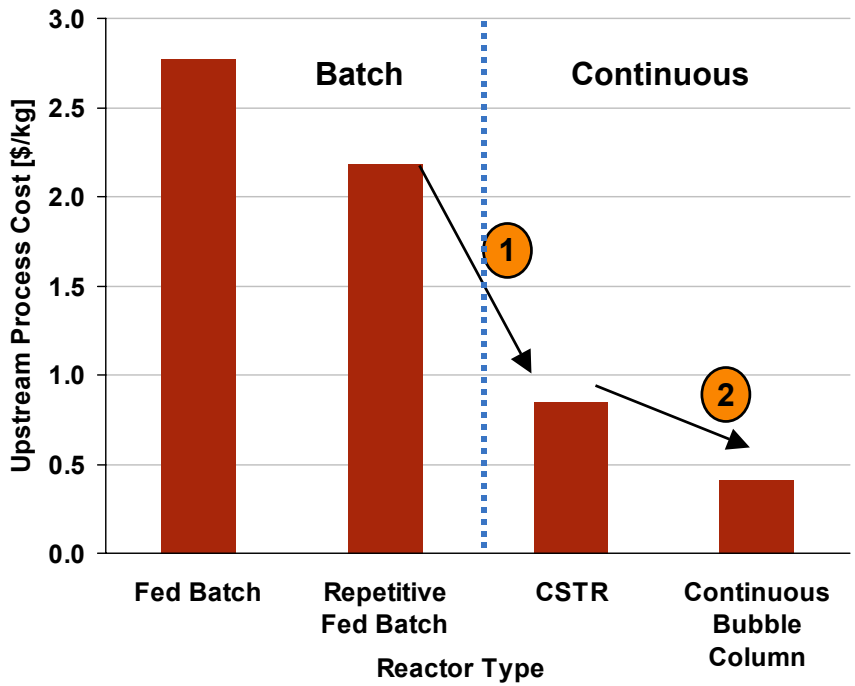
Worst Case Scenario, 2.77 $/kg



The costs shown do *not* include offsites, working capital, or owners cost or overall project contingency.

High-capacity continuous reactors will be needed for upstream conversion in order to achieve costs competitive with petroleum-based products.

Influence of Reactor Type and Process Type on Upstream Process Cost



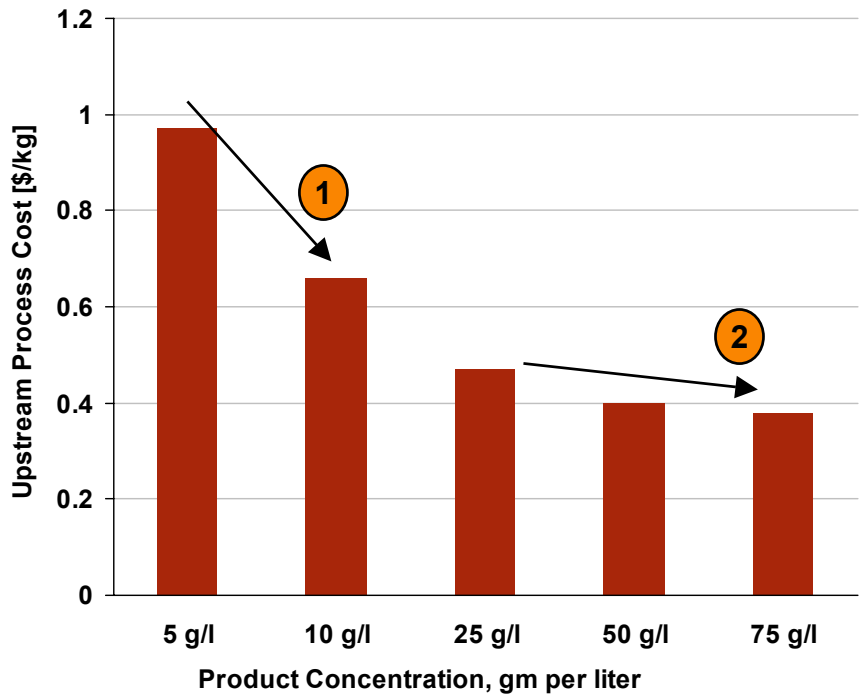
1. The significant reduction for the continuous process results from several parameters:
   - Better equipment utilization, requires less reactors
   - Less reactors result in lower investment cost
   - Less reactors result in lower operating cost
2. The further decrease in production cost using a bubble column type reactor (from a CSTR) is due to the larger reactor volume and the reduced energy input required for this type of reactor.

Note: The definitions of the reactors studied are as follows: Fed Batch is a Batch reactor in which the cells are grown to the optimal condition after which the product is harvested. The reactor is then emptied and sterilized and the cycle started over again. A repetitive fed batch is similar to the batch reactor except when harvesting is completed, a portion of the cell mass is retained as a "starter" for the next cycle. The cycle time for a repetitive fed batch reactor system is shorter than for a fed batch system. A CSTR is a continuously stirred tank reactor.

The costs shown do *not* include offsites, downstream purification (and their associated contingency), working capital, or owners cost.

To achieve low costs, a threshold product concentration must be achieved but little benefits accrues from exceeding that level.

Influence of Product Concentration on Upstream Process Cost



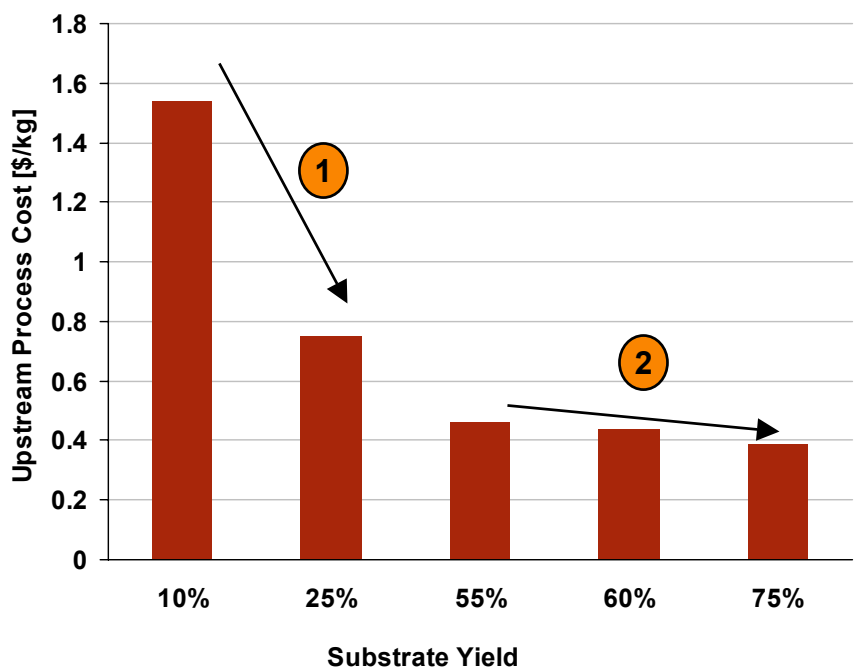
The costs shown do *not* include offsites, downstream purification (and their associated contingency), working capital, or owners cost.

1. Initial exponential reduction in product cost is due to the reduction in the total reactor volume and hence the number of reactors required.
2. After reaching a threshold level, further decreases in product cost are mostly due to improvements on the downstream processing side, which have a much smaller overall impact on the cost.

However, for commodity scale production, small savings in product cost can impact profit margin significantly.

Primary product yield is an important factor, since it influences total raw material cost and cell mass production for a given product.

Influence of Substrate Yield on Upstream Process Cost



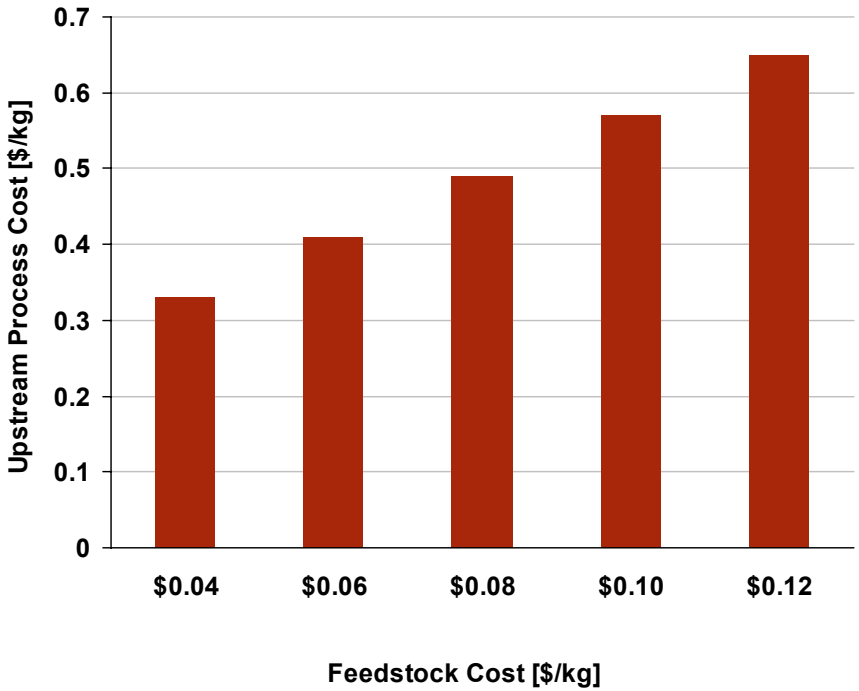
The costs shown do *not* include offsites, downstream purification (and their associated contingency), working capital, or owners cost.

1. Initial cost reduction is due to the reduction in feedstock cost (clearly more important when expensive feedstocks must be used).
2. After reaching a threshold level further decreases in product cost are mostly due to improvements on the downstream processing side due to lesser amounts of by-products and cell mass.

Improvements in substrate yield are more likely to be achieved through genetic engineering rather than through process design.

Reducing feedstock cost is an important aspect of achieving cost targets for commodity markets, but reduction of this cost alone will not be enough.

Influence of Feedstock Cost on Upstream Process Cost

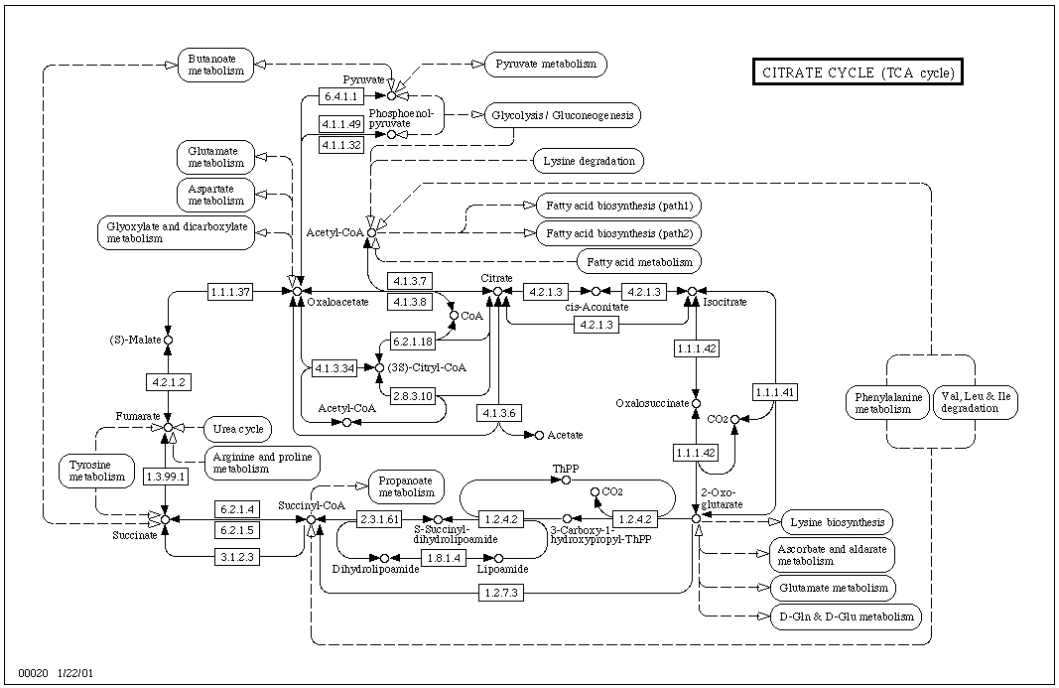


The costs shown do *not* include offsites, downstream purification (and their associated contingency), working capital, or owners cost.

1. The increase in upstream production cost correlates in a linear fashion with the raw materials cost.

Depending on the type of feedstock and of the desired product, the feedstock must be converted into molecules that can be utilized by the micro organisms.

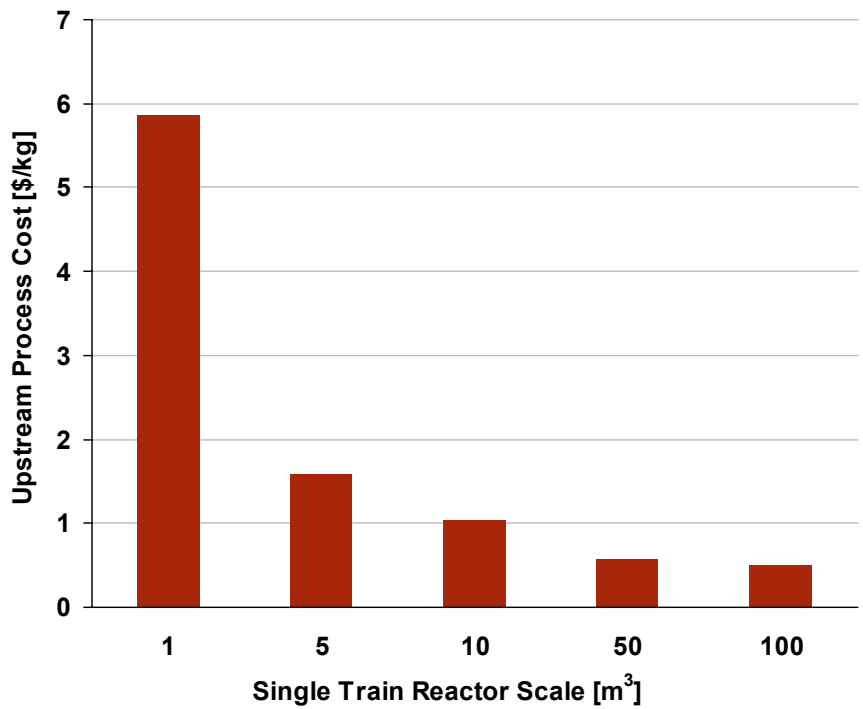
Influence of Feedstock Conversion



1. Feedstock conversion is almost always associated with the TCA cycle in one way or another
2. C5 and C6 sugars are general feed stocks utilizable for most pathways
3. Feedstock conversion can be a separate or concurring operation to the production of the desired bioproduct
4. Feedstock conversion can be a process limiting factor in terms of cost, quality and quantity of the final feedstock

Process scale-up is critical to achieving low cost because of the economy of scale benefits in both capital and non-energy operating costs.

Influence of Reactor Scale on Upstream Process Cost



The costs shown do *not* include offsites, downstream purification (and their associated contingency), working capital, or owners cost.

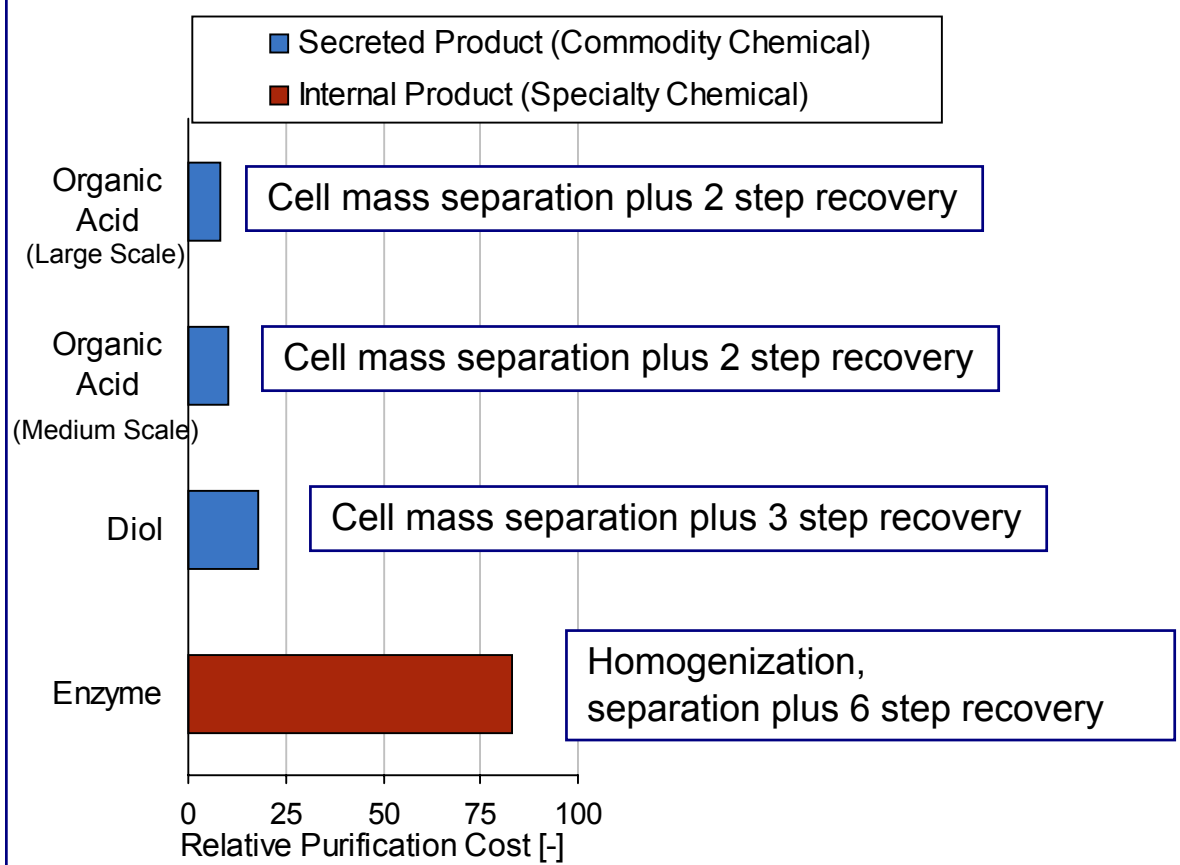
In general an optimal reactor size for cost effectiveness can be found for any process depending on the overall process scale and parameters due to the following trends:

- Relative investment cost decreases with increase scale
- Relative operating cost decreases with increases scale
- Energy intake increases with increased scale

Other limitations such as downstream capacity or plant size might dictate a reactor scale other than the cost minimum.

To achieve cost competitive production, the primary product must be in a form that allows low-cost downstream processing.

Example Purification Costs for Fermentation based Bioproducts



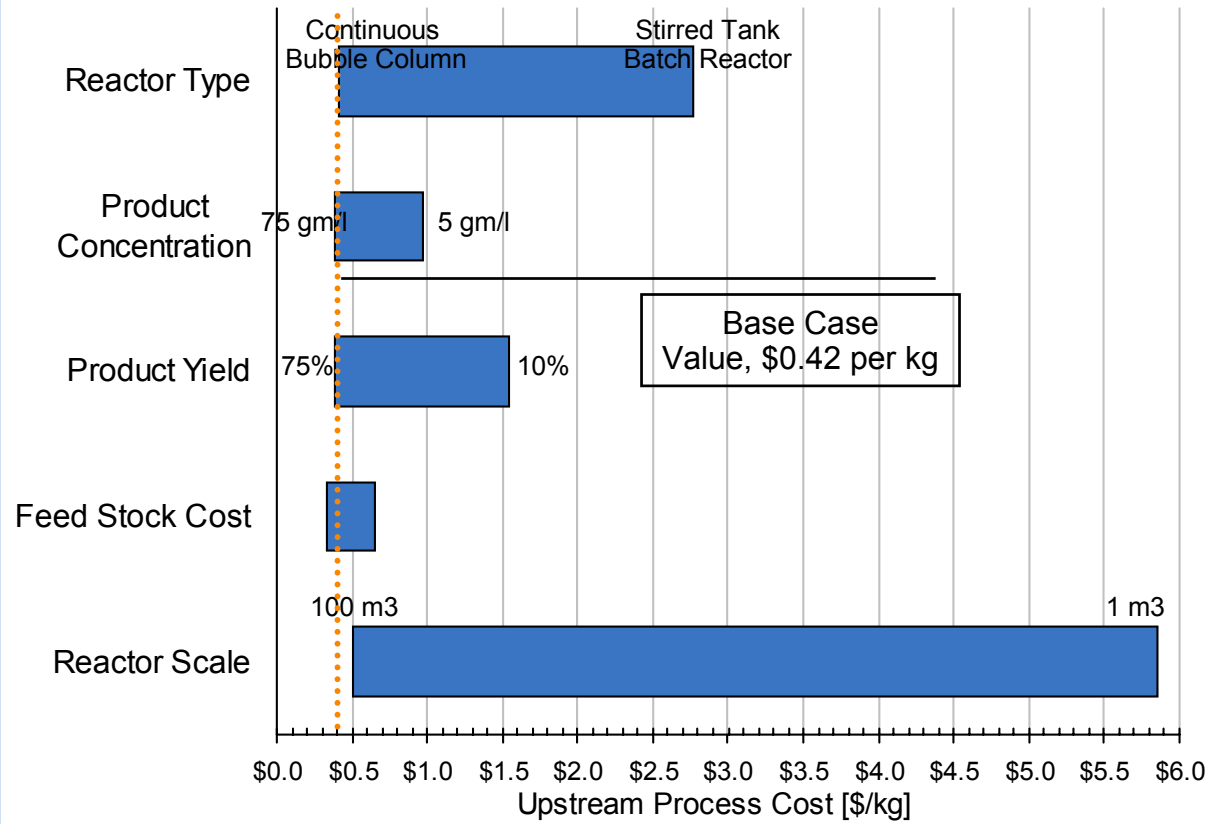
- Key issue in downstream processing is whether product is secreted or internal to the cells:
  - –Secreted product allows simple cell-mass separation and product recovery from supernatant
  - –Internal product requires cell destruction, homogenization, and more complex recovery from homogenized mixture
- Practically, cost-effective commodity products must be secreted

The costs shown do *not* include offsites, downstream purification (and their associated contingency), working capital, or owners cost.

Although reactor scale-up & continuous production are most important, other cost-reducing measures must also be implemented to achieve low cost.

Influence of Process Parameters on Estimated Upstream Process Cost

Range
Bubble Column Reactor, Stirred Tank Batch Reactor
5 gm/l to 75 gm/l
10 % to 75%
$0.04 to 0.12 per kg
1 m^3 to 100 m^3



The costs shown do *not* include offsites, downstream purification (and their associated contingency), working capital, or owners cost.

To achieve the necessary performance and cost improvements both improved organisms and improved reactor engineering will be required.

- Process engineering can be used to achieve the capacity scale needed for cost competitiveness
  - Continuous processing is required for commodity market competitiveness
  - Reaction scale and reactor type have to be sufficient to match both cost requirements and market capacity
  - Process engineering can influence product concentration and product yields
- Genetic engineering of the organisms determines to a large extent, achievable product yields, product concentrations and by-product selectivity
  - Product concentration has to be high enough to allow for effective and simple purification technology
  - Product yield should be high enough to allow for efficient substrate and equipment utilization
  - Product selectivity will be determined in large part by the metabolic pathways used to make the product by the organism
- Low cost (and available) feedstocks are required but alone will not ensure commodity scale cost competitiveness

Several bioproducts appear to be able to approach cost and performance competitiveness with conventional products.

- Fermentation-based polymer building blocks can could offer cost-competitive routes to commodity plastics provided key technology challenges are met:
  - High primary product yield and concentration
  - Large-scale, continuous-reactor production technology
  - Ability to use low-cost feedstock (i.e. waste or cheap to grow feedstock)
- Selected pyrolysis-based and low-temperature-processing-based products may be competitive in medium to large markets:
  - Phenolics from wood pyrolysis
  - Lipid based products such as fatty alcohols, acids, and esters
- Bioproducts based on C_1-chemistry do not appear to come close to being cost-competitive:
  - Should still be considered as co-products in FT-diesel or DME production (bio-refinery)
  - Require similar market premium or subsidy as most competitive fuels

In the long term, further advances in genetics and bioengineering could broaden the appeal of bioproducts.

- Biotechnology could lead to a broader range of products that could be produced through physical separation or fermentation:
  - Currently, fermentation-based products are limited to a few products that are biochemically feasible to produce
  - Agricultural biotechnology efforts utilizing plant production could lead to success for a much wider spectrum of potential products from physical separation and fermentation
- Development of stable production organism strains that allow for:
  - Sufficient product yield
  - Sufficient product concentration
  - Desired feedstock use
- Availability of the desired feedstock cost at low cost and sufficient quantities
  - There may be an optimization process involved
  - Lower cost feedstocks (for example cellulosics) may involve higher capital and operating costs to utilize (e.g. increased difficulty for micro organisms)
- Capital cost reductions are critical
  - There is a need to understand the limits of economy of scale achievable for processes utilizing micro organisms
  - The offsite requirements for biobased processes need to be confirmed
  - Offsite investments, depending on the location, may be a critical issue
  - Studying how existing chemical infrastructure can be leveraged may be critical
- Operating costs for consumables especially any enzyme use must be understood and optimized
- Overall product yield increases will involve an optimization with plant integration costs (e.g. onsite power requirements)
- The most promising bioproducts require little government support to become successful, compared with biofuels such as ethanol