# RECOMMENDATIONS FOR A BIOENERGY PLAN FOR CALIFORNIA

# APPENDIX A:

## Value Networks for Biomass Power and Biofuels - A Working Document to Support the Development of *Recommendations for a Bioenergy Action Plan for California*

FINAL CONSULTANT REPORT

*Prepared For:*

**The Bioenergy Interagency Working Group**

California Energy Commission
Air Resources Board
California Environmental Protection Agency
California Public Utilities Commission
California Resources Agency
Department of Food and Agriculture
Department of Forestry and Fire Protection
Department of General Services
Integrated Waste Management Board
State Water Resources Control Board

*Prepared By:*

**Navigant Consulting**

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# Value Networks for Biomass Power and Biofuels

Working Document to Support the Development of *Recommendations for a Bioenergy Action Plan* for the State of California

**FINAL**

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## Purpose of Document

This document contains information on biomass in California which is organized using Bioenergy Value Networks, a framework created by Navigant Consulting to facilitate analysis of policy options. This document was created with data extracted from the references reviewed as part of an assignment to capture existing information on biomass in California and to support the development of *Recommendations for a Bioenergy Action Plan* for the State (Contract No. 700-02-004). Value Networks for Biomass Power and Biofuels is a supporting document, and is not intended, in whole or in part, to be comprehensive or conclusive. The potential state actions listed in this document are a compilation from various sources and do not represent a prioritized or final list of recommended actions. This can be found in the *Recommendations for a Bioenergy Action Plan.* The reader should be advised that Navigant Consulting has not independently verified the data contained in the references utilized.

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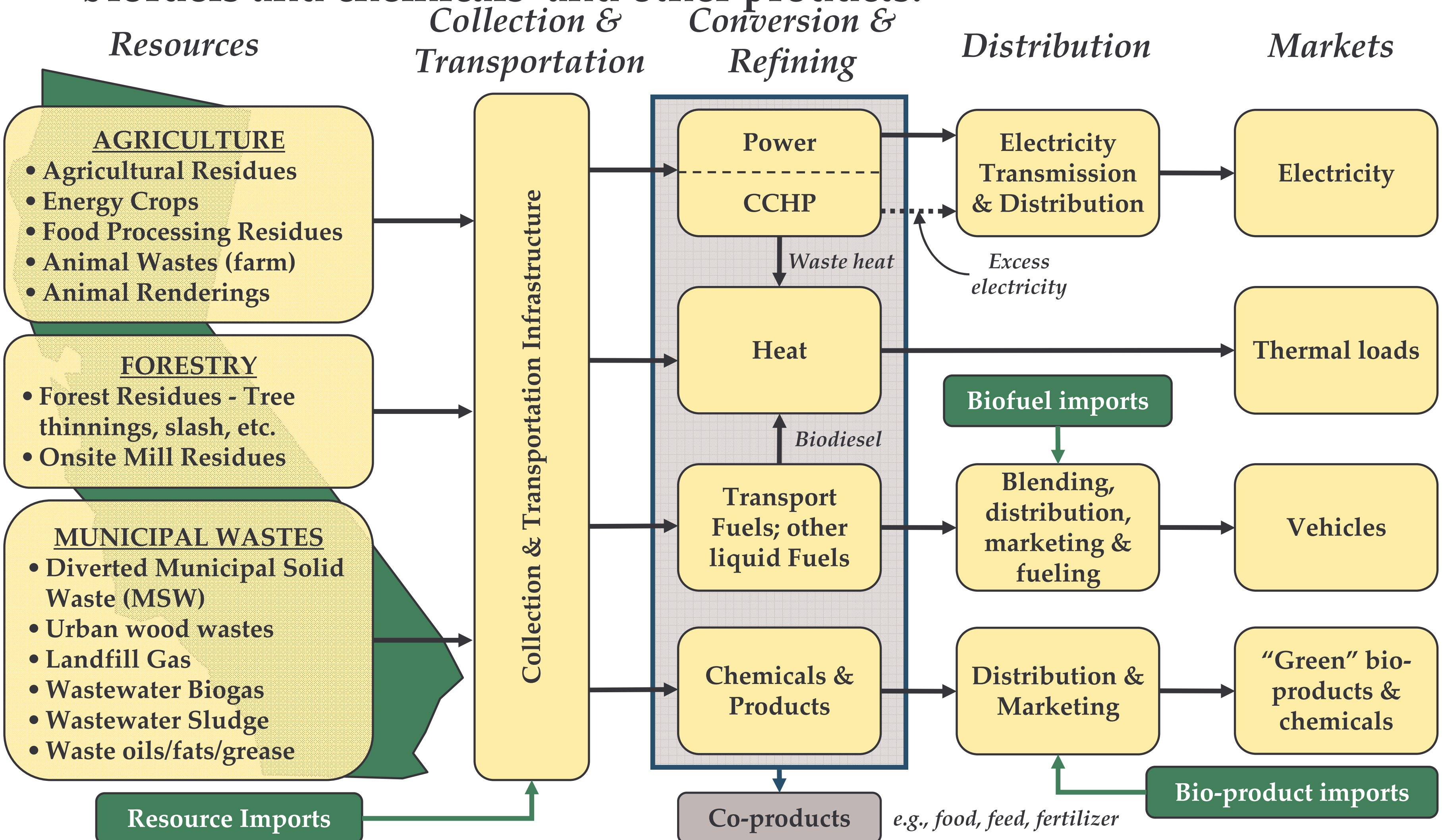
# Value Networks for Biomass in California produce power, heat, biofuels and chemicals and other products.



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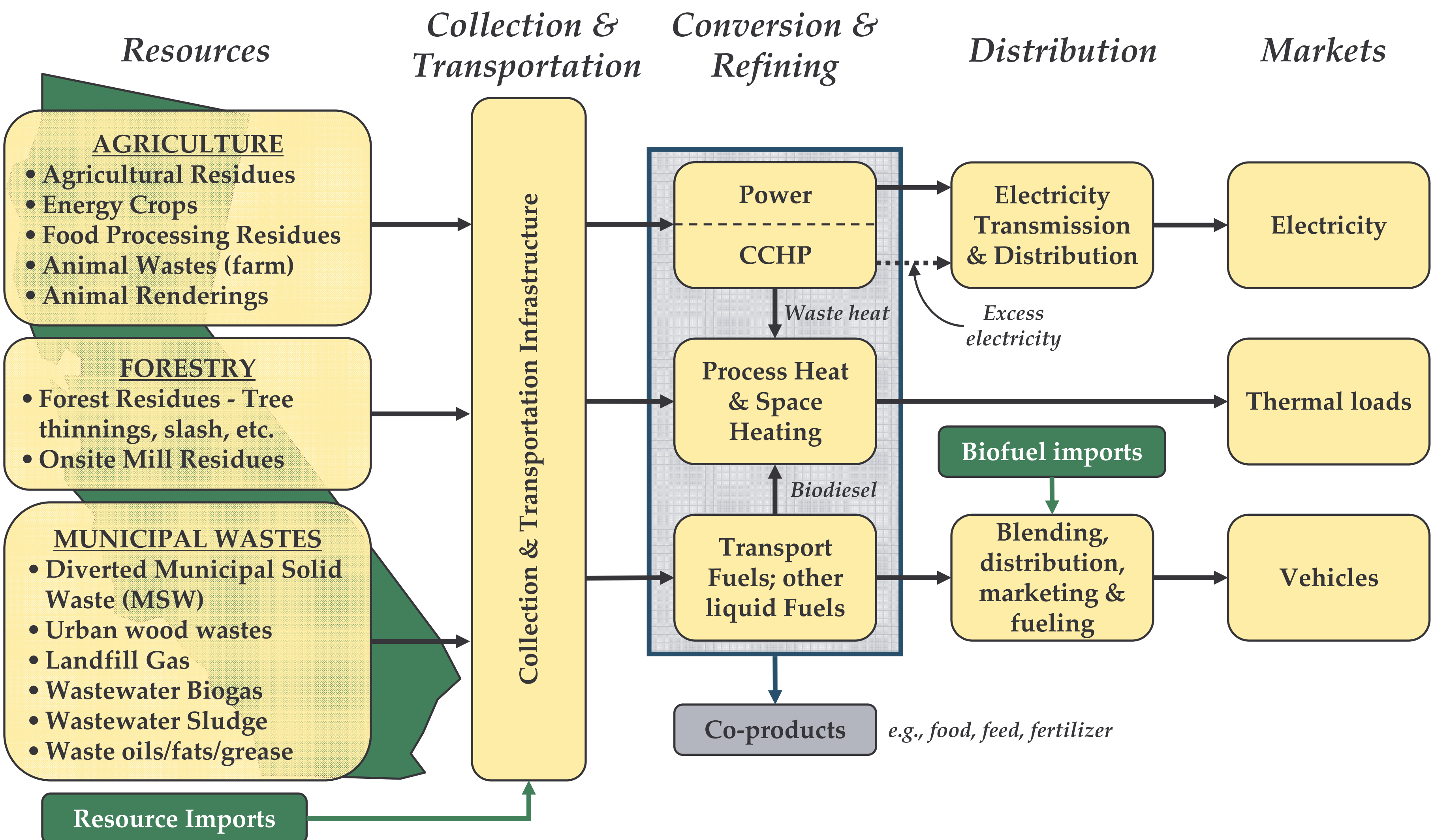
# The focus of this analysis was on power and fuels.



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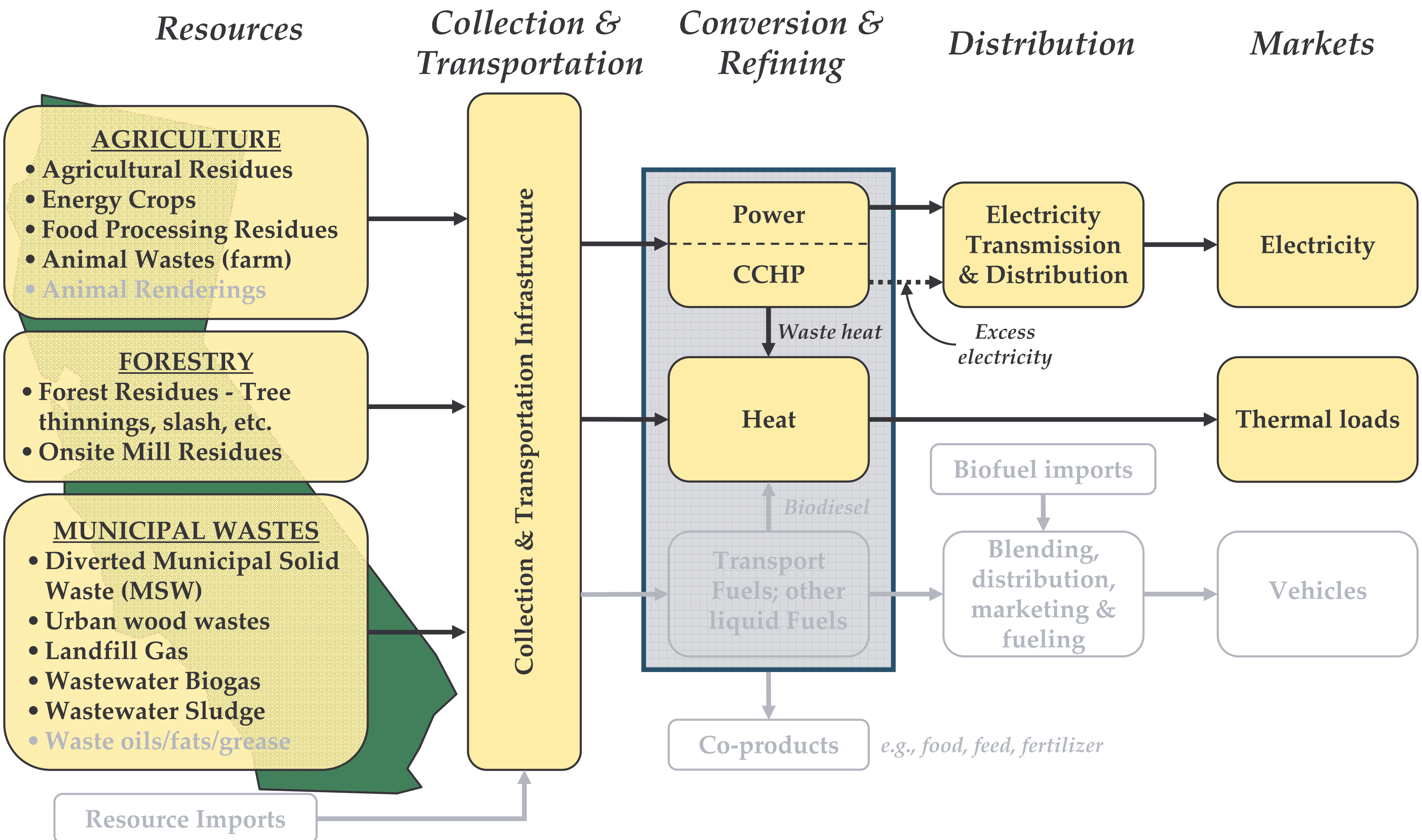
# Primary Value Networks for Biopower.



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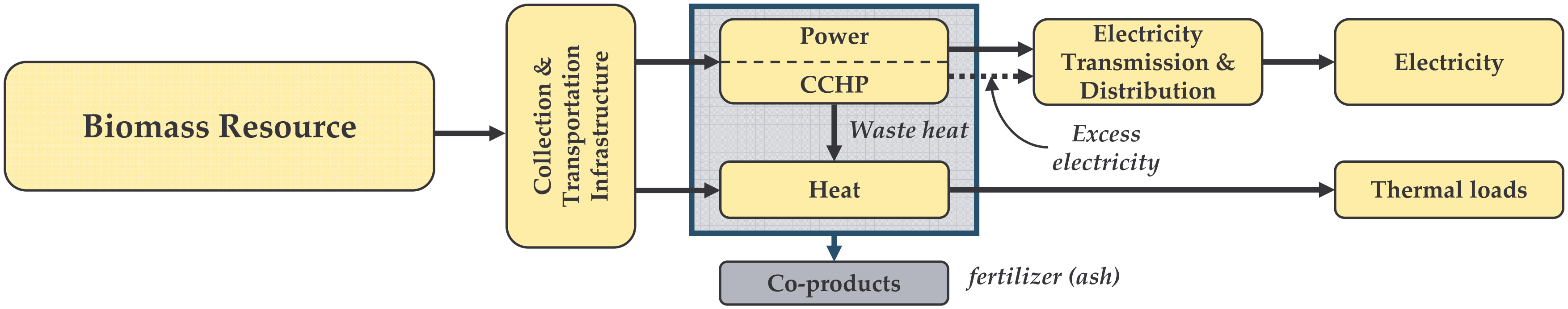
# Certain characteristics and issues are similar for many biopower resources. These are referred in succeeding slides as *Common Issues.*




| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • Of the 34 MDT technically available today, only 4-5 MDT are currently utilized. (7 pg 53) | • Current collection and transportation characteristics tend to be unique for each resource types and are detailed in the following slide. | • Thermochemical processes (e.g., combustion, gasification) tend to be high throughput as compared with biochemical processes and can utilize a wide range of biomass types (7 pg 33)<br>• Existing and near-term planned biomass grid generating capacity in CA in 2005 was 969 MWe including solid fuel combustion power plants and engines, boilers, and turbines operating on landfill gas, sewage digester gas, and biogas from animal manure. | • Biomass capacity is about 2% of statewide peak power capacity (7 pg 33)<br>• Current biomass accounts for 24% of California net renewable system power, and 20% of gross renewable power. (7 pg 36)<br>• Because power is exported to the grid, most facilities require interconnection to transmission substation<br>• Smaller onsite facilities may be entitled to utilize simpler interconnection standards under Rule 21 | • Most are operating under negotiated fixed price amendments to Standard Offer 4 (SO4) contracts created in 2001 at a price of 5.3¢/kWh (7 pg 40)<br>• Many facilities receive capacity payments under the SO4 contracts of 2¢/kWh (7 pg 40)<br>• Onsite, self-generation and combined heat and power (CHP) applications also exist. |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Costs** | • Fuel costs estimates between $20 and $40/BDT are assumed when developing LCOE figures. (7 page 50) | • Most transportation cost characteristics and issues are unique for each resource and described in the slides below. | • Most conversion and refining characteristics and issues are unique for each resource and described in the slides below. | • Interconnection costs are high for standby and exit fees if plant is designed to satisfy local load.<br>• Interconnection costs vary by location. | • For new facilities, the 2004 Market Price Referent (MPR) without Supplemental Energy Payments (SEP) is ~5.8¢/kWh<br>• The more efficient the technologies, the less impact feedstock price has on the LCOE.<br>• Direct combustion plants exceed the cost of wind and geothermal because of fuel costs. |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Constraints** | • Production costs for biomass fuel exceeds that for fossil fuels (7 pg 58) | • Transportation costs of distributed resources may limit size of facility to the fuel that can be delivered within a short distance (7 pg 48)<br>• Competition exists among vested utility, fuel, and waste management infrastructures (7 pg 56)<br>• Lack of coordination among jurisdictional agencies (7 pg 56) | • New biomass development to meet RPS requirements may only occur when feedstock supplies and long-term energy purchase contracts can be assured. (7 pg 36)<br>• Few programs exist for training skilled personnel to work in biobased industry. Educational institutions typically do not have the funds to develop these programs. (7 pg 58)<br>• Uncertainties in new technologies make financing difficult (7 pg 57)<br>• A lack of environmental data in new technologies makes permitting difficult. (7 pg 57)<br>• Lack of public awareness and advocacy (7 pg 56)<br>• Time consuming to permit (7 pg 59)<br>• Lack of environmental impact data on projects in operation results in "worst case" public perception (7 pg 60) | • Interconnection process is time and cost uncertain (7 pg 60)<br>• Simplified onsite generation interconnection (Rule 21) can still be costly (7 pg 60) | • Lack of Direct Access retail and wholesale level (7 pg 57)<br>• RECs not permitted to meet RPS, limiting market for biopower<br>• Net metering capped (7 pg 60)<br>• Fixed price contracts or SEPs do not account for inflation. (7 pg 57)<br>• Increased capital costs for more efficient technology my reduce any returns gained that could have offset SEPs not accounting for inflation<br>• SRAC calculation uncertainty<br>• Muni's only have RPS "targets" rather than requirements.<br>• Muni contracts do not pay SEP payments since SEP monies are from public goods charges (PGC) not collected by munis<br>• Federal tax credits for biomass are not as favorable as for other sources<br>• No GHG market<br>• Few direct development incentives exist and lack of predictable state and federal management programs (7 pg 56)<br>• Lack of stable long-term economic and financial incentives and compensation for public benefits provided (7 pg 56) |

## **Biopower** » Common Issues

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Potential, Timing, & Magnitude** | • Co-firing with other fuels, such as natural gas and coal, allows greater flexibility in fuel selection. Improvement in both thermo and bio conversion options will lead to greater fuel selection flexibility. (7 pg 33)<br>• Total feedstock expense to supply the statewide technical resource estimate of 34 MDT at $30/BDT would equal approximately $1B. (biogas not considered)<br>• Resources are available to meet projected demand, but such development would stimulate competition for biofuels like in the early 1990s, but could be offset by policies in waste management to separate solid waste. (7 pg 36) | • Locations benefiting transmission system "Hotspot sites" have been identified in the Strategic Value Analysis (37) | • Gasification combined cycle systems advancements should enable efficiencies to increase from current 20-28% up to 35% or more, (7 pg 33)<br>• Conversion efficiency improvements, growth in population, and dedicated crops resource should enable an incremental generation growth of 7,100MW by 2017. (7 pg 34)<br>• Without improving efficiencies, incremental capacity in 2017 would be closer to 4,800MW. (7 pg 34)<br>• By 2017, energy from biomass could reach 60,000GWh or 18% of projected statewide consumption of 334,000GWh. (7 pg 34)<br>• If biomass were to maintain a 20% share of net system power, then 660MW of biomass capacity would need to be added by 2017, assuming an average capacity factor of 85%. (7 pg 36) | • Smaller distributed facilities may be able to better capture benefits associated with voltage support for the local grid, reduced power transmission, decreased transportation, and better potential for waste heat utilization in combined heat and power (CHP) (7 pg 34)<br>• Some types of biomass systems could operate in peak markets, or , could serve as base load facilities to conserve natural gas supplies for meeting peak demands (7 pg 14)<br>• Distributed smaller generation systems have wider access to CCHP opportunities. (7 pg 42)<br>• Resource location relative to electric grid is critical | • Renewable Portfolio Standard (RPS) contracts with IOUs paying Market Price Referent (MPR) + Supplemental energy Payments (SEP)<br>• SO4 contracts with IOUs or Muni's paying higher SRAC or fixed prices<br>• Federal Development Incentives –Production Tax Credits ( PTC)<br>• Monetizing environmental and waste management benefits to defray fuel costs and improve economics (7 pg 41)<br>• Combining power applications improves economics such as matching power and heat applications (16 pg 42) |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Potential, Timing, & Magnitude (continued)** | | | • The current technical potential is 4700MW which could generate about 35,000GWh, or 12% of the 283,000 GWh of electricity currently used in the state (7 pg 33)<br>• Incremental capacity additions exclusive of existing and near term planned generation could exceed 3,600 MW. (7 pg 34)<br>• After meeting the RPS, annual increment of 14-16 MW would be needed to maintain biomass share if electricity demand continued to increase at the same rate and the RPS target remained at 20% (7 pg 36)<br>• If the state accelerates the implementation of the RPS to 33% by 2020, annual additions would need to increase to maintain 20% share at approximately 70-95MW per year and net cumulative addition through 2020 of 1,450MW. This would be ~2,400MW total. (7 pg 36) | | • The future value of greenhouse gas (GHG)/carbon credits, other emissions credits or offsets and renewable energy certificates (RECs) will all have a significant impact on biopower economics. |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Benefits** | • Reduced dependence on non renewable fuel<br>• Rural economic development | | • "The renewable energy sector generates more jobs per MW for electric power installed, per unit of energy produced, and per dollar invested than does fossil fuel sector" (7 pg 9)<br>• Biomass is estimated create 3-6 jobs/MW (37 pg 30)(7 pg 9)<br>• Lower emissions, higher efficiency, better resource utilization with new, more efficient technology | • Flexible energy resource that can be dispatchable or baseload. (7 pg 41 check)<br>• Distributed generation can alleviate load pockets and provide grid support<br>• Onsite generation avoids retail electricity costs (7 pg 42)<br>• Self-gen reliability | • Meeting Renewable Portfolio Standard. Biopower currently provides 20 percent of the renewable energy resources<br>• Using biomass in conversion technology rather than natural gas reduces CO2 emissions from natural gas (7 pg 4)<br>• Resource Adequacy Contribution to help provide power capacity reserves to enhance grid reliability and to help reduce risk of electric price volatility due to possible power supply shortages.<br>• Baseload capability. Use of biomass power facilities for this purpose could help reduce the amount of incremental new gas-fired facilities that would otherwise be required. |

## **Biopower** » Common Issues

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Needs** | • Need to adopt a policy on CO2 sequestration to meet state goals.<br>• Air quality permitting needs to take into account alternative fates of biomass fuels, which are usually much worse (16 pg 26) | • Agency coordination<br>• Smaller (onsite?) applications to reduce handling cost<br>• New technology to improve fuel handling and transportation infrastructure<br>• Need better developed production systems (7 pg 53) | • Increase public and policy awareness about technology and benefits through demonstration<br>• Expediting of permits<br>• Research and development (R&D) to increase conversion efficiency with without higher capital cost<br>• Skilled operating personnel<br>• Need comprehensive lifecycle assessment for integrated waste management and other biomass strategies. (45 pg 7)<br>• Direct incentives for development (7 pg 53)<br>• Incentives for increasing efficiency<br>• Matching of power and heat applications and combining of conversion applications to gain economic competitiveness (7 pg 41) | • Grid benefits of congestion reduction and voltage support could be monetized (16 pg 29, 42)<br>• Uniform statewide interconnection standard<br>• Expand net metering for biomass; eliminate caps | • Increased use of biomass in RPS, RPS needs a category for transmission benefits, baseload support or some combined category. (7 pg 57)<br>• Extension of PTCs, development programs, production tax incentives<br>• Carbon credits, incentives for CO2 sequestration through crop uptake<br>• Greenhouse gas (GHG) credits<br>• RECs need to account for direct environmental services provided, so biomass gets unique compensation (16 pg 11)<br>• long-term contacts |

| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | 2006<br>• CEC to provide permitting support to local agencies<br>— Develop a State New Source Review program<br>— Develop a single BACT for LFG projects<br>— Exemptions for biogas technologies as Pollution Control Projects<br>— Explore Cross or Inter pollutant netting<br>• Complete a comprehensive RD&D “roadmap” to guide future research, development and demonstration activities through the California Biomass Collaborative and other organizations<br>• Create training programs for operating personnel<br>• Promote state, local government procurement standards to use more biopower<br>• Work on extension of Federal PTC’s<br>• Establish standards for the sustainable development and use of biomass that ensure environmental objectives are met in all areas, including air and water quality.<br>• Coordinate state production incentives: SEP, state production tax credits, tradable credits to make useful for new projects<br>• Work with WGA to influence federal funding decisions<br>• Develop programs to monetize the environmental benefits of biomass-to-energy by estimating the costs of alternative fates for the biomass materials (e.g., forest fires). Could be implemented via a carbon tax, carbon adder, or other means).<br>• Conduct RD&D on cropping systems, harvesting, handling, storage & distribution practices and technology, in coordination with a larger state and Federal level R&D effort.<br>• Appoint Bioenergy Interagency Working Group (BEIWG) to implement the Action Plan and coordinate biomass activities on a statewide level.<br>2007 – 2010<br>• Establish carbon tax that benefits biopower production<br>• Encourage congress to mandate utilization of biomass energy at federal facilities |
| **Regulatory Actions** | • Develop clear long-term biopower regulatory policy.<br>• CPUC to expand role of biomass in RPS due to its baseload capacity abilities.<br>• CPUC to continue efforts on simplifying interconnection standards and practices<br>• CPUC to expand net metering for biomass; eliminate caps<br>• CPUC to create methodology that encourages long-term power contracts for new biopower projects |
| **Legislative Actions** | • Create state tax credits, energy investment tax credits or expand tax exempt financing from California Pollution Control Financing Authority<br>• Establish loan guarantee revolving fund to reduce risk<br>• Seek dedicated state funding in FY 2006 and FY 2007 budgets to support new financing, tax initiatives, and other programs. |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**

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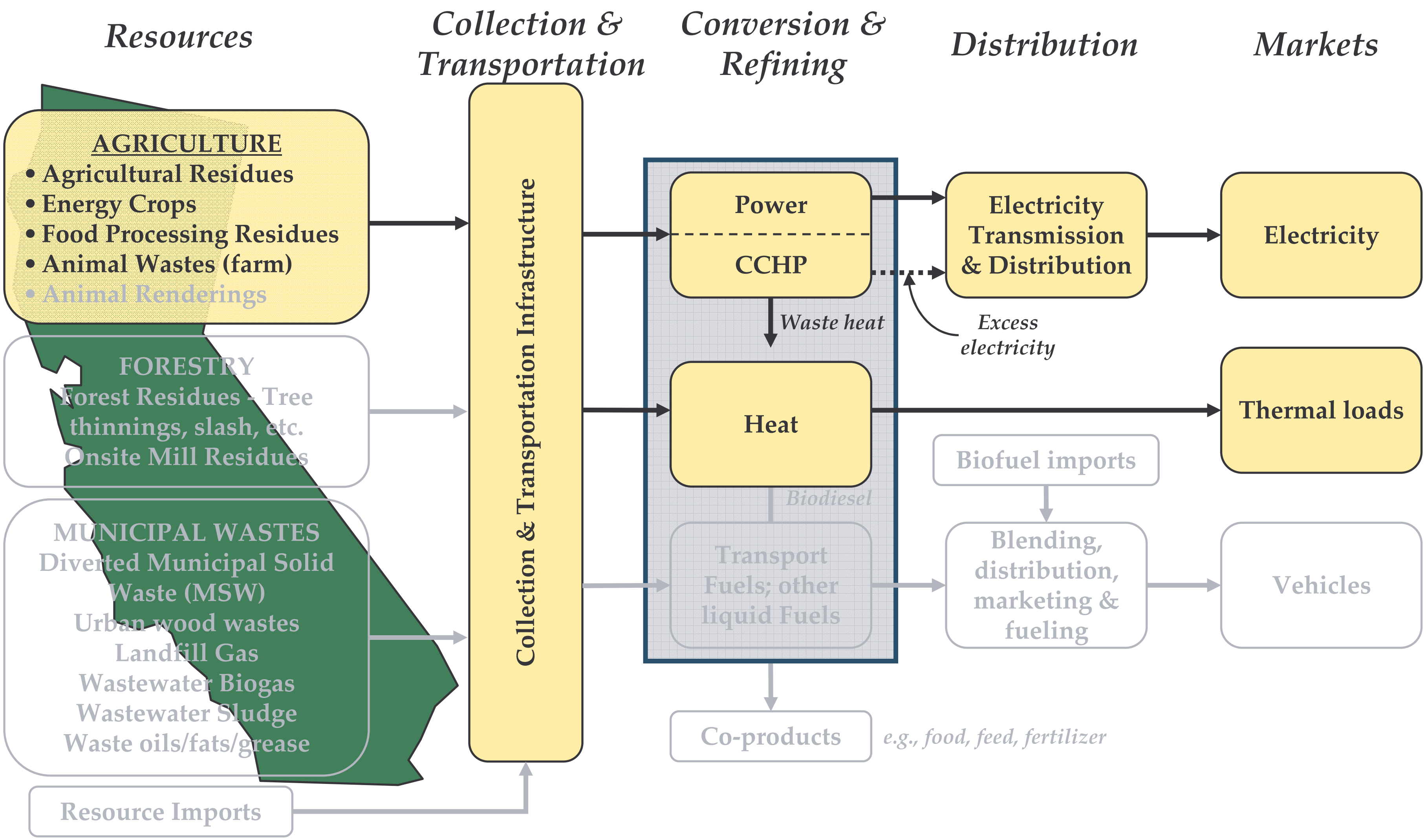
# Value Networks for Biopower from Agricultural Resources.



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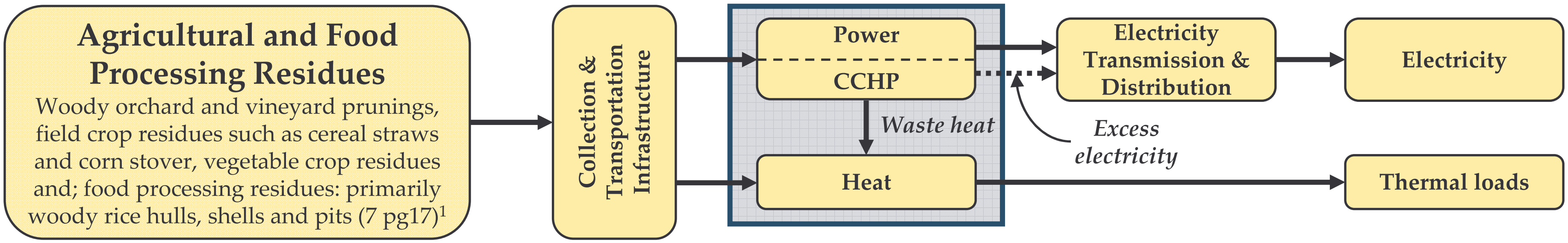


| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • 1 MDT/yr prunings used for power productions; typically with other other biomass (7 pg17)<br>• Field crops not generally utilized in power applications (7 pg17)<br>• Vegetable crop residues typically reincorporated into soils. (7 pg 17)<br>• 250,000 tons/yr food processing waste utilized for power (7 pg17) | • Offsite residues transported by trucks<br>• Large storage area often needed to balance timing of harvesting with energy production (7 pg 49)<br>• Collection and costs depends on crop & harvesting process (7 pg 48, 49)<br>• Densification not typical in current infrastructure (7 pg 49) | • Direct combustion technology (current)<br>• 93 MW orchard and vine waste power producing facilities in operation producing 694 GWh/yr (7 pg 35)<br>• 44 MW food processing waste power production facilities in operation producing 328 GWh/yr (7 pg 35) | • Distribution and interconnection characteristics similar for all biomass conversion types and detailed in the overall discussion slides. | • Existing markets are similar for all biomass and are detailed in the overall discussion slides. |

1. High moisture content food processing residues (e.g., cheese whey) can be utilized in onsite anaerobic digestion CCHP applications, or disposed of through municipal waste water and utilized as described in the WWTP section. (7 pg 33).



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## **Biopower** » Agricultural and Food Processing Residues › *Current Situation Assessment (2 of 2)*

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Costs** | • An average of $22/BDT for ag residues depending on distance and quality of resource (37 pg 11) | • Short haul costs included in resource cost, but do not include storage and processing (37 pg 53)<br>• Facilities utilizing feedstock onsite may have limited additional collection and transportation costs.(7 pg 48)<br>• Residue management or utilization costs not typically accounted for in commodity selling price (7 pg 48) | • New biomass power plants are estimated to have an installed capital costs of between $1,500-$3,000/kW (7 pg 38) | • See *Common Issues*. | • LCOE estimated at 6.2¢/kWh without production tax credit (PTC) for 25MW stoker boiler facility (37 pg 60, 62) assumed for ag applications with fuel at $22/BDT assumed for hauling prunings.<br>• LCOE estimated at 4¢/kWh for onsite nutshell type food processing applications with no fuel costs (37 pg 62) |
| **Constraints** | • Distance to fuel is critical. Low density, low BTU fuel limits allowable distance. (7 pg 49)<br>• Some crops require retilling of residue to maintain soil nutrients (7 pg 48)<br>• Food processing wastes may only be seasonally available. (7 pg 49) | • Production systems and markets not well developed. (7 pg 53) | • Fuel quality is critical; combustion system fouling more common with field crops than woody biomass. (7 pg 17) | • See *Common Issues* | • See *Common Issues*. |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Potential, Timing & Magnitude** | • 4.9 MDT/yr prunings, field crop, and vegetable crop residues, and food processing residues estimated technical potentially available today (8 tbl 4.1)<br>• Orchard removals are available year round (7 pg 49)<br>• Resource production expected to remain at current levels (7 pg 28)<br>• SB 705 restrictions on open burning and SB 700 repeal of ag air permitting exemptions increases resource availability (45 pg 26) | • Estimates assume a 25 mile radius limit from a substation for transportation, although some resource potential may be beyond feasible distance. (37 pg 72) | • 496 MW & 3,691 GWh technical at current capacity factor (55%) & efficiency (20%) (includes orchard and vine, field and seed, vegetable and food processing biomass) (7 pg 35)<br>• Could increase to ~750MW & 5,600 GWh/yr with new technology (e.g., BIGCC @ 35% efficiency) | • See *Common Issues* | • Reduced fuel costs could lower direct combustion application LCOE closer to that of wind projects. (7 pg 41)<br>• Advanced more efficient conversion technologies could reduce LCOE closer to wind, although increased capital costs could offset this. (7 pg 41)<br>• Valuing heat in CCHP applications can reduce LCOE below wind. Could reduce LCOE to .057¢/kWh. (7 pg 42) |



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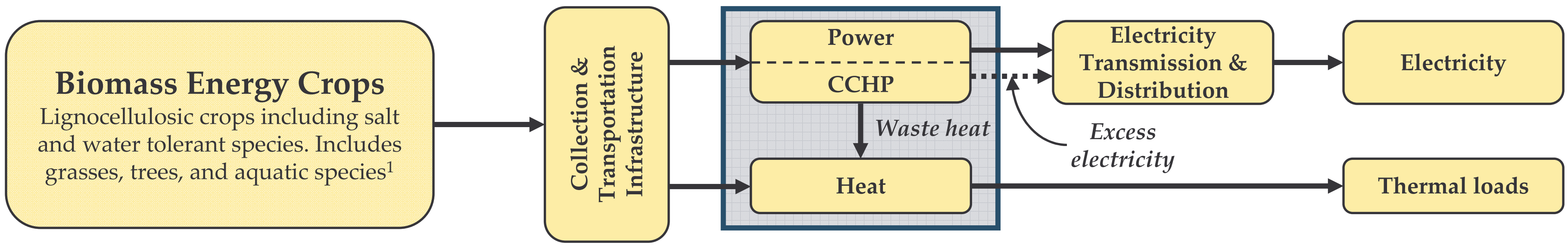
| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Benefits** | • Could create additional farm revenue from new products and markets (7 pg xiv)<br>• Opportunities exist for integrating dedicated biomass crops into remediation programs to repair salt-affected and other contaminated lands. | • Local (rural) economy benefits. A significant portion of the fuels and feedstocks originate in rural areas of the state. Could create new value-added markets and new local jobs. | • Local (rural) economic boost (37 pg 30)(7 pg 9) | • See *Common Issues* | • Decreased decomposition of residues in open fields reduces other green house gas pollutants such as methane |
| **Needs** | • Better Agency coordination (Waste, Ag and Energy) to support increased use of ag resources<br>• Biomass densification (7 pg 49) | • Agronomic practices and management approaches may need to change, (7 pg 53)<br>• See *Common Issues* | • Restarting mothballed plants<br>• See Common Issues | See *Common Issues* | • Farm commodity tax/fee to incentivize development (45 pg 10)<br>• See *Common Issues*<br>• Need more developed markets (7 pg 53)<br>• Power and heat applications need to be matched to gain economic competitiveness (7 pg 41) |

| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • Agency (Waste, Ag and Energy) coordination.<br>—Ag Agency report on market for agricultural crop residues<br>—Develop statewide system for capturing environmental benefits of biopower<br>—Widely disseminate broad based benefits of biopower – demo projects<br>• Facilitate long-term fuel delivery contracts to maintain collection and delivery infrastructure .<br>• Create training programs for operating personnel<br>• Establish (or provide loan guarantee for) a commercial demo biogasification project<br>• Establish regional manure management centers as potential sites for dairy bio-digesters in the San Joaquin Valley.<br>• Streamlined permitting.<br>• Develop clear long-term biopower regulatory policy.<br>• Expand and broaden programs such as the Dairy Power Production Program to encourage greater use of animal, food processing, and urban residues and waste waters for power generation and biofuels production.<br>• See *Common Issues*<br>2007-2010<br>• Create new R&D programs on harvesting, handling, and storage practices and technology<br>• New R&D to solve fouling problem and increase efficiency |
| **Regulatory Actions** | • Initiate a proceeding to address net metering opportunities for biomass (including consolidating net metering accounts on a farm, using existing power lines on their properties for grid access, & higher net metering limits). |
| **Legislative Actions** | |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**




| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • Not currently utilized in California | • NA | • 0 MW in operation | • NA | • No specific market for energy crops, but could compete in RPS solicitations just as residue projects are doing. |
| **Costs** | • Dedicated crops assume all production costs, but may also contribute to other high value benefits such as soil remediation (7 pg 48)<br>• Variable production costs due to species, production site, level of management, resulting yield (7 pg 48) | • Pretreatment or sorting processes to remove contaminants | • Higher capital costs for improved technologies to deal with pollutants | | |
| **Constraints** | • Water is the likely the limiting resource (5g 27)<br>• Crop yields are variable and depend on crop type and inputs (7 pg 27) | • See *Common Issues* | • Pollutants contained in crops utilized for soil remediation, then harvested for energy production, may cause negative impacts to energy conversion processes | • See *Common Issues*. | |

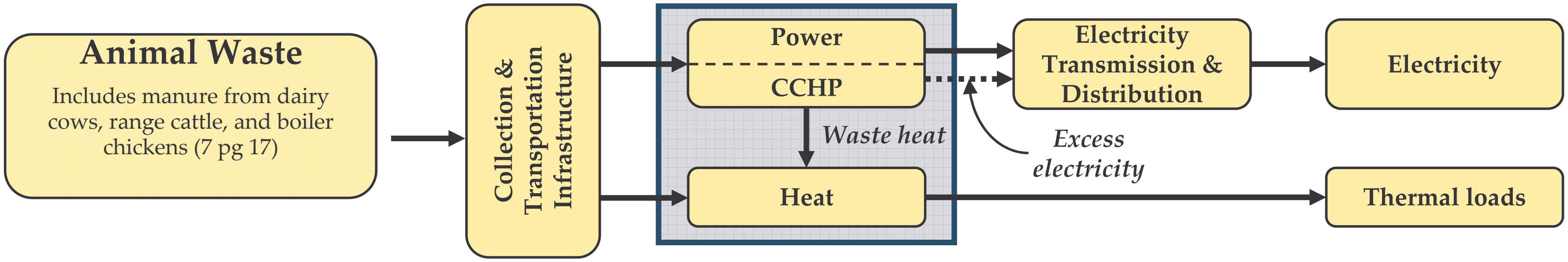
1. It is assumed that sugar, starch and oil crops (as well as lignocellulosic crops) could be used to create biofuels. Refer to the biofuels section for discussion. The lignocellulosic portion of sugar, starch & oil crops (i.e., residues) could be used for power production as covered in the section on agricultural residues.

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Potential, Timing & Magnitude** | • Specific crops can be used for soil remediation<br>• Eucalyptus is currently used in CA for integrated farm drainage management (IFDM) (7 pg 27)<br>• Integrated systems, such as IFDM, and other soil remediation practices may "prove one of the major growth areas in the future" (7 pg 53)<br>• 4.5 MDT estimated to be grown in CA by 2020. This represents 1/3 total biomass resource growth by 2017. (7 pg 28) (8 tbl 4.1) (note: it is unclear what crop types makes up the estimate).<br>• Best near-term opportunity on San Joaquin 1.5 M acres of lands that have never been drained or 100,000 acres that need better drainage and could be used for agriculture. (7 pg 27)<br>• The decrease in Federal support from some ag crops could promote the development of alternative crops such as energy crops (7 pg 27) | • Assumes full allocation of production costs in commodity price | • May help support industry development before other resource infrastructures are in place (7 pg 1) | • See Common Issues | • PTC available for "closed loop" biomass conversion systems at 1.9¢/kWh over ten years (7 pg 11) vs. 0.9 ¢/kWh for "open loop" biomass |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Benefits** | • Could supplement other biomass facilities<br>• Soil remediation from salt tolerant species and those that uptake pollutants including trees, grasses and halophytes, and improves over all sustainability of agriculture (7 pg 26, 27)<br>• Biomass growth can sequester CO2 in soils | • See *Common Issues* | • Waste heat from power generation could be used to purify drainage water by extracting salts (7 pg 28)<br>• Other conversion and refining benefits are similar for all biomass and detailed in the general discussion slides. | • See *Common Issues*. | • See Common Issues |
| **Needs** | • Assessment of potentially viable crops and land<br>• Promotion of planting renewable fuels<br>• Concerted R&D effort (7 pg 27)<br>• Analysis of types of crops needed for soil remediation , and for other Valley environmental considerations (7 pg 28) | • See *Common Issues* | • Continued testing to determine any saline impacts on thermal and bio processes (7 pg 29)<br>• Other conversion and refining needs are are similar for all biomass conversion applications and are detailed in the general discussion slides. | • See *Common Issues* | • See Common Issues |

| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • See *Common Issues*.<br>• Conduct RD&D on cropping systems, harvesting, handling, storage, and distribution practices and technology, in coordination with a larger state and federal level R&D effort. |
| **Regulatory Actions** | • See *Common Issues*. |
| **Legislative Actions** | • Reduction in support to other agricultural commodities would influence the development of energy crops<br>• Incentives for growing energy crops need to be developed |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**




| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • Approximately 33,000 milk cows are supported by the Dairy Power Production Program (7 pg 17) | • Onsite collection if dairies<br>• Not currently feasible for pastured animals (7 pg 48) | • Methane from anaerobic digestion of waste fires reciprocating engines (7 pg 40)<br>• Anaerobic digesters typically 50kW- several MW (7 pg 40)<br>• Waste heat used to improve digester or for other onsite processes (e.g., cheese production) (7 pg 40)<br>• 4 MW in operation producing 30 GWh/yr (7 pg 35)<br>• There are less than 7 animal and food processing digesters operating in the state, and approximately 16 that are not operating. (37 pg 50) | • See *Common Issues* | • CA Dairy Power Production Program and other federal dairy programs offer development incentives (7 pg 40)<br>• Dairies can use net metering programs or RPS solicitations (although smaller size may limit the practicality of latter option).<br>• See *Common Issues* |
| **Costs** | • Costs low when anaerobic digestion on site at dairy (7 pg 40) | • Costs low when anaerobic digestion on site of dairy (7 pg 48) | • ~$3,500/kW installed capital costs and $300/kW O&M for dairy waste biogas in 2005 dollars (37 pg 19) | • See *Common Issues* | • LCOE is estimated 4.3¢/kWh for 100kW system in 2003 constant dollars for energy from an animal waste digester (7 pg 42) |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Constraints** | • Resource distributed in nature for range cattle operations<br>• Increasing concerns over VOC emissions for confined animal feeding operations (CAFOs) (45 pg 6) | • Collection costs for range operations may be infeasible (7 pg 48)<br>• Need to have confined pens to be able to collect waste | • Sulfur in gas can cause combustion system fouling in older systems (7 pg 40)<br>• Despite new models equipped to remove sulfur, additionally required NOx scrubbing equipment still costly (7 pg 40)<br>• Gas scrubbing and catalytic emission control devices may cause efficiencies to decline (14 pg 33)<br>• Refer to Agriculture section for permitting constraints. | • See *Common Issues* | • See Common Issues<br>• Net metering for dairies expected to end 2006 (7 pg 42)<br>• Dairies and farms have different rules than solar for Net Metering , and some provisions may be limiting their participation. |

# **Biopower** » Animal Waste › *Opportunity Assessment*

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Potential, Timing, & Magnitude** | • ~3.6 MDT/yr of all animal manure technically available today, ~2.0 MDT/yr of confined dairy manure technically available today (8 tbl 4.1)<br>• Expected to increase over time, MSW and animal waste expected to account for 2/3 gross resource growth by 2017, which could be estimated to be about 1-2 MDT (7 pg 28)<br>• Due to SB 700 and the loss of air permitting exemptions for agriculture, alternative waste management practices will increase the availability of the resource. | • Onsite applications | • 385 MW & 2,863 GWh net technical potential at current efficiency (7 pg 35)<br>• ~$3,000/kW installed capital, $240/kW O&M – 2010 , and ~$2,600/kW installed capital, $150/kW O&M – 2017 (37 pg 19) | • See *Common Issues* | • Anaerobic digestion of animal wastes and LFGTE systems could achieve a lower LCOE than wind where there are no fuel costs (7 pg 41)<br>• See *Common Issues* |
| **Benefits** | • Utilization reduces methane release into atmosphere<br>• Refer to Agriculture section for farm revenue benefits | | • Conversion and refining benefits are similar for all biomass conversion applications and are detailed in the general discussion slides. | • See *Common Issues* | • See *Common Issues* |
| **Needs** | • Improved waste management practices<br>• Existing costs of waste management practices should compared against conversion alternatives. | • Agency coordination | • Incentives for increasing efficiency<br>• Skilled personnel | • Refer to Agriculture section for interconnection and net metering needs. | • long-term contracts<br>• Increased use of biomass in RPS<br>• Extension of production tax credits<br>• Carbon credits |



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| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • Increase funding for the Dairy Power Production Program<br>• See *Common Issues* |
| **Regulatory Actions** | • Legislation to simplify and expand net metering for biomass and biogas<br>• See *Common Issues* |
| **Legislative Actions** | • See *Common Issues* |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**

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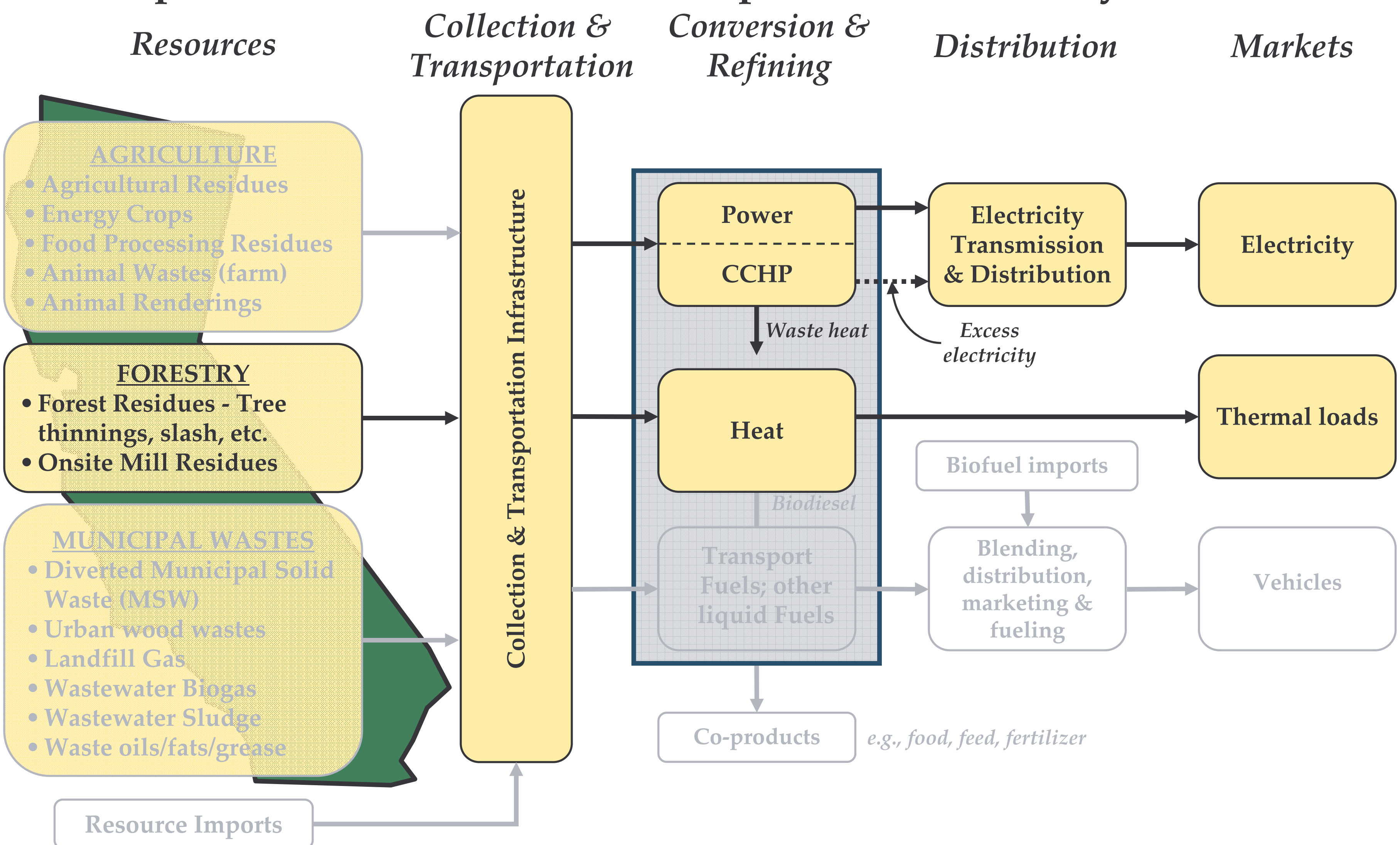
# Simplified Value Networks for Biopower from Forestry Resources.



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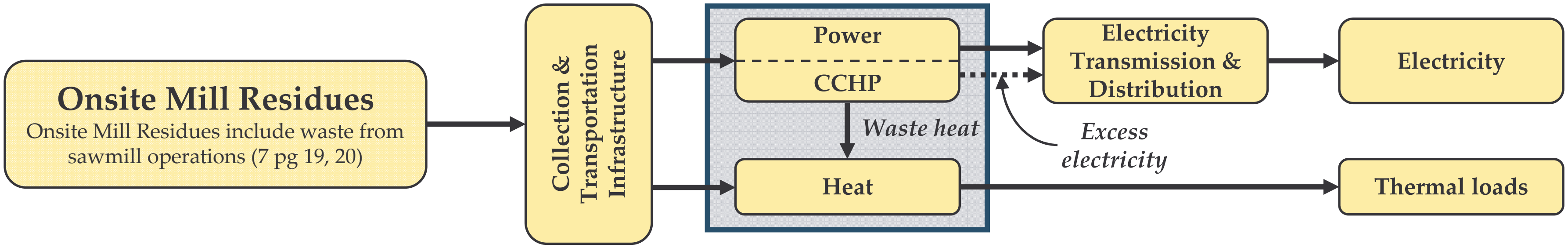


| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • Approx. 1.3 M tons/yr of sawmill residues used for power production (7 pg 20)<br>• Onsite forest residues located primarily in far northern California; ~50% on public land<br>• Remaining available residues are used for landscape and other products. (7 pg 20) | • Onsite mill residue collection and utilization well established | • Direct combustion technology (current)<br>• 268 MW in operation producing 1996 GWh/yr (7 pg 35)<br>• CHP applications such as waste heat used for kiln drying lumber (7 pg 42)<br>• Most forest product operations already generate power from their residues. | • Much of the power generated is being used on site and is not exported to the grid. (7 pg 20)<br>• See *Common Issues* | • See *Common Issues* |
| **Costs** | • Little or no costs assumed for onsite utilization of mill residues (37 pg 54) | • Refer to Agriculture section for limited cost of collection at onsite facilities. | • Refer to Agriculture section for installed capital costs for stoker boiler configurations assumed used in smaller onsite applications. | See *Common Issues* | • See *Common Issues* |
| **Constraints** | • Declining forest product industry (33 pg 4) | | • See *Common Issues* | • See *Common Issues*. | • See *Common Issues* |



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| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Potential, Timing & Magnitude** | • 3.3 MDT of mill residues technically available today (7 pg 15)<br>• Resource size is expected to remain at current levels in the future. | • Sites that benefit transmission system ("Hotspot sites") identified. (37) | • Improved technologies with higher efficiencies are becoming available like fluidized bed or gasification<br>• Restarting mothballed plants is one option<br>• 1,666 MW & 12,408 GWh technical (7 pg 35) at current capacity factor (85%) & efficiency (20%) (37)<br>• Competitive at larger project size | • Biomass meets utilities baseload requirements<br>• Range of facility sizes should allow for interconnection at a variety of substation voltages, but resource location relative to electric grid is important (37) | • By products from remaining forest product residues<br>• See Common Issues |
| **Benefits** | | | • See *Common Issues* | • Benefits to distribution are similar for all biomass conversion applications and are detailed in the general discussion slides. | |
| **Needs** | | | • See *Common Issues*. | • See *Common Issues* | • See *Common Issues* |



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| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • See Common Issues |
| **Regulatory Actions** | • See *Common Issues*. |
| **Legislative Actions** | • Advocate policies that collect payments from beneficiaries of environmental benefits, for example surcharges on water bills for forest thinning that improves water shed quality<br>• See *Common Issues*. |

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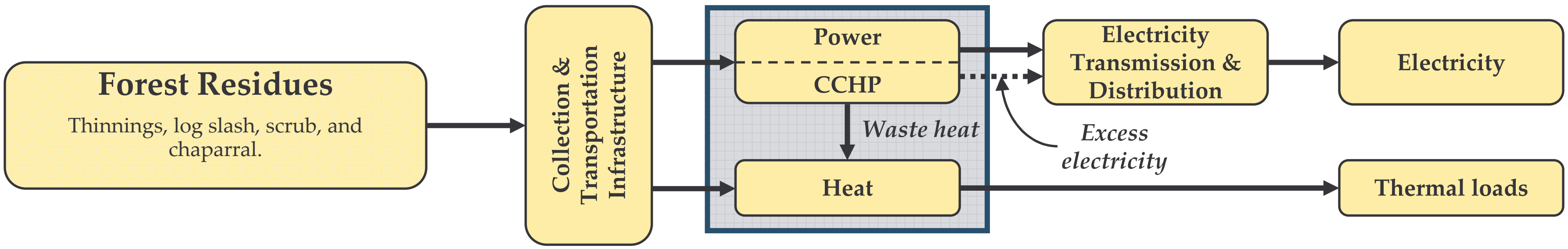


| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • Current utilization of forest thinnings and slash is unclear. It is assumed to be chipped onto the forest floor.<br>• Chaparral is cleared primarily in the Southern California region for fire protection (7 pg 20) | • Forest residue collection and transport is distance constrained | • See *Common Issues*<br>• Development of mobile biomass conversion systems (e.g., skid mounted) could facilitate utilization of forest residues | • See *Common Issues*. | • See *Common Issues*. |
| **Costs** | • ~$40/BDT forest thinnings and 'timber stand improvement' (37 pg 11) | • Collection cost becomes prohibitive on certain terrain | • $2,800/kW installed capital costs and $232/kW O&M for fluidized bed application in 2005 at 2004 dollars, not including $40 fuel cost. (37 pg 13) | | • LCOE estimated at 8.98¢/kWh for 25MW fluidized bed facility and assuming a 1¢/kWh increase per $10/ton increase in fuel cost. (37 pg 60, 62) |



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## **Biopower** » Off-Site Forest Residues › *Current Situation Assessment (2 of 2)*

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Constraints** | • Seasonal harvesting limitation<br>• Reliability, long-term supply of resource<br>• Controversy over how/if thinning should occur<br>• No consensus between environmental agencies how to manage. (7 pg 53)<br>• Chaparral has no commercial value (7 pg20)<br>• No markets exist for forest management operations (7 pg 53) | • Forest terrain can be infeasible for thinning<br>• Equipment access to lands may be limited seasonally due to winter or fire seasons (7 pg 49)<br>• Refer to Agriculture section for transportation cost constraints to the size of the facility. | • See *Common Issues* | • See *Common Issues*. | • See *Common Issues* |

1.



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| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Potential, Timing & Magnitude** | •2003 Healthy Forests Restoration Act and 2005 Energy Policy Act increases potential for thinnings (7 pg 53)<br>•11 MDT/yr estimated technical potential off-site forest residue | •Long-term fuel supply contracts would support consistent delivery<br>•Onsite applications can minimize cost of transportation | •Refer to onsite forestry for conversion potential. | • See *Common Issues* | •See *Common Issues* |
| **Benefits** | •Decreased fire risk benefits water and air quality and minimizes habitat destruction<br>•Reduced wild fire risks to large urban populations near fire prone areas.(7 pg 53) | •See *Common Issues* | •Emissions from power plants is significantly less than impacts from catastrophic fires.<br>•Decreased spending on fire protection which amounts to approximately $900M/year (45 pg 26) | •See *Common Issues* | |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Needs** | • Need better state policy regarding forest thinning (7 pg 53)<br>• Alternative fire prevention strategies are needed, since suppression strategies have created the fuel load (7 pg 53) | • Public awareness about benefit of thinning<br>• Integrated policy between Energy and Forestry Agencies<br>• Consensus between environmental organizations and land management agencies that wildland urban interfaces need to be managed to reduce fire risk. (7 pg 54)<br>• Costs of biomass management should be reasonably allocated to the beneficiaries.<br>• Need for increasing fuel supply infrastructure specifically related to fire prevention. (7 pg 57) | • Offset credits for thinning, prescribed burning, and wildfire, should be developed and recognized by US EPA (45 pg 9) | • See *Common Issues*. | • Long-term contacts for harvesting/thinnings<br>• Market must exist for forest management biomass (7 pg 54) |



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| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • Determine geographic areas in the Wildland Urban Interface most in need of fuel reduction.<br>• Identify actions that can be taken by the Board of Forestry to encourage biomass production and use.<br>• Work with Federal government to implement policies under the Healthy Forest Act that would provide larger, long-term biomass supply from Federal lands.<br>• Facilitate long-term fuel delivery contracts to maintain collection and delivery infrastructure .<br>• Work with Fed Govt to implement policies that would provide long-term biomass supply from federal lands.<br>• New R&D on harvesting, handling, and storage practices and technology<br>• Identify "biomass energy zones" in key forest and range areas and key agricultural areas of California, based on known resource potential.<br>• Examine the alternative methods for disposing of fuel reduction materials and determine the best practices for forestry management that have the least greenhouse gas impacts compared to wildfires.<br>• Build upon the existing California Climate Action Registry protocols and continue development of additional protocols for forest management and resource conservation (i.e., use of forest materials for fuels and wood products).<br>• Create fuel management surcharge fees to have beneficiaries pay for benefit of thinning activities.<br>• Assist the Department of Corrections and Forestry and Fire Protection in the installation of combined heat and power units at six facilities statewide.<br>• See *Common Issues* |
| **Regulatory Actions** | • Establish incentive for delivery infrastructure<br>• Establish fuel management surcharge fees to have beneficiaries pay for benefit of thinning activities.<br>• See *Common Issues* |
| **Legislative Actions** | • See *Common Issues*. |

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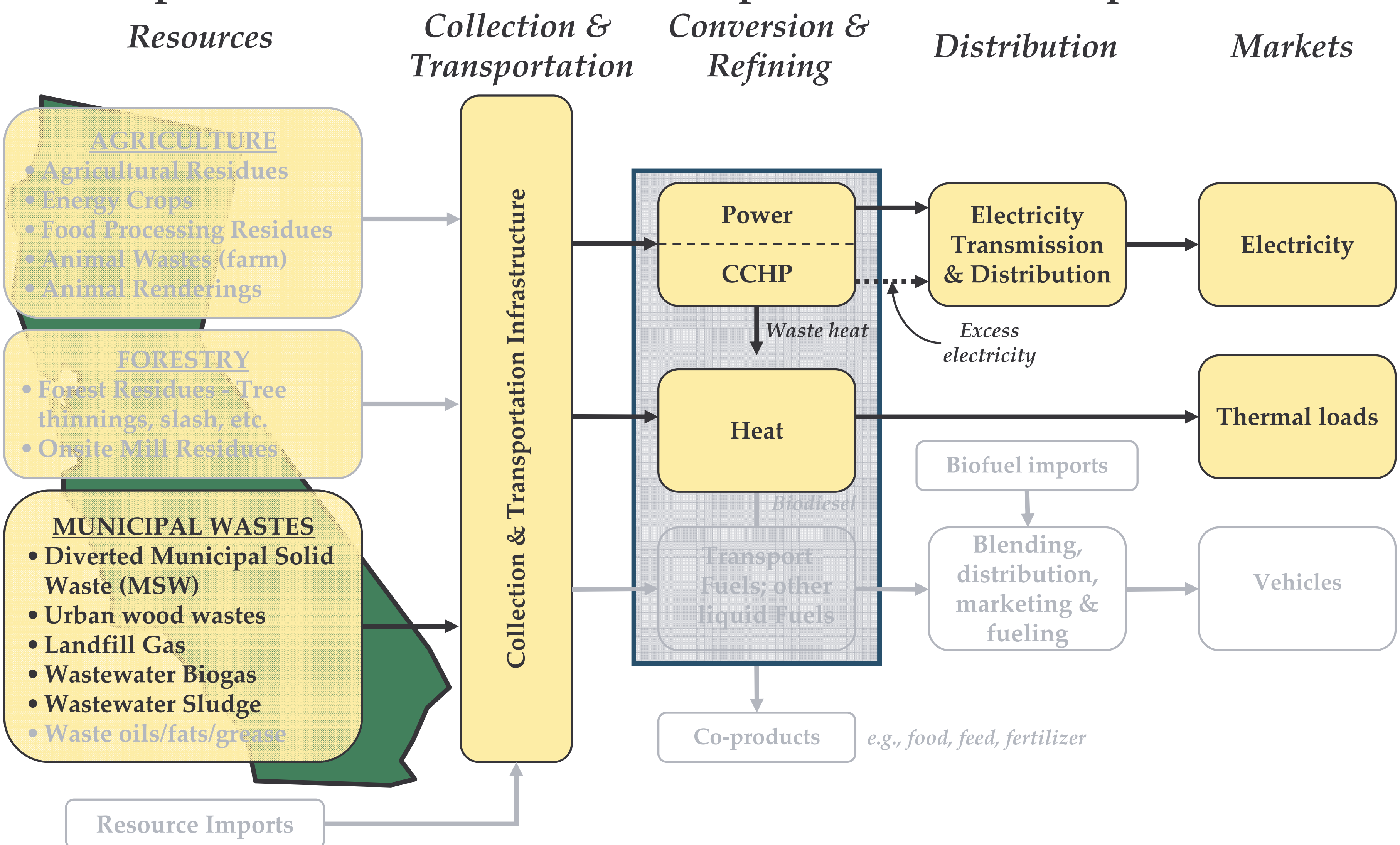
# Simplified Value Networks for Biopower from Municipal Wastes



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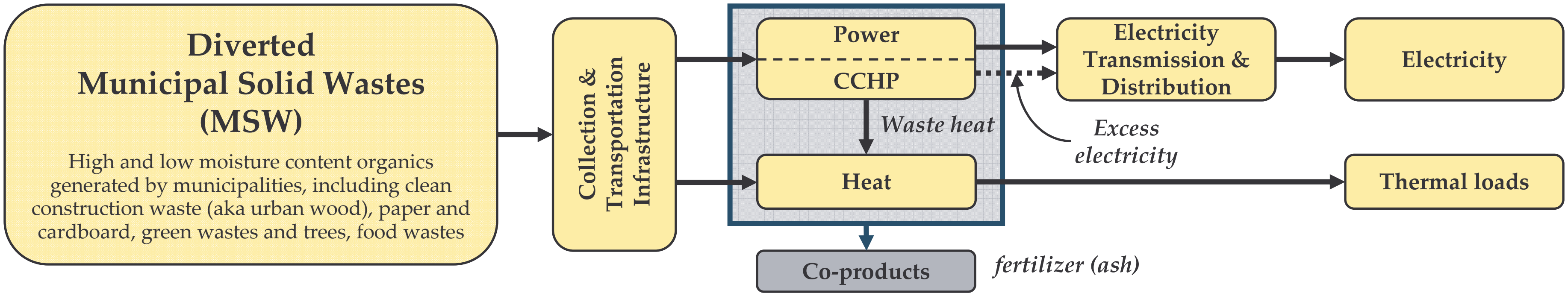


| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • Diverted MSW available for biomass conversion applications consist of 1.5 M tons of diverted clean construction/urban wood directly combusted in power plants. Demolition waste is not allowed for combustion due to air containments (7 pg 23)<br>• Diverted paper and cardboard assumed to be recycled.<br>• Diverted green wastes used for compost or alternative daily cover.[1] Quantities are unidentified. (7 pg 22) | • Well established collection of non sorted materials<br>• Tipping fees are charged for collection and disposal into a landfill and or transfer station<br>• 50% of all MSW currently diverted from land fills under state requirement (7 pg 22) | • Low moisture content or 'solid fuel' (urban wood) typically directly combusted.<br>• 239 MW planned or in operation producing 1780 GWh/yr (7 pg 35) although many biopower facilities are capable of accepting urban wood waste and very few burn this exclusively. | • See *Common Issues* | • Specifics related to the sale of energy from urban wood are unidentified.<br>• See Common Issues<br>• Details of market sales of any energy from MSW is unidentified. |

1. Diverted green waste is allowed as 'alternative daily cover' (ACD) in landfills and can be considered to contribute to the generation of landfill gas. Refer further to the discussion of landfill gas.

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Costs** | • $22/BDT for clean construction waste( aka: urban wood) (37 pg 11)<br>• The cost of green waste or paper and cardboard is mostly unidentified, although it has been stated generally that materials recovered at transfer stations are assumed to be available at little or no additional costs. (7 pg 48) | • Tipping fees can offset transport costs<br>• Transportation costs are similar for all biomass conversion applications and are detailed in the overall discussion slides. | • $2,800/kW installed capital costs and $392/kW O&M for fluidized bed application in 2005 at 2004 dollars, including $22 fuel cost. (37 pg 13) (note: capital and O&M costs for technologies to combust unsorted MSW would be higher) | • See *Common Issues*. | • LCOE estimated at 6.98¢/kWh without production tax credit (PTC) for 25MW fluidized bed facility (37 pg 60, 62) assumed for large urban applications with a with fuel at $22/BDT. |
| **Constraints** | • Lack of diversion credit can create limitations for long-term supply reliability (7 pg 5)<br>• Waste conversion processes development could increase resource competition and change tipping fees. (7 pg 48)<br>• Green wastes may only be seasonally available. (7 pg 49)<br>• No state policies limit total disposal, and no consensus exists how to reduce disposal to landfills (7 pg 54)<br>• There is a perception that conversion technologies may draw resources away from existing users of biomass from MSW. (7 pg 60) | • Mixed waste stream<br>• Collection and delivery costs | • Public perception of waste conversion technologies (7 pg 7, 60)<br>• Conversion technologies may discourage the public from producing less waste. (7 pg 60)<br>• The ability for tipping fees to change for landfill disposal may inhibit competition from new conversion technologies.<br>• Permitting facilities due to NOx (7 pg 7) | • See *Common Issues* | • "MSW" does not add to RPS because it is disallowed in SB 1078<br>• See *Common Issues* |

# **Biopower** » Diverted Municipal Solid Wastes › *Opportunity Assessment (1 of 2)*

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Potential, Timing & Magnitude** | •State polices aimed at reducing landfilled material (7 pg 5, 54)<br>•~7.4 MDT/yr technically available today (8 tbl 4.1)<br>•MSW and animal waste expected to account for 2/3 resource growth by 2017 (7 pg 28) which could be estimated to be less than 1-2 MDT, based on the estimate that there will be a ~6.4 increase from 33.6 MDT to 40 MDT, and if ~4.5 MDT of that increase is expected from dedicated crops. (7 pg 28) | •Presorting<br>•Onsite applications<br>•Regulations to move anaerobic digestion of MSW out of a 'transformation' category will allow it to receive diversion credits (7 pg 55)<br>•Definitions changes for other types of biomass conversion applications could also result in the availability of diversion credits. (7 pg 55) | •832 MW & 6,179 GWh technical potential at current efficiency (7 pg 35)<br>•Bioreactor landfills have efficiencies estimated to remain constant over time at 30%. (7 pg 29) | •See *Common Issues* | •Compost is by product of diverted material from landfill<br>•LCOE can decline with tipping fees, if fuel and handling cost do not increase (7 pg 40, 41)<br>•See *Common Issues* |
| **Benefits** | •Diversions from landfills, extends landfill capacity and reduces methane production (7 pg 29)<br>•Reduced dependence on non renewable fuel | •Can provide increase in jobs in urban areas (37 pg 30)(7 pg 9)<br>•Tipping fees can increase transport distances. (7 pg 48) | •New technologies like gasification reduce environmental impact of MSW conversion<br>•Revitalize local (urban) economy (37 pg 30)(7 pg 9) | •See *Common Issues* | |



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| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Needs** | • Changes in waste management policy that would open up market for large quantities of separated solid waste (7 pg 36)<br>• long-term supply reliability (7 pg 55)<br>• Expanded definition of waste transformation to include composting and biomass conversion (7 pg 55)<br>• Increased diversion rates need to be set (7 pg 58)<br>• Producer responsibility programs and limitation on total organic carbon content and energy content of waste such that have been implemented in EU. | • Incentives aimed to reduce waste generation to increase collection infrastructure<br>• Improvement in handling and separation technology (7 pg 54) (45 pg 12)<br>• Extended producer responsibility programs and limitations on quantities of organic material that can be landfilled (7 pg 54) | • Change in public perception about waste conversion technologies (7 pg 7, 60)<br>• Full diversion credit for conversion technologies (7 pg 5, 55)<br>• Conversion options should rely on performance based standards, environmental and life cycle assessment for integrated waste management and other biomass strategies. (7 pg 60) (45 pg 9)<br>• Conversion facilities should be characterizes as refineries and be regulated under non disposal facility elements (NDFE) (45 pg 12) | • See *Common Issues* | • The portion of waste that can be considered renewable for RPS eligibility needs to be determined<br>• See *Common Issues*.<br>• Monetizing environmental and waste management benefits to defray fuel costs and improve economics (7 pg 41) |

| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • Limit amount of organic matter allowed in landfills<br>• Increase landfill tipping fees to provide stable funding for grant and incentive program<br>• Increase public and policy education and awareness about technology and benefits through demonstration<br>• Waste management limitations could be based on per capita disposal<br>• Implementing regulations to restricting total organic carbon into land fills or by energy content<br>• Evaluate potential for increasing in-state processing of municipal waste (decrease out-of-state disposal)<br>• Improved handling and separation technology for MSW<br>• Develop plan to deploy bioreactor landfill technology on a commercial basis to increase the decomposition of organic material<br>• Refer above to general actions that can be implemented.<br>• See *Common Issues* |
| **Regulatory Actions** | • Define conversion technologies with environmental and life-cycle assessments<br>• Implement "extended producer-responsibility programs and limitations of the total organic content and energy content of waste going to landfills"<br>• Increase diversion credit for conversion technologies<br>• See *Common Issues* |
| **Legislative Actions** | • Propose amendments to existing law to provide diversion credits to local jurisdictions for solid waste processed by conversion technologies. (AB 1090 is a possible vehicle).<br>• See *Common Issues* |

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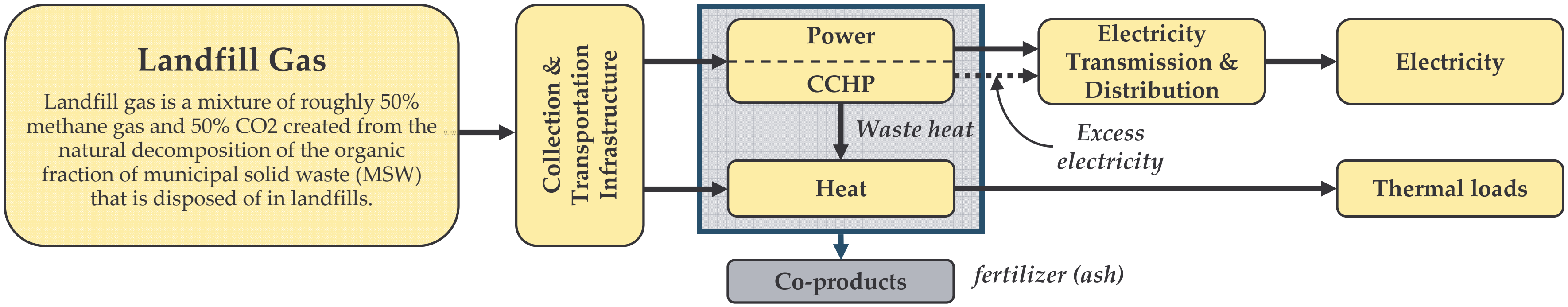


| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • CA is a national leader in landfill gas recovery and utilization. | • Onsite LFG collection systems required in larger landfills | • Methane collected from landfill typically fires reciprocating engines.<br>• Some CHP applications (7 pg 23)<br>• Avg size approx 2-5MW<br>• 59 facilities currently operate in CA (37 pg 50)<br>• 258 MW in operation producing 1,921 GWh/yr (7 pg 35)(37 pg 50) | • 228 MW exported to grid (from a total of 258MW in operation) (37 pg 50)<br>• See *Common Issues*. | • See *Common Issues* |
| **Costs** | • Fuel resource is generally free or of little cost | • Resource efficient due to co-location of fuel and plant<br>• Collection system costs are not a part of landfill gas to energy project costs | • Capital costs range from ~$1,100/kW for gas gensets to $6,000/kW (7 pg 40) for advanced technologies like fuel cells. | • See *Common Issues* | • IOU RPS allows payment up to MRP w/o SEP. Currently 5.8¢/kWh<br>• 2 MW landfill gas project is estimated to have a LCOE in 2003 constant dollars of 4.4¢/kWh (7 pg 42) |



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| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Constraints** | • Waste diversion away from landfills limits expansion of LFG facilities, however current waste in place still provides a product through 2017. (7 pg 29) | • Not all landfills have collections systems in place.<br>• Flaring may be more economical than producing energy and may produce less emissions (but does not provide offsets from electricity generation). | • Cost of permitting and development for small facilities is high on a per kW basis<br>• Highly efficient bioreactor landfills only at developmental stages (7 pg 29, 55)<br>• Flaring still has lower point source emissions than internal combustion engine. (7 pg 59) | • Because most facilities are less than 10 MW, interconnection process can be simplified, but not always the case<br>• Because AB 939 does not allow diversion credit for most conversion technologies, siting facilities in jurisdictions that have not met diversion requirement may be difficult.<br>• Siting facilities is difficult due to the approval requirements under county siting elements which require majority votes from jurisdictions with the majority of the populations for disposal facilities. | • See *Common Issues* |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Potential, Timing, & Magnitude** | •79 BCF/yr is technical potential<br>•Expected to increase with population growth (7 pg 29)<br>•It is estimated that 1/3 of increase of biomass generation will come from landfill and WWTP (37 pg 65)<br>•Gas storage could be added to digesters to increase resource availability during peak generation times (7 pg 23)<br>•Immediate shifts to bioreactor landfills can increase rate of gas generation by 30% by 2017. (7 pg 23, 29) | •Gas collection systems can be installed as a retrofit at existing landfills<br>•Pretreatment of waste prior to landfilling could mitigate long-term methane emissions issues. (45 pg 30) | •Bioreactor landfills employ leachate recirculation and membrane covers to increase the rate of gas generation, as do high-rate in vessel digesters.<br>•242 MW technical potential producing 1803 GWh (7 pg 35)<br>•Successful commercialization of fuel cells & microturbines may make smaller (<500kW) LFG projects economic<br>•Gas collection system cost could be attributed to the landfill operation. (7 pg 40) | •Utility interconnection standards exist under Rule 21 could be considered for LFG facilities to lower cost of interconnection. | •By 2017 1/3 of the state's 20% RPS could come from LFG and WWTP biogas (7 pg 28, 36)<br>•Is a natural fit for municipal utilities<br>•See *Common Issues* |
| **Benefits** | •Biogas can also produce transportation fuels or be upgraded to pipeline quality. (7 pg 23) | •Reduces fugitive methane emissions into atmosphere (7 pg 23) | | •See *Common Issues* | |



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| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Needs** | •LFG is a cost competitive technology that is widely deployed in CA. More effort is needed on accelerating deployment and creating opportunities at smaller landfills<br>•Change view of landfill to a biochemical reactor<br>•Identifying improved management strategies (7 pg 29) | •Improvement in handling and separation technology (7 pg 54) | •Increase public and policy awareness about technology and benefits through demonstration<br>•See *Common Issues* | •Siting of facilities needs to be considered under "Non Disposal Facility Elements"<br>•See Common Issues | •See *Common Issues*. |

| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • Develop plan for rapid development of landfill gas opportunities. Should include technology needs (e.g., emissions, permitting, interconnection, cost effectiveness of smaller sites) and business model needs as well as incentives to encourage facilities to upgrade with new technology.<br>• Establish a streamlined approach to the New Source Rule (NSR) for LFGTE and other biogas power projects, including:<br>• Explore exemptions for biogas power technologies as Pollution Control Projects (PCPs), "essential public services," and "resource recovery projects."<br>• See *Common Issues* |
| **Regulatory Actions** | • See *Common Issues*. |
| **Legislative Actions** | • Create state tax credits, energy investment tax credits or expand tax exempt financing from California Pollution Control Financing Authority<br>• Establish loan guarantee revolving fund to reduce risk<br>• See *Common Issues* |

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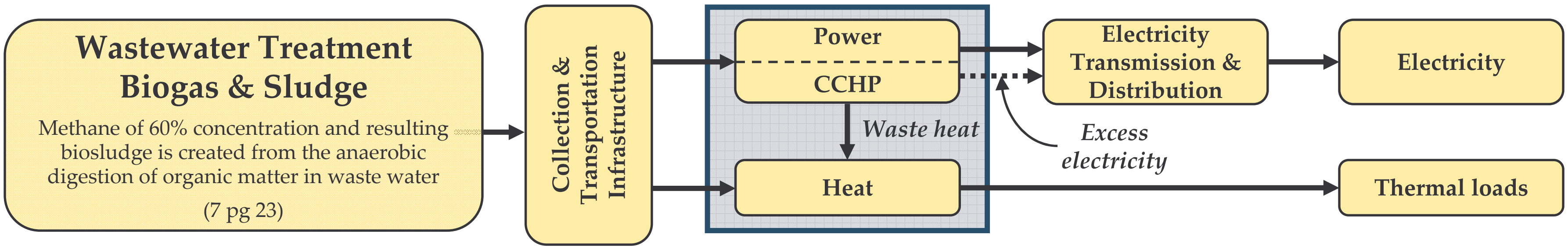


| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • Organic biosolids sludge transported off site and highly utilized in non energy uses (e.g., agricultural land applications, NOx control in cement mixes, or to landfills where they contribute to LFGTE (7 pg 23)<br>• Total BCF utilized in power operations unclear (7 pg 23). | • Onsite collection of methane and biosludge<br>• Biosludge transported by truck for off site utilization | • Methane fuels reciprocating engines typically to run onsite treatment plant operations, and the waste heat is used to enhance digester efficiency.<br>• 18 plants in operation produce 63 MW produce 469 GWh/yr (7 pg 35)<br>• 115 facilities exist in the state, the total number of plants operating needs to be verified (37 pg 50) | • Approximately 1 MW is exported to grid of the 63 MW in generation(37 pg 50)<br>• See *Common Issues* | • See *Common Issues* |



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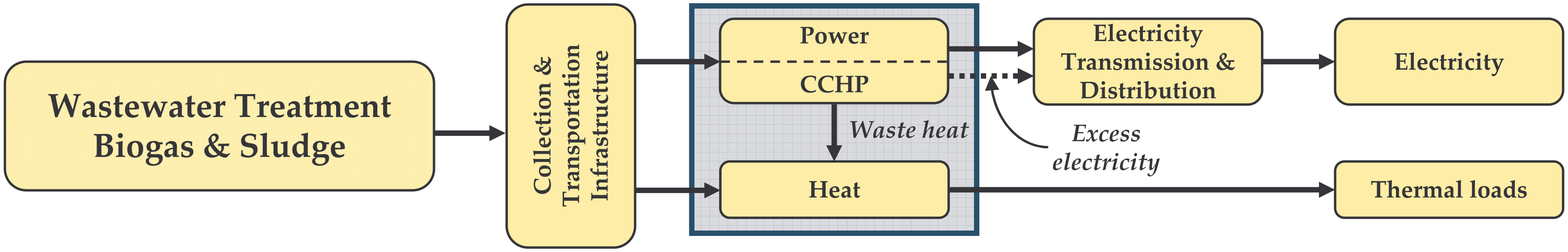


| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Costs** | • $0 costs due to onsite collection (37 pg )<br>• Transport and disposal costs of biosludge unidentified, or, unclear if any money is received from sludge utilization. | | • $1,350/kW installed capital costs and $175/kW O&M for WWTP biogas in 2005 at 2004 dollars (37 pg 20) | • See Common Issues | • 4.06¢/kWh at 2005 current dollars with no PTC for a 1MW facility (37 pg 60) |
| **Constraints** | • Onsite food processing power applications would decrease disposal through municipal waste water systems and could decrease organic matter availability at WWTP | | | • See *Common Issues.* | • See *Common Issues* |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Potential, Timing, & Magnitude** | •11 BCF/y technically available today (7 pg 15)<br>•Increased adoption of anaerobic technologies by munis increases biogas availability(7 pg 29) | | •15 MW & 109 GWh net technical potential today at current efficiency (7 pg 35)<br>•Biological conversion genset efficiencies estimated to remain constant over time at 30%<br>•$1,250/kW installed capital, $171/kW O&M in 2010. $1088/kW installed capital, $168/kW O&M in 2017 (37 pg 20) | •Onsite food industry digesters | •See *Common Issues* |
| **Benefits** | | •Onsite application | •Utilization reduces methane release into atmosphere | •See *Common Issues* | •See *Common Issues* |
| **Needs** | | | •See *Common Issues*. | •See *Common Issues* | •See *Common Issues*. |

| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • See *Common Issues* |
| **Regulatory Actions** | • Incentives for increasing efficiency<br>• See *Common Issues* |
| **Legislative Actions** | • See *Common Issues* |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**

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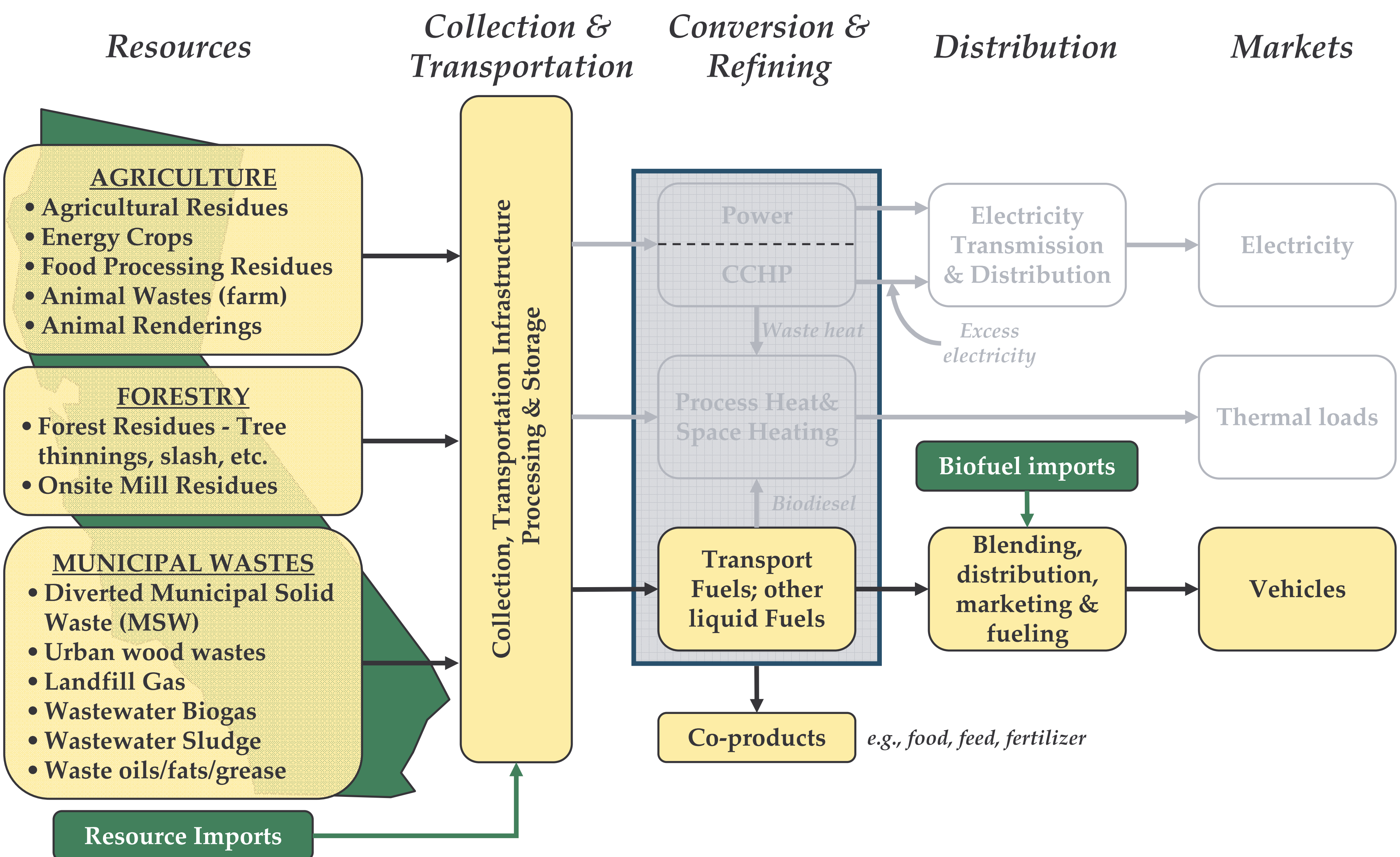




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# Biomass resources for biofuel production can be put into four main feedstock categories.

*Resources*

**AGRICULTURE**
- Agricultural Residues
- Energy Crops
- Food Processing Residues
- Animal Wastes (farm)
- Animal Renderings

**FORESTRY**
- Forest Residues - Tree thinnings, slash, etc.
- Onsite Mill Residues

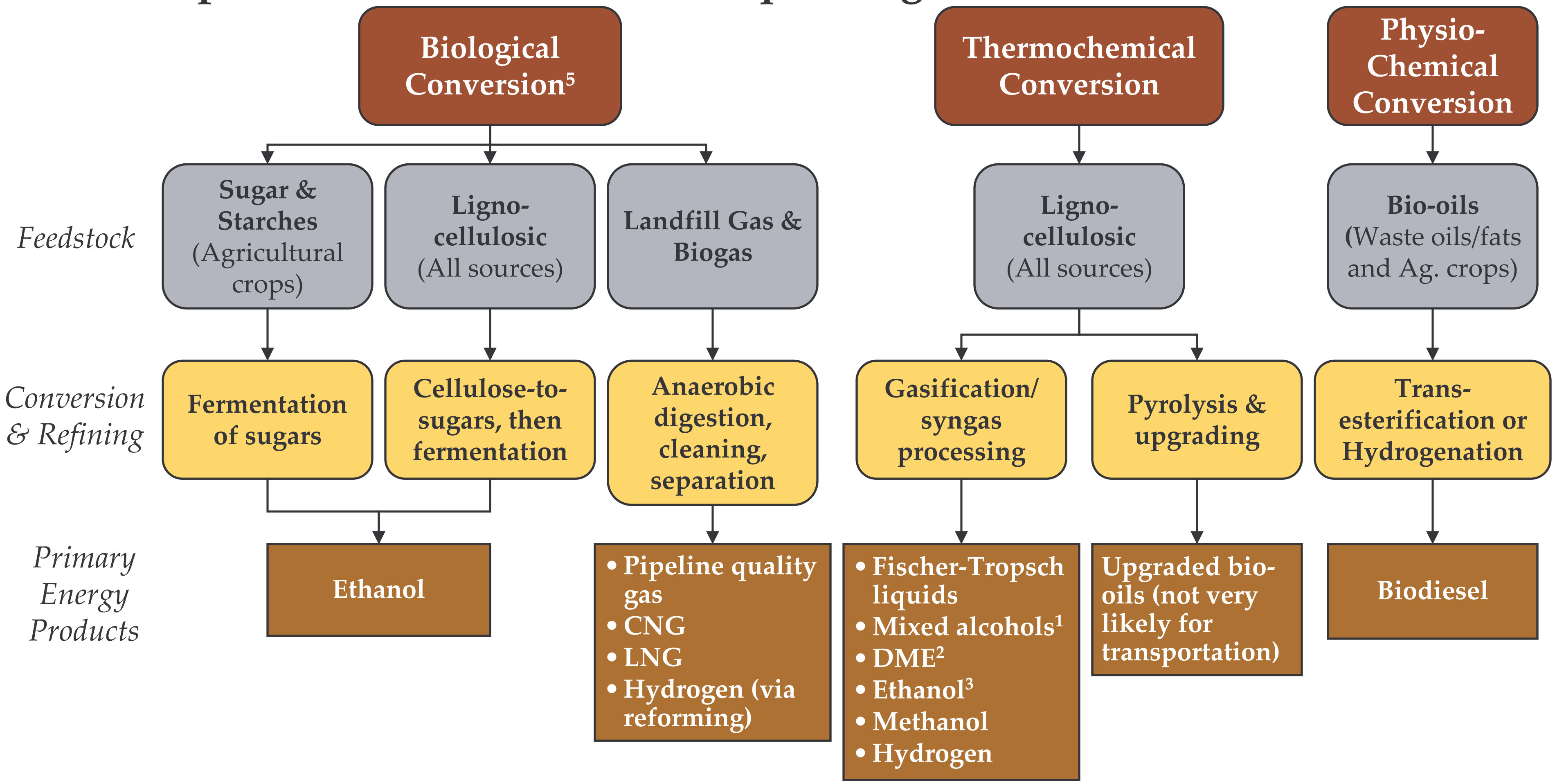
**MUNICIPAL WASTES**
- Diverted Municipal Solid Waste (MSW)
- Urban wood wastes
- Landfill Gas
- Wastewater Biogas
- Wastewater Sludge
- Waste oils/fats/grease

**Primary Biofuels Options**

| Resource | Feedstock for Conversion/ Upgrading | Conversion Process |
|---|---|---|
| Agricultural Crops *(sugars/starches)*, Food Processing Residues[2] | Sugars/Starches | • Biological conversion to ethanol |
| Agricultural Residues[3], Energy Crops, Food Processing Residues[2], Offsite and On-site Forestry Residues, Diverted MSW | Lignocellulosic Biomass | • Biological conversion to ethanol<br>• Thermochemical conversion to multiple transportation fuels |
| Agricultural Crops *(beans/oils)*, Waste oils/fats/grease | Bio-oils | • Physio-chemical conversion to biodiesel |
| Animal Waste (farm) Landfill Gas, Wastewater Biogas, Wastewater Sludge | Landfill Gas & Biogas | • Biological conversion to multiple transportation fuels |

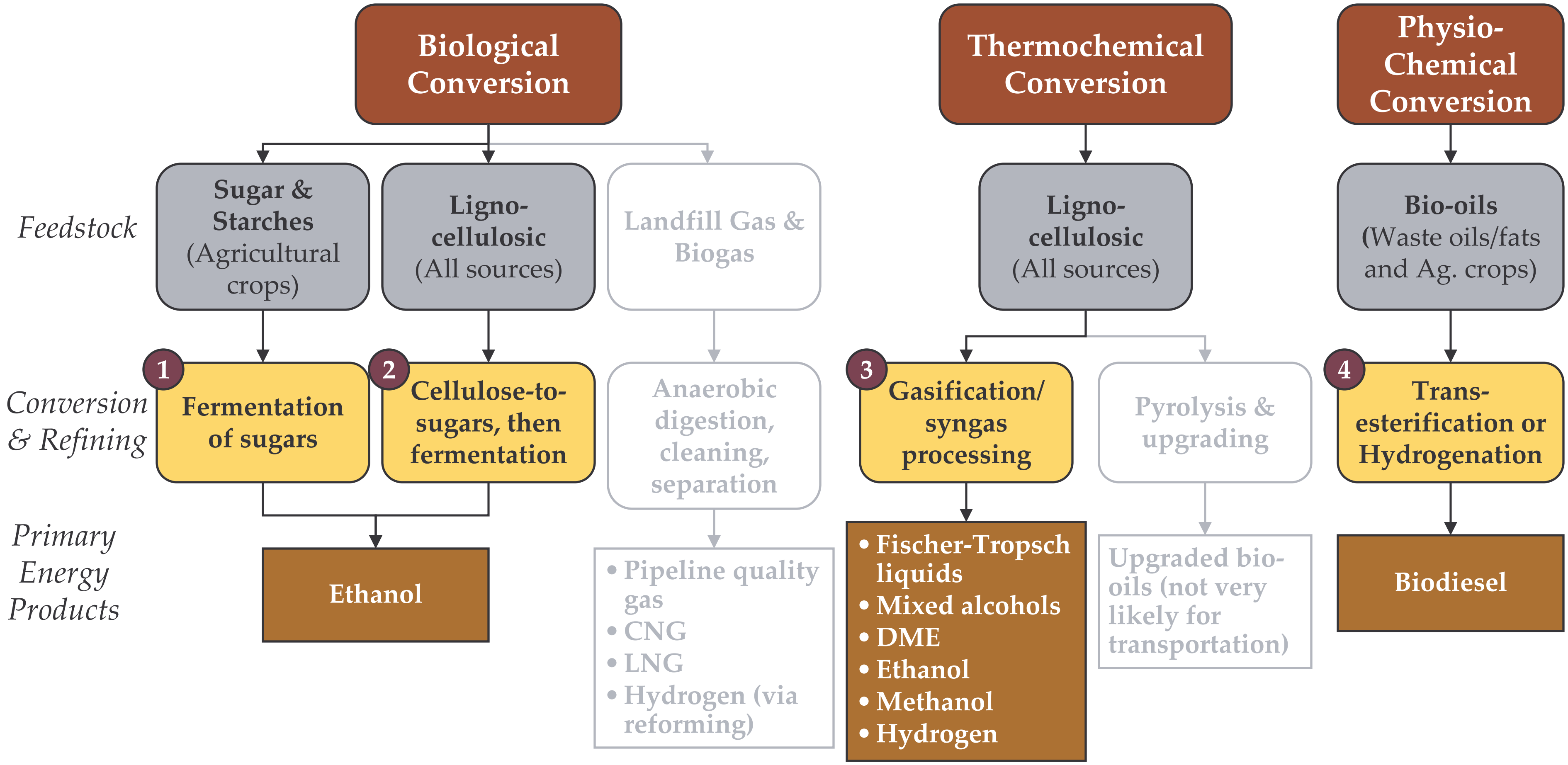
1. Animal renderings are not included in the analysis since the availability, in significant quantities is based on unplanned, periodic events, which is not conducive to development of a biofuels industry.
2. Majority of Food Processing Residues is lignocellulosic based. Some small fraction is waste sugar and starch material; it is probably too dispersed and seasonal to be the base for major ethanol production in the state.
3. Approximately 80% of Agricultural Residues is estimated to be lignocellulosic content.

# Using the four major feedstocks there are multiple pathways to create transportation fuels (and other liquid & gaseous fuels).




1. Via catalytic synthesis. 2. Dimethyl ether. 3. Via syngas fermentation. 4. Pyrolysis oils require substantial upgrading before they can be used for transportation applications (e.g., before they can be processed in a conventional refinery). It is more likely they would undergo more modest upgrading for use as boiler fuel or in a stationary IC engine or gas turbine. 5. Also includes direct microbial conversion of sunlight to hydrogen.

# NCI considered four main routes of biomass conversion to transportation fuels which rely on three main feedstocks.[1]




1. While all are technical feasible, these are considered the primary options based on a combination of resource potential and technology status.



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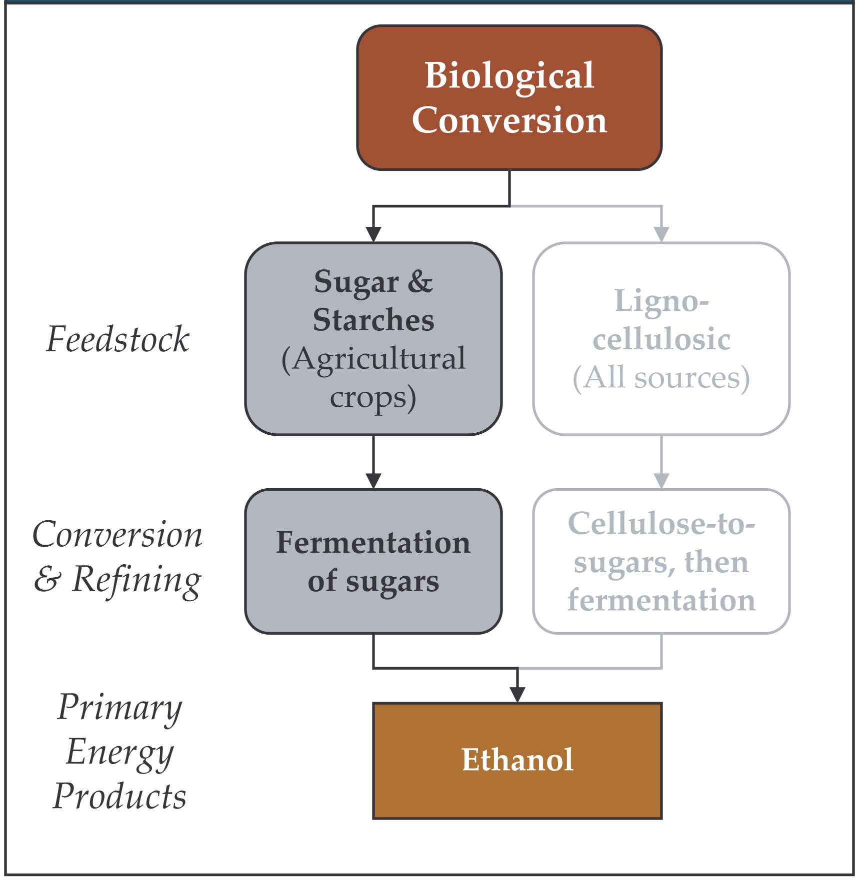
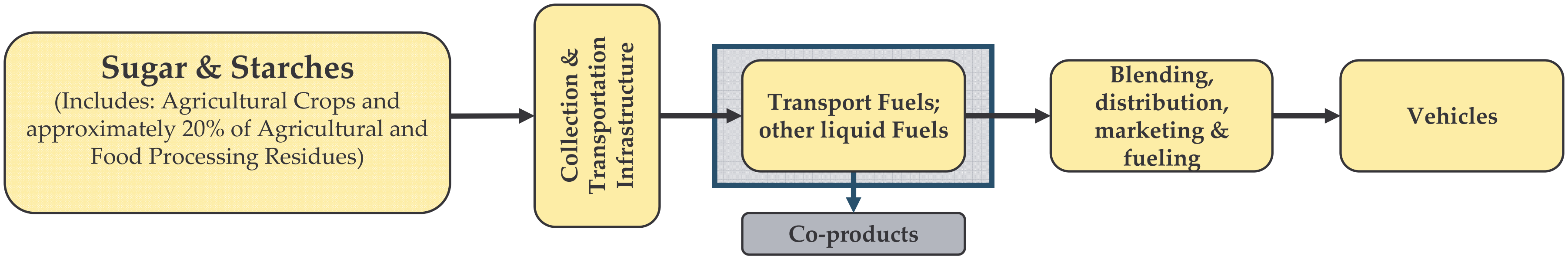
# California uses ~25% of U.S. ethanol production, but produces almost none in-state.

- All U.S. ethanol is produced from sugars & starches (almost entirely from corn)
- CA's current demand for ethanol is ~ 1 billion gpy (7 p 44).
- Nationally, production capacity is ~4.1 billion gpy, with ~1.7 billion gpy under construction.
- Conversion of sugar & starch feedstock to ethanol is a fairly mature process, with opportunities for efficiency improvements.
- Currently CA does not have dedicated sugar & starch crops for ethanol production and is importing almost all ethanol consumed in the state; ethanol plants under construction in CA are importing corn from the Midwest.
- Currently CA gasoline is ~6% ethanol content by volume, a renewable/non-petroleum/biofuel market inroad that would be extremely hard to match in the near-term with any other option. (T. McDonald personal communication)
- The Federal Energy Policy Act of 2005 eliminated the oxygenate requirement, and while a renewable fuel standard was imposed it is to be met by companies (as opposed to geographic regions) and can be done so anywhere in the country. Thus the future of ethanol in CA is uncertain. (31 p 3)

## Ethanol from Sugar/Starch Fermentation






| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • CA uses residual sugars, cheese whey; resulting in 10MM gpy of ethanol<br>• No/minimal use of sugar/starch crops grown for fuels.<br>• CA starting to import corn from Midwest (Pacific Ethanol, Phoenix Biofuels/25 MM gpy facility); fermentation residues for animal feed; crop material not fermented could be burned for fuel on-site (e.g. corn stalks)(7 p 44) | • None currently, other than importation of ethanol via train (well established); ethanol plants currently under construction will import corn from the Midwest. | • Most CA ethanol comes from Midwest plants<br>• As of 1/2006, US production capacity ~4.3b gpy with ~1.7b gpy under construction<br>• CA has about 35 million gallons per year produced in-state using residual sugars from food processing and imported corn.*<br>• One other project is currently under construction in California that would add another 35 million gallons per year to California's in-state supply. **<br>• Dry milling is the technology of choice for new plants | • CA gasoline contains on average ~6% ethanol.<br>• 70 CA petroleum products terminals are upgraded for ethanol.<br>• Gasoline refiners in CA have long-term contracts for ethanol delivery from the Midwest. [95% delivered by rail, 5% by barge/marine tanker]<br>• One E85 retail refueling station; 4 fleet refueling stations in CA (26) | • In 2004 ~900 million gal ethanol was used in CA 2004 (20+% of US total).<br>• Historically, ethanol cost +40-50 ¢/gallon of gasoline equivalent higher than gasoline production cost.<br>• Almost no E85 use; although size of FFV fleet in CA exceeds 260,000 vehicles (<1% of on-road vehicles) and is an order of magnitude larger than next most numerous alternative fuel vehicle category in CA. Although sales are decreasing. (29 p2)<br>• FEPA 2005 extended AMFA CAFÉ credits through 2010 which provide support for technology viability; but does not assure expansion of current FFV market share or in-use FFV population (29 p 4) |

* Parallel Products, Rancho Cucamonga, has been in operation since 1984, producing up to 5 million gal/yr of ethanol from food and beverage industry wastes. Golden Cheese of California, Corona, has been in operation since 1985, producing up to 3.5 million gal/yr of ethanol from cheese processing wastes. Phoenix Bioindustries/Western Milling Co., Goshen, started up a 25 million gal/yr ethanol plant in the fall of 2005.

** Pacific Ethanol has a 35 million gallon/year plant under construction in Madera, also to use corn, with operation scheduled for fourth quarter 2006.

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Costs** | • Startup costs associated with putting additional land under cultivation. | • Investments in trucks for feedstock transport<br>• Importing feedstock into CA requires contracts with railroad companies (a 35m gpy ethanol plant requires ~ 1 train delivery of corn per week) | • Capital cost is about $1.5 m per 1MM gpy of production.<br>• Producing co-products with ethanol is important for profitability, up to 50% of revenue can come from sales of co-products (31 p 20) | • Ethanol benefits from federal tax policy that provides tax credits when blended with petroleum fuels, among other incentives<br>• The value of the tax credits for the blender is 51¢ per gallon of ethanol. | • Ethanol projected to stay competitive as new supply comes on-line; currently ethanol may be in excess supply.<br>• Price of ethanol highly dependant on incentives, price of feedstock, and price of gasoline, but has historically been in the range of $1.00-1.50/gal.<br>• E85 could cost less than gasoline in near-term (20,23), although recent studies show that on an energy-per-gallon basis, the equivalent price is still above regular gasoline (29 p 4) |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Constraints** | • Currently, there are no dedicated feedstocks grown in CA for ethanol production.<br>• The main candidate crops are corn and sweet sorghum<br>• There are no comprehensive studies on what it would take to create dedicated sugar & starch feedstocks for ethanol in CA or what the potential is. | • In CA the infrastructure is currently not in place, and would need to be developed in parallel to crop production. | • Modern corn dry-milling technology produces only modest net energy gains relative to petroleum fuels (when considering the entire fuel chain), but does produce significant petroleum displacement (Wang)<br>• Production in CA could lead to some price pressure on natural gas (5 p 44), unless other fuels (e.g., biomass residues) are used to meet mill energy needs. Every gallon of ethanol requires ~40,000 Btu of natural gas. | • Because of its characteristics (phase separation resulting from solubility in water), pipeline operators have been reluctant to ship ethanol or ethanol-gasoline blends, on a commercial scale. Ethanol is shipped by truck or railroad to finished product terminals. At higher ethanol blends separation is less likely to occur and pipelines can be used to ship ethanol. (31 p 11)<br>• One critical element for the FFV is availability of infrastructure to provide E85 as an alternative fuel. (31 p 29) which is a "daunting proposition" (29 p 4)<br>• Current distribution network has limited capacity for "segregation" (keeping E85 separate from other fuels) (need delivery infrastructure, refueling stations and certified vapor recovery) | • FEPA 2005 eliminates oxygenate requirement; making long-term demand for ethanol in CA uncertain. Federal RFS can be met by companies on a nation-wide basis. (31 p 17)<br>• E10: Higher ethanol blends with gasoline (e.g., E10) opposed by CARB b/c/o evaporative emissions and increased NOx (not an issue with E85).<br>• E85: There is some uncertainty if US auto manufactures will continue to make FFV & if they will invest in E85 specific emissions issues (26,20). Vehicles generally require 1.34 g of E85 to replace 1 g of gasoline (29 p 4)<br>• Ethanol w/ Diesel: No ASTM specs for use of ethanol with diesel. Other technical barriers also exist for using ethanol in diesel engines (e.g., materials compatibility) (26) |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Timing & Magnitude** | • Best near-term opportunity for dedicated crop development is on retired land in San Joaquin Valley<br>• CA DFA studies identified sweet sorghum, kenaf, Jerusalem artichoke sugar beets and eucalyptus. If on 1MM acres, could generate 500MM gpy. (31 p 22)<br>• Corn in CA generally considered uneconomical; recent industry analysis shows CA production more energy efficient (dry corn w/ sun in CA) (31 p 22)<br>• CA has approx. 1 mdt/y of sugar & starch feedstock available from Agricultural and Food Processing Residues (7), however, this would be difficult for a dedicated ethanol plant because the feedstock may be highly dispersed and seasonal<br>• Estimated dedicated crop technical potential by 2020 is 5 M BDT/y with 90% availability (includes lignocellulosic and oil and sugar crops, no break-out for sugar & starch crops (5 p S.3). | • Would need to develop alongside in-state production capacity and be commensurate in scale. | • In 2030 even if 4 million FFVs in CA used E40 (on average) and the rest of the fleet used E10, CA would represent <20% of U.S. projected production. | | • Consuming over 20% of total US production, in-state ethanol production could support huge demand even without any increase in demand.<br>• CA gasoline expected to maintain 15-35 ¢/gallon retail premium, which could ensure ethanol supply to CA market (over other states)<br>• Widespread E10 could displace 9% of on road gas and diesel by 2025 and result in demand of 1.4b gpy by 2020, 40% of CA alternative fuel goal. (20 p AD-2F-1)<br>• Elimination of Federal requirements for oxygenate means that these requirements cannot be counted on to assure long-term ethanol market<br>• Pursing an E85 strategy for meeting state goals is a longer-term strategy than promoting/mandating E10 |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Benefits** | • Local source of DDGS or similar co-products may lower animal feed costs<br>• Increased agricultural production in CA<br>• GHG emissions reductions<br>• CA could leverage residues to offset NG costs in ethanol production.<br>• Dedicated crop production might lead to crop shifting but could utilize marginal lands (5 p 2.4) | • Would provide additional employment to trucking. | • Could combine conventional ethanol production with use of agricultural residues or other biomass as fuel for the ethanol plants<br>• Additional in-state jobs associated with local ethanol industry | • Ethanol at a blend level of up to 10% can be used in conventional gasoline fuel systems with little or no change from production to end-use | • Higher ethanol content provides hedge against petroleum price increases<br>• Assuming CA refiners/ marketers exceed their Federal RFS requirements, they may have excess credits to sell.<br>• "Ethanol blending is now widely recognized as a viable public policy strategy with greatest near-term potential to reduce petroleum dependence and CO2 emissions." (REAP)<br>• FFVs have merits as an alternative fuel vehicle because consumers have option to fuel with petroleum-based gasoline or ethanol |
| **Needs** | • Assistance for farmers converting to new crops or expanding production on idle land.<br>• Assessment of potential land and water implications. | • In state crops for ethanol would require infrastructure; could take advantage of existing farm infrastructure. | • Continued improvements in conventional technology to reduce energy needs and to improve value of co-products (e.g., corn dry fractionation)<br>• If corn is not the main feedstock, finance community may need additional assurances to offset perceived risk | • For E85 market to expand, distribution infrastructure is required | • Consistent state policy on ethanol to stimulate high capital investment required.<br>• For E85 market to expand, consumers need awareness of FFV options (26) |

| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • Assess sugar/starch crop potential and issues relative to other energy crops or biodiesel crops<br>• Support RD&D to better understand which sugar/starch crops would be best suited to conventional ethanol production<br>• Conversion support or incentives for farmers to switch to sugar/starch crops<br>• Assistance in resolving air quality issues<br>• Examine a "systems" or "portfolio" approach to air quality` issues which allows tradeoffs along the value chain.<br>• Create ethanol (or more broadly, biofuel) purchasing program for state or local vehicle fleets (see Carl-Moyer program which accelerated adoption of cleaner and cost-effective vehicles at the municipal level)<br>• Establish fuel specifications that promote the increased use of biofuels in transportation fuels.<br>• No backsliding – declare ethanol will be part of fuel mix at minimum of current levels for next 10 years, to maintain existing demand in order to create a market [production]).<br>• Education/outreach<br>• Research exhaust emissions and permeation effects of low ethanol blends on environment (31 p 57)<br>• Encourage in-state production opportunities until blending issue is resolved and RFS is in place, create minimum annual statewide ethanol consumption levels.<br>• Initiate an effort to install an extensive E-85 fueling network throughout California (in cooperation with the Energy Commission, ARB and the Department of Food and Agriculture).<br>• Encourage auto companies to expand production of FFVs, including FFV hybrids.<br>• Create a FFV and alternative fuel purchasing program for state or local vehicle fleets (see Carl-Moyer program which accelerated adoption of cleaner and cost-effective vehicles at the municipal level).<br>• Revise the state's vehicle procurement process to encourage the purchase of flexible fueled vehicles. Develop convenient fueling infrastructure to support FFV fleet. |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**

| | Potential State Actions[1] |
|---|---|
| **Regulatory Actions** | • Address air quality issues holistically to enable higher blends of ethanol in gasoline |
| **Legislative Actions** | • Legislation for a Renewable Fuel Standard that creates a longer term market for ethanol, consistent with other state goals on transportation energy use and GHG emissions<br>• Like Minnesota, CA could adopt aggressive policies to provide incentives for E85 refueling stations.<br>• Package of tax incentives, production incentives, loan guarantees, and/or grants to encourage in-state production and use of biofuels. Exact mix of incentives TBD.<br>• Establish stable funding to establish needed bio-fueling infrastructure<br>• Consider phasing in requirement for FFVs for all vehicles sold in the state<br>• Take steps to facilitate transition of all vehicles to FFVs, including the phasing in of a requirement to have all vehicles sold in the state be FFVs |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**

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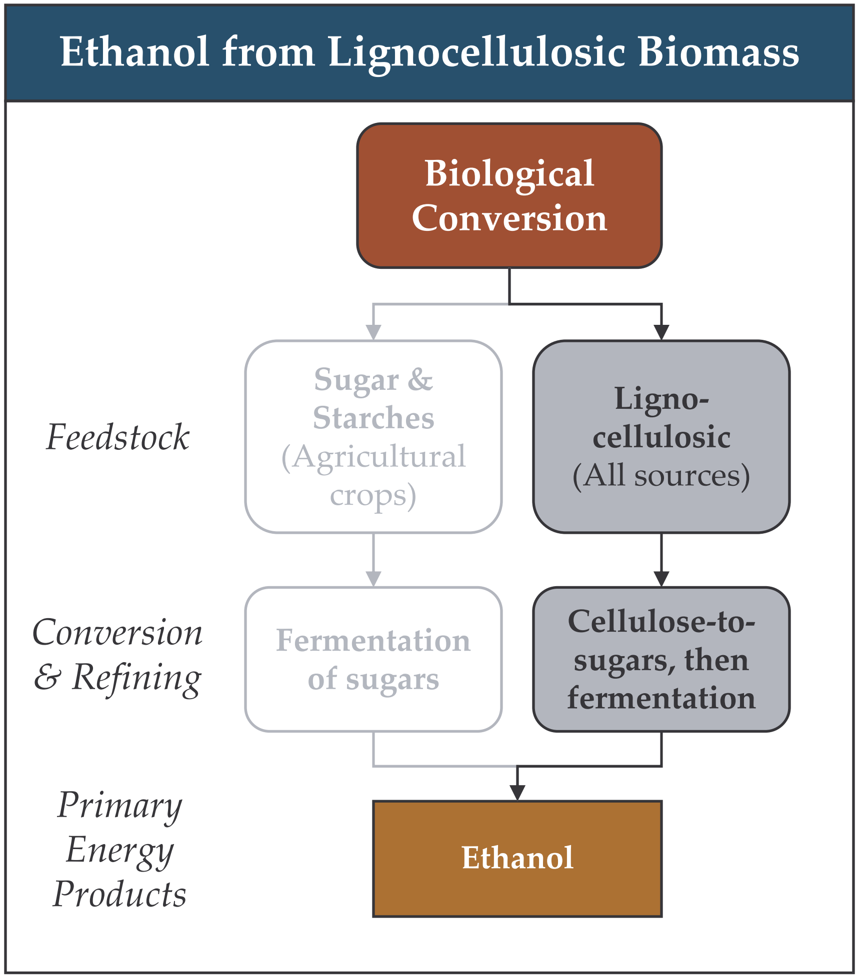
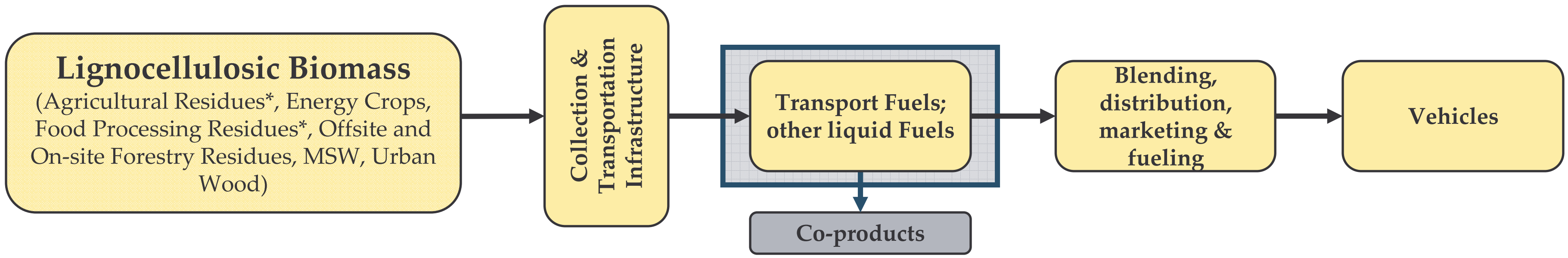
# The conversion of lignocellulosic feedstock to ethanol is not yet commercial; but could have tremendous benefit for CA.

- Dedicated biomass crops, including herbaceous and woody crops, have not emerged as a large scale agricultural enterprise in CA, but there is increasing interest due to changes in renewable fuels, including ethanol (5)
- Ethanol production from cellulosic biomass is still developmental (5)
- Cellulose conversion may contribute over the long term, and represents a larger resource base than sugars and starches.
- Ethanol from lignocellulosic biomass can achieve much higher net energy gains have the potential for lower cost than ethanol from sugars and starches. (5)
- "With high land prices and crop values, the prospects of a flourishing CA ethanol industry heavily depends on using cellulosic material for feedstock. "(26 p 3)
- "Feasibility of [lignocellulosic] ethanol industry in CA depends largely on the development of new and more efficient technologies that convert biomass to ethanol and significantly decrease cost." (26 p 26)






| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • Current utilization of the lignocellulosic resource is detailed in the biopower section.<br>• No lignocellulosic energy crops are being grown in CA | • CA has an abundant amount of feedstock; challenge is cost competitive access. (31 p 24)<br>• See relevant biopower value networks | • Pilot facilities are in operation in the U.S. and Canada at scales <1 mmgpy.<br>• No commercial lignocellulosic plants are in operation, but several have been proposed over the years.<br>• Investment capital has been unavailable (31 p 3); level of risk uncertain (31 p 21) | • See "Ethanol from Sugar & Starch" Fermentation | • See "Ethanol from Sugar & Starch" Fermentation |
| **Costs** | • Unknown for ethanol production; but see lignocellulosic feedstocks in the biopower section for information on costs.<br>• For cellulosic ethanol, each additional $10/ton for feedstock results in $0.07-0.14/gal; feedstock cost is critical (7 p 50) | • See relevant biopower value networks | • Unknown but cost is targeted to be similar to sugar/starch to ethanol productions.<br>• Current state-of-the-art is about $4-5/gallon-yr of capacity for a world scale plant (>100 MM gpy). Target is much lower.<br>• Long-term target is production cost <$1/gal (7 p50). | • See "Ethanol from Sugar & Starch" Fermentation | • See "Ethanol from Sugar & Starch" Fermentation |

* Approximately 80% is estimated to be lignocellulosic

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Constraints** | • Current resource is distributed. | • See relevant biopower value networks<br>• Major production challenge is cost of collection and handling for forest, ag and other cellulosic wastes (31 p 3)<br>• Plants may need to be located near resources (31 p 24) | • Commercial scale, low-cost cellulosic ethanol will not be available for several years; technology is just approaching readiness for commercial demonstration (>10MMGPY).<br>• Cost issues related to enzyme manufacturing, fermentation technology and high-capital cost of pre-treatment<br>• Permitting process significantly increases the cost of sitting an ethanol plant; it can take 12 – 18 months. (31 p 27)<br>• Plant size matters as economies of scale apply. However, size is limited by availability of feedstock (31 p 28).<br>• CA producers have to compete with mature Midwest ethanol industry based on corn and other countries where production costs are lower (although import tax currently reduces this threat) (31 p 28) | • See "Ethanol from Sugar & Starch" Fermentation | • See "Ethanol from Sugar & Starch" Fermentation |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Timing & Magnitude** | • Even without new energy crops, CA has 27 mdt/y of lignocellulosic feedstock technically available.[1]<br>• Rice straw is most attractive source (31 p 24).<br>• Cellulosic biomass could support 1.5b gpy (@ 70 gal. of ethanol per ton of biomass). The same amount from corn would require 3 million acres (1/3 irrigated land in CA) and 12 million acre-feet of water (7)<br>• Trials underway on salt tolerant species for application in salt-affected San Joaquin Valley. (5 p S.2.4)<br>• Could achieve scale similar to biopower w/ability to accept large quantities of biomass (7)<br>• Estimated dedicated crop technical potential by 2020 is 5 M BDT/y with 90% availability (includes agricultural oil and sugar & starch crops, no break-out for lignocellulosic "energy" crops) (5 p S.3) | • See relevant biopower value networks<br>• Challenges related to collection of forest materials (delicate eco-systems, cost) and agricultural residues (cost, storage, wet materials). (31 p 23) | • If cost effective technology exists to convert lignocellulosic feedstock to ethanol, then there are business opportunities in CA. | • See "Ethanol from Sugar & Starch" Fermentation | • See "Ethanol from Sugar & Starch" Fermentation |

1. Approximately: 4 mdt/y Agricultural & Food Residues, 14 mdt/y on-site & Off-site Forestry Residues, 9.2 mdt/y Diverted MSW.

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Benefits** | • Lignocellulosic plants may have environmental remediation potential<br>• Additional farm income from new crops and/or sale or residues<br>• Beneficial use of marginal land<br>• If starch/sugar crops also grown for ethanol, residues could be used for cellulosic ethanol to bring additional economies of scale.<br>• CA rich in ag and forestry lignocellulosic resources (31 p 23)<br>• Dedicated crop production might lead to crop shifting but could utilize marginal lands (5 p 2.4)<br>• Ethanol produced from lignocellulosic material is about 3 times more effective in reducing GHG compared to corn (45 p 39) | • See relevant biopower value networks | • A biofuel plant could be sited where a biopower plant cannot because large electricity transmission capacity out of facility is not needed for biofuels.<br>• Plants could be energy self sufficient, thus contributing to the RPS and not impacting NG markets. | • See "Ethanol from Sugar & Starch" Fermentation | • See "Ethanol from Sugar & Starch" Fermentation |
| **Needs** | • Better inventory of available lignocellulosic resources in CA. | • See relevant biopower value networks<br>• New/improved techniques and technologies for harvesting residues. | • Research on radically reducing cost of enzyme production and fermentation. (7)<br>• Commercial scale plant is required to test recent developments in enzyme manufacturing; high capital cost of pre-treatment is barrier. | • See "Ethanol from Sugar & Starch" Fermentation | • See "Ethanol from Sugar & Starch" Fermentation |



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| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • Identifying financing for start-up companies will remain an important consideration in bringing new products to market.<br>• Assess energy crop potential and issues relative to other land uses<br>• RD&D on new/improved harvesting of agricultural residues<br>• Commercialization program for cellulosic ethanol in California<br>• RFS should contain provisions that encourage in-state cellulosic ethanol (similar to Federal RFS)<br>• Conduct RD&D on critical technology platforms needed to commercialize lignocellulosic biofuels, including enzyme production for cellulosic ethanol and thermochemical conversion options.<br>• Figure out how to get an integrated biorefinery built in California<br>• Seek a larger portion of DOE research funds for bioenergy |
| **Regulatory Actions** | • Streamlined permitting for cellulosic ethanol plants (maybe to also encourage cogeneration with lignin residues or co-location with existing biomass power plants) |
| **Legislative Actions** | |

1. **This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions. Implicit here is that all the market and fuel related issues from Sugar & Starch ethanol production also apply here. The actions listed here are focused more on resources and production technology.**

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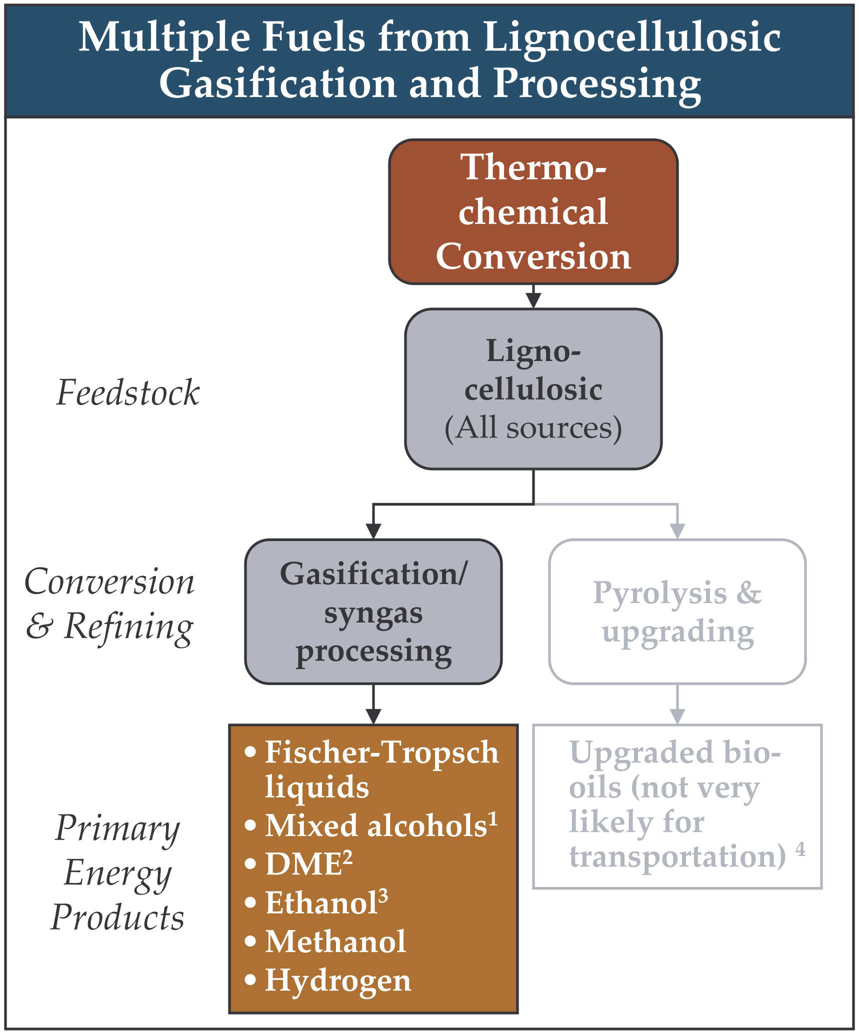
# Gasification can turn almost any biomass resource into transportation fuel; NCI considered those most likely to contribute significantly.

- There are benefits to CA considering non-ethanol transportation fuel options given the air quality concerns associated with ethanol
- Gasification of lignocellulosic material may be a better use of California's resources than the diversion of sugar and starch crops to ethanol production.
- There are potentially large emissions benefits for CA to develop substitutes for diesel fuel.
- Pyrolysis is less mature than gasification, but in the long-term could also contribute to the overall energy mix.




1. Via catalytic synthesis. 2. Dimethyl ether. 3. Via syngas fermentation.

# NCI considered three thermochemically-derived fuels as the most likely to contribute significantly to CA transportation fuel demand.

| Biofuel | Comments |
|---|---|
| Fischer-Tropsch (FT) Liquids | • ***High-performance diesel blendstock.*** Fischer-Tropsch (FT) liquids can be blended with diesel. FT diesel is sulfur free, contains no aromatics and is high cetane. The conversion technology (for clean syngas to FT liquids) is relatively well established and several large plants, based mainly on natural gas, are under construction around the world. Crude FT liquids can be readily refined in stand-alone plants or can be brought to existing petroleum refineries. |
| Mixed Alcohols (MOH) | • ***Gasoline additive.*** Mixed alcohols can be treated like ethanol, but offer higher octane and energy density. The conversion technology (specifically, catalysts for MOH synthesis) is still is development, but one U.S. company (Power Energy Fuels Inc) is preparing to market a MOH product (Ecalene™) and has received EPA registration, but in general, will require certification for use in transportation applications. |
| DME | • ***Clean diesel replacement.*** DME is being considered in Europe as a substitute for diesel, with significant emissions benefits (mainly NOx and particulates). However, DME requires motor vehicle conversion since it must be stored similar to propane. For fleet vehicles this is an option. DME production from clean syngas is straight forward, as it is almost identical to methanol production. In the near-term DME could be blended with propane for traditional cooking and heating applications. |



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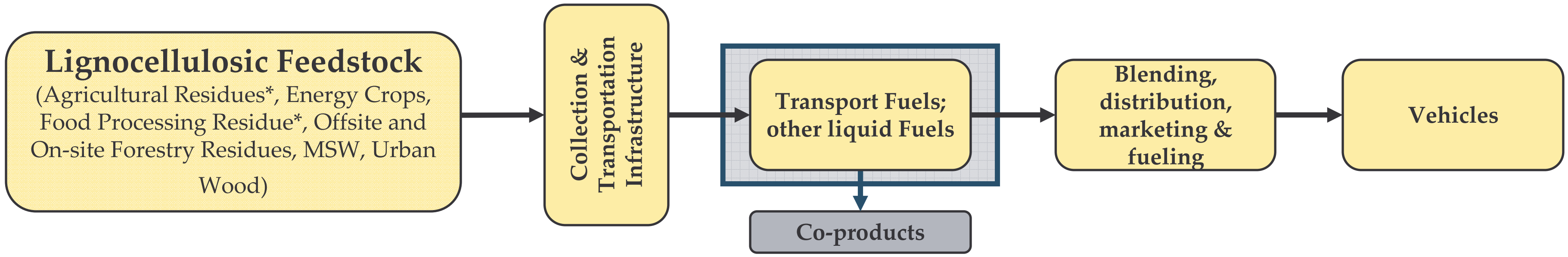
# NCI did not consider other processes due to concerns regarding potential to contribute to transportation fuel demand.

| Biofuel | Comments |
| --- | --- |
| Ethanol (via syngas fermentation) | • ***Gasoline additive.*** The technology to produce ethanol via syngas fermentation is still in early stage development. |
| Methanol | • ***Gasoline additive.*** There are serious barriers to methanol uptake in the marketplace due to concerns over toxicity and handling. |
| Hydrogen | • ***Transportation fuel replacement.*** This is a long-term option dependant on development of a hydrogen distribution and retail infrastructure within the state, as well as hydrogen storage and hydrogen-powered vehicles. However, biomass-derived hydrogen may be the lowest cost option for renewable hydrogen, and developments with other thermochemically-derived biofuels will benefit hydrogen production (e.g., gasification and gas cleanup). |




| | Resources | Collection & Transportation | Conversion & Refining | Distribution** | Markets** |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • No lignocellulosic biomass resource is being gasified in CA for biofuels.<br>• Utilization of the lignocellulosic resource are detailed in the biopower section.<br>• See also relevant biopower value networks | • See relevant biopower value networks | • FT (BTL) has been produced in small quantities in Europe (20)<br>• Developing thermochemical technologies may provide alternative for large-scale lignocellulosic fermentation for ethanol production (7 p 44) | • CEC staff assume existing diesel fuel retail infrastructure can store and dispense diesel with up to 20% RE diesel content w/o modifications (20) | • Not currently used |
| **Costs** | • See relevant biopower value networks | • See relevant biopower value networks | • FT (BTL) has the potential to be the most productive per acre of RE diesel fuel options and produces higher quality fuel (20)<br>• In general, TC conversion options should have highly yields per acre by virtue of utilizing the entire plant. | | • FT (BTL) fuel is anticipated to have 0-30% higher costs than diesel. Recent studies say 7% higher. (20) |
| **Constraints** | • See relevant biopower value networks | • See relevant biopower value networks | • FT (BTL) has significant capital cost, plant complexity and risk compared to conventional crude production and refining (20).<br>• FT (and DME and Mixed-OH) facilities for biomass are conceptual at this time (7 p 47) | • DME would require new fuel infrastructure | • Current biodiesel tax incentives do not apply to FT (BTL) (20)<br>• Same is true of DME unless can be blended with existing fuels |

* Approximately 80% is estimated to be lignocellulosic.

** Ethanol Distribution and Markets covered in "Ethanol from Sugar & Starch Fermentation"

| | Resources | Collection & Transportation | Conversion & Refining | Distribution[2] | Markets[2] |
|---|---|---|---|---|---|
| **Timing & Magnitude** | • Cellulosic biomass could support 1.5b gpy (@ 70 g of ethanol per ton of biomass). The same amount from corn would require 3 million acres (1/3 irrigated land in CA) and 12 million acre-feet of water (7)<br>• Trials underway on salt tolerant species; for application in salt-affected San Joaquin Valley<br>• Even without new energy crop, CA has 27 mdt/y of lignocellulosic feedstock technically available.[1]<br>• Estimated dedicated crop technical potential by 2020 is 5 M BDY/y with 90% availability (includes agricultural oil and sugar & starch crops, no break-out for lignocellulosic "energy" crops) (5 p S.3) | • See relevant biopower value networks | • Largely unknown due to multiple technology developments that are required (gasification, gas cleanup, synthesis technologies)<br>• FT (BTL): unknown future volume (20)<br>• Generally speaking, could be large as it leverages California's significant lignocellulosic resources.<br>• E.g., every 1 million dry tons could produce ~70 MM gal of FT liquids | • Would need to be developed in parallel to production & use | • CEC staff assume 5% displacement of diesel with RE diesel by 2015 and 20% by 2025 (1000m gpy) |

1. Approximately: 4 mdt/y Agricultural & Food Residues, 14 mdt/y on-site & Off-site Forestry Residues, 9.2 mdt/y Diverted MSW.
2. Ethanol Distribution and Markets covered in "Ethanol from Sugar & Starch Fermentation"

| | Resources | Collection & Transportation | Conversion & Refining | Distribution** | Markets** |
|---|---|---|---|---|---|
| **Benefits** | • Lignocellulosic plants may have environmental remediation potential<br>• Dedicated crop production might lead to crop shifting but could utilize marginal lands (5 p 2.4) | • See relevant biopower value networks | • FT liquids offer a higher degree of tailoring for specific engines than biodiesel (7 p 45)<br>• In the long term, thermochemical conversion could be combined with traditional biological conversion plants to create fully integrated biorefineries.<br>• Elements of TC biofuels plants can also be used for power generation (e.g., gasification, gas cleanup) | • FT liquids should be largely fungible with existing infrastructure.<br>• MOH should be largely fungible with existing ethanol infrastructure | • Higher FT costs may offset costs associated with compliance with low-sulfur diesel requirements.<br>• MOH currently eligible for key Federal incentives<br>• DME could have near-term market blending with propane to ease transition to transport fuel |
| **Needs** | • Assessment needed of economic feasibility of feedstocks for attaining 20% diesel displacement CA goal. (20) | • See relevant biopower value networks | • Investment for production capacity to meet 20% diesel replacement goal is unknown (20)<br>• Impacts on cost of evolving technology and possible increases in feedstock cost unknown (20) | • FT – no special needs<br>• DME – new infrastructure<br>• MOH – similar to ethanol | • Clear, long-term state government program to encourage development of necessary infrastructure |

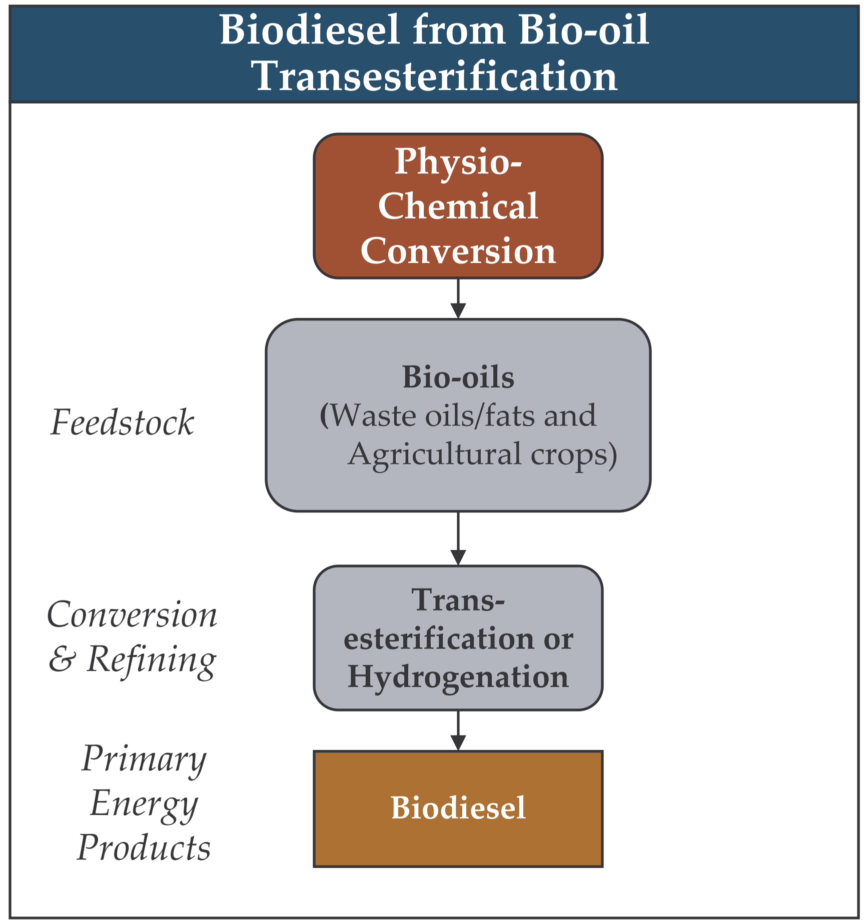
** Ethanol Distribution and Markets covered in "Ethanol from Sugar & Starch Fermentation"

| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • Identifying financing for start-up companies will remain an important consideration in bringing new products to market.<br>• Assess energy crop potential and issues relative to other land uses<br>• Conduct RD&D on critical technology platforms needed to commercialize lignocellulosic biofuels, including enzyme production for cellulosic ethanol and thermochemical conversion options.<br>• RD&D on new/improved harvesting of agricultural residues<br>• RD&D on critical technology platforms needed to commercialize thermochemical (TC) derived biofuels<br>• Commercialization program for TC-derived biofuels in California<br>• RFS should contain provisions that encourage in-state TC-derived biofuels (similar to how Federal RFS gives "bonus credits" to cellulosics ethanol) |
| **Regulatory Actions** | • Streamlined permitting for TC biofuel plants (maybe to also encourage co-location with existing biomass power plants)<br>• Necessary fuel specs for the various TC-derived biofuels. |
| **Legislative Actions** | • Incentives for TC-derived biofuels production, distribution and fueling infrastructure (e.g., production incentives, investment tax credits, fuel excise tax exemptions) |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**

# NCI considered four main routes of biomass conversion to transportation fuels which rely on three main feedstocks.

- Biodiesel feedstock comes from two main biomass resources; waste oils, fats and grease and agricultural crops such as soybeans and oil seeds
- There are currently no dedicated oils crops in CA being used for biodiesel production
- Biodiesel's maximum on-road transportation fuel displacement is frequently characterized as 5% on an average nationwide basis by the biodiesel industry; higher blends are possible.



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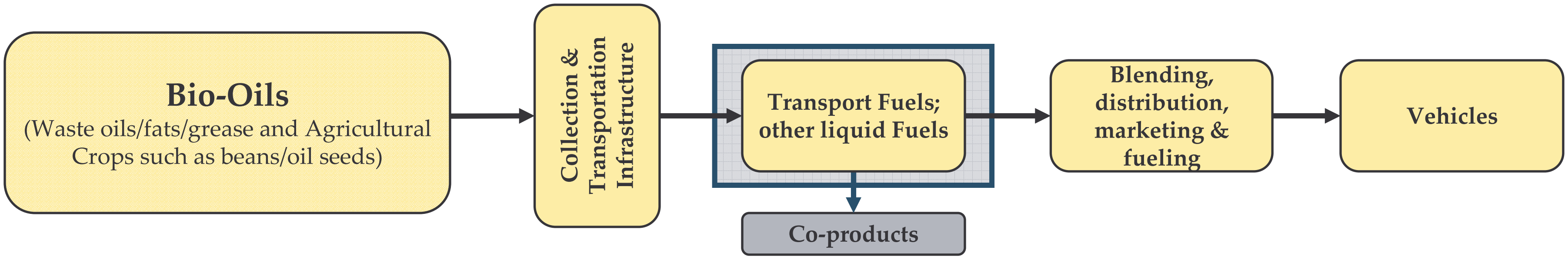
## **Biofuels** » Biodiesel from Bio-oil Transesterification › *Current Situation Assessment (1 of 2)*




| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Utilization/ Situation** | • No oil/bean energy crops dedicated to biodiesel production.<br>• Oil crops for biodiesel production are currently in field trials within the states (5 p S.2.4) | • Waste oils are currently collected for disposal. | • Production is expanding rapidly. In 2004 27 biodiesel plants in US produced over 33 million gallons. (20 p AD-2J-4). In 2005 the US produced over 75 MM gal (biodiesel.org). | • In CA 4 production facilities, 29 distributors (primarily petroleum distributors), 23 retail outlets (34) | • 2004 US production from 27 commercial plants >33 m g. (20)<br>• CA consumption was less than 5m gallons in 2004 (20 p AD-2J-2).<br>• Several gov't and utility fleets in CA use biodiesel (26 p 3)<br>• B20 considered alternative fuel under FEPA requirements. (26 p 3) |
| **Costs** | | | • Production cost for diesel from seed oil ~$2.50/gal (driven by feedstock cost)<br>• Tax credit equivalent to $1.00/gal enacted 2004 for biodiesel from virgin oils (50¢/gal if from waste oils) | • Biodiesel receives tax credits when blended with petroleum fuels (19)<br>• Added expense for fuel handling and logistics increase price (34) | • Biodiesel appears broadly competitive as a blending ingredient (19)<br>• B20 retails 12 to 22 cents per gallon more than petroleum diesel (20 AD-2J-4) |



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| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Constraints** | • Because only the oil component of crops can be used for biodiesel, the yield of fuel per acre is relatively low. Co-utilization of the lignocellulosic fraction of dedicated oil crops would improve overall yields of energy per acre. | | • DOE estimates that 1 gal of petroleum fuel is required to produce 3.37 gal of biodiesel on a "well-to-wheels" basis (20)<br>• Tailoring the characteristics of biodiesel to specific diesel engine requirements is difficult (7 p 45)<br>• Large scale production of biodiesel could drive up oil crop prices (food oil demand is inelastic) (7 p 45) | • CEC staff assume terminals and racks will require $50-$500k modification per terminal for biodiesel. (20)<br>• Concerns about fuel quality by OEM's and petroleum industry (34) | • Some compatibility issue with seals & gaskets in engines manufactured before 2004 with blends higher than B20 (20)<br>• Biodiesel contains 7% less energy per gallon than CARB diesel (20)<br>• Higher NOx emissions result in regulatory problems in CA. (7)<br>• According to a CEC study that evaluated the overall social value of various non-petroleum fuel alternatives, biodiesel was rated as slightly negative "overall benefit" (19 p 6) |

| | Resources | Collection & Transportation | Conversion & Refining | Distribution | Markets |
|---|---|---|---|---|---|
| **Timing & Magnitude** | • Oil crops production could be developed in CA; San Joaquin Valley.<br>• Oil crops for biodiesel are currently in field trials (sunflower & safflower) | • Would need to develop alongside in-state production capacity and be commensurate in scale. | • In general, market is growing rapidly (50-100% per year). According to biodiesel.org, at start of 2006, 35 companies reported plants under construction, suggesting additional capacity of 278 MM gallons could be online by mid-2007 | • CEC staff assume existing diesel fuel retail infrastructure can store and dispense diesel with up to 20% RE diesel content w/o modifications | • Biodiesel's max. diesel displacement is frequently characterized as 5-10% on a nationwide basis, by biodiesel industry.<br>• CEC assumes 5% displacement of diesel with RE diesel by 2015 and 20% by 2025 (1000m gpy) (2025 figure equivalent to 4.75% of on-road gasoline and diesel) (19 p 6); this is an aggressive case, base case is 40-80 m gpy by 2020 (26 p 5) |
| **Benefits** | • High value utilization of waste oils could result in higher collection rates (this is speculative). | • Would provide additional employment to trucking | • Net energy gains for biodiesel (output/input=3.2) are greater than ethanol (1.3-1.6)<br>• Biodiesel produces byproducts of oil seed meal and glycerol. | • B20 can be used in conventional petroleum fuel systems with little or no change from production to end-use (19) | • Over lifecycle, biodiesel produces 78% less CO2 emissions than petroleum diesel.<br>• Lower toxicity and greater biodegradability than diesel; emissions lower except for NOx.<br>• B20 improves lubricity properties of low-sulfur diesel<br>• Most engine manufactures approve of B20 in heavy duty engines (apart from VW) (26 p 4)<br>• Biodiesel is sulfur free, helping meet low-sulfur diesel requirements. |
| **Needs** | • Assessment needed of economic feasibility of feedstocks for attaining 20% diesel displacement CA goal. (20) | • In state crops for biodiesel would require infrastructure; could take advantage of existing farm infrastructure. | • Investment for production capacity to meet 20% diesel replacement goal is unknown (20) | | |

| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • Identifying financing for start-up companies will remain an important consideration in brining new products to market.<br>• Identify after-treatment technology or other engine modifications for diesel cars that will eliminate NOx increases (could be part of new cars, but issues remains with old vehicles).<br>• Conduct statewide assessment of biodiesel feedstock<br>• Assess oil crop potential and issues relative to other energy crops or agricultural crops<br>• Aggressively pursue collection of waste fats oils & grease in a manner that facilitates conversion to biodiesel<br>• Education/outreach<br>• Require state fleets to use biofuels (general, not just biodiesel).<br>• Develop programs to encourage private fleets to use biodiesel blends |
| **Regulatory Actions** | • Does the state need fuel specs for biodiesel and biodiesel blends? ASTM standard already exists for B100 for us as fuel or for mixing with petroleum fuels (ASTM D 6751).<br>• Address air quality issues holistically (e.g., NOx may go up, but other pollutants may go down, like PM, HC, CO).<br>• Address biodiesel emissions issue related to NOx. |
| **Legislative Actions** | • Incentives for biodiesel production, distribution and fueling infrastructure (e.g., production incentives, investment tax credits, fuel excise tax exemptions |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**

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| | Potential State Actions[1] |
|---|---|
| **Administrative Actions** | • Create a demonstration and commercialization program for lignocellulosic biofuels (including those derived from municipal wastes) in California.<br>• Urge the Governor to join the 31 other U. S. states that are members of the Governor's Ethanol Coalition.<br>• Provide conversion support or incentives for farmers to switch to sugar/starch crops or other energy crops.<br>• Examine the air pollutant emissions performance of biofuels and biomass power and recommend appropriate emissions performance standards. Ensure that the regulations maximize the flexibility to use biofuels while concurrently preserving or enhancing the environmental benefits of the regulations.<br>• Work with federal agencies to coordinate on the possible development of national policies to reduce net greenhouse gas emissions and improve infrastructure and public access to renewable fuels and products aimed at enhancing the value of renewable energy and emission reduction credits to realize the intrinsic benefits of renewable resources.<br>• Establish incentive programs to support investments in new and emerging technologies relating to bio-energy, such as gasification, cellulosic ethanol, BTL, distributed energy systems, landfill gas-to-energy, and for technologies that are linked to alternative fuels and to climate change initiatives.<br>• Develop programs to monetize the environmental benefits of biomass-to-energy and bio-fuels by estimating the costs of alternative fates for the biomass materials (e.g., forest fires). Could be implemented via a carbon tax, carbon adder, or other means).<br>• Identify financing options for start-up companies to aid in bringing new products to market.<br>• Conduct emissions testing to measure benefits, tradeoffs, and impacts of biofuel use. R&D on engine modifications & after-treatment to address emissions issues, including exhaust and permeation. Key examples include low ethanol blends and NOx from biodiesel.<br>• Establish procurement standards to encourage other public entities (school districts, UC system) to use biofuels and purchase biomass power.<br>• Direct CEC to prepare a comprehensive, peer-reviewed economic assessment of the costs and benefits of expanded use of biofuels by fuel type, and impacted group (fuel producers, fuel distributors, agriculture, government and consumers). |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**

| | Potential State Actions[1] |
|---|---|
| **Regulatory Actions** | • Establish necessary fuel specifications for transportation bio-fuels used in blends and as neat fuels. Include low-ethanol blends with gasoline, E85, E-diesel, FT diesel, B5, B20, B100. Spec should recognize the climate change benefits of renewable fuels. Work with existing specs, such as ASTM standard for B100 for us as fuel or for mixing with petroleum fuels (ASTM D 6751).<br>• Develop streamlined permitting for cellulosic ethanol and thermochemical biofuel production plants (maybe to also encourage cogeneration with lignin residues or co-location with existing biomass power plants) |
| **Legislative Actions** | • Develop the rules and regulation for the RFS<br>• Establish a Renewable Fuels Standard that covers biofuels that can be used in blends or as neat fuels. The RFS would cover all biofuels and could contain special provisions to encourage in-state production and the deployment of new technology. The RFS would be a way to help achieve existing state goals on transportation energy use and GHG emissions.<br>• Design and recommend a package of tax and other financial incentives to encourage use of biomass, biofuels and bio-products. These could include: in-state production or tax credits, investment tax credits for E-85 delivery infrastructure, insurance products such as efficacy insurance to reduce cost of risk to private sector, fuel excise taxes based on energy content, fuel tax exemptions.<br>• Develop appropriate incentives for growing energy crops<br>• Create a Public Goods type charge to fund biofuels production and infrastructure development |

**1. This list is a compilation from various sources and does not represent a prioritized or final list of recommended actions.**

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| Acronym | Explanation |
|---|---|
| **$/kWh** | Dollars per kilowatt hour. The standard unit of measure for the price of energy. |
| **$/kW** | Dollars per kilowatt. The standard unit of measure to represent the installed costs of power plants. |
| **BTU** | British thermal unit. |
| **CCHP** | Combined cooling, heat and power. CCHP applications examples include the use of water treatment plant generated methane combusted to energize onsite reciprocating engines to run plant operations, and the waste heat from the generator is applied to digesters to increase process rates. |
| **CHP** | Combined heat and power. |
| **CO2** | Carbon dioxide. |
| **GWh** | Gigawatt hours. The standard unit of measure for the total amount of energy produced over a period of time. One gigawatt is 1,000 MW. |
| **GHG** | Greenhouse gas. |
| **IOU** | Investor Owned Utility |
| **LCOE** | Levelized cost of energy. |
| **MDT** | Million Dry Tons. The standard unit of measure for biomass. |
| **MPR** | Market Price Referent. Used to calculate payment of RPS contacts and SEPs. |
| **MW** | Megawatt. The standard unit of measure for the amount of power produced from a plant. One megawatt is 1,000 kilowatts. |
| **PTC** | Production Tax Credit |
| **R&D** | Research and Development |
| **RPS** | Renewable Portfolio Standard. The requirement that IOUs must contract a percent of there load with renewable energy. |
| **SEP** | Supplemental Energy Payments. These are funds available to pay renewable power producers who have been awarded contracts under RSP solicitations. The supplemental payment represents the cost of energy being pay above a calculated market price referent (MPR) |
| **SO4** | Standard Offer Contracts under PURPA |
| **SRAC** | Short run avoided costs. The calculated price at which energy prices are determined under SO4 contracts. The prices is typically calculated based on current natural gas market prices. |

| Acronym | Explanation |
|---|---|
| **B100** | 100% biodiesel |
| **B20, B5, B2** | Petroleum diesel blended with 20%, 5%, and 2% biodiesel, respectively |
| **BTL** | Biomass-to-Liquids - produces primarily a high-quality synthetic diesel product through gasification of biomass followed by conversion of the syngas to a liquid using a the Fisher-Tropsch reaction. Requires further upgrading (similar to conventional refining) to produce finished fuels |
| **CARB** | California Air Resources Board |
| **CaRFG3** | CA reformulated gasoline with 5.7 percent ethanol, the only oxygenated gasoline available in CA after MTBE was phased-out 3/31/03 |
| **E10** | Ethanol Blend - Gasoline blended with 10% ethanol |
| **E85** | Ethanol Hi-Content Blend - Gasoline blended with 85% ethanol |
| **E40** | Half-time use of E85 by drivers of FFVs |
| **FFV** | Flexible Fuel Vehicles – capable of running on any mixture of gasoline and E85 |
| **LEV2** | California Low Emission Vehicle tailpipe and evaporative emissions standards. In the future all manufactures will have to comply with LEV2. |
| **RFG** | Reformulated gasoline |
| **TCP** | Thermal Conversion Process – creates diesel-like crude oil using temperate and pressure to breakdown and process biomass input |
| **ZEV** | Zero Emission Vehicle |

# Definition of Biomass Resources for Power and Biofuels

**AGRICULTURE**
- Agricultural Residues
- Energy Crops
- Food Processing Residues
- Animal Wastes (farm)
- Animal Renderings

**Agricultural Residues:** Woody orchard and vineyard prunings, field crop residues such as cereal straws and corn stover, vegetable crop residues and; Food Processing Residues: primarily woody rice hulls, shells and pits (8pg17)

**Energy Crops:** "Dedicated Crops" which include lignocellulosic "Energy Crops" and also sugar and starch crops, and oil crops such as sunflower and safflower. Sugar, starch, and oil crops, as well as lignocellulosic crops could be used to create biofuels, whereas energy crops grown specifically for biopower would be limited to lignocellulosic crops.

**Animal wastes (farm):** Animal waste includes manure from dairy cows, range cattle, and poultry

**Animal rendering:** Residues from animal processing facilities and potentially, animal carcasses in the event of outbreaks of avian flu or other diseases requiring the culling of animal populations.

**FORESTRY**
- Forest Residues - Tree thinnings, slash, etc.
- Onsite Mill Residues

**Onsite Mill Residue:** Onsite Mill Residues are waste streams from forest products mills, such as waste from sawmill operations

**Forestry Site Residues:** Off site forest residues are considered to be forest thinnings, log slash, scrub, and chaparral.

**MUNICIPAL WASTES**
- Diverted Municipal Solid Waste (MSW)
- Urban wood wastes
- Landfill Gas
- Wastewater Biogas
- Wastewater Sludge
- Waste oils/fats/grease

**Municipal Solid Waste:** Diverted MSW available for biomass conversion applications consist of both high and low moisture content organics generated by municipalities, including clean construction waste (aka urban wood), paper and cardboard, green wastes and trees, food wastes, and . (8pg 22, 23)

**Urban wood waste:** clean wood waste, such as construction waste and tree trimmings. Generally excludes painted or contaminated wood.

**Landfill gas:** Landfill gas is a mixture of roughly 50% methane gas and 50% $CO_2$ created from the natural decomposition of the organic fraction of municipal solid waste (MSW) that is disposed of in landfills. (8pg 23)

**Wastewater biogas & sludge:** Methane of 60% concentration and resulting biosolids (sludge) is created from the anaerobic digestion of organic matter in waste water (8pg 23)

**Waste oils/fats/grease:** Various types of animal and vegetable waste (e.g., yellow grease from restaurants)