APPENDICES

EVALUATION OF BIOMASS-TO-ETHANOL FUEL POTENTIAL IN CALIFORNIA

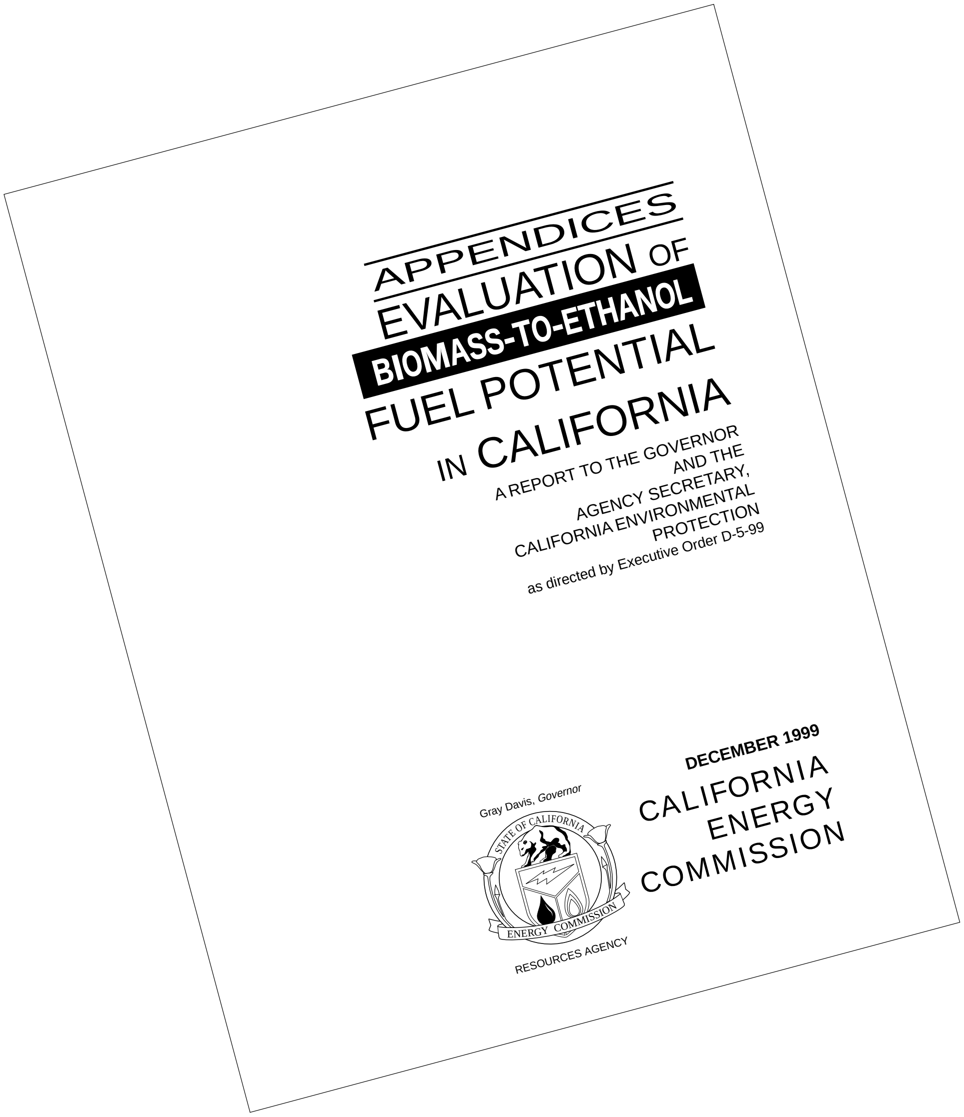
A REPORT TO THE GOVERNOR
AND THE
AGENCY SECRETARY,
CALIFORNIA ENVIRONMENTAL
PROTECTION
as directed by Executive Order D-5-99

Gray Davis, *Governor*

DECEMBER 1999

CALIFORNIA
ENERGY
COMMISSION

RESOURCES AGENCY



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STATE OF CALIFORNIA
ENERGY COMMISSION

RESOURCES AGENCY

CALIFORNIA ENERGY COMMISSION

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TABLE OF CONTENTS

Chapter VII – Economic Evaluation

LIST OF TABLES

Appendix VII-C

LIST OF FIGURES

Appendix ES-A

Governor Gray Davis

Executive Order

EXECUTIVE DEPARTMENT

STATE OF CALIFORNIA

EXECUTIVE ORDER D-5-99
by the
Governor of the State of California

WHEREAS, the University of California prepared a comprehensive report on the "Health and Environmental Assessment of Methyl Tertiary-Butyl Ether (MTBE)" which has been peer reviewed by the Agency for Toxic Substances and Disease Registry and the Unites States Geological Survey and other nationally recognized experts;

WHEREAS, the University of California report was widely available for public review and written comment, including hearings in northern and southern California to receive public testimony;

WHEREAS, the findings and recommendations of the U.C. report, public testimony, and regulatory agencies are that, while MTBE has provided California with clean air benefits, because of leaking underground fuel storage tanks MTBE poses an environmental threat to groundwater and drinking water;

NOW, THEREFORE, I, GRAY DAVIS, Governor of the State of California, do hereby find that "on balance, there is significant risk to the environment from using MTBE in gasoline in California" and, by virtue of the power and authority vested in me by the Constitution and statutes of the State of California, do hereby issue this order to become effective immediately:

1. The Secretary for Environmental Protection shall convene a task force consisting of the California Air Resources Board, State Water Resources Control Board, Office of Environmental Health Hazard Assessment, California Energy Commission and the Department of Health Services for the purpose of implementing this Order.

2. On behalf of the State of California, the California Air Resources Board shall make a formal request to the Administrator of the U.S. Environmental Protection Agency for an

immediate waiver for California cleaner burning gasoline from the federal Clean Air Act requirement for oxygen content in reformulated gasoline.

3. The California Environmental Protection Agency shall work with Senator Feinstein and the California Congressional Delegation to gain passage of Senate Bill 645. This legislation would grant authority to the Administrator of the U.S. Environmental Protection Agency to permanently waive the Clean Air Act requirements for oxygen content in reformulated gasoline to states such as California that have alternative gasoline programs that achieve equivalent air quality benefits.

4. The California Energy Commission (CEC), in consultation with the California Air Resources Board, shall develop a timetable by July 1, 1999 for the removal of MTBE from gasoline at the earliest possible date, but not later than December 31, 2002. The timetable will be reflective of the CEC studies and should ensure adequate supply and availability of gasoline for California consumers.

5. The California Air Resources Board shall evaluate the necessity for wintertime oxygenated gasoline in the Lake Tahoe air basin. The Air Resources Board and the California Energy Commission shall work with the petroleum industry to supply MTBE-free California-compliant gasoline year around to Lake Tahoe region at the earliest possible date.

6. By December 1999, the California Air Resources Board shall adopt California Phase 3 Reformulated Gasoline (CaRFG3) regulations that will provide additional flexibility in lowering or removing the oxygen content requirement and maintain current emissions and air quality benefits and allow compliance with the State Implementation Plan (SIP).

7. In order that consumers can make an informed choice on the type of gasoline they purchase, I am directing the California Air Resources Board to develop regulations that would require prominent identification at the pump of gasoline containing MTBE.

8. The State Water Resources Control Board (SWRCB), in consultation with the Department of Water Resources and the Department of Health Services (DHS), shall expeditiously prioritize groundwater recharge areas and aquifers that are most vulnerable to contamination by MTBE and prioritize resources towards protection and cleanup. The SWRCB, in consultation with DHS, shall develop a clear set of guidelines for the investigation and cleanup of MTBE in groundwater at these sites.

9. The State Water Resources Control Board shall seek legislation to extend the sunset date of the Underground Storage Tank Cleanup Fund to December 31, 2010. The proposed legislation would increase the reimbursable limits for MTBE groundwater cleanups from $1 million to $1.5 million.

10. The California Air Resources Board and the State Water Resources Control Board shall conduct an environmental fate and transport analysis of ethanol in air, surface water,

and groundwater. The Office of Environmental Health Hazard Assessment shall prepare an analysis of the health risks of ethanol in gasoline, the products of incomplete combustion of ethanol in gasoline, and any resulting secondary transformation products. These reports are to be peer reviewed and presented to the Environmental Policy Council by December 31, 1999 for its consideration.

11. The California Energy Commission (CEC) shall evaluate by December 31, 1999 and report to the Governor and the Secretary for Environmental Protection the potential for development of a California waste-based or other biomass ethanol industry. CEC shall evaluate what steps, if any, would be appropriate to foster waste-based or other biomass ethanol development in California should ethanol be found to be an acceptable substitute for MTBE.

IN WITNESS WHEREOF I have hereunto
set my hand and caused the Great Seal of
the State of California to be affixed this
25th day of March 1999.

Governor of California

(*Signature of Gray Davis*)

ATTEST:

(Signature of Bill Jones)

Secretary of State

This document can also be found on the Internet at: www.ca.gov/s/governor/d599.html

Appendix ES-B-1

Summary of September 10, 1999 Workshop on Report for Governor: "Evaluation of Biomass-to-Ethanol Fuel Potential in California"

A public workshop was held on September 10, 1999 at the California Energy Commission to receive comments on staff's draft report on the *Evaluation of Biomass-to-Ethanol Fuel Potential in California.* The purpose of the workshop was to solicit public input on the report and also to seek feedback on the eight questions included in the workshop announcement. These questions were specifically designed to answer the question: Should the State of California take an active role in fostering a biomass to ethanol industry; and if so, how? This information will assist staff in crafting the recommendations portion of the report and provides valuable input from industry stakeholders before developing a policy.

Approximately 50 people attended the event. A total of 18 presentations were made, including the two by staff and ethanol expert Dr. Jim Kerstetter. Project manager Pat Perez facilitated the meeting and began with introductions, a summary of workshop agenda and provided an overhead slide presentation on the report background, schedule, and key findings and recommendations.

Next, Dr. Jim Kerstetter presented information on the history of ethanol production in California and salient issues confronting the industry. Dr. Kerstetter highlighted the Energy Commission's work on the Senate Bill 620 project, an effort in the early 1980s to study ethanol and methanol in vehicles and the feasibility of producing ethanol in California. The project revealed two important points: 1) that California-produced ethanol could not economically compete with corn-based ethanol from the Midwest, and 2) you need to have clear markets for ethanol.

What has happened since SB 620 project?
- ✓ Corn still predominant feedstock and still sells at ~ $2.50/bushel
- ✓ Ethanol now marketed as octane and oxygenate product and captures higher value
- ✓ Biomass to ethanol technology still not commercially demonstrated
- ✓ Biomass/ethanol yields have increased at pilot plant level from improved pretreatment and C5 sugar fermentation (e.g., xylose)
- ✓ Process energy requirements have declined
- ✓ Global climate change has become a significant issue
- ✓ Low feedstock prices and developed market for product are two key concepts

Dr. Kerstetter then discussed how inflation adjusted oil prices have been declining over most of this century, whereas carbon dioxide levels in the atmosphere have steadily increased. Finally, Dr. Kerstetter highlighted areas he felt needed attention in the report. These areas included:

- ♦ Concern about the 50 million tons of biomass figure use in the report. How much is really available at low cost is critical, not the physical resource.
- ♦ Need supply curves for feedstocks.

- ♦ Midwest may produce biomass ethanol at lower cost than California, even with transportation cost penalty.
- ♦ Capital costs appear low: e.g., cost difference between Jennings, Louisiana plant ($ 90 million) vs. California projects ($52 million).
- ♦ Secure product markets and feedstock supplies are critical to any project.
- ♦ Be careful with forecasting, it can be useful, but is often wrong.
- ♦ Should pay for production not just for the construction of a plant.

What follows is a summary of key points by those commenting on the draft report and responses to questions listed in the workshop announcement:

Art Krause: Legislative Advocate, representing the Williams Companies and Pekin Energy Group
The discussion in Appendix H, below table A-1 contains an error. Minnesota does not mandate any particular oxygenate.

Dr. Raphael Katzen: Consulting Engineer, representing himself
- Report is a "magnificent piece of work"
- Energy value is incorrectly presented. Ethanol has an octane of 113, which compensates for its lower Btu.
- Brazil has utilized ethanol in its vehicles for several years. The vehicles cost only $200-300 more to build and areas like Sao Paulo, according to Dr. Katzen's personal experience, have dramatically improved air quality because of ethanol use in vehicles.
- Subsidies are not bad. According to a 1976 DOE/Battelle Memorial Institute study, petroleum industry subsidies totaled $70 Billion.
- The state should provide loan guarantees to the industry and should subsidize the feedstock.
- Cogeneration opportunities make sense.
- Sweden has done a great deal with lack of natural resources and making use of forest material. Should send staff delegation to Sweden.
- Responded to question about the significance of co-products. Based on research and testing of lignin, the best thing to do is burn it.
- Russian ethanol industry has 40 plants running for about 50 years and they burn the lignin.
- Don't base business on co-products.
- Noted his past observation that the California Air Resources Board has been resistant to ethanol/gasoline blending in the state.
- Doesn't feel that MSW-derived ethanol is attractive because of materials variability, increasing use of plastics, difficulty in dealing with municipalities, etc.

Phil Reese: Colmac Energy, Inc., and member of the California Biomass Energy Alliance
- Need to support the existing biomass power industry
- At its peak, California had 44 plants, 8 million tons of biomass consumed. Now down to 30 plants and 6 million tons consumed.

- Without help, the industry will likely shrink to about 5 plants, which will destroy the current fuel supply infrastructure that is critical to the biomass/ethanol industry.
- Biomass industry would not exist today if it had not been able to assure a consistent and adequate long-range fuel supply by funding long-range contracts with fuel suppliers.
- Green energy concept is not working. Citizens have shown that they are not willing to pay more for "green energy." Role for government to help biomass power industry.
- Could add ethanol plant to power plant with few regulatory/siting issues.
- Looked at raising energy crops, but found it to be very costly.
- Pointed out that same environmental benefits will be realized whether electricity generated and/or ethanol produced.
- Biomass is disadvantaged compared to other renewables. Solar, wind, etc. all have zero fuel costs. Biomass is costly to collect and transport.
- The lack of a biomass policy today in the face of a deregulated electric generation business is leading to the demise of the existing biomass power industry
- Bottom line – A "biomass" policy needed, not a "renewables" policy.
- Has calculated greenhouse gas impacts of biomass and will make available to the Commission.
- There needs to be a connection between the existing industry and the yet-to-be developed biomass-to-ethanol industry.

Dave Allen: Director, California Biomass Energy Alliance
- State needs a biomass policy that includes policies that favor "waste utilization" over "non-productive waste disposal."
- Need to create markets for wastes. Don't favor one feedstock over another.
- Don't favor ethanol production over electricity production.
- Distinction should be drawn between short-term measures (e.g., feedstock subsidies) and long-term viability/stability (supporting the creation of markets).
- A stable industry will result by supporting markets which favor waste utilization
- Co-products can be important and must be considered.

John Prevost: Scotia Pulp Mill – Pacific Lumber Company
- Talked with the National Renewable Energy Lab (NREL) regarding siting an ethanol facility, but could not justify it. Part of the problem is that their means of processing wood has improved and the resulting waste residues have fallen in quality.
- Traditionally produced 10MWe of electricity and sold to PG&E, but this amount has dropped in recent years.
- We use highest value for wastes that remain-- compost and soil amendments.
- Went to Congress to seek assistance for biomass power through closed loop biomass tax credit, but was defeated by Congressman Archer of Texas.
- Expensive to pull materials out of the forest, because of hills, etc.

Norm Hinman: BC International

- Now completing financing for Jennings, Louisiana plant.
- Very good report – superb job of highlighting biomass-to-ethanol benefits.
- Add that ethanol would extend the state's fuel supply, providing a buffer against the possibility of future price hikes.
- Need two types of policies: 1) guarantee of 10 year market for biomass-to-ethanol and 2) low interest loans (i.e., 3%).
- We can work to achieve White House goal of tripling biomass use.
- California should look to establish policies and incentives similar to what other states have done which would support the development of an industry.
- Need to get first few plants up and running.
- Need streamlined financing process for entering market.
- Need a secure market for ethanol.
- Examples of state help include:
    - Insurance policy to assure ethanol market or act as broker
    - Use state owned vehicles to guarantee fuel use
    - Could create a renewable fuel standard
    - A 3%, 15 year loan would be useful (perhaps from CA Air Pollution Control Finance Authority)

John Chilcote: Placer County Resource Conservation District and American River Watershed Institute

- High labor costs are an issue for forest residue collection.
- Specialized vehicles to chop/chip trees are not allowed on highways because of CA vehicle codes.
- Should make allowances in vehicle code like those for farmers.
- We need to forget turf wars, especially true in state government (CDF mentioned).

Steve Shaffer: California Dept. of Food and Agriculture

- CDFA has long history of work on ethanol from agricultural residues.
- State biomass policy is sorely needed.
- Should highlight other ethanol market opportunities (e.g., oxydiesel, E100).
- Include livestock manure in biomass characterization.
- Think of feedstocks as underutilized resources rather than wastes.
- Energy crops information should be added, including information on reclaimed water.
- Energy crops may be valuable over long period (20-50 year time frame).
- Should mention Rice Straw Utilization Tax Credit is administered by CDFA and is capped at $400,000/yr.

Rus Miller: Arkenol, Inc.

- Make a reliable ethanol market, 10-15 years.
- California Integrated Waste Management Board needs to be more involved in this process

- The CIWMB needs to review their act to allow diversion of materials to be accounted so municipalities are not dis-incentivized from considering the waste conversion to ethanol option.
- Need low interest loans for project financing (i.e., 3%).
- Their plan to produce 12 million gal/yr. is now 4 million, with the remainder going to produce more valuable citric acid. Ethanol is the secondary product.
- Citric acid market small in comparison to potential ethanol market, which is the only sink that can absorb large amounts of product.
- Conversion rate of 70gal/bdt may be too low depending on feedstock, etc.

Jim Boyd: Energy Advisor, Secretary for Resources
- Responded to criticism of state agencies and said that various agencies are working together on this issue: CDF, CDFA, CARB, etc.
- We see biomass as a high priority.

Neil Koehler: Parallel Products
- Ethanol production and use in California is very consistent with the Energy Commission's vision and mission statements.
- Have survived producing ethanol (only producer in state), despite hostile regulatory environment. Fuels regulations that are fuel neutral won't work for non-petroleum based fuels.
- Half of the ethanol they produce goes to industrial market (higher value)
- Must have stable, long-term market. Unique market opportunity with MTBE phase out.
- California needs a renewables policy that could include a renewable portfolio standard.
- [Showed graph that emphasized a relatively stable price for ethanol compared to MTBE and gasoline. (short-term).]
- Low interest loans are a good idea.
- Government should not pick winners, should not take an equity position.
- Need to integrate air quality benefits of ethanol with existing policies, including CO_2.

Kent Hoekman: Chevron Products Co.
- While the report is very good, the executive summary lacks depth and substance.
- Add quantified numbers to report on greenhouse gas benefits and air quality benefit.
- Say that there is no urban air quality benefit with ethanol production and use.
- If you want incentives say it and how much.

Catherine Witherspoon: California Air Resources Board
- (Responded to remarks about CARB's treatment of ethanol) There is no prohibition on the use of ethanol in California by virtue of the air standards.
- There are 30 million gallons of ethanol being used today per year in California gasoline, and we expect that to increase in the future.

Loyd Forrest: TSS Consulting
- Financing is the key issue. Need 10-year market for ethanol is critical for financing.

- Agreed with Dr. Kerstetter that the first couple of plants are probably going to cost 30 percent more in terms of capital investment, next two about 15 percent more.
- Need to ask question “are there enough public benefits to justify subsidies?”
- It is the state’s job (CEC, governor, and legislature) to say yes.
- A direct subsidy on feedstock doesn’t make sense.

Daryl Harms: MASADA OxyNol

- Project in New York that has been developing for past five years, based on guarantee that municipalities 1) promise to deliver all their waste and 2) promise a set tipping fee.
- Business will process 230,000 tons of waste and 360,000 tons of sewage and wastewater.
- Expect to recycle or convert to beneficial use over 90 percent of the waste stream that comes into plant.
- Typical landfill that would handle that amount of waste that our plant processes will emit 480 tons/yr. of VOCs. Our plant emits 21 tons/yr.
- Capital costs are higher and financing is more complex than anyone is giving credit for.
- Questions the methodology for analyzing the MSW. Also breaking down subcategories for MSW and sludge is dangerous.
- Furthermore, it is dangerous for legal and technical reasons to identify potentially valuable commodities somewhere within the process without looking at it from a front-end to back-end process.
- Four points that are critical to setting up the right structure are:
  1) Count the conversion of waste to ethanol as diversion credit under the 50% mandate
  2) Ban siting of new landfills or expansions without first considering biomass to energy first.
  3) Ban land application of sludge and wastewater without first considering biomass to energy first
  4) Allow co-collection of recycling materials with garbage

Kay Martin: County of Ventura, Public Works, Solid Waste Management Dept.

- MSW has unique qualities.
  – 65% of MSW is biomass
  – California is a major producer of MSW
  – Built in infrastructure
  – Consistent waste stream
- A trend in California is toward the closure of urban landfills and the regionalization of more remote rural landfills, meaning that the waste stream is increasingly being collected and transferred through centralized collection points called transfer facilities or material recovery facilities (MRF).
- This change increased the potential for collocation of ethanol/waste facility.
- Negative cost feedstocks not adequately reflected in report.

Expand plant modeling to include one or more collocated MRF/ethanol production options.

Appendix ES-B-2

**Summary of November 19, 1999 Public Hearing on Report for Governor:
"Evaluation of Biomass-to-Ethanol Fuel Potential in California"**

A public hearing was held on November 19, 1999 at the California Energy Commission to receive comments on the Energy Commission's Fuels and Transportation Committee's draft report on the *Evaluation of Biomass-to-Ethanol Fuel Potential in California*. Commissioners Michal C. Moore and Robert Pernell of the California Energy Commission led the hearing. Jim Boyd, Energy Advisor to the California Resources Agency, and Dr. Alan Lloyd, Chairman of the California Air Resources Board, also participated from the dais. Bill Vance from CalEPA was also in attendance throughout the hearing.

Over 40 interested parties attended the hearing. Comments were received from 12 speakers including an Energy Commission staff presentation by Pat Perez.

What follows is a summary of key points by those commenting on the draft report:

Greg Krissek: Assistant Secretary of the Kansas Department of Agriculture, on behalf of Kansas Governor Bill Graves, current chair of Governors' Ethanol Coalition

- Governors' Ethanol Coalition now comprises 23 states and 4 international members.
- Ethanol plays an important environmental and economic role in the portfolio of U.S. energy sources.
- Believes the report provides a detailed examination of biomass fuel alternatives.

Todd Sneller: Nebraska Ethanol Board/Governors' Ethanol Coalition

- Illinois stimulated ethanol production by creating a "buy Illinois" policy that created a performance-based production credits program. Producers were paid after they performed.
- Nebraska established contract program to provide assurances to reduce risk for government.
- Nebraska has 350 million gallons per year of ethanol capacity and is working to modify grain-based plants to accept biomass.

Neil Koehler: Parallel Products

- Likes the interagency cooperation that exists between state agencies.
- A false sense of petroleum supply security exists and fuel diversity is needed.
- Need an integrated environmental, energy, and air quality policy.
- Need a long-term (>10 years) stable market for ethanol in the transportation market.
- California has been a "hostile" market for ethanol use in the past decade.

- Recommends a renewable fuels standard policy be developed for California (e.g., 5% of fuels and 5% of electricity supplies should be from renewable sources).
- Ethanol as a fuel source for fuel cells should be investigated.
- Opposes financial assistance where the State of California chooses the winners and losers.
- The state should not take an equity position in any ethanol plants and believes no direct investment is necessary.

Phil Reese: Colmac Energy and California Biomass Energy Alliance

- Represents 28 of the 30 currently operating biomass power plants in California.
- Disagrees with statement on page I-8 of report that says "no definitive study of benefits has yet been conducted" regarding the quantification of the value of a biomass-to-ethanol industry to the state. Three studies exist including one NREL study that was cosponsored by Energy Commission that quantifies the benefits.
- Biomass power plants can compete in deregulated market if zero-cost feedstock is made available.
- Feedstock fuel cost is the main consideration in plant economics.
- Questioned why the "Cost-Shifting" report by CalEPA is still in the Governor's Office.
- The diversion credit (AB 939) has "no teeth" even with recommended revision to full 50%.
- In 1992-94, 45 biomass power plants were in operation using 8 million tons of biomass annually. Today there are only 29 plants using about 5 million tons of biomass annually. By 2002, there will be only 10 plants or fewer operating and the infrastructure for collocating with ethanol plants will disappear.
- We don't need a biomass-to-ethanol policy; rather we need more interagency cooperation.
- The rationale for the "Pro" argument for creating a biomass policy on page I-1 in the report should be expanded to acknowledge that the existing biomass power industry could be used as a springboard for biomass-to-ethanol development.
- Wants the Energy Commission to extend the renewable production credit for biomass power plants.
- Noted that the biomass industry was unable to get the federal production tax credits for "closed-loop biomass extended to biomass power plants through the closed-loop credit."
- The Research, Development and Demonstration Options listed on pages I-3 to I-5 should expand the work that has been done to reduce the cost of feedstock at the gate.
- The "Con" rationale on page I-4, that the federal government is already applying significant resources to reduce the cost of feedstock, is not supported in the report.
- The recommendation to develop a biofuels policy on page I-3 may lead to funding that is ill spent (i.e., the efforts of consumers to buy green energy has been a failure).
- Public goods are paid for by government.
- The state should not underestimate the difficulty of securing financing.
- Recommends staff consider what must occur before we have a sustained market and what is the schedule for seeing this happen? Can government step in to save the biomass power industry in two years?

Bill Carlson: Wheelabrator and Chairman of the USA Biomass Power Alliance

- A known market exists, but ethanol is not valuable
- Recently returned from Washington D.C. where the battle was lost to change definition of closed-loop biomass because of Representative Archer's (Texas) opposition.
- Avoid creating direct competition between existing biomass power industry and biomass-to-ethanol industry.
- The existing biomass power industry needs incentives to ensure continued operation.
- Likes optional policy noted on page I-1 to develop a biomass policy and believes that biomass should be utilized for ethanol production and for generating electricity
- Efforts should be encouraged to lower cost of raw materials or increase value of products.
- Report should focus on biomass wastes and not energy crops.
- The values of lignin and moisture value content appear to be wrong in the report.
- No more studies are needed. We need to implement steps to make things happen.

Necy Sumait: Arkenol

- A very comprehensive report.
- Ethanol is the largest "sink" for biomass.
- Carbon reduction and diversity goals should be adopted.
- Fuel diversity is a necessity, not an option.
- The California Integrated Waste Management Board needs to be involved.
- Policy focus should be on demonstrations and developing long-term markets.
- Supports full diversion credit for biomass-to-ethanol.

Chris Trott: OGDEN Pacific Power, Inc.

- Supports developing a comprehensive biomass policy to assist biomass-to-ethanol industry.
- Currently working with the Energy Commission and federal government on two proposals to collocate ethanol facilities with existing biomass power plants.
- Supports broad-based policy to address waste and environmental issues.
- All state agencies should be working together on a joint solution.
- A healthy biomass power industry is essential to a California biomass-to-ethanol industry.
- The Energy Commission should concentrate on utilizing waste biomass first before exploring the use of energy crops.
- If the biopower industry declines, the associated feedstock infrastructure will also decline.
- The Energy Commission should act as the catalyst for the development of a comprehensive statewide biomass policy developed through interagency cooperation.

Norm Hinman: BC International

- Have developed plans to build biomass-to-ethanol facilities in Gridley and Chester, California and completing the financing to construct a 20 million-gallon per year ethanol facility in Louisiana.

- Encourage policies to ensure 10-year market for biomass ethanol.
- Provide state government backed 15-year low interest (3-4%) loans
- Recommended exploring use of low interest loans from California's Pollution Control Finance Authority.
- Examples of what other states such as Minnesota have done demonstrate that the benefits greatly outweigh the costs of providing loans.
- One 1997-study for the Midwestern Governors' Conference shows that for every dollar spent to support ethanol, more than six dollars is returned to the economy as government revenue.
- Biomass-to-ethanol can provide protection against gasoline price spikes.
- To ensure a market for ethanol, the state should consider implementing polices that require state vehicles to operate on ethanol blends, develop a renewable fuel standard to require a minimum percentage of ethanol or other renewable fuel be sold, create greenhouse gas standards for fuels, and California could provide an insurance policy to ensure a market and act as a broker for buying and selling ethanol if demand is not large enough.

Steve Shaffer: California Department of Food and Agriculture

- The driving force for using agricultural wastes is current and future environmental regulations and the need for new markets, crop shifting and infrastructure investment.
- Recommends adding discussion on oxydiesel, ethanol use in fuel cells, and listing potential actions for supporting E-10 and E-22 vehicles.
- Take best shot at a suite of specific recommendations to provide a foundation for a task force to work on and provide a timeline by November 2000 to act on the recommendations.

John Chilcote: Placer County RCD

- Mechanization is the solution as labor costs are very high for collection and transportation of feedstock.
- Need for husbandry exemptions, removal of registration fees, and other restrictions that prevent forest residue harvesting and transporting equipment to use on state's highways.
- Need to involve water interests in forum.
- Excess biomass removal leads to more water being available later in the year when it is most needed.
- Expand vehicle code exemptions that exist for agriculture to silviculture.

John Prevost: Pacific Lumber Company

- Lumber mills use 1500 tons of fuel.
- As forestry rules have changed, the use of helicopters for logging has increased, minimizing impacts to forest floor.
- Helicopter use in logging may preclude collection of forest residues.
- In-forest chipping is questionable.

Jim Boyd: Energy Advisor to Secretary of Resources

- Add discussion on the Interagency Biomass Group's efforts.
- Supports an interagency approach to developing a suite of recommendations.
- We should develop consistent environmental, energy, forestry and agricultural policies.
- Strong personal interest in biomass use and conversion.

Alan Lloyd, Ph.D.: Chairman of Air Resources Board

- We need to make it happen (the report should not end up in a waste bin).
- We want to see ethanol plants built and retained.
- Pledged continued cooperation with the Energy Commission and pleased about work underway to evaluate ethanol use for fuel cells.

Robert Pernell: Commissioner of California Energy Commission

- Complimented interested parties and staff for presentations and said report will not end up in a wastebasket.
- Looks forward to continued interagency cooperation
- Believes government should look for ways to help ethanol industry grow and recommended funding from the state's "Infrastructure Bank" be explored.

Michal C. Moore: Commissioner of California Energy Commission

- We are in a market driven period and it will be difficult to retain subsidies for biomass power industry.
- Don't count on a return to the "dark days" of subsidies.
- Supports efforts to enhance markets, eliminate obstacles, and create tipping fees for waste disposal.
- Fuel cycle costs need to be made visible to customers
- Raise the profile of benefits of biomass industry.
- The biomass industry is clearly undervalued.
- Very pleased with other agency participation and would like to see more involvement by forest and water agencies.

Appendix ES-C

Glossary

A

Acid hydrolysis: A chemical process in which acid is used to aid in the conversion of cellulose or starch to sugar.

Aerobic: Life or biological processes that can occur only in the presence of oxygen.

Agricultural residues: Above-ground organic matter left in the field after the harvest of a crop.

Alcohol: A general class of hydrocarbons that contain a hydroxyl group (OH). The term "alcohol" is often used interchangeably with the term "ethanol," even though there are many types of alcohol. (See, Ethanol, Methanol.)

Alkali: A soluble mineral salt.

Ambient air quality: The condition of the air in the surrounding environment.

Anaerobic: Life or biological processes that occur in the absence of oxygen.

Anaerobic digestion: A biochemical process by which organic matter is decomposed by bacteria in the absence of oxygen, producing methane and other byproducts.

Attainment area: A geographic region where the concentration of a specific air pollutant does not exceed federal standards.

Avoided costs: An investment guideline describing the value of a conservation or generation resource investment by the cost of more expensive resources that a utility would otherwise have to acquire.

B

Barrel of oil equivalent: A unit of energy equal to the amount of energy contained in a barrel of crude oil, approximately 5.78 million Btu or 1,700 kWh. A barrel is a liquid measure equal to 42 gallons.

BDT: See bone dry ton

Biochemical conversion process: The use of living organisms or their products to convert organic material to fuels.

Biochemical oxygen demand: (BOD) A standard means of estimating the degree of pollution of water supplies, especially those which receive contamination from sewage and industrial waste. BOD is the amount of oxygen needed by bacteria and other microorganisms to decompose organic matter in water. The greater the BOD, the greater the degree of pollution. Biochemical oxygen demand is a process that occurs over a period of time and is commonly measured for a five-day period, referred to as BOD5.

Biodegradable: Capable of decomposing rapidly under natural conditions.

Bioenergy: Useful, renewable energy produced from organic matter. The conversion of the complex carbohydrates in organic matter to energy. Organic matter may either be used directly as a fuel or processed into liquids and gases.

Biofuels: Fuels made from cellulosic biomass resources. Biofuels include ethanol, biodiesel, and methanol and others.

Biogas: A combustible gas derived from decomposing biological waste. Biogas normally consists of 50 to 60 percent methane.

Biomass: Matter produced through photosynthesis consisting of plant materials and agricultural, industrial, and municipal wastes and residues derived therefrom. Biomass is organic matter available on a renewable basis and includes residues such as: forest and mill residues, agricultural crops and wastes, wood and wood wastes, animal wastes, livestock operation residues, aquatic plants, fast-growing trees and plants, and municipal and industrial wastes.

Biomass fuel: Liquid, solid, or gaseous fuel produced by conversion of biomass.

Biomass energy: See Bioenergy.

Biotechnology: Technology that use living organisms to produce products such as medicines, to improve plants or animals, or to produce microorganisms for bioremediation.

BOD: See Biochemical oxygen demand.

Boiler: Any device used to burn biomass fuel to heat water for generating steam.

Bone dry ton: A ton of material (2000 lbs.) having zero percent moisture content. A residue heated in an oven at a constant temperature of 212º F or above until its weight stabilizes is considered bone dry or oven dry.

British thermal unit: (Btu) A unit of heat energy equal to the heat needed to raise the temperature of one pound of water from 60ºF to 61ºF at one atmosphere pressure.

Btu: See British thermal unit

C

Capital cost: The total investment needed to complete a project and bring it to a commercially operable status. The cost of construction of a new plant. The expenditures for the purchase or acquisition of existing facilities.

Carbohydrate: A chemical compound made up of carbon, hydrogen, and oxygen. Includes sugars, cellulose, and starches.

Cellulose: The main carbohydrate in plants. Cellulose forms the skeletal structure of the plant cell wall. Cellulose contains six carbon sugars, primarily glucose.

Centralized sewage treatment: The collection and treatment of sewage from many sources to remove pollutants and pathogens.

Chipper: A machine that produces wood chips by knife action.

Chips: Woody material cut into short, thin wafers. Chips are used as a raw material for pulping and fiberboard or as biomass fuel.

Clean Air Act: Federal law enacted originally in 1970 establishing ambient air quality emission standards to be implemented by participating states. Latest amendment was in 1990.

Clearcut: The removal, in a single cutting, of the entire stand of trees within a designated area. Stand regeneration is accomplished by planting the site or by natural seeding from adjacent stands.

Cogeneration: The sequential production of electricity and useful thermal energy from a common fuel source. Reject heat from industrial processes can be used to power an electric generator (bottoming cycle). Conversely, surplus heat from an electric generating plant can be used for industrial processes, or space and water heating purposes (topping cycle).

Combustion: Burning. The transformation of biomass fuel into heat, chemicals, and gases through chemical combination of hydrogen and carbon in the fuel with oxygen in the air.

Combustion gases: The gases released from a combustion process.

Commercial forest land: Forested land which is capable of producing new growth at a minimum rate of 20 cubic feet per acre/per year, excluding lands withdrawn from timber production by statute or administrative regulation.

Cull: Any item of production picked out for rejection because it does not meet certain specifications. Chip culls and utility culls are specifically defined for purposes of log grading by percentage of sound wood content.

D

Denature: The process of adding a substance to ethyl alcohol to make it unfit for human consumption.

Digester: An airtight vessel or enclosure in which bacteria decomposes biomass in water to produce biogas.

Discount rate: A rate used to convert future costs or benefits to their present value.

Discounting: A method of converting future dollars into present values, accounting for interest costs or forgone investment income. Used to convert a future payment into a value that is equivalent to a payment now.

Distillation: The process to separate the components of a liquid mixture by boiling the liquid and then recondensing the resulting vapor.

Distillers dried grain with solubles: (DDGS) The dried byproduct of the grain fermentation process. Typically used as a high-protein animal feed.

Draft environmental impact statement: (DEIS) A draft statement of environmental effects. Section 102 of the National Environmental Policy Act requires a DEIS for all major federal actions. The DEIS is released to the public and other agencies for comment and review.

Duff: The layer of forest litter.

E

Effluent: The treated waste water discharged by sewage treatment plants.

Emission offset: A reduction in the air pollution emissions of existing sources to compensate for emissions from new sources.

Emissions: Waste substances released into the air or water.

Endangered species: See Threatened, endangered, and sensitive species.

Energy: The ability to do work.

Energy crops: Crops grown specifically for their fuel value. These include food crops such as corn and sugarcane, and nonfood crops such as poplar trees and switchgrass. Currently, two energy crops are under development: short-rotation woody crops, which are fast-growing hardwood trees harvested in 5 to 8 years, and herbaceous energy crops, such as perennial grasses, which are harvested annually after taking 2 to 3 years to reach full productivity.

Environmental assessment: (EA) A public document that analyzes a proposed federal action for the possibility of significant environmental impacts. The analysis is required by NEPA. If the environmental impacts will be significant, the federal agency must then prepare an environmental impact statement.

Environmental impact statement: (EIS; FEIS) A statement of the environmental effects of a proposed action and of alternative actions. Section 102 of the National Environmental Policy Act (NEPA) requires an EIS for all major federal actions.

Enzymatic hydrolysis: A process by which enzymes (biological catalysts) are used to break down starch or cellulose into sugar.

Ethanol: Ethyl alcohol produced by fermentation and distillation. An alcohol compound with the chemical formula CH_3CH_20H formed during sugar fermentation by yeast. Sometimes called grain alcohol.

Externality: A cost or benefit not accounted for in the price of goods or services. Often "externality" refers to the cost of pollution and other environmental impacts.

F

Feedstock: Any material that is converted to another form or product.

Fell: To cut down a tree. Cutting down trees and sawing them to manageable lengths is referred to as "felling and bucking" or "falling and bucking."

Feller-buncher: A self-propelled machine that cuts trees with giant shears near ground level and then stacks the trees into piles to await skidding.

Fermentation: The biological conversion of biomass by yeast or sugar. The products of fermentation are carbon dioxide and alcohol.

Forest residues: Material not harvested or removed from logging sites in commercial hardwood and softwood stands as well as material resulting from forest management operations such as pre-commercial thinnings and removal of dead and dying trees.

Forest health: A condition of ecosystem sustainability and attainment of management objectives for a given forest area. Usually considered to include green trees, snags, resilient stands growing at a moderate rate, and endemic levels of insects and disease. Natural processes still function or are duplicated through management intervention.

Forested areas or land: Any land that is capable of producing or has produced forest growth or, if lacking forest growth, has evidence of a former forest and is not now in other use.

Fossil fuel: Solid, liquid, or gaseous fuels formed in the ground after millions of years by chemical and physical changes in plant and animal residues under high temperature and pressure. Oil, natural gas, and coal are fossil fuels.

Fuel: Any material that can be converted to energy.

Fuel cycle: The series of steps required to produce electricity. The fuel cycle includes mining or otherwise acquiring the raw fuel source, processing and cleaning the fuel, transport, electricity generation, waste management and plant decommissioning.

Fuel handling system: A system for unloading wood fuel from vans or trucks, transporting the fuel to a storage pile or bin, and conveying the fuel from storage to the boiler or other energy conversion equipment.

Furnace: An enclosed chamber or container used to burn biomass in a controlled manner to produce heat for space or process heating.

G

Gasification: A chemical or heat process to convert a solid fuel to a gaseous form.

Gasifier: A device for converting solid fuel into gaseous fuel. In biomass systems, the process is referred to as pyrolitic distillation. See Pyrolysis.

Gasohol: A motor vehicle fuel which is a blend of 90 percent (by volume) unleaded gasoline with 10 percent ethanol.

Global Climate Change: Also referred to as greenhouse effect: The effect of certain gases in the earth's atmosphere in trapping heat from the sun.

Green ton: 2,000 pounds of undried biomass material. Moisture content must be specified if green tons are used as a measure of fuel energy.

Greenhouse gases: Gases that trap the heat of the sun in the Earth's atmosphere, producing the greenhouse effect. The two major greenhouse gases are water vapor and carbon dioxide (CO_2). Other primary greenhouse gases include methane, ozone, chlorofluorocarbons, and nitrous oxide.

Grid: An electric utility's system for distributing power.

H

Habitat: The area where a plant or animal lives and grows under natural conditions. Habitat includes living and non-living attributes and provides all requirements for food and shelter.

Hammermill: A device consisting of a rotating head with free-swinging hammers which reduce chips or hogged fuel to a predetermined particle size through a perforated screen.

Hardwoods: Usually broad-leaved and deciduous trees.

Hemicellulose: A carbohydrate compound found in plants, made up of five carbon sugars – primarily xylose.

Hydrocarbon: Any chemical compound containing hydrogen, and carbon.

Hydrolysis: Decomposition of a chemical compound by reaction with water.

I

Incinerator: Any device used to burn solid or liquid residues or wastes as a method of disposal. In some incinerators, provisions are made for recovering the heat produced.

Inorganic compounds: Those compounds lacking carbon but including carbonates and cyanides. Compounds not having the organized anatomical structure of animal or vegetable life.

Investment tax credit: A specified percentage of the dollar amount of certain new investments that a company can deduct as a credit against its income tax bill.

K

Kilowatt: (kW) A measure of electrical power equal to 1,000 Watts. 1 kW = 3,413 Btu/hr = 1.341 horsepower.

Kilowatt hour: (kWh) A measure of energy equivalent to the expenditure of one kilowatt for one hour. For example, 1 kWh will light a 100-watt light bulb for 10 hours. 1 kWh = 3,413 Btu.

L

Landfill gas: Gas that is generated by decomposition of organic material at landfill disposal sites. Landfill gas is approximately 50 percent methane.

Lignin: An amorphous polymer that together with cellulose forms the cell walls of woody plants and acts as the bonding agent between cells.

Log choker: A length of cable or chain that is wrapped around a log or harvested tree to secure the log to the winch cable of a skidder or to an overhead cable yarding line.

Logging residues: The unused portion of wood and bark left on the ground after harvesting merchantable wood. The material may include tops, broken pieces, and unmerchantable species.

M

Materials recovery facility (MRF): A recycling facility for municipal solid waste.

Merchantable: Logs that can be converted into sound grades of lumber ("standard and better" framing lumber).

Methane: An odorless, colorless, flammable gas with the formula CH_4 that is the primary constituent of natural gas.

Methanol: Methyl alcohol having the chemical formula CH_30H. Methanol is usually produced by chemical conversion at high temperatures and pressures. Although usually produced from natural gas, methanol can be produced from gasified biomass (syngas). Sometimes called wood alcohol.

Metric ton: (or tonne) 1000 kilograms. 1 metric ton = 2,204.62 lb = 1.1023 short tons.

MGD: Million gallons per day.

Mill residue: Wood and bark residues produced in processing logs into lumber, plywood, and paper.

Mitigation: Steps taken to avoid or minimize negative environmental impacts. Mitigation can include: avoiding the impact by not taking a certain action; minimizing impacts by limiting the degree or magnitude of the action; rectifying the impact by repairing or restoring the affected environment; reducing the impact by protective steps required with the action; and compensating for the impact by replacing or providing substitute resources.

Moisture Content: (MC) The weight of the water contained in wood, usually expressed as a percentage of weight, either oven-dry or as received.

MRF: See Materials recovery facility.

MSW: See Municipal solid waste.

Municipal solid waste: (MSW) Garbage. Refuse offering the potential for energy recovery; includes residential, commercial, and institutional wastes.

N

National Environmental Policy Act: (NEPA) A federal law enacted in 1969 that requires all federal agencies to consider and analyze the environmental impacts of any proposed action. NEPA requires an environmental impact statement for major federal actions significantly affecting the quality of the environment. NEPA requires federal agencies to inform and involve the public in the agency's decision making process and to consider the environmental impacts of the agency's decision.

National Forest Management Act: A federal law passed in 1976 as an amendment to the Forest and Rangeland Renewable Resources Planning Act requiring the preparation of Regional Guides and Forest Plans and the preparation of regulations to guide that development.

NEPA: See National Environmental Policy Act

Net heating value: (NHV) The potential energy available in the fuel as received, taking into account the energy loss in evaporating and superheating the water in the sample. Expressed as $NVH = (HHV \times (1- MC / 100) - (LH(2)O \times MC / 100)$

Net present value: The sum of the costs and benefits of a project or activity. Future benefits and costs are discounted to account for interest costs.

O

Old growth: Timber stands with the following characteristics: large mature and over-mature trees in the overstory, snags, dead and decaying logs on the ground, and a multi-layered canopy with trees of several age classes.

Organic: Derived from living organisms.

Organic compounds: Chemical compounds based on carbon chains or rings and also containing hydrogen, with or without oxygen, nitrogen, and other elements.

P

Partial cut: A harvest method in which portions of a stand of timber are cut during a number of entries over time. Precommercial thinning operations are not considered partial cuts.

Particulate: A small, discrete mass of solid or liquid matter that remains individually dispersed in gas or liquid emissions. Particulates take the form of aerosol, dust, fume, mist, smoke, or spray. Each of these forms has different properties.

Particulate emissions: Fine liquid or solid particles discharged with exhaust gases. Usually measured as grains per cubic foot or pounds per million Btu input.

pH: A measure of acidity or alkalinity. A pH of 7 represents neutrality. Acid substances have lower pH. Basic substances have higher pH.

Pilot scale: The size of a system between the small laboratory model size (bench scale) and a full-size system.

Pound: Pound mass (sometimes abbreviated lb). A unit of mass equal to 0.454 kilograms.

Precommercial thinning: Thinning for timber stand improvement purposes, generally in young, densely stocked stands.

Prescription: Specific written directions for forest management activities.

Present value: The worth of future receipts or costs expressed in current value. To obtain present value, an interest rate is used to discount future receipts or costs.

Process heat: Heat used in an industrial process rather than for space heating or other housekeeping purposes.

Pyrolysis: The thermal decomposition of biomass at high temperatures (greater than 400º F, or 200º C) in the absence of air. The end product of pyrolysis is a mixture of solids (char), liquids (oxygenated oils), and gases (methane, carbon monoxide, and carbon dioxide) with proportions determined by operating temperature, pressure, oxygen content, and other conditions.

R

RDF: See Refuse-derived fuel.

Recovery boiler: A pulp mill boiler in which lignin and spent cooking liquor (black liquor) is burned to generate steam.

Refuse-derived fuel: (RDF) Fuel prepared from municipal solid waste. Noncombustible materials such as rocks, glass, and metals are removed, and the remaining combustible portion of the solid waste is chopped or shredded. RDF facilities typically process between 100 and 3000 tons of MSW per day.

Renewable energy resource: An energy resource replenished continuously or that is replaced after use through natural means. Sustainable energy. Renewable energy resources include bioenergy (derived from biomass), solar energy, wind energy, geothermal power, and hydropower.

Return on investment: (ROI) The interest rate at which the net present value of a project is zero. Multiple values are possible.

ROI: See Return on investment.

Rotation: Changing crop species periodically. The number of years allotted to establish and grow a forest stand to maturity.

S

Sewage: The wastewater from domestic, commercial and industrial sources carried by sewers.

Short rotation energy plantation: Plantings established and managed under short-rotation intensive culture practices.

Short rotation intensive culture: Intensive management and harvesting at 2 to 10 year intervals of cycles of specially selected fast- growing hardwood species for the purpose of producing wood as an energy feedstock.

Silviculture: The theory and practice of forest stand establishment and management.

Skidder: A self-propelled machine to transport harvested trees or logs from the stump area to the landing or work deck.

Slash: The unmerchantable material left on site subsequent to harvesting a timber stand, including tops, limbs, cull sections.

Slow pyrolysis: Thermal conversion of biomass to fuel by slow heating to less than 450ºC in the absence of oxygen.

Sludge: The mixture of organic and inorganic substances separated from sewage.

Splash Blending: Usually refers to the practice of blending ethanol or other oxygenates with gasoline outside of the refinery. This is usually accomplished by adding the ethanol to gasoline tank trucks at distribution terminals prior to delivery to retail stations.

Stand: (tree stand, timber stand) A community of trees managed as a unit. Trees or other vegetation occupying a specific area, sufficiently uniform in species composition, age arrangement, and condition as to be distinguishable from the forest or other cover on adjoining areas.

Stillage: The grains and liquid effluent remaining after distillation.

Sunk cost: A cost already incurred and therefore not considered in making a current investment decision.

Surplus electricity: Electricity produced by cogeneration equipment in excess of the needs of an associated factory or business.

Sustainable: An ecosystem condition in which biodiversity, renewability, and resource productivity are maintained over time.

Sustained yield: The maintenance in perpetuity of regular, periodic harvest of wood resources from forest land without damaging the productivity of the land.

T

Therm: A unit of energy equal to 100,000 Btus; used primarily for natural gas.

Timberland: Forest land capable of producing 20 cubic feet of wood per acre per year.

Tipping fee: A fee for disposal of waste.

Toxic substances: A chemical or mixture of chemicals that presents a high risk of injury to human health or to the environment.

Transmission: The process of long-distance transport of electrical energy, generally accomplished by raising the electric current to high voltages.

V

VOC: see Volatile organic compounds.

Volatile organic compounds: (VOC) Emissions of non-methane hydrocarbons.

Volatiles: Substances that are readily vaporized.

W

Waste streams: Unused solid or liquid by- products of a process.

Watershed: The drainage basin contributing water, organic matter, dissolved nutrients, and sediments to a stream or lake.

Watt: The common base unit of power in the metric system. One watt equals one joule per second, or the power developed in a circuit by a current of one ampere flowing through a potential difference of one volt. One watt = 3.413 Btu/hr.

Wetlands: Lands where saturation with water is the primary factor determining soil development and the kinds of plant and animal communities living on or under the surface.

Whole-tree harvesting: A harvesting method in which the whole tree (above the stump) is removed.

References:

The Bioenergy Glossary, published by the Oregon Department of Energy

Washington State Biomass Data Book, J. A. Deshaye, J. D. Kerstetter, Washington State Energy Office, Olympia, WA 98504-3165. July 1991

Appendix ES-D

External Peer Review Group
For Ethanol/Biomass Report

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Doug G. MacKenzie – Pacific Rim Ethanol Corporation
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Appendix I-A

State Alternative Fuel Incentives and Initiatives

The following list provides selected information from a variety of databases available in the literature or on the Web. The principal source of information is Department of Energy's "Incentives and Laws – Guide to Alternative Fuel Vehicle Incentives and Laws", September 1998 with updates obtained from the Alternative Fuels Data Center web site at **www.afdc.doe.gov** The September 1999 issue of the Clean Fuels Report was also used in updating information appearing below.

Alabama – Offers incentives for conversion of fleet vehicles to alternatives up to $25,000 per project. Several utilities offer incentives for vehicle conversion to natural gas on a case by case basis and fueling facility conversion as well. One private organization offers financing of the conversions at 9.5% interest.

Alaska – If gasoline contains 10% ethanol, it is exempt from the state fuel tax of 8 cents per gallon. This is equivalent to an 80 cent per gallon ethanol subsidy. Incentives exist for the conversion to natural gas vehicles. Under the combination of a wintertime state regulation and a local ordinance, Anchorage requires the use of E10 in all motor vehicles.

Arizona –Uses a combination of income tax reductions, vehicle license and fuel tax reductions to encourage conversion to or the purchase of vehicles capable of using alternative fuel. A $1000 tax credit is available for purchase of conversion to alternative fuels. $1000 available for small business or home refueling equipment. Grants of up to $100,000 available for construction of public alternative fuel vehicle (AFV) refueling sites. Tax credit for vehicle purchase becomes larger the lower the emission standard to which the vehicle is manufactured. Taxpayers may subtract 25 percent of the cost of the purchase of an AFV from their adjusted gross income.

Arkansas - A $250,000 a year fund exists for the conversion of vehicles to alternative fuels. Ethanol and methanol vehicle conversion rebates of up to $1000 are available. The same rebate is also available for new purchases of manufacturer produced vehicles.
Compressed natural gas (CNG) has a preferred lower fuel tax rate relative to gasoline and other alternative fuel options.

Colorado – Has a tax credit and rebate program good through 2006 for natural gas and LPG vehicles. The program is available to AFVs operating on propoane, CNG, methanol and ethanol and applies to public and private fleets only excepting federal and utility fleets. Another program provides income tax credit for construction of alternative fuel facilities and partial payment of incremental costs of any vehicle (gasoline or alternative fuel) meeting low emission vehicle (LEV) or better emissions standards. The National Ethanol Vehicle Coalition (NEVC) offers forgivable loans for installation of public E85 fueling facilities. Fuel tax exemptions for natural gas and LPG exist. Ethanol and methanol are not eligible for this fuel tax exemption.

Connecticut- Has a 1 cent per gallon fuel tax exemption for ethanol gasoline blends. The state offers a 50% state corporate tax credit for the cost of conversion of vehicles to LPG, CNG, LNG and electricity. Extends to fueling facility conversion as well. A 50% state investment tax credit is also available for vehicle conversions and fueling facility installations. Also offers exemptions from the sales and use tax on the incremental cost difference between gasoline and AFV versions of original equipment manufactured (OEM) new vehicles. The state requires the use of clean alternative fuels in state vehicles under definition found in EPACT (1992).

Delaware – Applies Petroleum Violation Escrow Account (PVEA) funds to fund the incremental cost of AFV conversions or new vehicle purchases. Also applies the funds to train mechanics, develop infrastructure, educate fleet operators, and do vehicle emissions testing. No special tax provisions or exemptions for any fuels including ethanol.

District of Columbia – The District of Columbia has no special provisions or incentives for alternative fuels or AFVs.

Florida – Uses PVEA funds for incremental vehicle cost or conversion to alternative fuels- state vehicles only. Is applicable to CNG and LNG, but not to E85 flexible fuel vehicles. $2.5 million low-interest revolving fund for AFVs in three counties is available. $1.1 million available in grants to local governments in a Clean Cities coalition. City of Sunrise/Gas systems offers $300 worth of fuel for any individual or fleet signing up to use public natural gas fueling facilities. EVs exempt from sales tax from July 1, 1995 through June 30, 2000. State exempts local government AFVs from decal fee.

Georgia - $1500 tax credit is available for purchase or lease of all AFVs. Also gives AFVs access to high occupancy vehicle (HOV) lanes for single occupancy vehicles. Educates legislators on the use of AFVs. Grants of up to $50,000 are available to local governments who demonstrate committed use of clean alternative fuels. Propane is exempt from the 4.5 cent a gallon excise tax when sold to consumer distributor. Flat tax credit of $1500 available to any EPACT defined alternative fuel vehicle (converted or new) that achieves Environmental Protection Agency LEV or better emissions level. Can be carried over for three years on tax return. No special provisions for alcohol beyond what is mentioned above.

Hawaii – Gasoline blended with 10% biomass derived denatured alcohol sold in the state is exempt from the 4 percent sales tax. There is no set termination date for this provision. This amounts to a 30 to 50 cents per gallon subsidy of ethanol produced under 1998 gasoline prices. State income tax deductions available from $2000 to $50,000 for installations of clean fuel refueling facilities as defined in EPACT. Propane gets a two-thirds reduction in fuel tax relative to diesel fuel.

Idaho – Provides a fuel excise tax exemption for biofuels up to 21 cents per gallon at the 10 percent level. Applies to biodiesel and ethanol/gasoline blends. For ethanol this is equivalent to a $2.10 subsidy per gallon of ethanol produced. Governor required by Executive Order that all state vehicles use E10 whenever possible effective in 1987. The Idaho Energy Division offers a rebate for the difference in cost between the E85 and gasoline for state agencies operating E85 fuel-flexible vehicles.

Illinois – The state rebates 80% on the conversion or incremental cost of AFVs up to $4000 per vehicle. A federal state energy program (SEP) grant provides incremental costs of 50 AFVs for municipalities and state vehicles. NEVC provides forgivable loans for the installation of E-85 fueling facilities. A $20 a vehicle fleet user fee for fleets in excess of 10 vehicles funds the state Alternative Fuels Act. Funds go to ethanol research and the state AFV rebate program. Individuals can receive 80% of conversion or incremental costs of new AFVs if vehicle operates on ethanol or methanol at 80 volume percent or higher.

An Executive Order in 1987 required all state vehicles to use E10. A 30% reduction in taxes on the proceeds of sales of gasohol made before July 1, 2003 exists. This returns to 100% of the taxes thereafter. Requires by 2000 that 70% of all state vehicles be capable of operating on clean alternative fuels. A state resolution (1997) encourages the federal government to cooperate in funding research intended to increase the use and production of ethanol. All vehicles leased by any state college or university must use E10 whenever possible. All public transportation authority districts with populations greater than 50,000 are required to use ethanol blends.

Indiana – Grants of $2000 to $10000 are available from the Small Business Energy Initiative Grant Program to help pay for the incremental costs of purchasing AFVs or for the installation costs of fueling facilities. NEVC provides forgivable loans for the installation of public E85 stations. Passed a law in 1996 providing a 10% gross income tax deduction for improvements to ethanol production facilities or soy diesel producing facilities. In 1993 a price preference of 10% was established for state and local government procurement of soy diesel. Provides some incentives for natural gas as well.

Iowa – The Iowa Energy Bank (state run) provides low interest energy loans for conversions and purchases of AFVs by state, local and non-profit entities. Department of Natural Resources has funded the installation of public E-85 refueling sites. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. In 1988 the governor required that all state vehicles be fueled with E10 whenever practical. All vehicles owned or leased by city and county school districts and the Board of Directors of the community colleges must use E10. In 1998, the legislature extended the 1 cent a gallon sales tax exemption for ethanol blended fuels through 2007. For E10 this amounts to a 10 cent per gallon of ethanol tax credit. A $4 million dollar a year program funds a renewables program (50% of these funds) for commercial renewable agricultural energy projects such as ethanol plant construction. Maximum project amount is $ 900,000 with 20% as a grant and the remainder as a low interest loan.

Kansas – Up to $2500 state tax credit for 50% of the cost of factory equipped AFV or individuals may take 5% of the total cost of the vehicle. For fleets of ten or more, an income tax credit can also be taken for on qualified AFV property, conversion equipment, and refueling property. After January 1, 1999, the tax credit for individuals drops to 40% of the cost of factory produced vehicles. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. A 14-cent per gasoline gallon equivalent tax break is available for CNG and LPG fuels. In 1992, the Governor required that all state agencies use alternative fuels in their fleets when cost effective.

Kentucky – Up to $1000 rebate is available from Western Kentucky Gas for conversion or incremental cost of new CNG vehicles. No mandates and incentives for any other fuel exist. Some demonstrations underway.

Louisiana – A state income tax credit is available for 20% of the cost of converting a vehicle to alternative fuels or up to $1500 for 20% of the incremental cost of a new OEM vehicle. A 20% income tax credit is also available for alternative fuel refueling stations. Utilities provide some incentives for natural gas conversion and use. Act 927 required that 80% of all state vehicles be converted to operate on alternative fuels by 1998. The law also forbade subsidies and incentives for the production of CNG, LPG, reformulated gasoline, methanol or ethanol. LPG was given a special alternative method for calculation of tax.

Maine – Provides a partial tax exemption for the purchase of clean fuel vehicles. Exemption applies to incremental cost of vehicle. Where no identical gasoline vehicle exists the exemption is 30% for internal combustion engines and 50% for electric and fuel cell vehicles. Department of Economic and Community Development provides loan guarantees to fleet operators for alternative fuel vehicle support. AFVs are exempt from sales and use tax, parking fees, and registration fees.

Maryland – An $800 to $2000 state tax credit is available to all owners of converted or purchased AFVs. Rebate is based on gross vehicle weight classification. These are available to fleets or individuals only if federal or state purchase requirements have already been achieved. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. Electric vehicles (EVs) are given an experimental time-of-use rate of 2.512 cents per kW-hour. Provides a tax exemption of 1 cent per gasoline gallon equivalent for alternative fuels as defined by EPACT. Special incentives provided for natural gas and LPG. Sun Company will work with customers to establish fuel pricing. In 1993, Governor required that 20% to 25% of new vehicle purchases be alternative fuel.

Massachusetts- Some incentives from utilities and private organizations for natural gas. Excise tax exemption for CNG and LPG of 11 cents per gasoline gallon equivalent, about half of the 21 cent per gallon state excise tax on gasoline. Neither provisions nor incentives for alcohol exist.

Michigan - $500 rebate for dedicated natural gas and $300 rebate for dual-fuel vehicle available from Consumers Power Company. There are no incentives for AFVs in Michigan (1998). Special electricity rate available from Detroit Edison. No mention of any alcohol related incentives.

Minnesota – Provides a 20-cent per gallon producer's incentive for fuel alcohol (ethanol) not to exceed $3 million per year per producer. Incentive remains effective for 10 years for each producer, but the program expires June 20, 2010. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. A state policy exists which states that it is in the states best long-term interest to promote the development and market penetration of alternative fuels, and to develop additional markets for indigenous crop based fuels. Incentives are offered by utilities for natural gas vehicle conversion in the range of $250- $1000. E-85 fuel is taxed at 14.2 cents per gallon, methanol at 11.4 cents per gallon and gasoline at 20 cents per gallon.

Mississippi – Does not have incentives or mandates for AFVs. There are no fuel production incentives as well. One gas utility provides incentives for natural gas vehicles on a case by case basis.

Missouri – Offers a 20-cent per gallon production incentive of ethanol. There are no financial incentives offered for alternative fuel vehicles. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. An excise tax exemption of 2 cents per gallon exists for ethanol/gasoline blends which have10% or greater ethanol content. Missouri Appropriates funds yearly for the Missouri Ethanol Producer Incentive Fund. The Governor required that 50% of all state owned vehicles operate on E10 by 2000.

Montana – In 1993 Montana created an ethanol producers tax credit of 30 cents per gallon. $6 million was appropriated that year and is available on a first come first served basis. A 50% income tax credit is available to individuals and companies for conversion costs of AFVs. $500 to $1000 maximum is available depending on the weight of the vehicle. State law requires that all state vehicles be fueled with ethanol gasoline blends when competitive with gasoline. Gas utilities provide additional incentives for natural gas vehicles.

Nebraska- has a 20-cent per gallon direct incentive for producers of ethanol with a cap of $25 million per plant. Created the Ethanol Development Act and a fund to research, develop and promote renewable agricultural ethyl alcohol. Offers no-cost and low cost loans for conversion of vehicles to alternative fuels. This applies to public and private vehicles. Funds are also available for installation of fueling facilities. In 1979 the Governor declared that all state vehicles fuel with E10 whenever practical.

Nevada – No incentives are offered statewide for the use of alternative fuels. A private fleet program exists in the Las Vegas area. Up to $3500 is available after the entity puts up the first $1500 for the conversion to natural gas only. 90% of all government fleet vehicles greater than 26,000 lbs. must convert to alternative fuels by the year 2000. Alternative fuels use is required.

New Hampshire – Has no incentives for alternative fuel use. Has no fuel production incentive.

New Jersey - Tax incentives exist for LPG and natural gas. PVEA funds ($1.5 million) are used by the Division of Energy for conversion of state vehicles to alternative fuels. While not specifically designating ethanol capable vehicles, New Jersey has an aggressive slate of projects and programs aimed at deploying AFVs consistent with EPACT requirements and utilizing DOE's Clean Cities Programs.

New Mexico - A partial exemption on fuel excise tax provides a 4 cents per gallon benefit for all alternative fuels. This exemption is being phased in over 6 years. At the same time, the tax on gasoline is scheduled to rise in 3 cent per gallon increments every two years until 2002 at which time 12 cents per gallon will have been added to the base gasoline tax of 16 cents per gallon. The Energy Conservation and Management Division of The Energy, Minerals and Natural Resources Department provides grant funds to reduce energy demand and consumption of petroleum products. Funds are provided on an annual basis and allocated through a competitive process for projects. Owners of AFVs can purchase an annual fuel tax decal for $15 per year in lieu of paying the per gallon road tax.

New York- The retail sales tax for the difference between the cost of a new converted AFV and the list price of a comparable vehicle. New York City established a program in 1991 to convert to alternative fuel or purchase 80% AFVs for the light duty non-emergency vehicle sector and 15% in the transit bus sector. Generous credits are offered for EVs and Hybrid EVs though these are scheduled to be phased-out in 2005. New York administers an AFV research and demonstration program through a competitive process. Utilities provide incentives to natural gas and EV vehicle owners and provide fueling facilities as well.

North Carolina- Since 1987 the state has provided a corporate and personal income tax credit for construction of certain new ethanol fuel plants for the state. Promotional rates for electricity and natural gas are also offered by two utilities. Alternative fuel vehicle projects are supported on a case-by-case basis.

North Dakota- the governor has ordered that all state vehicles must be must be fueled with E10 when possible. The North Dakota State Bank provides loan guarantees for construction of ethanol production facilities in the state. In 1995, $3,657,000 was appropriated for an incentive of 40 cents per gallon for agricultural fuel produced and sold in North Dakota. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. Incentives for natural gas vehicle conversion are offered by one utility. In 1995 limits were placed on what any single company could receive in ethanol subsidies.

Ohio - The state provides a 1-cent per gallon income tax credit for sale of E10 with a maximum of $15 million per year. In 1990 the governor directed fleets in three agencies to use E10 whenever possible. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. Two utilities provide fueling facilities for natural gas users and some forms of assistance. No vehicle conversion incentives are provided.

Oklahoma- Provides a 50% income tax credit for vehicle conversions to alternative fuels and 10% of the total vehicle cost up to $1500 to individuals who buy an AFV. An income tax credit is also available for installing refueling equipment for AFVs. A private loan program exists with a 3% interest rate for conversion of private fleets to alternative fuels. 3 years are allowed for payback. All alternative fuels as defined by EPACT are eligible. CNG, LPG and LNG are exempt from fuel excise tax and pay a flat yearly fee instead. Ethanol and methanol receive no special fuel tax consideration.

Oregon - Offers a business energy tax credit of 35% available for vehicle conversions and fueling stations. All natural gas utilities will buy back the 35% credit at present value for purchase of an AFV.

Pennsylvania- Incentive grants are provided for the purchase of AFVs and fueling facilities in accordance with EPACT definitions. The funding varies from 40(1998) to 20 (2001 and on) percent and is paid from gross tax receipts paid by some Pennsylvania utilities. $3 million to $4 million is available each funding cycle and some distribution rules apply. Gas and electric utilities provide incentives for EVs and natural gas vehicles.

Rhode Island - Taxpayers receive a 50% credit for costs of installing fueling facilities and 50% for the cost of converting a car to use alternative fuels, or 50% of the incremental cost of an OEM vehicle. Rebates and incentives are providing by utilities for natural gas vehicles on a case-by-case basis.

South Carolina - Does not offer any incentives for AFVs. A promotional gas rate for natural gas is available for AFV users.

South Dakota - Offers reduced fuel taxes for AFVs. The NEVC provides forgivable loans for the installation of public E-85 fueling sites. Incentives for natural gas vehicle conversions are available.

Tennessee - No incentives provided for alcohol fuels. Some incentives for natural gas exist as provided by one gas utility.

Texas - Incentives provided for natural gas and LPG vehicles and fueling facilities. Utilities are involved in this process. 50% of state fleet vehicles were required to operate on alternative fuels by 1996. Local fleet requirements as well. A 1995 law allows the Texas Public Finance Authority to sell bonds up to $50 million to finance loans for school districts, local mass transit authorities and state agencies to convert vehicles to alternative fuels, purchase new vehicles and install facilities. CNG and LNG pay an annual sticker permit fee in lieu of fuel tax.

Utah - Tax credit and loan programs exist for AFV purchases. 20% tax credit up to $400 offered for each new AFV registered and a tax credit up to $400 for fueling facilities for CNG, LPG, and LNG. CNG and electricity are exempt from franchise taxes imposed by municipal and county governments.

Vermont - No state incentives offered. One gas utility offers incentives for natural gas vehicle conversions on a case-by -case basis.

Virginia - Provides no-charge licensing for AFVs and exemption from HOV lane use requirements. Provides a 10% tax credit, a 1.5- percent sales tax reduction and an AFV fuel tax reduction of 6 cents per gasoline gallon equivalent. The state provides a $700 tax credit to a corporation that creates a full time job related to the manufacturing of AFVs or AFV components or job related to converting vehicles to run on alternative fuels. A revolving fund provides grants to local governments and state agencies for conversion of publicly owned vehicles from gasoline and diesel to alternative fuels.

Washington - Offers fuel tax reductions to LPG and natural gas vehicles and infrastructure development for compressed natural gas from PVEA funds. Light-duty vehicles operating on LPG and natural gas pay an $ 85 annual fee in lieu of fuel excise taxes. No special treatment for alcohol fuels.

West Virginia - $3,750 to $50,000 in tax credits for purchase and conversion of alternative fuel vehicles (up to 26,000 lbs. and more). Tax credit available on the incremental cost of AFVs. Grants for conversion for local governments from the state with a 50% local match of funds. CNG, electricity and methanol are eligible fuels. Tax credit good for all alternative fuels including alcohol and alcohol derived liquids.

Wisconsin - Competitive grants available to municipalities. $4,500 to $15,000 (trucks, vans or buses). Uses federal Congestion Mitigation and Air Quality (CMAQ) funding. Utilities offer electric and natural gas incentives and rebates. Governor has a goal of 2000 vehicles purchased by 2000 thus exceeding EPACT requirements. State has initiated private-public partnerships to stimulate ethanol, CNG, propane, methanol, and biodiesel fuels and infrastructure.

Wyoming - Has no vehicle conversion incentives. Use PVEA funds to convert state vehicles to alternative fuels. Provides a 4-cent per gallon fuel tax exemption for E10 use. This is equivalent to a 40 cent per gallon subsidy and extends to June of 2000. Issues credit vouchers to ethanol producers which are redeemable by gasoline wholesalers with tax liability (E10) or gasoline.

Appendix I-B

Minnesota's Ethanol Incentive Programs

In 1996, the State of Minnesota Legislative Audit Commission requested an evaluation of the costs and benefits of several State programs designed to promote the production and use of ethanol as an automotive fuel. The resultant report[1] authored by the Office of the Legislative Auditor addressed issues of costs, program success, economic and environmental benefits, and major risks affecting future viability of production of ethanol in Minnesota. The report authors note that Minnesota provides substantially more support to ethanol when compared to programs and incentives of other states. The following sections extract major findings of the report to illustrate the Minnesota approach in developing a corn-based ethanol industry.

Background and Program Description

Minnesota's support of ethanol production includes producer payments, subsidized loans, use of tax increment financing at the local level, and an ethanol blender's tax credit. At the time the report was written, Minnesota had 8 plants with a combined production capacity of 92 million gallons per year. Since that time, the number of plants has increased to 14 with a production capacity of 215 million gallons per year and three new plants with 50 million gallons per year capacity are planned for the future (see Appendix II-A). The dramatic increase in the production of ethanol in the state since enactment of these incentives is a result of several measures combined with a statewide oxygen-in-gasoline requirement that goes beyond the geographic and time-of-year requirements of the federal Clean Air Act. This 2.7 weight percent requirement (10% by volume ethanol) is being met through the use of ethanol even though methyl-tertiary-butyl-ether could be used as the oxygen source for gasoline.

Minnesota used several grant and subsidized loan programs including economic recovery grants from its Department of Trade and Economic Development and two loan programs administered by the Minnesota Department of Agriculture. The latter include loans for ethanol producers as well as loans for farmers to purchase shares in ethanol producing co-operatives. Large loans at low interest rates are provided through the Ethanol Production Facility Loan Program and provide up to $500,000 per plant. The array of incentive programs offered for ethanol facility construction and production are more fully defined in the following sections.

Ethanol Producer Payments

The producer payment program provides ethanol producers 20 cents per gallon of ethanol produced up to $3 million per plant with a statewide limit of $30 million. This appears to be one of the most attractive incentive elements administered by the State. The report notes that

[1] "Ethanol Programs – A Program Evaluation Report," Office of the Legislative Auditor, State of Minnesota, Report # 97-04, February 1997.

Department of Agriculture officials, lenders, and plant managers all indicated that producer payments were critical in financing production facilities. A 15 million-gallon per year "dry mill" facility costs $25 to $30 million to construct. 20 cents per gallon for such a facility generates a revenue stream of $3 million per year for the cost of the plant ($30 million) over ten years. Financial institutions are willing to finance half the project cost ($15 million) over a 7 to 10 year period given this guaranteed revenue stream. The report also notes that under such an arrangement financial institutions do not have to be concerned about the long-term viability of the ethanol production facility.

Ethanol Blender Credit

In addition to the producers payment of 20 cents per gallon, Minnesota had a blender's tax credit of 20 cents per gallon of ethanol blended in gasoline until October of 1994. This credit was reduced in each of the subsequent three years and phased out in October of 1997. The decision to phase out the tax credit coincided with legislation that raised the annual maximum of funding for ethanol producer payments.

Ethanol Production Facility Loan Program

This program was established in 1993 by the legislature to help finance ethanol plants with low-interest loans of up to $500,000 per plant. As explained, this type of loan was meant to encourage private lenders through demonstration of a state commitment to complete or fill-in gaps in plant financing arrangements. The report notes that with capital costs in the range of $25-30 million for a 15 million gallon a year dry mill facility, this program plays a minor role in comparison to yearly producer payments which are several times the value of the one-time low interest (6%) loan. Financing comes from the Ethanol Development Fund created by the legislature. Repayments of loans are returned to the fund thus creating a revolving account to assist other projects.

Value-Added Agricultural Product Loan Program

This program, also known as the Stock Loan Program, was enacted to help farmers finance the purchase of stock in a co-operative proposing to build or purchase and operate a facility to process agricultural crops. The loan can be used to finance the purchase of stock in various farmer owned co-operatives including ethanol plants. Funding for this program was at $450,000 in 1995 according to the report. A maximum of $24,000 in state funds is available to farmers from local lenders. Local lenders must match the state share with a 55% to 45% ratio. Loans are for eight years (maximum) with the state's share at 4 percent or one-half the lender rate, whichever is lower.

Economic Recovery Grants

Minnesota administers economic recovery grants through its Department of Trade and Economic Development. The report states a maximum of $150,000 for several ethanol plants. This level of funding indicates that this fund plays an additional role in supporting construction of ethanol production facilities, however, the funding level is small in comparison to yearly ethanol producer payments.

Tax Increment Financing

In 1995 the legislature set a limit of $1.5 million for what is termed "tax increment financing." According to the report, most operating ethanol plants in the early 1990s received this type of financing. Again, in comparison to ethanol producer payments, this incentive mechanism appears to be quite small.

Costs of Incentive Programs

The Auditor's report identifies three major cost elements to the state and consumers in supporting Minnesota's ethanol industry. The producer payment cost was $ 22.1 million for the three-year period of 1994 to1996 with total program costs since inception in 1987 of $39 million. This latter number when divided by total ethanol production over this time period (281 million gallons), yields an average producer payment of about 14 cents per gallon. The report projects additional producer payments of $ 66 million for 1997 through 1999.

With the phase-out of the blender's tax credit in 1997, the cost of this incentive is projected to be about $8.7 million from 1997 through 1999 or about one-seventh the producer payment projections over this time period. For the 1994 through 1996 time period, the tax credit cost was $ 61.2 million or about three times the cost of producer payments reflecting the state's early strategy which focused on a tax credit for ethanol blending with gasoline.

With regard to consumers, the cost of ethanol in Minnesota gasoline is projected to add about 2 to 3 cents to the base gasoline price projection (in 1997). For the Minnesota market of about 2 billion gallons per year, the report indicates a range of $33 to $50 million per year, or an average of about $125 million over the three year period of 1997 through 1999.

In summary, the Auditor projects total government costs at about $67 million per year for a three-year period beginning in 1997 and ending in 1999.

Economic Benefits

In assessing the benefits, the report notes that Minnesota's programs are directly responsible for the development of a sizable ethanol production capacity. These findings were based on direct interviews with publicly owned ethanol producers, cooperative ethanol producers, corn farmers, financial institutions, local government officials, and citizens.

In estimating the benefits in 1997, the report indicates that ethanol programs produce net economic benefits. Jobs, tax revenues, economic growth in rural areas, and improvements in city and small community roads and utility infrastructure occur as a result of the siting of ethanol facilities. The analysis also indicates creation of jobs is uncertain outside of the rural communities and, in fact, statewide jobs may decrease as a result of the state's role. The analysis for 1997 shows a net decrease in jobs statewide.

In round numbers, the analysis shows that the current (1997) levels of industrial development generate about $269 million in economic activity (not including profits or losses of corn producers). Projected corn profits (or losses) could be $58 million in 1997. Taking producer payments, the blender's tax credit, higher fuel costs, and lower fuel economy into account results in projections of costs between $67 and $102 million. ***Thus, the report concludes that the net economic benefit projected for 1997 should be in the range of $109 and $260 million***. In addition there is a one-time benefit of $174 to $261 million projected from plant construction activities.

With regard to personal income, the analysis concludes that the ethanol industry has a net positive impact on total state personal income under all but the most unfavorable combination of assumptions. An increase of $44 million of personal income is projected, but this may be adjusted up or down by $7 million depending on whether corn growers profit or lose in the corn market.

Projections of Economic Benefits in 2001

The report also provides a projection for economic benefits in 2001 assuming that 178 million gallons of ethanol will be produced that year. The annual statewide benefits (after subtracting producer payments) are estimated to be in the range of $341 to $549 million, however, the authors note that this is a best case estimate. Actual results will probably be lower.

Appendix I-C

A Producer Payment Incentive Scenario for California

The review of Minnesota's ethanol program in the previous section forms a basis for consideration of a hypothetical producer payment scenario in California. The scenario developed here is meant to provide a rough idea of potential costs should this mechanism be chosen to support the first few biomass-to-ethanol facilities built in California. The producer payment has been chosen for this scenario because of the apparent relative effectiveness of this incentive mechanism in Minnesota as reflected in the Legislative Auditor's report on the Minnesota Ethanol Program in 1997.

In developing the scenario, it is assumed that financial institutions may require additional inducements beyond producer payments or a higher-level producer payment to lower their risk in investing in the first projects in California. This is based on the fact that waste biomass-to-ethanol facilities require the use of technology not yet commercial anywhere in the United States. To capture this additional financial risk, two levels of producer payment are considered. The first is $0.20 per gallon reflecting the level of Minnesota's producer payment for proven conventional technology (corn-to-ethanol dry or wet mill projects). The second is $0.40 per gallon to capture what financial institutions might require for the first few projects using yet-to-be demonstrated large-scale cellulose-to-ethanol conversion technology. The $0.40 per gallon actually corresponds to the producer payment offered by the State of North Dakota for "agricultural fuel" production (i.e., corn-derived ethanol). Three projects are assumed to provide a combined ethanol production capacity of 50 million gallons per year. All are assumed to come on-line in 2003 and the producer payments are assumed to last for ten years. The table below summarizes cumulative producer payment outlays for the scenario.

Cumulative Producer Payments for 50 M gallons per year (First Three California Projects Scenario- $ millions)

Year	20 cents/gallon	40 cents/gallon
2003	10	20
2004	20	40
2005	30	60
2006	40	80
2007	50	100
2008	60	120
2009	70	140
2010	80	160
2011	90	180
2012	100	200

The scenario indicates yearly outlays of producer payments of $10 or $20 million with the cumulative total reaching $100 or $200 million after 10 years. To put the 50 million gallons a year in context, this volume represents about one-third of the low case ethanol demand in Appendix II-B (148 million gallons per year) or about five percent of the high demand case of about 1 billion gallons per year under an MTBE phase-out scenario. When compared with yearly state gasoline tax revenues, $20 million dollars a year in producer payments represents less than one percent of gasoline fuel excise taxes assessed by the State of California.

This scenario should not be construed as a recommendation that the producer payment mechanism is the only or the most appropriate form of financial assistance to be considered for an emerging biomass-to-ethanol industry in California. In addition, the $0.20 and $0.40 per gallon producer payments, while representative of what other states are currently providing for conventional corn-to-ethanol facilities, may not necessarily represent the right level of support for biomass-to-ethanol facilities that produce high value co-products and ethanol. However, it is worth noting that California does have an existing unfunded producer payment “grant” program in statute that could serve as a mechanism to initiate producer payments.[1]

[1] Public Resources Code Section 25678 describes this program which was added through SB 2637, Statutes of 1988. As authored, this grant program would provide a 40-cent per gallon production incentive for liquid fuels fermented from biomass and biomass resources in California. Ethanol, methanol, and vegetable oils are mentioned specifically, however, the statute does not preclude other liquid fuels that might be produced from biomass. There is no history of any funds ever being allocated for this program.

RESOLUTION NO: 80-0409-17

Appendix I-D

CALIFORNIA ENERGY COMMISSION

RESOLUTION

ALCOHOL FUELS POLICY

WHEREAS, California and the U.S. have become increasingly dependent on imported petroleum products and subject to the threat of economic and social disruption from the manipulation of petroleum supplies and prices; and

WHEREAS, the transportation sector is almost totally dependent on petroleum products primarily in the form of gasoline, such that more than half of the petroleum used in the State is used in the transportation sector; and

WHEREAS, the Legislature called for the development of an alcohol fuels program as a means of reducing reliance on imported petroleum products for transportation; and

WHEREAS, the Energy Commission is participating in such a program and has (1) conducted field tests of autos using alcohol and gasoline fuel blends, (2) initiated feasibility studies leading to financial support for the construction of two or more commercial facilities to produce at least two million gallons per year of alcohol fuel from agricultural wastes and surplus, and (3) initiated a program to field test over 100 vehicles fueled by straight alcohol fuels and capable of mass production for use in state and local captive fleets; and

WHEREAS, Commission tests and other studies have demonstrated that:

(1) gasoline/alcohol fuel blends can be used without significant changes in fuel efficiency or exhaust emissions in existing motor vehicles,

(2) blended fuels cause substantial increases in fuel system evaporative emissions,

(3) additional research is necessary to determine the extent, to which evaporative emissions from blended fuels can be avoided,

(4) straight alcohol fuels used in properly modified motor vehicles increase thermal efficiency, substantially decrease exhaust emissions for all regulated pollutants, and eliminate evaporative emissions of regulated pollutants that occur with either gasoline or gasoline/alcohol blends; and

WHEREAS, the displacement of gasoline with pure alcohol fuels can occur with the least difficulty in captive fleets, including fleets operated by state and local governments, and can provide reliable and economic fuels for essential government transportation services, thus insulating these services from foreign manipulation of petroleum prices and supplies.

IT IS THEREFORE RESOLVED, THAT:

(1) The California Energy Commission supports the vigorous development of an alcohol fuels industry in California.

(2) For transportation fuels, the major emphasis should be placed on the use of straight alcohol fuels; and as a first step, the state should encourage the use of such fuels in fleet vehicles.

(3) The Commission supports the limited near-term use of alcohol/gasoline blends consistent with California's air quality goals.

(4) Future expansion of alcohol/gasoline blend fuels must depend on development of satisfactory techniques to substantially reduce or eliminate the evaporative emissions attendant with the use of such fuels.

IT IS FURTHER RESOLVED THAT the California Energy Commission shall continue to implement a program to develop alcohol fuels in California, including but not limited to the following actions:

(1) Identifying means to improve efficiency of alcohol conversion and its use in vehicle engines.

(2) Creating markets for alcohol fuels in California by encouraging utility use of alcohol as a boiler and turbine fuel and by demonstrating the advantages of using alcohol fuels in captive fleets.

(3) Developing and recommending appropriate incentives for alcohol use.

(4) Promoting the construction of alcohol production facilities by providing engineering feasibility analysis, loans and other financial incentives for potential producers and marketers.

(5) Supporting programs that will enable state and local governments and private industries to convert captive fleets to use of straight alcohol fuels, and vehicle manufacturers to offer mass-produced vehicles capable of using such fuels.

(6) Securing available federal funds for additional development of an alcohol fuels industry in California.

(7) Determining the most appropriate and efficient sources and conversion processes for alcohol fuels from natural gas, coal, and biomass alternatives.

(8) Developing quantitative goals for production and utilization of alcohol fuels in California.

DATED: April 9, 1980

RUSSELL L. SCHWEICKART,
Chairman

Appendix II-A

Current and Projected U.S. Ethanol Production Capacity

COMPANY	LOCATION		FEEDSTOCK	MMGPY
A.E. Staley	Loudon	TN	Corn	45
AGP	Hastings	NE	Corn	45
Agri-Energy	Luverne	MN	Corn	15
Alchem	Grafton	ND	Corn	10.5
Al-Corn	Claremont	MN	Corn	17
Archer Daniels Midland	Decatur	IL	Corn	200
	Peoria	IL	Corn	200
	Cedar Rapids	IA	Corn	200
	Clinton	IA	Corn	150
	Walhalla	ND	Corn/barley	0
Broin Enterprises	Scotland	SD	Corn	7
Cargill (total capacity)	Blair	NE	Corn	130
	Eddyville	IA	Corn	--
Central Minnesota	Little Falls	MN	Corn	15
Chief Ethanol	Hastings	NE	Corn	40
Chippewa Valley Ethanol	Benson	MN	Corn	17
Corn Plus	Winnebago	MN	Corn	17.5
DENCO	Morris	MN	Corn	8
Eco Products of Plover	Plover	WI	Whey/potato waste	4
ESE Alcohol	Leoti	KS	Corn/milo	1.1
Ethanol2000	Bingham Lake	MN	Corn	15
Exol, Inc.	Albert Lea	MN	Corn	15
Georgia-Pacific	Bellingham	WA	Paper waste	7
Golden Cheese	Corona	CA	Whey	2.8
Grain Processing Corp.	Muscatine	IA	Corn	10
Heartland Corn Products	Winthrop	MN	Corn	15
Heartland Grain Fuel	Aberdeen	SD	Corn	8
Heartland Grain Fuel	Huron	SD	Corn	12
High Plains Corporation (total capacity)	York	NE	Corn/milo	68
	Colwich	KS		--
	Portales	NM		--
J.R. Simplot	Caldwell	ID	Potato waste	3
	Burley	ID	Potato waste	3
Jonton Alcohol	Edinburg	TX	Corn	1.2
Kraft, Inc.	Melrose	MN	Whey	3
Manildra Ethanol	Hamburg	IA	Corn/milo/wheat starch	7
Merrick/Coors	Golden	CO	Brewery waste	1.5
Midwest Grain (total capacity)	Pekin	IL	Corn/wheat starch	108
	Atchison	KS		--
Minnesota Clean Fuels	Dundas	MN	Waste sucrose	1.5
Minnesota Corn Processors (total capacity)	Columbus	NE	Corn	110
	Marshall	MN	Corn	--
Minnesota Energy	Buffalo Lake	MN	Corn	12
New Energy Corp.	South Bend	IN	Corn	85
Pabst Brewing	Olympia	WA	Brewery waste	0.7
Parallel Products	Louisville	KY	Beverage waste	7
	Bartow	FL	Beverage waste	5
	R. Cucamonga	CA	Beverage waste	6
Permeate Refining	Hopkinton	IA	Sugars & Starches	1.5
Pro-Corn	Preston	MN	Corn	15
Sunrise Energy	Blairstown	IA	Corn	5
Sutherland plant	Sutherland	NE	Corn	15
Reeve Agri-Energy	Garden City	KS	Corn/milo	10

Source: Bryan & Bryan Inc. October 1999 (with minor adjustments made by Energy Commission staff)

Williams Bioenergy (total capacity)	Pekin	IL	Corn	130
	Aurora	NE	Corn	--
Wyoming Ethanol	Torrington	WY	Corn	5
Subtotal Current Production Capacity				**1804**

Plants Under Construction

COMPANY	LOCATION		FEEDSTOCK	MMGPY
Adkins Energy	Lena	IL	Corn	30
BC International	Jennings	LA	Bigasse/rice hulls	20
NE Missouri Grain Processors	Macon	MO	Corn	15
Lake Area Corn Processors	Wentworth	SD	Corn	40
Golden Triangle	St. Joseph	MO	Corn	25
Schmidt Brewery	St. Paul	MN	Beer waste	15
Subtotal Under Construction Capacity (by 2000)				**145**

Proposed Plants

COMPANY	LOCATION		FEEDSTOCK	MMGPY
American Agri-Technology Corporation	Great Falls	MT	Wheat/Barley	30
Lower Caskaskia Economic Devp. Board	Lower Caskaskia	IL	Corn	100
BC International- Collins Pine	Chester	CA	Forest Residues	20
BC International-Gridley	Oroville	CA	Rice Straw	20
Sacto Ethanol Partners/Arkenol	Sacramento	CA	Rice Straw	4
MASADA	Middletown	NY	Municipal Solid Waste	6.6
Sustainable Energy Devp.	Central Region	OR	Wood Waste	30
Pacific Rim Ethanol Corp.	Moses Lake	WA	Grain	40
Pacific Rim Ethanol Corp.	Longview	WA	Grain	40
GreenLeaf	Platte	SD	Corn	15
Pratte Project	Pratte	KS	Corn/milo	15
Iowa #1	Central Iowa	IA	Corn	15
Iowa #2	Central Iowa	IA	Corn	15
Sealaska	Southeast Alaska	AK	Forest Residues	6
SIRS	Central Missouri	MO	Corn	30
N/A	Black Hills	SD/WY	Forest Residues	12
Subtotal Proposed Capacity (by 2001)				**398.6**

TOTAL CURRENT AND PROJECTED ETHANOL PRODUCTION CAPACITY	**2,348**

MMGPY = million gallons per year

Source: Bryan & Bryan Inc. October 1999 (with minor adjustments made by Energy Commission staff)

Appendix II-B

Estimates of Ethanol Demand for Use in California Gasoline	
Study and Assumptions	Ethanol Demand (million gallons per year)
TSS Consultants (26)	
5.7% ethanol in federal RFG areas -- winter only	222
10% ethanol in federal RFG areas -- winter only	390
5.7% ethanol in all gasoline year around	741
5.7% ethanol in all summer gasoline, 10% ethanol in all winter gasoline	909
no federal oxygenate requirement, 5.7% ethanol in all premium gasoline (est. 20% of market)	148
no federal oxygenate requirement, 10% ethanol in all premium gasoline (est. 20% of market)	260
Downstream Alternatives/RFA (27)	
5.7% ethanol in federal RFG areas year around	550
5.7% ethanol in federal RFG areas and in all premium and mid-grade gasoline (est. 30% of market) year around	628
Jaffoni -- Cargill (28)	
5.7% ethanol in federal RFG areas year around	550
5.7% ethanol in federal RFG areas and in all premium gasoline (est.15% of market) year around	589
10% ethanol in federal RFG areas year around	966
10% ethanol in federal RFG areas and in all premium gasoline (est.15% of market) year around	1,034

26, 27, 28 –See complete study references at end of Chapter II of main report.

Appendix III-A

Information on Forest and Crop Residues

What are the components of cellulosic biomass?

About 35% to 50% of the material are cellulose, a polymer of the six-carbon sugar glucose that forms a crystalline structure. Another 15% to 30% are hemicellulose, a heterogeneous polymer of various sugars generally dominated by the five-carbon sugar xylose. The remaining 20% to 30% are composed primarily of lignin (a heterogeneous aromatic polymer), with lesser amounts of extractives, ash and other components.

How much forest land in California should be thinned?

According to the Department of Forestry and Fire Protection, California's timber industry yields about $1 billion annually. The state has approximately 40 million acres of forestland, most being in the northern portion of the state. There are approximately 16 million acres of commercial timberland in California. Of this, approximately 13 million acres are at a slope of 30° or less, a requirement for thinning the forest economically.

California's Agricultural Crops

Field and Seed Crops

		Residue		
Crop	**97 Prod. Acres Harv.**	**Conv. Factor BDT/Acre**	**BDT Total**	**92 CEC Biom Rprt**
Barley	180,000	1.3	234,000	305,500
Bean	132,000	1.0	132,000	161,500
Corn	575,000	4.7	2,702,500	1,565,500
Cotton	1,059,000	1.5	1,588,500	1,503,000
Oat	35,000	1.2	42,000	39,500
Rice	510,000	3.5	1,785,000	1,309,600
Sugar Beets	99,000	2.4	237,600	406,800
Wheat	544,000	1.9	1,033,600	1,189,900

Source: California Department of Food and Agriculture, *1998 California Agricultural Resource Directory*, November 1998

Conversion factors: California Energy Commission,*1991 Biomass Resource Assessment Report for California, Draft;* P500-94-007, December 1992

Fruit and Nut Crops

Crop	97 Prod. Acres Harv.	Residue Conv. Factor BDT/Arce	Residue BDT Total	92 CEC Biom Rprt
almond	410,000	1.3	533,000	350,200
apple	38,500	2.2	84,700	35,900
apricot	19,100	2.0	38,200	25,000
avocado	57,700	1.5	86,550	73,000
cherry	13,700	0.4	5,480	2,700
date	4,800	1.0	4,800	3,200
fig	16,000	2.2	35,200	21,000
grapefruit	18,600	1.0	18,600	12,200
grape	675,700	2.0	1,351,400	873,000
kiwi	6,100	2.0	12,200	
lemon	46,500	1.0	46,500	29,400
lime	-	1.0	-	600
olive	35,300	1.5	52,950	29,200
orange	199,000	1.0	199,000	111,100
peach	66,200	2.0	132,400	73,500
pear	22,800	2.3	51,300	32,800
pistachio	65,400	1	65,400	
plum	42,000	1.5	63,000	39,800
prune	79,500	1.0	79,500	50,200

Source: California Department of Food and Agriculture, *1998 California Agricultural Resource Directory*, November 1998

Conversion factors: California Energy Commission,*1991 Biomass Resource Assessment Report for California, Draft;* P500-94-007, December 1992

Vegetable Crops

Crop	97 Prod. Acres Harv.	Residue Conv. Factor BDT/Acre	Residue BDT Total	92 CEC Biom Rprt
artichoke	9,100	1.7	15,470	19,400
asparagus	30,100	2.2	66,220	75,300
cucumber	5,700	1.7	9,690	10,300
lettuce	201,000	1.0	201,000	209,200
melon	107,000	1.2	128,400	147,800
potato	43,700	1.2	52,440	58,800
squash		1.2		9,500

Source: California Department of Food and Agriculture, *1998 California Agricultural Resource Directory*, November 1998

Conversion factors: *California Energy Commission*,1991 Biomass Resource Assessment Report for California, Draft; *P500-94-007, December 1992*

Appendix III-B

Summary of Biomass-Derived Transportation Fuels and Conversion Processes

The following Table III-B-1 is a list of many of the transportation fuels that can be derived from cellulosic biomass feedstocks. The list is not intended to be exhaustive, but rather to present a variety of relevant process technologies, and the end products (potential transportation fuels in this case) that can be derived from cellulosic biomass. The status of the technologies varies widely. Products other than transportation fuels that can be produced from biomass include soil amendments, livestock feed, building materials, commodity and specialty chemicals, etc.

Three principal routes for converting biomass are: 1) thermochemical (e.g., thermal gasification), 2) biochemical (e.g., fermentation) and 3) physicochemical (e.g., esterification, extrusion, etc.). In practice, combinations of two or more of these routes may be used in the processing of the biomass feedstocks into these products. (1)

Table III-B-1 Transportation Fuels Producible from Cellulosic Biomass

PROCESS	PRODUCT	COMMENTS
Fermentation	Ethanol	Traditional means for producing ethanol. Basic steps include 1) pretreatment, 2) hydrolysis, 3) separation of acids and sugars, 4) fermentation and 5) product purification (distillation). [Discussed in detail in Chapter V and the accompanying Appendix V-A.]
Gasification	Ethanol	By heat or other means, biomass is turned to a mixture of gases referred to as syngas, suitable for further conversion. Gasification of biomass can Produce very high ethanol yields as cellulose, hemicellulose *and* lignin are utilized in the conversion process.
Hynol	Methanol	The Hynol process combines biomass feedstocks with natural gas to improve the efficiency of biomass conversion. The basic process consists of two reactions: 1) hydrogenation of the carbonaceous feedstock to produce methane, followed by 2) the endothermic reaction of methane with steam to produce H_2 and CO. (2)
Gasification	Methanol	Biomass gasification can produce synthesis gas (syngas), a mixture of Carbon monoxide and hydrogen. Syngas is feedstock in commercial Methanol production.
Biofine	MTHF	MTHF (methyl tetrahydrofuran) is a fuel additive that can be produced from levulinic acid, which can be produced from cellulose by the Biofine process (3). MTHF is a co-solvent facilitating larger percentage mixtures of ethanol into gasoline.
Esterification	Esters	Can be produced from vegetable and animal fats or oils. Through a process called transesterification, organically derived oils are combined with alcohol and chemically altered to form fatty esters such as ethyl or methyl ester. The biomass-derived esters can be blended with conventional diesel fuel or used as a neat fuel (biodiesels) (4)
Catalysis	Ethers	Common ethers include Methyl Tertiary Butyl Ether (MTBE) and Ethyl Tertiary Butyl Ether (ETBE). These ethers can be produced by converting biomass to an alcohol. MTBE is produced by a catalytic reaction between methanol and isobutylene over an acidic ion exchange resin. Similarly, ETBE is produced by a catalytic reaction between ethanol and isobutylene over an acidic ion exchange resin.(5)
Collection and Cleaning	Methane	Landfill gas, composed primarily of methane, is produced by the decomposition of waste deposits and is considered a problem if it is not contained. Can be processed and cleaned to operate boilers, vehicles, etc.
Anaerobic Digestion	Methane	Fermentation by anaerobic bacteria is used to produce biogas, a gaseous fuel consisting primarily of methane, with lesser amounts of carbon dioxide, water and small quantities of hydrogen sulfide.
Fischer-Tropsch	Fischer-Tropsch fuels	In this conversion process, hydrocarbons are synthesized from carbon monoxide and hydrogen over iron or cobalt catalysts. The CO and H_2 feed gases are produced from carbon-containing feedstock by gasification of biomass or other materials (e.g., natural gas, coal). The process steps may include 1) gasification and gas clean up, 2) reforming, 3) F-T synthesis, 4) CO_2 removal, 5) hydrocracking and hydrocarbon recovery. (6,7) A variety of hydrocarbon fuels can be produced by these methods, including synthetic gasoline and diesel fuels.
Gasification and pyrolysis	Hydrogen	Hydrogen produced from high-temperature gasification and low temperature pyrolysis of biomass.(1)

These examples illustrate the many processes available to produce a variety of fuels from biomass. The first two entries are assessed further in this biomass-to-ethanol report.

The references cited for entries in this table are as follows:

1) Jenkins, Bryan; *Energy Systems*, Course compendium, University of California, Davis.
2) Sethi, P.,Chaudry, S., and Unnasch, S. "Methanol Production from Biomass Using the Hynol Process", Overend and Chornet, *Biomass: A growth opportunity in green energy and value-added products*, Vol. 1, Proceedings from the 4th Biomass Conference of the Americas, 843.
3) Elliott,D., Fitzpatrick,S., Bozell, J., Jarnefeld, J., Bilski,R., Moens, L., Frye, J., Wang, Y., Neuenschwander, G., "Production of Levulinic Acid and Use as a Platform Chemical for Derived Products", Overend and Chornet, *Biomass: A growth opportunity in green energy and value-added products*, Vol.1, Proceedings from the 4th Biomass Conference of the Americas, 595.
4) NREL, Internet Web site: www.nrel.gov, October 1999
5) Department of Energy, Internet Web site www.ott.doe.gov/biofuels/what_are.html, October 1999
6) Larson, E. and Jin, H., "Biomass Conversion to Fischer-Tropsch Liquids: Preliminary Energy Balances", Ovberend and Chornet, *Biomass: A growth opportunity in green energy and value-added products*, Vol. 1, Proceedings from the 4th Biomass Conference of the Americas, 843.
7) National Renewable Energy Lab, et al; Environmental Life Cycle Implications of the Use of California Biomass in Production of Fuel Oxygenates, 1998

Appendix III-C

Rice Straw Diversion Plan

California Air Resources Board

December 1998

PREFACE

This report was written by Lesha Hrynchuk under the supervision of Terry McGuire, Chief of the Technical Support Division. Copies of this report may be obtained by calling the Public Information Office at (916) 322-2990 or via the Internet at the following address: http://www.arb.ca.gov/rice/ricefund/ricefund.htm

EXECUTIVE SUMMARY

State legislation requires the Air Resources Board to develop an implementation plan and schedule to find uses for 50 percent of the rice straw from the Sacramento Valley by the year 2000. The burning of rice straw has been phasing down over the last seven years, leaving rice growers with the only available option of plowing the straw into the soil. Some growers object to soil incorporation because it is costly, may be conducive to crop diseases, and presents logistics problems.

In recent years, about 500,000 acres have been annually planted in rice in the Sacramento Valley. When the fields are burned, about 3 tons of straw are burned per acre. However, when the straw is harvested, only about 2.25 tons of straw can be removed from an acre. Thus, the total yield is about 1.125 million tons of straw annually. This Rice Straw Diversion Plan targets finding uses for about 562,500 tons of rice straw, which is 50 percent of the total straw yield on 500,000 acres.

Not all of the straw grown is expected to be available for harvest. Four factors which would limit straw availability are disease burning, preferred incorporation, hunting clubs, and poor straw condition. These four factors could decrease the availability of straw by up to 50 percent.

Since only about 13,500 tons of rice straw are currently used off-field, increasing the use by more than 50-fold will require a tremendous effort. Many issues need to be resolved before a successful market can be created for 50 percent of the straw. A straw infrastructure needs to be created to solve the logistics problems of harvesting, transporting and storing over half-a-million tons of straw within the six-to-eight-week harvest period during the fall. Straw specifications of the end-

users of straw also need to be defined.

If additional measures are not implemented, forecasts call for 3 percent use of rice straw in 2000 and about 20 percent use in 2003. If the Legislature were to implement additional measures, the earliest, practical date by which resources could be appropriated would be during late 1999 or early 2000. This would allow only about 9 months to develop and implement programs that could affect the September 2000 straw harvest. There are very few straw usage categories which could be targeted in such a short time frame.

To comply with the SB 318 requirement for a 50 percent diversion plan, the ARB staff has identified two approaches which would achieve the 50 percent goal on the most expeditious schedule possible. One approach is targeted to divert 50 percent in the year 2000, as required in the legislation. However, meeting the diversion goal by this date could be accomplished only with large subsidies and even then would face substantial logistic and technical difficulties. For this 2000 plan, a dairy and cattle feed marketing program could be pursued, which would include a $20 per ton subsidy, to induce dairy and cattle ranchers to buy rice straw for animal feed. This subsidy, totaling almost $10 million annually, would need to continue until other uses of rice straw were developed.

Because of the extreme difficulty and high cost of achieving a 50 percent diversion by the year 2000, the ARB also identified an alternative plan targeted at the year 2003. The approaches for diverting 50 percent of rice straw by 2003 include appropriating resources for analyzing straw production, harvest and availability; funding to build straw storage facilities; funding for prospective straw businesses; assisting potential straw businesses in developing viable business plans; directing state agencies to use and promote rice straw products; and modifying the Rice Straw Tax Credit Program.

Report to the Legislature
Rice Straw Utilization Tax Credit Program
California Department of Food and Agriculture
June 1, 1998

The Rice Straw Utilization Tax Credit Program was established by SB 38 (Lockyer, Ch 954, 1996) as Section 17052.10 of the State Revenue and Taxation Code. The law provides that for each taxable year beginning on or after January 1, 1997, and before January 1, 2008, there shall be allowed as a credit against the amount of "net tax," as defined (California state income tax), the amount of $15 per ton of rice straw that is grown within California and purchased during the taxable year by the taxpayer. The taxpayer must be the "end user" of the rice straw, meaning anyone who uses the rice straw for any purpose, including but not limited to processing, generation of energy, manufacturing, export, or prevention of erosion, exclusive of open burning, that consumes the rice straw. The taxpayer cannot be related, under the Internal Revenue Code to any person who grew the rice straw within California. The law limits the aggregate amount of the tax credit to $400,000 for each calendar year. In cases where the tax credit exceeds the "net tax," the excess may be carried over to reduce the "net tax" for the next ten taxable years, or until the credit has been exhausted, which ever comes first.

Under the law, the California Department of Food and Agriculture (CDFA) must:
- certify that a taxpayer has purchased rice straw during the specified taxable year,
- issue certificates to qualified taxpayers on a first-come, first-served basis,
- provide an annual listing to the Franchise Tax Board,
- provide the taxpayer with a copy of the certification,
- obtain the taxpayer's identification number, and
- provide an annual informational report to the Legislature.

Background:
The Connelly-Areias-Chandler Rice Straw Burning Reduction Act of 1991 (AB 1378, Ch 787, 1991) mandated the phase down of open field rice straw burning by 1998. The phase down period was recently extended until 2000 (Thompson, SB 318, Ch 745, 1996) due in part to the recognition that alternative straw management options were costly and slow to develop. Furthermore, soil incorporation of straw, the only widely available management option, continues to cause adverse effects to rice farming operations including but not limited to increased costs, increased incidence of disease and weeds, and other land and irrigation management problems.

The Legislature, recognizing the need for incentives to speed the development of off-field uses of rice straw, established the tax credit as one incentive. The $400,000 annual tax credit represents 26,667 tons of rice straw, or about 9,000 to 13,000 acres. Approximately 465,000 acres of rice was planted in the Sacramento Valley in 1998, down about 5% from 1997.

Program Status:

Last year, 1998, was the second year of the program. Those that requested information concerning the 1997 Program were automatically sent information for 1998. An additional 60 telephone, written and faxed inquiries were received and responded to by the Department.

Applications for the tax credit were accepted on a first-come, first-served basis starting on December 1, 1998 at 8:00 am at the CDFA headquarters in Sacramento. To date for the 1998 tax year 22 applications were received requesting $111,745 in tax credits for purchase of 7,450 tons of rice straw. CDFA approved 20 applications totaling $88,360 in tax credits for purchase of 5,891 tons of rice straw. Two applications were denied because purchases were not adequately documented. Please see Table 1.

Table 1: Program Summary

Requests	Number	Tons	Tax Credit ($)
Total	22	7,449.66	$111,744.90
Certificates Issued	20	5,890.66	$88,359.90
Denied	2	1,559	$23,385.00

Of the 20 applications approved, 15 were dairies, two were manufacturing companies, two were other livestock operations and one was a citrus grower. The primary uses of the rice straw were for animal bedding, animal feed and erosion control. Please see Table 2 and Table 3.

Table 2: Types of Businesses

Business	Number	Tons	Tax Credit ($)
Dairy	15	2,644.84	$39,672.60
Cattle	2	1337.36	$20,060.40
Citrus grower	1	5	$ 75.00
Feed Manufacturer	1	235.92	$3,538.80
Erosion Control Mfg.	1	1,667.54	$25,013.10
TOTAL	20	5,890.66	$88,359.90

Table 3: Methods of Use

Method	Number*	Tons
Animal bedding	15	2,530.35
Feed	5	1,687.77
Erosion control	2	1,672.54
TOTAL	22	5,890.66

*Two certified applicants used the straw for multiple purposes (feed/bedding). They did indicate how much went to each use.

Participation in the Rice Straw Utilization Tax Credit Program in 1998 was comparable to 1997 levels by most measures – approved applications, tonnage, and thus tax credit amount. However, the number of inquiries and number of applications submitted were down about 25% from the first year of the Program. There were two main factors that may account for this. First, the industry and end-users were now familiar with how the program worked. New inquiries tended to be reasonably well informed about the program and primarily wanted the most recent application form and often wanted leads as to potential sources of rice straw. Second, due to weather constraints, straw availability was limited as compared to the previous year. Thus, there may have been a supply constraint that prevented expanded participation in the Program. The CDFA received many calls inquiring as to potential sources of rice straw. Please see Table 4 for a comparison of the program for 1997 and 1998.

Table 4: Annual Comparison – 1997 and 1998

	1997	1998
Applications received	35	22
Applications approved	28	20
Tonnage applied for	31,230.6	7,449.66
Tonnage approved	6,033.995	5,890.66
Tax credit applied for	$468,459	$111,744.90
Tax credit approved	$90,509.34	$88,359.90

The Department has prepared an annual listing of the qualified taxpayers who were issued certificates and the amount of rice straw purchased by each taxpayer and provided it to the Franchise Tax Board on computer readable form and in the manner prescribed by the Board.

The Department will announce the 1999 Rice Straw Utilization Tax Credit Program in August 1999, before rice harvest begins. The Department anticipates accepting applications for the 1999 tax credit on a first-come, first-served basis in late November or early December 1999.

It has been suggested that the Department accept applications for the tax credit on a first-come-first-served basis prior to the harvest season. It is believed that this would facilitate arrangements between growers, handlers and end-users and improve logistics for the fall harvest season. The Department will take this under advisement during 1999.

Conclusions and Recommendations:

Industry experts and the University of California, Department of Agricultural and Biological Engineering estimate that less than 30,000 tons of rice straw were harvested in 1998. Most probably, the figure does not exceed 20,000 tons. Thus, about 20% to 30% of the harvested rice straw was purchased under the tax credit. Currently, the potential for harvesting rice straw is limited by equipment availability, storage availability and during this past year, weather.

The rice straw utilization tax credit is limited in scope by the annual cap of $400,000 (26,667 tons of rice straw) when compared to the amount of potentially harvestable rice straw – in the order of 1 million tons. However, the program is not yet limited when compared to the current market for the resource or the ability to harvest the resource as evidenced by the fact that the program has yet to be fully utilized. There is no existing large market for rice straw that can take full advantage of the tax credit. The dairy industry seems to be in the best position to claim the tax credit. In this situation, the tax credit serves to offset the transportation costs associated with hauling the straw from the Sacramento Valley rice production region to dairies in the San Joaquin Valley. It is anticipated that many more dairy operators will take advantage of the tax credit in the coming years.

A successful startup of a commercial straw processing facility could change the dynamics of the program drastically. Any such facility that processes straw to straw board, fiber board, feed, ethanol fuel, electricity, erosion control materials, pulp or paper, or other products at a commercial scale would easily consume the amount of straw each year that would be eligible for the tax credit. At this point in the development of these projects, project financing and straw handling infrastructure and logistics are more formidable barriers than the cost of rice straw. This is not to say that rice straw costs, and thus, the incentive provided by the tax credit is not important. An assured reduction in the straw acquisition cost that can be provided by the tax credit can make some straw processing projects more attractive to potential investors.

As demand for the tax credit increases, and economic and environmental benefits of off-field rice straw utilization are documented, the Legislature may want to consider expanding the program by lifting the annual $400,000 cap in order to attract larger and more diverse projects.

The CDFA has also received comments concerning the equity of the “first-come, first-served” provision, since conceivably, one entity could use the entire credit. Some have suggested that a cap of $1,000 to $4,000 be established for individual applications.

The tax credit provides little incentive to new startup processing facilities with little or no California income tax liability. The Legislature may want to consider a tax credit purchase or trading program that would allow new straw utilization projects with little or no California income tax liability to sell their tax credits to a profitable entity that could take advantage of the tax credit. The CDFA has received several inquiries and suggestions in this regard.

Several members of the rice industry have suggested that the unused tax credit from each year be dedicated to other activities that support off-field utilization of rice straw. Such activities may include but not be limited to development of rice straw harvest and storage infrastructure, market development and expansion for rice straw based products and support for those potential utilization technologies not supported through other programs.

Attachments:
1998 Summary Table
1997 Summary Table

1998 Summary
Rice Straw Utilization Tax Credit Program
California Department of Food and Agriculture

Type of Business	Use	Tons	$ Credit $
Dairy	Animal Bedding	23.87	$ 358.05
Dairy	Animal Bedding	263.11	$3,946.65
Dairy	Animal Bedding	182.95	$2,744.25
Cattle	Livestock Feed	368.32	$5,524.80
Dairy	Animal Bedding	76.01	$1,140.15
Dairy	Animal Bedding	384.42	$5,766.30
Dairy	Animal Bedding	79.46	$1,191.90
Dairy	Animal Bedding	540.0	$8,100.00
Dairy	Animal Bedding	84.0	$1,260.00
Dairy	Animal Bedding	11.42	$ 171.30
Dairy	Animal Bedding Livestock Feed	405.69	$6,085.35
Manufacturer	Erosion Control Blankets	1667.54	$25,013.10
Dairy	Animal Bedding	139.42	$2,091.30
Dairy	Animal Bedding	170.69	$2,560.35
Dairy	Livestock Feed	35.0	$ 525.00
Dairy	Animal Bedding Livestock Feed	48.80	$ 732.00
Manufacturer	Livestock Feed	235.92	$3,538.80
Dairy	Animal Bedding	200.00	$3,000.00
Cattle	Livestock Feed	969.04	$14,535.60
Citrus Grower	Erosion Control	5.00	$ 75.00
TOTAL		**5890.66**	**$88,359.90**

1997 Summary
Rice Straw Utilization Tax Credit Program
California Department of Food and Agriculture

Type of Business	Use	Tons	$ Credit $
Dairy	Animal Bedding	87	$1,305.00
Dairy	Animal Bedding	19.27	$289.05
Dairy	Animal Bedding	15.1	226.5
Owner/Builder	Building Construction	4.0	$60.00
Cattle	Livestock Feed	9.0	$135.00
Dairy	Animal Bedding	199.75	$2,996.25
Hydroseeding Contractor	Erosion Control	49.0	$735.00
Dairy	Animal Bedding	159.11	$2,386.65
Dairy	Animal Bedding	65.04	$975.60
Manufacturer	Compost/Fertilizer	1,263.75	$18,956.25
Dairy	Animal Bedding	159.82	$2,397.30
Dairy	Animal Bedding	300.0	$4,500.00
Dairy	Animal Bedding	181.615	$2,724.23
Dairy	Animal Bedding Livestock Feed	855.18	$12,827.70
Manufacturer	Erosion Control Blankets	58.48	$877.20
Owner/Builder	Building Construction	45.7	$685.50
Dairy	Animal Bedding	43.34	$650.10
Dairy	Animal Bedding	43.02	$645.30
Dairy	Livestock Feed	25.87	$388.05
Dairy	Animal Bedding Erosion Control	352.74	$5,291.10
Manufacturer	Livestock Feed	336.285	$5,044.28
Dairy	Animal Bedding	40.075	$601.13
Dairy	Animal Bedding	79.28	$1,189.20
Dairy	Animal Bedding	119.79	$1,796.85
Dairy	Animal Bedding	200.0	$3,000.00
Dairy	Animal Bedding	46.54	$698.10
Dairy	Livestock Feed	370.0	$5,550.00
Cattle	Livestock Feed	905.2	$13,578.00
TOTAL		**6,033.955**	**$90,509.34**

Appendix III-D

President Clinton's Executive Order

THE WHITE HOUSE

Office of the Press Secretary

For Immediate Release August 12, 1999

EXECUTIVE ORDER 13134

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DEVELOPING AND PROMOTING BIOBASED PRODUCTS AND BIOENERGY

By the authority vested in me as President by the Constitution and the laws of the United States of America, including the Federal Advisory Committee Act, as amended (5 U.S.C. App.), and in order to stimulate the creation and early adoption of technologies needed to make biobased products and bioenergy cost-competitive in large national and international markets, it is hereby ordered as follows:

Section 1. Policy. Current biobased product and bioenergy technology has the potential to make renewable farm and forestry resources major sources of affordable electricity, fuel, chemicals, pharmaceuticals, and other materials. Technical advances in these areas can create an expanding array of exciting new business and employment opportunities for farmers, foresters, ranchers, and other businesses in rural America. These technologies can create new markets for farm and forest waste products, new economic opportunities for underused land, and new value-added business opportunities. They also have the potential to reduce our Nation's dependence on foreign oil, improve air quality, water quality, and flood control, decrease erosion, and help minimize net production of greenhouse gases. It is the policy of this Administration, therefore, to develop a comprehensive national strategy, including research, development, and private sector incentives, to stimulate the creation and early adoption of technologies needed to make biobased products and bioenergy cost-competitive in large national and international markets.

Section 2. Establishment of the Interagency Council on Biobased Products and Bioenergy.

(a) There is established the Interagency Council on Biobased Products and Bioenergy (the "Council"). The Council shall be composed of the Secretaries of Agriculture, Commerce, Energy, and the Interior, the Administrator of the Environmental Protection Agency, the Director of the Office of Management and Budget, the Assistant to the President for Science and Technology, the Director of the National Science Foundation, the Federal Environmental Executive, and the heads of other relevant agencies as may be determined by the Co-Chairs of the Council. Members may serve on the Council through designees. Designees shall be senior officials who report directly to the agency head (Assistant Secretary or equivalent).

(b) The Secretary of Agriculture and the Secretary of Energy shall serve as Co-Chairs of the Council.

(c) The Council shall prepare annually a strategic plan for the President outlining overall national goals in the development and use of biobased products and bioenergy in an environmentally sound manner and how these goals can best be achieved through Federal programs and integrated planning. The goals shall include promoting national economic growth with specific attention to rural economic interests, energy security, and environmental sustainability and protection. These stra-tegic plans shall be compatible with the national goal of producing safe and affordable supplies of food, feed, and fiber in a way that is sustainable and protects the environment, and shall include measurable objectives. Specifically, these strategic plans shall cover the following areas:

(1) biobased products, including commercial and industrial chemicals, pharmaceuticals, products with large carbon sequestering capacity, and other materials; and

(2) biomass used in the production of energy (electricity; liquid, solid, and gaseous fuels; and heat).

(d) To ensure that the United States takes full advantage of the potential economic and environmental benefits of bio-energy, these strategic plans shall be based on analyses of: (1) the economic impacts of expanded biomass production and use; and (2) the impacts on national environmental objectives, including reducing greenhouse gas emissions. Specifically, these plans shall include:

(1) a description of priorities for research, development, demonstration, and other investments in biobased products and bioenergy;

(2) a coordinated Federal program of research, building on the research budgets of each participating agency; and

(3) proposals for using existing agency authorities to encourage the adoption and use of biobased products and bioenergy and recommended legislation for modifying these authorities or creating new authorities if needed.

(e) The first annual strategic plan shall be submitted to the President within 8 months from the date of this order.

(f) The Council shall coordinate its activities with actions called for in all relevant Executive orders and shall not be in conflict with proposals advocated by other Executive orders.

Section 3. Establishment of Advisory Committee on Biobased Products and Bioenergy.

(a) The Secretary of Energy shall establish an "Advisory Committee on Biobased Products and Bioenergy" ("Committee"), under the Federal Advisory Committee Act, as amended (5 U.S.C. App.), to provide information and advice for consideration by the Council. The Secretary of Energy shall, in consultation with other members of the Council, appoint up to 20 members of the advisory committee representing stakeholders including representatives from the farm, forestry, chemical manufacturing and other businesses, energy companies, electric utilities, environmental organizations, conservation organizations, the university research community, and other critical sectors. The Secretary of Energy shall designate Co-Chairs from among the members of the Committee.

(b) Among other things, the Committee shall provide the Council with an independent assessment of:

(1) the goals established by the Federal agencies for developing and promoting biobased products and bioenergy;

(2) the balance of proposed research and development activities;

(3) the effectiveness of programs designed to encourage adoption and use of biobased products and bioenergy; and

(4) the environmental and economic consequences of biobased products and bioenergy use.

Section 4. Administration of the Advisory Committee.

(a) To the extent permitted by law and subject to the availability of appropriations, the Department of Energy shall serve as the secretariat for, and provide the financial and administrative support to, the Committee.

(b) The heads of agencies shall, to the extent permitted by law, provide to the Committee such information as it may reasonably require for the purpose of carrying out its functions.

(c) The Committee Co-Chairs may, from time to time, invite experts to submit information to the Committee and may form subcommittees or working groups within the Committee to review specific issues.

Section 5. Duties of the Departments of Agriculture and Energy. The Secretaries of the Departments of Agriculture and Energy, to the extent permitted by law and subject to the availability of appropriations, shall each establish a working group on biobased products and biobased activities in their respective Departments. Consistent with the Federal biobased products and bioenergy strategic plans described in sections 2(c) and (d) of this order, the working groups shall:

(1) provide strategic planning and policy advice on the Department's research, development, and commercialization of biobased products and bioenergy; and

(2) identify research activities and demonstration projects to address new opportunities in the areas of biomass production, biobased product and bioenergy production, and related fundamental research.

The chair of each Department's working group shall be a senior official who reports directly to the agency head. If the Secretary of Agriculture or Energy serves on the Interagency Council on Biobased Products and Bioenergy through a designee, the designee should be the chair of the Department's working group.

Section 6. Establishment of a National Biobased Products and Bioenergy Coordination Office. Within 120 days of this order, the Secretaries of Agriculture and Energy shall establish a joint National Biobased Products and Bioenergy Coordination Office ("Office") to ensure effective day-to-day coordination of actions designed to implement the strategic plans and guidance provided by the Council and respond to recommendations made by the Committee. All agencies represented on the Council, or that have capabilities and missions related to the work of the Council, shall be invited to participate in the operation of the Office. The Office shall:

(a) serve as an executive secretariat and support the work of the Council, as determined by the Council, including the coordination of multi-agency, integrated research, development, and demonstration ("RD&D") activities;

(b) use advanced communication and computational tools to facilitate research coordination and collaborative research by participating Federal and nonfederal research facilities and to perform activities in support of RD&D on biobased product and bioenergy development, including strategic planning, program analysis and evaluation, communications networking, information and data dissemination and technology transfer, and collabora-tive team building for RD&D projects; and

(c) facilitate use of new information technologies for rapid dissemination of information on biobased products and bioenergy to and among farm operators; agribusiness, chemical, forest products, energy, and other business sectors; the university community; and public interest groups that could benefit from timely and reliable information.

Section 7. Definitions. For the purposes of this order:

(a) The term "biomass" means any organic matter that is available on a renewable or recurring basis (excluding old-growth timber), including dedicated energy crops and trees, agricultural food and feed crop residues, aquatic plants, wood and wood residues, animal wastes, and other waste materials.

(b) The term "biobased product," as defined in Executive Order 13101, means a commercial or industrial product (other than food or feed) that utilizes biological products or renewable domestic agricultural (plant, animal, and marine) or forestry materials.

(c) The term "bioenergy" means biomass used in the production of energy (electricity; liquid, solid, and gaseous fuels; and heat).

(d) The term "old growth timber" means timber of a forest from the late successional stage of forest development. The forest contains live and dead trees of various sizes, species, composition, and age class structure. The age and structure of old growth varies significantly by forest type and from one biogeoclimatic zone to another.

Section 8. Judicial Review. This order does not create any enforceable rights against the Unites States, its agencies, its officers, or any person.

WILLIAM J. CLINTON

THE WHITE HOUSE,
August 12, 1999.

Appendix V-A

Biomass-to-Ethanol Process Technologies

Biomass Conversion Options

There is real potential for biobased products to be cost-competitive with petroleum-based production if research, development, and demonstrations reduce processing costs. (Ref. V-1) Advances in chemical pretreatment of cellulosic wastes and in biological conversion of the resulting molecules (such as sugars) make major cost reductions seem likely. This Appendix describes the most competitive current technologies and probable directions for increasing the rate of conversion, yield and efficiency, and thereby lowering the costs of production, of ethanol, electricity, and chemical co-products from urban, agricultural, and forest wastes.

After the feedstocks are delivered to the plant, they are reduced in size, if necessary, by cutting and milling, and may be washed. Most biomass conversion processes then utilize two or three technologies, sometimes in combination:

(1) pretreatment that makes the cellulosic components of the biomass more accessible to
(2) hydrolysis by acids, or by enzymes called "cellulases", that shorten sugar polymers into sugars that then undergo
(3) fermentation by microbes , converting the five- and six-carbon sugars to ethanol and other oxygenated chemicals.

The latter two steps may be combined into Simultaneous Saccharification and Fermentation, called SSF. (Ref. V-2) If cellulases are produced in the same vessel, the approach is called consolidated bioprocessing (Ref. V-3) or DMC (Direct Microbial Conversion.) After fermentation is complete, the ethanol produced can be distilled to the characteristics required for its uses, such as transportation fuel.

The remainder of this chapter surveys the various technologies for converting biomass to ethanol, electricity, and added-value co-products.

V-1 Pretreatment, Hydrolysis, and Fermentation

The methods referred to as pretreatment separate the four chemical components of biomass (hemicelluloses, cellulose, lignin, and extractives) to various extents, and make them accessible to further chemical or biological treatment. It is preferable to make the pretreatment as mild as possible, so as not to diminish the chemical values in the biomass.

The term hydrolysis means decomposition or dissolving in a watery medium. In the context of biorefining, it generally means cutting the long hemicellulose and cellulose molecules, which are polymers, chemically into their component sugars. These sugars are much shorter molecules, each containing only five or six carbon atoms, plus hydrogen and oxygen. These are called pentoses and hexoses, respectively, and they can be converted into ethanol.

The conversion of starches and sugars to ethanol is called fermentation, a process that has been practiced by mankind as long as the cultivation of grain and grapes.

V 1.1 Pretreatment

Conversion of biomass to ethanol, electricity and co-products usually requires a mechanical size reduction step, followed by physical, chemical, or biological pretreatment, or sometimes a combination of these (Ref. V-4) Commercial wood chips have 1-3 cm length, width, and 0.5-1 cm thickness, that is usually reduced to 0.3 cm or less in every dimension before further processing.

The most common physical pretreatments are (1) comminution, that is, size reduction by ball milling or compression milling, and (2) aqueous/steam processing, to be discussed below.

Chemical pretreatments to make the biomass more digestible have received by far the most research interest. They include dilute acid, alkaline, organic solvent, ammonia, sulfur dioxide, carbon dioxide, or other chemicals.

Biological pretreatments have been tested primarily to solubilize lignin, and so make the cellulose more accessible to hydrolysis and fermentation. Sometimes a combination of chemical and biological methods has been employed.

These various pretreatment processes result in a variety of product streams for further processing. In many cases, the cellulose, hemicellulose, and lignin are separated into two streams, such as a liquid stream rich in hemicellulose, and a stream containing the cellulose and lignin as solids; or, if delignification is used, the liquid stream contains the lignin and hemis, and the second stream contains cellulose and the remaining unsolubilized hemis as solids. Combined pretreatments may result in separating the three major components and extractives into individual product streams.

Three examples of the wide variety of possible pretreatments are the organosolv, AFEX, and aqueous/steam methods.

A variation on the dilute acid processes known as ACOS or organosolv, adds acetone to a dilute acid solution with the objective of producing higher yields of sugar (in particular, glucose), leading to higher yields of ethanol after fermentation.

A line of development pursued by Texas A&M uses dilute ammonia, an alkaline chemical, to aid hydrolysis. A sudden pressure release (colloquially called an “explosion”) is employed in this AFEX method. Advantages claimed for the method are reduced degradation of the materials to be fermented to ethanol, and no economic need to recycle the ammonia.

Aqueous/steam pretreatment methods may use acid or base catalysis, but they aim to minimize the use of acids and other chemical reagents, by processing biomass with hot water and/or steam at high temperatures and pressures for short periods of time. Their goals include reduction of milling costs, high sugar recovery, and minimal inhibition of fermentation. One subclass of these methods, sometimes called aquasolv, uses liquid hot water pretreatment. Another mixes steam with biomass, such as wood chips, in a pressure cooker for a few minutes at temperatures near 200°C, then releases the mixture to atmospheric pressure in a “steam explosion”. This technology has been advanced at the University of British Columbia, among others, and embodied in a continuous process by a Canadian company, Staketech. Both aqueous/steam and dilute acid methods are being considered as treatments to precede enzymatic hydrolysis.

If an appreciable fraction of the delivered biomass is in the form of easily-removable extractives, as in California softwoods, it is often best to remove these first, for conversion into valuable chemical products, and to ease further processing of the three major components. Thus, we now discuss separation of extractives as a form of pretreatment.

Separation of Extractives

The bark and needles of California softwoods contain resins and other valuable biochemicals that are part of the immune system of the trees. (The taxol from yew trees in the Pacific Northwest and maltol derived from Canadian conifers are two examples.) There is amorphous silica in rice straw and hulls that may be adapted to the demands of rubber and other industries. Organic and inorganic substances (ash) that are smaller but valuable fractions of biomass will here be called extractives. Separating these extractives in an early pretreatment step (for subsequent conversion to pharmaceutical or other commercial products) serves two valuable purposes: the manufacture of co-products to make the biorefinery economically self-sustaining, and the removal of materials that might inhibit later steps in the processing of hemicelluloses, cellulose and lignin.

The percentage in extractives (typically 4% to 5%) varies with biomass species and is highest in small trees and in residues rich in bark and branches, where up to 20% of the raw material (dry basis) is extractives. Recovery of extractives from coniferous trees was the foundation of the naval stores industry. A newly important and growing sector is directed toward natural chemicals from biomass used in food flavorings, fragrances, and as pharmaceutical intermediates. The sources of this biomass may include degraded trees as well as small living trees and shrubs that need to be removed to maintain a healthy and fire-safe forest.

Because organic extractives are soluble in simple alcohols and in hot pressurized water, they can be separated by mild front-end pretreatment. The process steps may include water treatment of the feedstocks to saturate the fiber materials through complete capillary penetration, ethanol extraction to remove slightly hydrophobic materials, followed by an ethyl acetate extraction, if needed. Inorganic material is removed in all steps, preferentially the first one. The resulting solid product, separated from the extractive streams, is a “refined biomass” suitable for conversion into ethanol, pulp, other commodity products, or power.

V 1.2 Hydrolysis

Several of the following subsections on hydrolysis and fermentation utilize historical and current information provided by the National Renewable Energy Laboratory (NREL) in its 1999 Bioethanol Strategic Roadmap (Ref. V-2). Projections of future performance consider this and other technical material published by NREL, but also include numerous other judgments from the technical literature, collected from academic, governmental, and industrial sources. The hydrolysis methods of this section are presented in an order generally ranging from those that rely most on chemical engineering to those more dependent on new biological (especially, genetic) technologies.

Concentrated Acid Hydrolysis

Dissolving and hydrolyzing cellulose with concentrated sulfuric acid followed by dilution with water at modest temperatures, provides complete and rapid conversion to glucose, with little degradation. Most of the research on this approach after 1918 has been performed on agricultural residues. In 1937 the Germans built commercial-scale plants based on the use and recovery of hydrochloric acid. Work at the United States Department of Agriculture laboratory in Peoria, Illinois further refined the concentrated sulfuric acid process. The Japanese then introduced membranes to separate the sugar from the acid in the product stream. Further improvements were made in the United States by Purdue University and by the Tennessee Valley Authority (TVA). Minimizing the use of sulfuric acid and recycling it effectively are critical factors in the economic viability of the process.

Concentrated acid methods will be used by Arkenol in its rice-straw-to-ethanol plant at Rio Linda in Sacramento County, California and by the Masada Resource Group in its MSW-to-ethanol facility in Orange County, New York. Arkenol plans to recover citric acid and amorphous silica from the rice straw as co-products**.** Masada plans to recover and sell gypsum and carbon dioxide as co-products.

Dilute Acid Hydrolysis

Dilute acid hydrolysis is the oldest technology for converting biomass to ethanol. Begun in Germany in 1898, the process was developed further there and in the United States by the USDA's Forest Products Laboratory and at TVA facilities. A dilute solution of sulfuric acid (H_2SO_4) percolating through a bed of wood chips was found by 1952 to be a simple and effective reactor design. Petroleum shortages of the 1970s renewed interest in this technology under USDA and DOE sponsorship. By 1985, the limits of the percolation designs were recognized: their 70% glucose yields were achieved by producing highly dilute sugar streams. Attention shifted to higher solids concentrations, countercurrent flow, and shorter processing times (6 to 10 seconds) at higher temperatures (around 240° C.) Most current designs use two stages of hydrolysis, the first at milder conditions to maximize the yield from hemicellulose, while conditions in the second stage are optimized for the cellulose fraction. This is diagrammed in Figure V-1 (from Ref. V-2). Both of these hydrolyzed solutions are then fermented to alcohol.

Lime used to neutralize residual acids before the fermentation stage is converted to gypsum for sale as a soil amendment, or for disposal. Residual cellulose and lignin are used as boiler fuel for electricity or steam production.

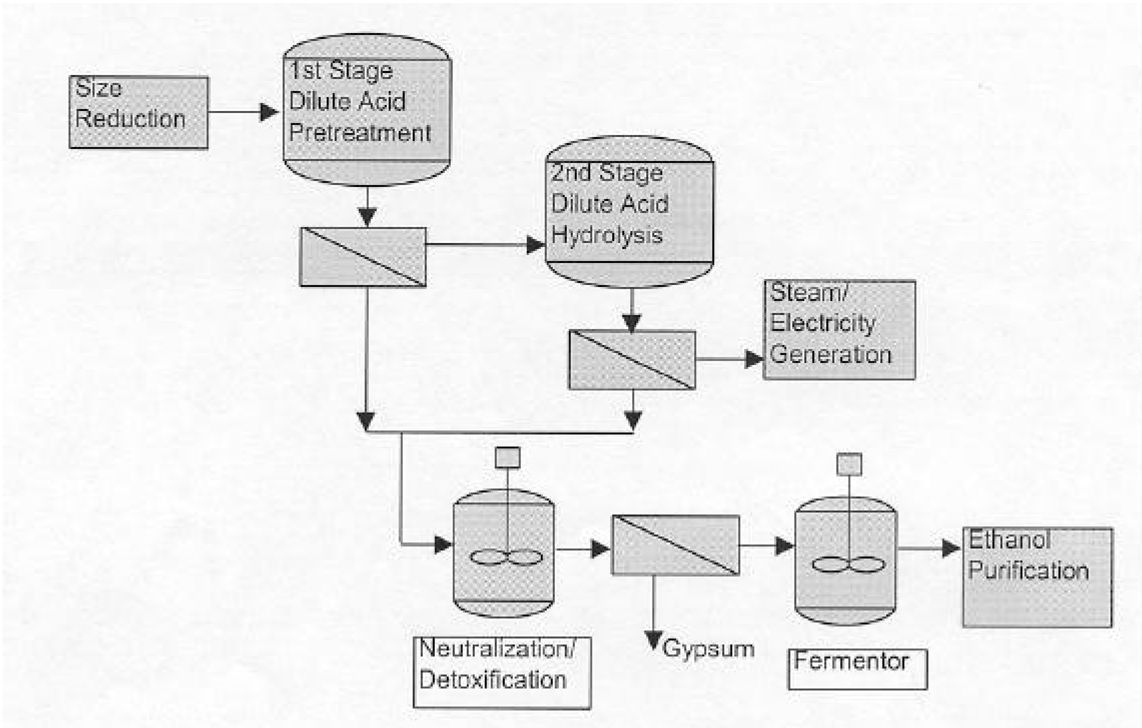


Figure V-1: General Schematic of Two-Stage Dilute Acid Hydrolysis Process (from Ref. V-2)

BC International (BCI) and the DOE Office of Fuel Development have formed a cost-shared partnership to develop a 20 million gallons per year biomass-to-ethanol plant in Jennings, LA. Dilute acid hydrolysis will be used to recover sugar from bagasse (sugar cane wastes) and rice hulls, and a proprietary, genetically-engineered organism will ferment the sugars from bagasse and rice hulls to ethanol.

BCI presently plans to use two-stage dilute sulfuric acid technology with rice straw and wood wastes as the feedstocks in the Gridley biomass-to-ethanol facility collocated with the Pacific Oroville Power Plant. If enzymatic hydrolysis (to be discussed) proves soon to be reliable and cost-effective, then one-stage of dilute acid pretreatment followed by enzymatic hydrolysis will be considered as an alternative.

The Collins Pine/BCI project in Chester, CA, is also collocated with an electric power plant. The plan is to pretreat the softwood feedstocks with dilute sulfuric acid, followed by enzymatic hydrolysis and fermentation of sugars to ethanol (using proprietary bacterial enzymes). The softwood extractives will be converted to two or three chemical co-products: the beginnings of a California forest waste biorefinery.

Tembec and Georgia Pacific operate sulfite pulp mills that use dilute acid hydrolysis to dissolve hemicellulose and lignin from wood and produce specialty cellulose pulp. The hexose sugars in the spent sulfite stream are fermented to ethanol. The lignin is either burned to produce process steam or converted to value-added products such as dispersing agents or animal feed binders.

A dilute acid hydrolysis process using nitric acid, rather than sulfuric acid, was developed at the University of California and licensed to HFTA of Oakland, CA. Its stated economic advantages include being less corrosive to steel (permitting lower capital costs), no gypsum produced for landfill, and less use of acids and neutralizing chemicals. The Northeastern California Ethanol Manufacturing Feasibility Study (Ref. V-5) prepared by the Quincy Library Group and other organizations evaluated nitric acid hydrolysis comparably with processes using dilute and concentrated sulfuric acids.

V 1.3 Hydrolysis Combined with Fermentation

In the fermentation step, sugars are converted by yeast into ethanol. This production step may follow hydrolysis or it may be combined with enzymatic hydrolysis.

Two widely-held convictions among many informed workers on biomass-to-ethanol conversion are: (1) that biological processes offer more promise than chemical processes for effecting large changes in the economics of production; and (2) that the integration of two or more steps (or consolidation of all steps) will result in increased efficiency of conversion and large cost savings.

The following paragraphs provide a simplified introduction to two developments that can qualitatively and quantitatively change the economic competition between biomass-derived and petroleum-derived fuels. The first is enzymatic hydrolysis. The second is direct microbial conversion. Both will be discussed below.

Interest in enzymatic hydrolysis of cellulose began in the South Pacific during World War II, when an organism now called Trichoderma reesei destroyed cotton clothing and tents. The U.S. Army laboratory at Natick, Massachusetts set out to understand the action of this fungus and to harness it. It found that the fungus produces enzymes that hydrolyze cellulose. The enzymes are protein chemicals that consist of a chain of amino acids. They are known as “cellulases” because of their effectiveness in hydrolyzing cellulose. Subsequent generations of cellulases have been developed with significantly increased effectiveness that has found commercial applications.

The first application of enzymes to the hydrolysis of wood for ethanol production was simply to replace the acid hydrolysis step with an enzymatic hydrolysis step. This process configuration is now known as Separate Hydrolysis and Fermentation, SHF. Pretreatment of the biomass, as discussed above, is performed to make the cellulose more accessible to the enzymes.

Subsequently an important process improvement was made by Gulf Oil Company and the University of Arkansas known as Simultaneous Saccharification (sugar-making) and Fermentation, SSF. This process configuration reduces the number of reactors by using one vessel for both hydrolysis and fermentation, which minimizes or avoids the problem of product inhibition associated with sugar buildup. In the SSF approach, cellulase enzymes and fermenting microbes are combined. As sugars are produced by the enzymes, the fermenting organisms convert them to ethanol.

More recently, the SSF process has been improved to include the cofermentation of both five-carbon and six-carbon sugars. This new variant of SSF, sometimes known as SSCF for Simultaneous Saccharification and CoFermentation, is shown schematically in Figure V-2. Note that SSCF combines hydrolysis (of hemicellulose and cellulose to sugars) and fermentation (of all sugars to ethanol) in one vessel, reducing capital costs, and by fermenting the sugars as soon as they form, eliminating problems associated with sugar accumulation and enzyme inhibition.

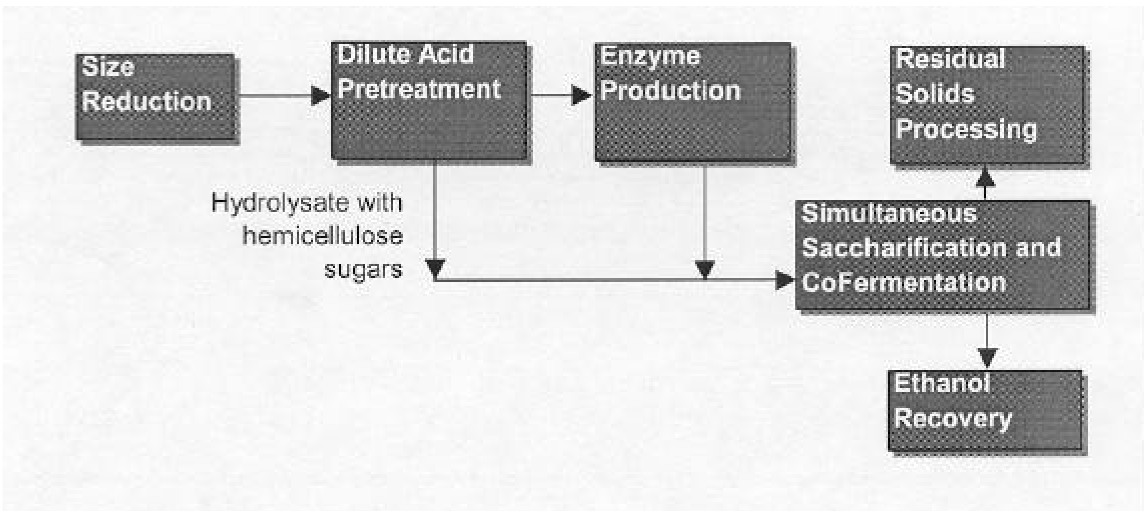


Figure V-2: The Enzyme Process Configured for Simultaneous Saccharification and CoFermentation (SSCF) (from Ref. V-2)

There are many feedstock options for enzymatic hydrolysis, including agricultural residues, paper wastes, wood wastes, green wastes, industrial process wastes, and energy crops. Feedstocks must first be milled to reduce the particle size of the biomass to allow more complete access to its porous structure. The biomass is then pretreated by dilute sulfuric acid or another economically viable method to hydrolyze the hemicellulose into sugars and make the cellulose available for hydrolysis. The pretreated material is then inoculated with an enzyme and fermenting agent such as a recombinant yeast, to hydrolyze the cellulose to sugar under mild temperature and pressure conditions, and to ferment all the sugars to ethanol. The remaining solids, mostly lignin, are separated out, dried and used as fuel for power, or possibly for co-products. The ethanol is distilled to the concentration and purity required for its use as a transportation fuel.

In 1997, Petro-Canada signed an agreement with Iogen Corporation to co-fund development of a biomass-to-ethanol technology based on Iogen’s proprietary cellulase technology, and with the aid of the Canadian government, to begin construction of a demonstration plant in 1999. As previously mentioned, BC International intends to begin operation of their plant in Jennings, LA using dilute acid hydrolysis technology, but they will allow for the utilization of enzymatic hydrolysis when cellulase production becomes cost-effective.

Thus, two-stage dilute acid pretreatment and hydrolysis is a process available for near-term plant construction and operation. Single-stage dilute acid pretreatment followed by enzymatic hydrolysis (SHF) may be a near-term option or, more likely, a mid-term plant adaptation, if the price of producing cellulases with the required activities is significantly reduced. SSCF is not likely as a near-term option, but it may well qualify as an mid-term method according to the definitions used in this report. SSCF is widely perceived as one of the most attractive development routes, but because a mixture (sometimes called a cocktail, or a consortium) of enzymes with the proper balance of activities is required, the development time to attain this balance of enzymatic activities at attractive production costs is uncertain.

Two observations are helpful in establishing a context for microbial conversions. The first observation, from NREL (Ref. V-2) says, “While our understanding of cellulase’s modes of action has improved, we have much more to learn before we can efficiently develop enzyme cocktails with increased activity.” The second, from Lynd, Elander, and Wyman (Ref. V-3) says, “few experts would doubt the achievability of creating organisms compatible with consolidated processing given a sufficient effort,” leaving open the question of what is a sufficient effort.

Direct Microbial Conversion (DMC)

When cellulase production (for the enzymatic hydrolysis of biomass feedstocks) and ethanol production are accomplished in a unit operation by a single microbial community, the process is called Direct Microbial Conversion (DMC). After mild pretreatment, the production of cellulase, hydrolysis of cellulose, and fermentation of all sugars are to be completed in one process step, called “consolidated bioprocessing”. This requires that the genetic engineering methods used to enable enzymatic hydrolysis be extended to grow robust organisms capable of performing a variety of functions at the same temperature, pressure, and pH conditions in a single vessel.

Direct microbial conversion saves on capital and operating costs by reducing the number of vessels and by obtaining enzymes from the fermenter organisms. Using fermenters that produce cellulase eliminates the need to divert a portion of the sugar stream for cellulase production, thereby increasing overall ethanol yield. Also, DMC methods can be used to produce a wide variety of value-added products.

The most crucial difficulty is in finding organisms that can perform all of the required functions robustly on a variety of feedstocks after mild pretreatments. Engineering fermenting organisms that produce cellulase in sufficient quantities to completely hydrolyze the cellulosic biomass is a key development. Lowering the cost of producing these organisms is another. If the required technological advances can be achieved through genetic engineering followed by cost reductions through improved practice, then consolidated bioprocessing (or variations thereon, for inclusion in a biorefinery) can serve as a model for what might be achieved long-term in the California biomass-to-ethanol industry.

An example given in Reference V-3, for a large biomass-to-ethanol plant operating on poplar as an energy crop, if adapted to smaller plants in California using agricultural, urban, or forest wastes as feedstocks, suggests an eventual cost around 50 cents per gallon for producing ethanol, using advanced methods in a mature industry.

V 1.4 Gasification Followed by Fermentation

A different approach from the pretreatment and hydrolysis methods described above is outlined here. Gasification-fermentation first converts biomass into smaller component molecules including carbon monoxide (CO), carbon dioxide (CO_2), and hydrogen (H_2) gases by heating to suitably high temperatures. In a later stage, the process reassembles these molecules into ethanol by fermentation processes different from those described above.

The production of a mixture of CO, CO_2, H_2 and other gases, collectively called "synthesis gas", benefits from gasification technology developments over the past several decades at large-scale demonstration facilities and commercial plants operating on fossil feedstocks such as coal. After gasification of the biomass, anaerobic bacteria are used to convert the resulting synthesis gas into ethanol (C_2H_5OH). High rates of conversion are obtained because the rate-limiting process in this fermentation method is the relatively fast transfer of gas into the liquid phase compared to the rate of fermenter action on carbohydrates.

Bioengineering Resources, Inc. (BRI) has developed synthesis gas fermentation technology that can be used to produce ethanol from a variety of waste biomass feedstocks. Plans are underway to pilot the technology as a step toward commercialization. The yields can be high (a figure of 136 gallons of ethanol per ton of feedstock is projected) because all of the major biomass fractions, hemicellulose, cellulose, and lignin can be converted to ethanol. BRI has developed reactor systems that require less than a minute for fermentation at elevated pressure, resulting in reduced equipment costs.

V-2 Biorefineries

In the main text, we have several times referred to biorefineries designed to produce ethanol, electricity, and other chemical products from agricultural, forest, and urban wastes, as the best framework in which to establish an economically and environmentally self-sustaining California biomass-to-ethanol industry. In this section we will pull together some of these thoughts, and list some of the products that might result from a California biorefining industry.

The two more mature industries with which California waste biomass-to-ethanol must compete, Midwest corn-to-ethanol and Mideast crude oil, *rely* on refineries producing a slate of products to maintain their present cost and pricing structure. A corn-to-ethanol company producing only ethanol, or a petroleum corporation producing only gasoline for automobiles, would not survive.

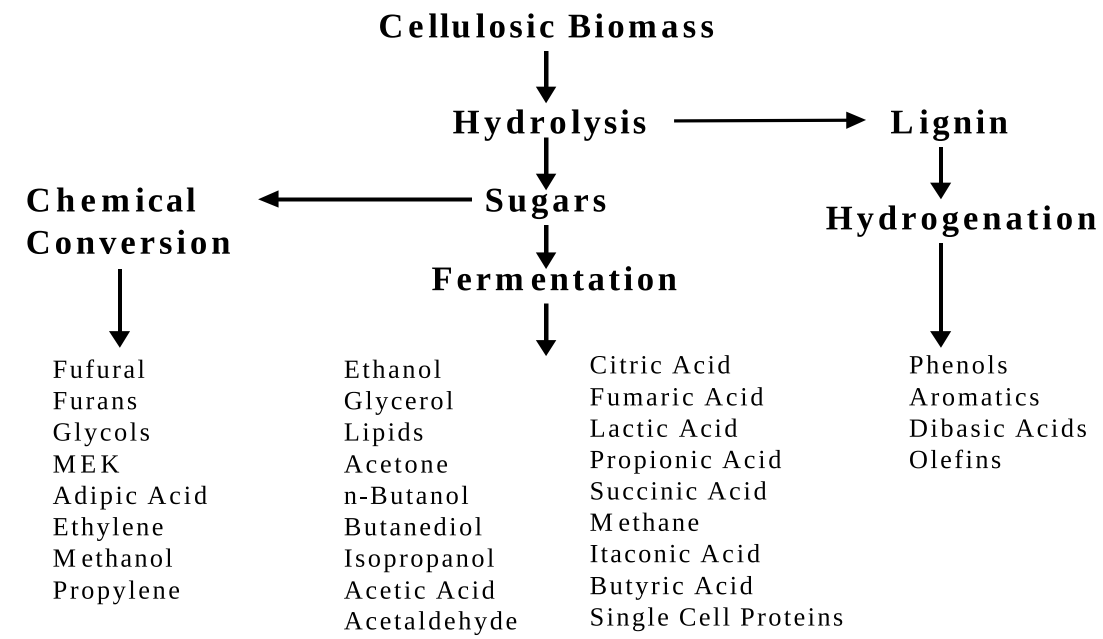
In these more mature industries, the cost of the feedstocks is said to be 65%-70% of the total production costs. The chemical components must be optimally used, and the levels of production of the product streams adapted to meet current market demands. A California waste biomass-to-ethanol industry must also make the best economic uses of the chemicals in its waste feedstocks. The industry should grow to adapt its output of various products to market demand.

In some projects, this process has already begun. The proposed California biomass-to-ethanol plants in Chester, CA (Collins Pine project) and in Oroville, CA (Gridley project) are both collocated with existing electric power plants. The biomass plant will utilize power from the electric plant, and will supply the electric plant with lignin as a high-energy fuel. Each is a customer of the other. This synergy from cogeneration results in reduced capital and operating costs that enable both plants to be more competitive. The next step is to produce along with ethanol, a slate of other chemical products. This is proposed by the SEP project in Rio Linda, CA and also by the Collins Pine project in Chester.

The SEP project, using the Arkenol concentrated acid process on rice residues and wood wastes as the feedstocks, plans to produce citric acid and amorphous silica from the rice straws as co-products**.** The Collins Pine project using California softwoods and lumber mill wastes as feedstocks, expects to produce several chemicals (as yet unspecified) from the extractives as co-products. These co-products can significantly improve the process economics, while separating off substances to facilitate further processing of the carbohydrate streams. State policies should permit the production of ethanol, electric power, and value-added co-products in biorefineries converting waste biomass. In seeking financing for biomass-to-ethanol projects, value-added co-products may be viewed as upside potential.

The purpose of a refinery is to process all of the chemical components (fractions) to their highest and best (most profitable) end uses. For biomass, there are four major fractions: the hemicelluloses, cellulose, lignin, and extractives (defined in this section to include both organic and inorganic materials). A mature California waste-to-ethanol biorefinery should aim to make the best use of these four fractions. A chart (Figure V-3) provided by John Ferrell of the US Department of Energy, Office of Fuels Development, possible chemical products from the cellulose, hemicellulose, and lignin, especially lists some of the illustrating the versatility of the cellulose fraction. Some of these products, and certainly the sum of these products, have the market sizes to assist California in sustaining a long-term, profitable presence in biomass conversion, sometimes referred to as the “carbohydrate economy”.

Figure V-3
Conversion of Biomass to Chemicals & Fuels



This discussion of the four fractions of lignocellulosic materials begins with extractives (usually less than 5% of the dry weight, but in some feedstocks, up to 25%) because these are the least-known fraction, and often the first to be separated off. Extractives from softwood wastes can be converted to high value products, some of which (terpenes, maltol, resin acids) have already been commercialized successfully. Candidate co-products include: azelaic acid for biodegradable lubricants ($4/lb.); oxyalcohols; terpenic products, such as sitosterol, a hormone precursor and texturing agent (over $100/lb.); gallic acids, which are phenol derivatives that sell for $10-$20/lb.; specialty chemicals, such as cyclotene and maltol (over $100/lb.); resin acids and their derivatives, some of which are marketed as surfactants at $5-$10/lb.; polyphenols, such as proanthocynadins, in the $100/lb. range; and pharmaceuticals from specific conifers (taxols, from Northwest yew trees are the best-known example.) (Ref. V-6)

This list is not intended to put stars in the eyes of potential owner-operators, for most waste feedstocks contain only a few weight percent in extractives; California softwoods average about 4%-5%. Even a few percent of products at the listed prices can make a significant difference in plant economics. But customers must be found and markets developed. Silica, an inorganic material that is present up to 25% in rice straw and hulls, can be viewed as "ash" or as an inorganic extractive available for potential commercialization. Though chemical products from extractives may help a California biomass-to ethanol industry get underway profitably, it is the specialty and commodity chemicals with large, long-term and growing markets that may aid in sustaining the industry through economic cycles.

The two most important fractions for the production of ethanol and other chemical products from biomass are the hemicelluloses (typically 15% to 30% of the dry weight) and cellulose (typically 35% to 50% of the dry weight). The hemicelluloses are easier to hydrolyze, but until recently, more difficult than cellulose to ferment to ethanol. That has changed recently with the development of bacterial enzymes that simultaneously ferment both five-carbon and six-carbon sugars (Refs. V-7, V-8, V-9) The "highest and best" use for the hemicellulose fraction of California waste biomass remains conversion into ethanol transportation fuel.

Cellulose presents more alternatives to the owner-operator. Conversion to ethanol transportation fuel is an excellent choice: it is technically feasible, environmentally desirable, and perhaps the most economically advantageous choice for a California waste biomass-to-ethanol program. Cellulose is also used to produce pulp, paper, and textiles. Cellulose derivatives, such as glucose, can be processed into a variety of useful, high volume products, including animal feeds.

A thorough assessment of alternative feedstocks by scientists and engineers from five national laboratories (Ref. V-10) identified several classes of chemicals, including organic acids (such as succinic and levulinic acids) and neutral solvents (such as butanol and acetone), that may be produced competitively from cellulosic biomass, using glucose syrup as the primary feedstock. Chemicals such as acetaldehyde, acetic acid, glycerol and isopropanol can also be produced by biomass refineries. (Ref. V-11) Adhesives, biodegradable plastics, biocompatible solvents, degradable surfactants, and enzymes may also be considered. Thus, the owner-operator of a suitably configured biomass refinery will have opportunities for diversification, if future markets dictate.

The lignin fraction (perhaps 15% -30% of the dry weight) is usually planned as an energy source for the biorefinery, or for a collocated electric power plant. This is in all likelihood, the best use for lignin in the current generation of biomass-to-ethanol plants. Other present conversions of lignin by the pulp and paper industry are to products such as dispersing agents, animal feed binders, concrete additives, drilling mud additives, and soil stabilizer. (Ref. V-2)

A biorefinery concept proposed for Quebec would produce lignin derivatives, cellulose fibers for food products, and lignin derivatives for pharmaceutical applications. (Ref. V-11) Elements of this Lignix process have been proven commercially, however, the entire process remains to be tested at the pilot plant stage. In the future, the owner-operator of a biorefinery can consider the use of some fraction of the lignin for adhesives, for particle board, for production of oxyaromatics (such as vanillin), or even possibly for octane enhancers, to advance the goals of a California clean fuel industry.

This brief summary in Section V-2 is meant to suggest that even in the short-term and especially in the mid-term, there are opportunities for entrepreneurs to benefit by developing California waste-biomass-to-ethanol facilities as biorefineries. The capital and operating costs will be higher than those for a single-product plant, reflecting the costs of equipment and labor to process the additional product streams. But, as experience in the petroleum and corn-to-ethanol industries has shown, profits will also be higher, and there will be valuable flexibility to adapt and survive profitably in changing markets.

V-3 Technology Improvements in a Mature Industry

Four technological trends leading toward the development of a profitable biomass-to-ethanol industry for California have been identified in preceding sections. These are: (1) improved pretreatment, (2) increasing use of genetically-engineered organisms with improved properties for hydrolysis and fermentation of cellulosic biomass, (3) integrating process steps to reduce capital and operating costs, and (4) producing ethanol from waste biomass in a biorefinery.

The first three trends lead to cost reductions and improved profitability through advances such as commercial-scale Simultaneous Saccharification and CoFermentation (SSCF), with possible subsequent consolidation of the key processes (including cellulase production) into a single vessel for Direct Microbial Conversion (DMC). The fourth trend encourages the best economic and environmental use of *all* chemical components of the waste biomass: hemicellulose, cellulose, lignin, organic and inorganic extractives.

Within these primary trends, there are a variety of alternative, often complementary research and development paths toward the goal of very low cost production of ethanol from waste biomass. Several of these, as listed by Prof. Lynd of Dartmouth (Ref. V-12), are reduction of milling costs, pretreatments to render cellulose more reactive, a low-cost method for recycling cellulase, and higher-temperature fermentation. A breakthrough in one such area has the potential to lessen or eliminate difficulties in other areas. This diversity of activity increases the overall probability of developing low-cost biomass-to-ethanol technology.

Approaches that have the largest economic impact reduce the cost of making biomass fermentable. Consolidated bioprocessing is the preferred strategy of Prof. Lynd, because he believes that "it offers the potential for a streamlined process that takes full advantage of the power of biotechnology for efficient and low-cost catalysis." This path requires the development, through genetic engineering of robust microorganisms for producing cellulases, hydrolyzing carbohydrates, and fermenting five-carbon and six-carbon sugars in a single reactor.

What are the potential cost reductions for ethanol production that may result from the anticipated improvements in technology when these are incorporated into a mature biomass industry? In the literature, there are several fairly consistent estimates by respected scientists, engineers, and research organizations.

The National Renewable Energy Laboratory (Ref. V-13) has set cost reduction targets of about 50 cents per gallon for technology cost savings by the year 2005, and about 60 cents per gallon by the year 2010. On this or a somewhat longer time-scale, Drs. Lynd, Elander, and Wyman (Ref. V-3) estimate production costs of about 52 cents per gallon using consolidated bioprocessing with poplar trees as the energy crop for a very large facility.

In comparison, California has the advantage of using much lower-cost (waste) feedstocks, but may not be able to realize the advantages of scale accruing to larger plants (greater than 100 million gallons per year production). In petroleum and corn processing, about 65%-70% of the total production costs are attributable to feedstocks, so in this respect, the use of waste biomass is a significant advantage.

The above improvements in production costs are attributed to anticipated improvements in the conversion of cellulosic biomass to ethanol. They do not include the effects of producing the ethanol in a biorefinery that benefits from the production of electricity and added-value co-products. For an estimate of the impact of biorefining on a mature industry, we use values provided by Elander and Putsche in Ref. V-14 and by Katzen in Ref. V-15 for the advantage in unit production costs of (more capital-intensive) wet-milling of corn, compared to the older dry-milling process.

Wet-milling facilities are corn biorefineries. They can produce ethanol from corn at a cost 10 cents to 19 cents per gallon less than the dry-milling facilities that produce only ethanol and DDGS. The co-products from cellulosic biomass will be different from those from corn, but we assume comparable impacts on the cost of producing ethanol**.** When a single figure is required, 15 cents per gallon may be assumed as the estimated average reduction in cost of producing ethanol, when the ethanol production is accomplished within a biorefinery, but a range of zero to 30 cents per gallon cost reduction is plausible.

One final observation: combining the estimate of 52 cents per gallon for ethanol production costs from a mature biomass-to-ethanol plant, with a reduction of perhaps 15 cents per gallon in “net feedstock costs” for the economic benefits of selling co-products from a biorefinery, results in a (most optimistic?) projection of 37 cents per gallon for delivered feedstock plus processing costs in a technologically-mature waste biomass-to-ethanol plant. Is this a reasonable estimate for total production costs in the years 2010-2020, when 65%-70% of the total costs may be those for collecting, transporting, sorting and delivering the biomass wastes used as feedstocks? It makes 50 cents per gallon appear to be a very difficult, but perhaps achievable goal.

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Appendix VI-A

Composition and Yields of Biomass Resources

Each of the twelve biomass Resource Categories listed in Table VI-1 contains several individual species of trees and crops, or types of municipal waste. This is detailed in Table VI-A-1 compiled by Quang Nguyen of NREL, which presents the average compositions and theoretical ethanol yields for many of the individual feedstocks included in the Resource Categories of Table VI-1. Within these averages for each species, there is much variability, so that each individual biorefinery must perform statistical samplings adequate to characterize its intended sources of feedstock.

The glucan, mannan, and galactan in the top row of the chart are hydrolyzed to six-carbon sugars (hexoses), and the xylan and arabinan are hydrolyzed to five-carbon sugars (pentoses.) The hexoses plus pentoses sum to total carbohydrates. The sugars are then fermented to ethanol with conversion efficiencies to be discussed below.

The Theoretical Ethanol Yield given in the last column of Table VI-A-1 (gal/OD ton is the same as gal/bdt) is the quantity of ethanol that would be produced by 100% efficient chemical conversion of the total carbohydrates, hexoses plus pentoses, to ethanol. The figures for Theoretical Ethanol Yield range from a maximum of 150.0 gal/bdt through 112.8 for mixed softwood thinnings, to 109.0 (est.) for typical municipal solid wastes (MSW), down to 96.1 for newspaper and 87.4 gal/bdt for rice straw**.** Potential sources such as sugar beets, algae, sewage sludge, cattle manure, and chaparral are not listed in Table VI-A-1.

The calculation of ethanol production potentials in Table VI-A-1 utilizes expected yields (conversion efficiencies) for commercial systems, as provided by M. Yancey and A. Aden of the National Renewable Energy Laboratory for the 12 major Resource Categories of California waste biomass. These were provided for two time periods. The near-term yields are based on current NREL 2-stage dilute acid experimental and modeling work. The mid/long-term yield estimates are based on NREL goals for the SSCF process (1-stage dilute acid followed by enzymatic hydrolysis with simultaneous co-fermentation). The process assumptions on which these yields are based are tabulated below.

Yields for	Near-Term Conversion		Mid/Long-Term Conversion	
	Sugar Yield	Ethanol Yield	Sugar Yield	Ethanol Yield
Glucan to Glucose	60%	90%	90%	95%
Mannan to Mannose	90%	90%	85%	95%
Galactan to Galactose	90%	90%	85%	95%
Xylan to Xylose	80%	75%	85%	95%
Arabinan to Arabinose	80%	0%	85%	95%

Table VI-A-1

Composition of Lignocellulosic Biomass and Theoretical Ethanol Yield

(compiled by Quang Nguyen, NREL)

Feedstock	(Percent dry weight of unextracted feedstock)								(kg/metric ton OD feedstock)			(gal/OD ton)
	Glucan	Mannan	Galactan	Xylan	Arabinan	Total lignin	Ash	Extractive	Total hexose	Total pentose	Total carbohydrate	Theoretical Ethanol Yield
Un-coated Free Sheet	74.9	2.7	0.3	8.9	0	5.3	7.7		865.5	101.1	966.6	150.0
Packaging Papers	66.2	3.2	0.6	6.6	0.6	15.6	0.7		777.7	81.8	859.5	133.4
Aspen wood	50	2	1.5	18	4	18	0.8		594.4	249.9	844.3	131.0
Yellow poplar	49.9	4.7	1.2	17.7	1.8	18.1	0.5		619.9	221.5	841.5	130.6
CO Douglas fir (debarked)	43.6	13.3	4.5	6.4	4.7	24.6	0.3	4.4	682.2	126.1	808.3	125.4
White oak	43.6	2.9	0.4	18	2.4	23.2	0.6		521.1	231.7	752.8	116.8
Wheat straw	41	0	2.2	19	3.5	18	7.2		480.0	255.6	735.6	114.1
Radiata pine	43.9	11.6	2.5	6.1	1.6	27.9	0.3		644.4	87.5	731.9	113.6
Corn stover	40.9	0	1	21.5	1.8	16.7	6.3		465.5	264.7	730.2	113.3
QLG mixed softwood forest thinnings	43.3	10.2	2.8	7.4	1.5	28.6	0.9	5	625.5	101.1	726.6	112.8
CA Ponderosa pine (whole tree)	42.6	10.5	3.3	7.4	1.5	28.5	0.7	4.1	626.6	101.1	727.7	112.9
Hybrid poplar N11	51.8	0.3	0.7	11.3	0.3	22.5	0.6		586.6	131.8	718.4	111.5
Hybrid poplar NE388	48.6	0.5	0.3	14.6	0.3	21.8	0.7		548.8	169.3	718.1	111.4
MSW*	41.7	5.3	0.8	13.3	1.8	24.2	4.8		531.1	171.5	702.6	109.0
CA White fir (whole tree)	40.7	10.4	3.2	7.3	1.2	29.9	0.6	3.3	603.3	96.6	699.8	108.6
Hybrid poplar DN-34	41.7	3	1	15.6	1.2	26.7	2.1		507.7	190.8	698.6	108.4
Un-coated Groundwood	49.7	5.5	0.7	5.2	0.7	29.3	4.9		621.0	67.0	688.1	106.8
Switchgrass	36.6	0	1.2	16.1	2.2	21.9	5.6		420.0	207.9	627.8	97.4
Coated Paper	46.8	2.3	0	7	0.7	19	24.1		545.5	87.5	633.0	98.2
Almond tree prunings	31.2	1.4	0.8	20.5	1.9	31.2	5.8		371.1	254.5	625.5	97.1
Newspaper	44.3	4.9	0.6	5.2	0.6	29.3	3.5		553.3	65.9	619.2	96.1
Rice straw	32	0.2	0.9	13.8	3.4	13.1	25		367.7	195.4	563.1	87.4

*Model MSW feedstock comprises of 35% fir (lumber waste) + 20% almond tree prunnings + 20% wheat straw + 12.5% office waste paper + 12.5% newsprint

Appendix VI-B

Location of Some Solid Waste Handling Facilities in California

The three maps and the table in this Appendix were provided by the California Integrated Waste Management Board (CIWMB) from its Solid Waste Information System (SWIS) database. The 426 entries in Table VI-B-1 are only a fraction of the solid waste handling facilities in California. The writers of this report are grateful to several members of the CIWMB for guidance in the selection of a portion of the information available, and especially to Steve Barnett of the CIWMB Information Management Branch for compiling the data in its present form.

The three maps show the locations in California of facilities characterized as solid waste transfer stations (Figure VI-B-1), materials recovery facilities (Figure VI-B-2), and solid waste landfills (Figure VI-B-3). These sites were chosen by further specifying the types of wastes handled at each site to be those considered suitable for biomass-to-ethanol conversion, as discussed below.

Table VI-B-1 contains information on 168 large volume transfer/processing facilities, 69 materials recovery facilities (MRFs, pronounced "murfs"), 187 solid waste landfills, and 2 wood waste disposal sites not contained in the preceding list. The information provided includes the activity designation (one of the 4 above), waste type handled, site name and location, operator name and address. Much more information is available, including phone numbers, if one wishes to learn the capabilities and interests of the site operators. Tonnages handled and tipping fees are provided for some of these facilities on the Internet at *http://www.ciwmb.ca.gov/landfills/* and in a monthly publication, the "Solid Waste Digest" (Pacific Region). The large numbers of composting facilities were not included in this table of candidate sites because the waste materials are already being recycled to advantage. Their eventual uses will be determined by economic considerations.

The large volume transfer/processing facilities (abbreviated LVT/PF in Table VI-B-1) serve as hubs for collection and processing. They can provide low cost, perhaps "negative cost" waste biomass feedstock if they already have, or are willing to add, the necessary sorting capabilities. MRFs are prime candidates for collocation with a biorefinery. Separation of the various categories of solid wastes is actively underway. It may be possible to customize the content of the streams to meet the process needs of an adjoining biorefinery. The owner of the MRF might be interested in becoming a partner of the combined operation.

Solid waste landfills (designated SWL in the table) receive a large fraction of the waste materials, but there is a State mandate to reduce the quantity of waste that will end in landfills. Some of the owner/operators of landfills may be willing to add capabilities and join in a venture that is legally defined as "diversion" of some of the materials transported to their facilities. They too may be willing to customize these sorting and processing activities to the needs of a nearby or adjacent large client biorefinery. The two wood waste disposal sites (WWDS) that conclude the list are those that were not otherwise listed in the categories requested.

The types of waste included in this request are agricultural wastes, green materials, wood mill wastes, mixed municipal wastes (a large fraction), and sludge. Facilities that handle manure and various other waste categories were not requested, but the information is there in the SWIS data base. The type of waste processed at each facility is listed in the second column of the table. Some of the sludge will not be a good candidate to provide biomass for conversion to ethanol, because of the amount of pretreatment needed; but other sources of sludge may be suitable for beneficiation and conversion.

Paper contaminated with food waste, grease, and liquids may be unattractive for recycling, but completely appropriate for ethanol production. The same may be said of some composting materials, where the presence of small amounts of contaminants, such as plastics, may make them unattractive for recycling, but suitable for conversion to ethanol and co-products.

The list of permutations and combinations of possibilities is large. A number of locations exist for facilities that may offer existing collection, sorting, and preprocessing infrastructure for the collocation of a biomass-to-ethanol plant. If some of these facilities can provide a “negative feedstock cost” in the near-term and a very low delivered feedstock cost long-term, they are worthy of careful consideration. The owner-operator may become a partner.

Figure VI-B-1

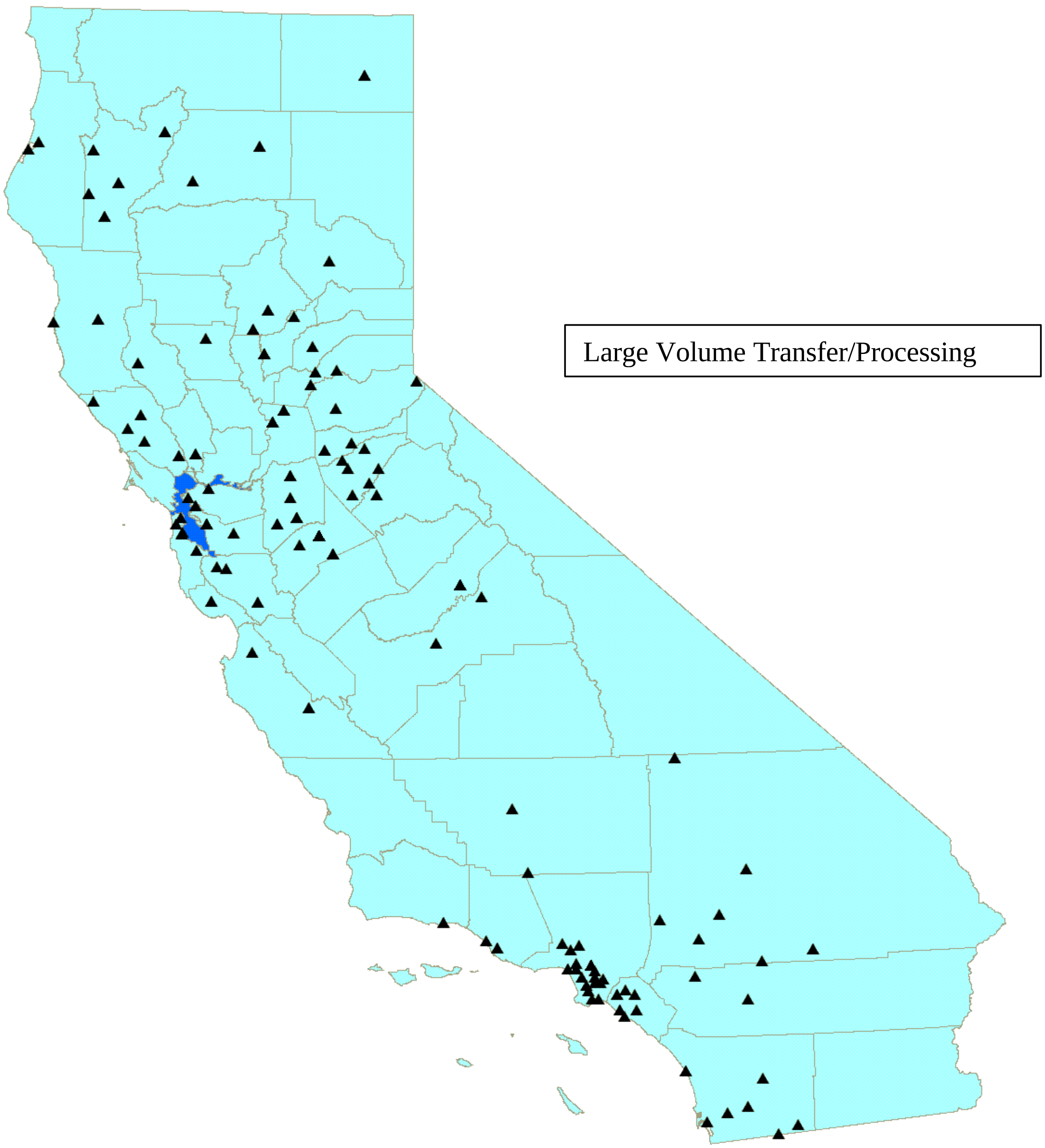

Figure VI-B-2

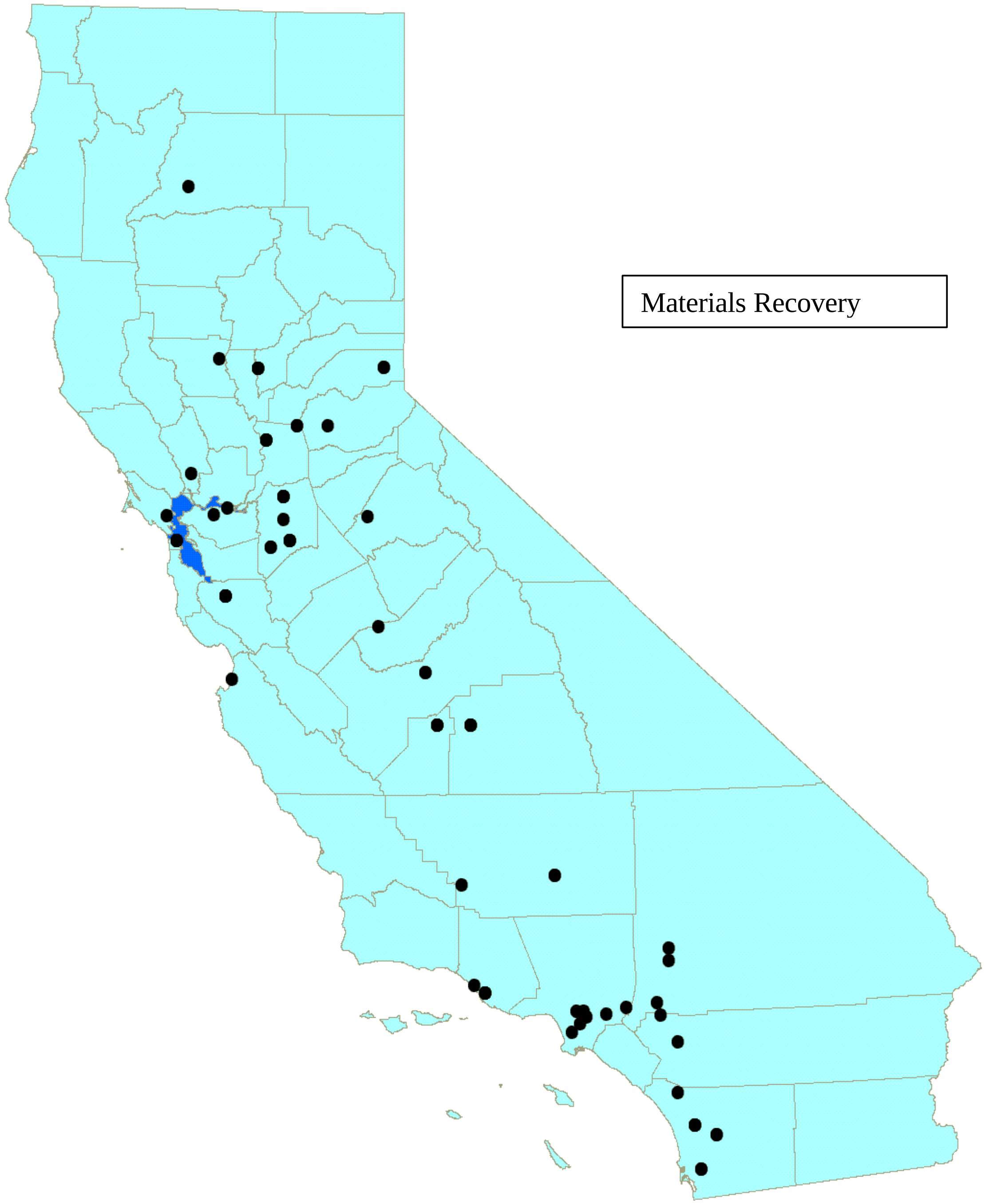

Figure VI-B-3

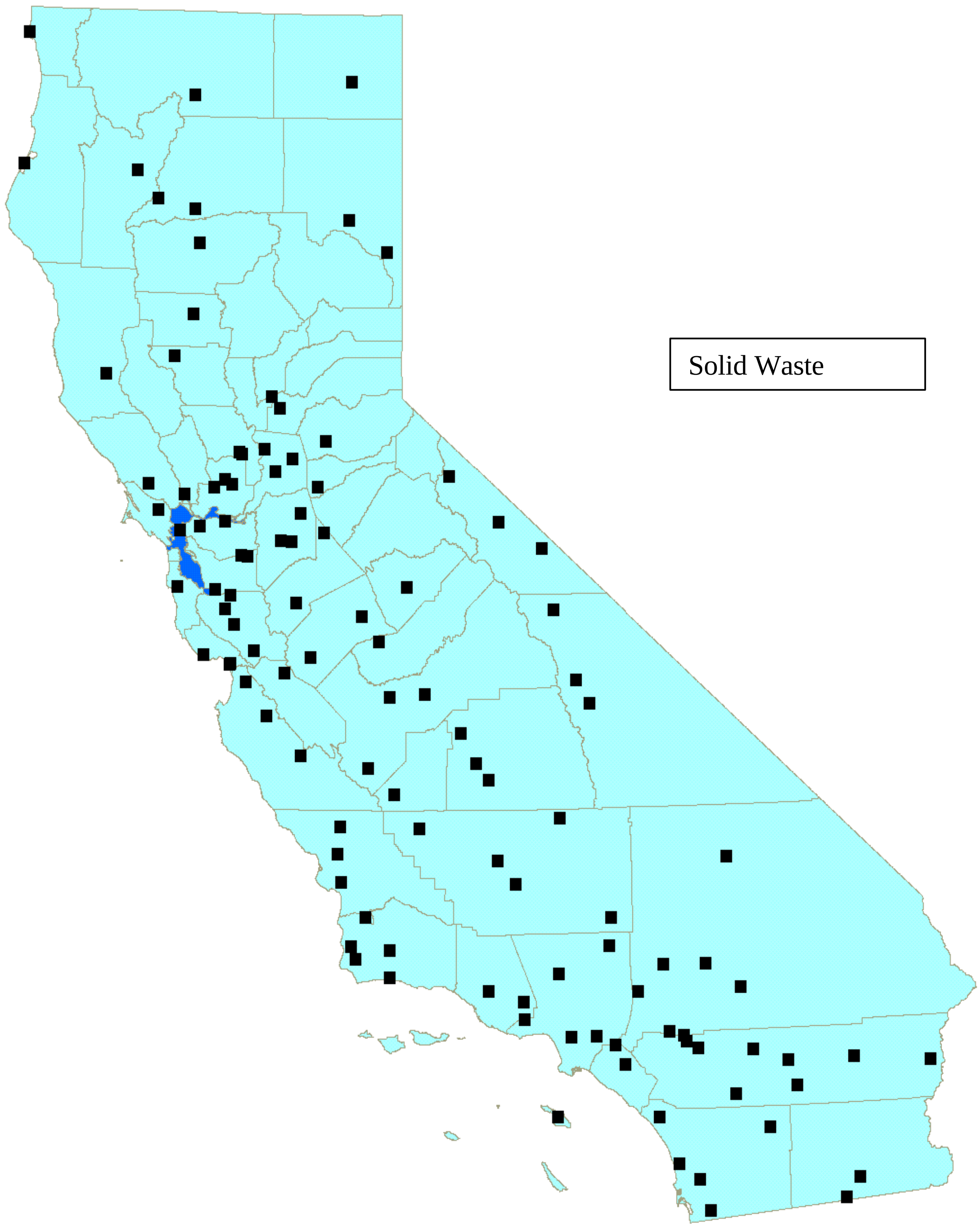

TABLE VI-B-1 **Location of Some Solid Waste Handling Facilities in California**

Activity	Waste	Site Name	RGS	Site location	PlaceName	Operator	OperatorCity
LVT/PF	Mixed Mun	PLEASANTON GARBAGE SERVICE SW TS	P	3110 BUSCH Rd	Pleasanton	PLEASANTON GARBAGE SERVICE, INC	PLEASANTON
LVT/PF	Green Mat	DAVIS ST TRANS STA/Res RECOV COMPLX	P	2615 DAVIS St	San Leandro	OAKLAND SCAVENGER Co	OAKLAND
LVT/PF	Mixed Mun	DAVIS ST TRANS STA/Res RECOV COMPLX	P	2615 DAVIS St	San Leandro	OAKLAND SCAVENGER Co	OAKLAND
LVT/PF	Wood mill	DAVIS ST TRANS STA/Res RECOV COMPLX	P	2615 DAVIS St	San Leandro	OAKLAND SCAVENGER Co	OAKLAND
LVT/PF	Green Mat	BERKELEY Solid wst Trnsf Statn	P	1109 SECOND St	Berkeley	CITY of BERKELEY Solid wst MGMT. DIV.	BERKELEY
LVT/PF	Mixed Mun	BERKELEY Solid wst Trnsf Statn	P	1109 SECOND St	Berkeley	CITY of BERKELEY Solid wst MGMT. DIV.	BERKELEY
LVT/PF	Mixed Mun	PINE GROVE Pub Trnsf Statn	P	14390 WALNUT St	Pine Grove	A.C.E.S., INC.	Jackson
LVT/PF	Agricultural	WERN AMADOR Rec Fac	P	6500 Buena Vista Rd	Ione	AMADOR Disp SERVICES	SUTTER CREEK
LVT/PF	Mixed Mun	WERN AMADOR Rec Fac	P	6500 Buena Vista Rd	Ione	AMADOR Disp SERVICES	SUTTER CREEK
LVT/PF	Agricultural	ORD RANCH Rd Trnsf Statn	P	E of HWY 99E- ORD RANCH Rd	Gridley	NORCAL Solid wst systm - Mrysvl	Mrysvl
LVT/PF	Mixed Mun	ORD RANCH Rd Trnsf Statn	P	E of HWY 99E- ORD RANCH Rd	Gridley	NORCAL Solid wst systm - Mrysvl	Mrysvl
LVT/PF	Green Mat	OROVILLE Solid wst Trnsf Statn	P	2720 S 5th Ave	Oroville	NORCAL Solid wst systm - OROVILLE	Oroville
LVT/PF	Mixed Mun	OROVILLE Solid wst Trnsf Statn	P	2720 S 5th Ave	Oroville	NORCAL Solid wst systm - OROVILLE	Oroville
LVT/PF	Mixed Mun	AVERY Trnsf Statn	P	SEGALE Rd NEAR MORAN RD	Avery	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Agricultural	SAN ANDREAS Trnsf Statn	P	4 MI N SAN ANDREAS ON HWY 49	San Andreas	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Mixed Mun	PALOMA Trnsf Statn	P	2 MI S PALOMA ON PALOMA Rd	Paloma	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Mixed Mun	COPPEROPOLIS Trnsf Statn	P	O'BYRNES FERRY Rd	Copperopolis	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Mixed Mun	WILSEYVILLE Trnsf Statn	P	W of STORE AND POST ofF	Wilseyville	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Mixed Mun	RED HILL Trnsf Statn	P	5314 RED HILL Rd	Vallecito	Co of CALAVERAS	SAN ANDREAS
LVT/PF	Mixed Mun	MAXWELL Trnsf Statn	P	HWY 99 NEAR MAXWELL	Maxwell	COLUSA Solid wst AND Rec, INC.	CORNING
LVT/PF	Mixed Mun	Contra Costa TS and Recvry	P	951 Waterbird Way	Martinez	BFI wst systm of North America	Los Angls
LVT/PF	Mixed Mun	CENTRAL PROCESSING Fac	P	101 Pittsburg	Richmond	W Co Res Recvry INC	RICHMOND
LVT/PF	Mixed Mun	S TAHOE REFUSE CO.,INC., T.S/MRF	P	RUTH AVE BTWN DUNLAP & 3rd St	S Lake Tahoe	S TAHOE REFUSE CO., INC.	S LAKE TAHOE
LVT/PF	Mixed Mun	WERN EL DORADO Recvry systm MRF	P	4100 Dimetrics Way	Diamond Sprg	WERN EL DORADO REG SYSTEM	Diamond Spr
LVT/PF	Mixed Mun	SHAVER LAKE Trnsf Statn	P	E of HWY 168-DINKEY CREEK RD	Shaver Lake	Co of FRESNO Pub WORKS	FRESNO
LVT/PF	Green Mat	RICE Rd RECYCLERY & Trnsf Statn	P	10463 NORTH RICE Rd	Fresno	BROWNING-FERRIS Inds of CALIF, INC	Sylmar
LVT/PF	Mixed Mun	CITY GARBAGE CO. of EUREKA Trnsf STN	P	949 W. Hawthorne St.	Eureka	CITY GARBAGE Co of EUREKA, INC.	EUREKA
LVT/PF	Mixed Mun	LEBEC INTERIM Trnsf Statn	P	300 Lfl Rd	Lebec	Co of KERN wst Mngmt DEPT.	BAKERSFIELD
LVT/PF	Mixed Mun	MCFARLAND-DELANO Trnsf Statn	P	11249 STADLEY AVE.	Bakersfield	Co of KERN wst Mngmt DEPT.	BAKERSFIELD
LVT/PF	Mixed Mun	LAKEPORT Trnsf Statn	P	910 BEVINS St	Lakeport	Co of LAKE	LAKEPORT
LVT/PF	Mixed Mun	Action Trnsf Statn	P	1449 W. Rosecrans Ave.	Gardena	RePub Services of California II, LLC	Gardena
LVT/PF	Mixed Mun	S GATE Trnsf Statn	P	9530 S GARFIELD AVENUE	S Gate	Co of Los Angls SANITATION DIST	WHITTIER
LVT/PF	Mixed Mun	CITY of SANTA MONICA Trnsf Statn	P	2500 Michigan Ave	Santa Monica	CITY of SANTA MONICA	SANTA MONICA
LVT/PF	Mixed Mun	Browning Fer Indst. Rec. & Transf.	P	2509 W ROSECRANS AVENUE	Compton	BROWNING-FERRIS Inds of CALIF, INC	Sylmar
LVT/PF	Mixed Mun	CITY of INGLEWOOD Trnsf Statn	P	222 W BEACH AVENUE	Inglewood	CITY of INGLEWOOD	INGLEWOOD
LVT/PF	Mixed Mun	BEVERLY HILLS REFUSE Trnsf Statn	P	9357 W THIRD St	Beverly Hills	CITY of BEVERLY HILLS	BEVERLY HILLS
LVT/PF	Mixed Mun	CULVER CITY Trnsf/Rec STATION	P	9255 W JEFFERSON BLVD	Culver City	CITY of CULVER CITY	CULVER CITY
LVT/PF	Mixed Mun	Downey Area Rec & Trnsf, Inc.	P	9770 Washburn Rd	Downey	CALSAN,INC	DOWNEY

LVT/PF	Mixed Mun	VAN NUYS St MDY	P	15145 OXNARD St	Van Nuys	CITY of Los Angls BUR of St MAINT	Los Angls
LVT/PF	Mixed Mun	EAST St MAINTENANCE DISTRICT YARD	P	452 SAN FERNANDO Rd	Los Angls	CITY of Los Angls BUR of St MAINT	Los Angls
LVT/PF	Mixed Mun	GRANADA HILLS St MDY	P	10210 ETIWANDA AVENUE	Northridge	CITY of Los Angls BUR of St MAINT	Los Angls
LVT/PF	Mixed Mun	SW St MDY	P	5860 S WILTON PLACE	Los Angls	CITY of Los Angls BUR of St MAINT	Los Angls
LVT/PF	Mixed Mun	PARAMOUNT Res Rec Fac	P	7230 PETTERSON LANE	Paramount	METROPOLITAN wst Disp CORP.	PARAMOUNT
LVT/PF	Mixed Mun	SERN CAL Disp Trnsf Statn	P	1908 FRANK St	Santa Monica	SERN CAL Disp	SANTA MONICA
LVT/PF	Mixed Mun	BEL-ART Trnsf Statn	P	2501 EAST 68TH St	Long Beach	ConSolidated Disp Services L.L.C.	Santa Fe Springs
LVT/PF	Mixed Mun	CARSON Trnsf Statn & MRF	P	321 W FRANCISCO St	Carson	CARSON Trnsf Statn & MRF	Torrance
LVT/PF	Mixed Mun	FALCON REFUSE CENTER, INC	P	3031 EAST "I" St	Wilmington	BFI wst systm of North America	Los Angls
LVT/PF	Mixed Mun	COMMUNITY Rec AND Res RECOV.	P	9147 DE GARMO AVENUE	Sun Valley	DE GARMO St DUMP	SUN VALLEY
LVT/PF	Mixed Mun	CENTRAL Los Angls Rec CNTR & T S	P	2201 WASHINGTON BOULEVARD	Los Angls	BLT ENTERPRISES	MONTEBELLO
LVT/PF	Mixed Mun	MISSION Rd Rec & Trnsf STATIO	P	840 S MISSION Rd	Los Angls	wst Mngmt INC - BRADLEY LF & MISS	SUN VALLEY
LVT/PF	Mixed Mun	ANGELUS WERN PAPER FIBERS, INC.	P	2474 PORTER St	Los Angls	ANGELUS WERN PAPER FIBERS, INC.	Los Angls
LVT/PF	Agricultural	NORTH FORK Trnsf Statn	P	33699 Rd 274	North Fork	MADERA Disp systm,INC.	MADERA
LVT/PF	Green Mat	NORTH FORK Trnsf Statn	P	33699 Rd 274	North Fork	MADERA Disp systm,INC.	MADERA
LVT/PF	Mixed Mun	NORTH FORK Trnsf Statn	P	33699 Rd 274	North Fork	MADERA Disp systm,INC.	MADERA
LVT/PF	Sludge	NORTH FORK Trnsf Statn	P	33699 Rd 274	North Fork	MADERA Disp systm,INC.	MADERA
LVT/PF	Mixed Mun	CASPAR Trnsf Statn	P	S END of PRAIRIE WAY	Caspar	CITY of FORT BRAGG & MENDOCINO Co	UKIAH
LVT/PF	Green Mat	Willits Solid wst Trnsf & Recy. Cen	P	350 Franklin Avenue	Willits	Solid wstS of WILLITS INC	Willits
LVT/PF	Mixed Mun	Willits Solid wst Trnsf & Recy. Cen	P	350 Franklin Avenue	Willits	Solid wstS of WILLITS INC	Willits
LVT/PF	Agricultural	ALTURAS Trnsf Statn	P	1 mile off Cty. Rd. 54 on Cty. Rd. 60	Alturas	Co of MODOC Pub WORKS DEPT	ALTURAS
LVT/PF	Mixed Mun	ALTURAS Trnsf Statn	P	1 mile off Cty. Rd. 54 on Cty. Rd. 60	Alturas	Co of MODOC Pub WORKS DEPT	ALTURAS
LVT/PF	Mixed Mun	SALINAS Disp, Trnsf & Rec	P	1120 MADISON LANE	Salinas	SALINAS Disp SERVICE, INC	SALINAS
LVT/PF	Agricultural	DEVLIN Rd Trnsf Statn	P	800 DEVLIN Rd	Napa	S NAPA wst Mngmt AUTHORITY	NAPA
LVT/PF	Mixed Mun	DEVLIN Rd Trnsf Statn	P	800 DEVLIN Rd	Napa	S NAPA wst Mngmt AUTHORITY	NAPA
LVT/PF	Mixed Mun	MCCOURTNEY Rd LARGE VOLUME T.S.	P	14741 WOLF MOUNTAIN Rd	Grass Valley	CO.of NEVADA, DEPT.of SAN. & TRANS.	NEVADA CITY
LVT/PF	Agricultural	STANTON Trnsf AND Rec CENTER #8	P	11232 KNOTT AVENUE	Stanton	CR Trnsf INC.	STANTON
LVT/PF	Mixed Mun	STANTON Trnsf AND Rec CENTER #8	P	11232 KNOTT AVENUE	Stanton	CR Trnsf INC.	STANTON
LVT/PF	Mixed Mun	RAINBOW Rec/Trnsf Statn	P	17121 NICHOLS AVENUE	Hunt Beach	RAINBOW Trnsf/Rec INC.	HUNT BEACH
LVT/PF	Wood mill	RAINBOW Rec/Trnsf Statn	P	17121 NICHOLS AVENUE	Hunt Beach	RAINBOW Trnsf/Rec INC.	HUNT BEACH
LVT/PF	Mixed Mun	CONSolidATED VOLUME TRANSPORTERS	P	1131 N. BLUE GUM St	Anaheim	Disp SERVICES, INC.	ANAHEIM
LVT/PF	Mixed Mun	SUNSET ENVIR INC TS/Res REC FAC	P	16122 CONSTRUCTION CIR W	Irvine	SUNSET ENVIRONMENTAL	IRVINE
LVT/PF	Mixed Mun	CITY of NEWPORT BEACH Trnsf Statn	P	592 SUPERIOR AVENUE	Newport Beach	CITY of NEWPORT BEACH	Newprt Bch
LVT/PF	Mixed Mun	ORANGE Res Recvry systm, INC.	P	2050 GLASSELL St	Orange	ORANGE Res Recvry systm, INC	ORANGE
LVT/PF	Mixed Mun	AUBURN PLACER Disp Trnsf Statn	P	12305 SHALE RIDGE RD	Auburn	AUBURN PLACER Disp SERVICE INC	AUBURN
LVT/PF	Mixed Mun	FORESTHILL Trnsf Statn	P	PATENT RD ofF TODD VALLEY RD	Foresthill	AUBURN PLACER Disp SERVICE INC	AUBURN
LVT/PF	Mixed Mun	MEADOW VISTA Trnsf Statn	P	COMBIE Rd AP# 72-030-02	Meadow Vista	AUBURN PLACER Disp SERVICE INC	AUBURN
LVT/PF	Mixed Mun	EAST QUINCY Trnsf Statn	P	ABERNATHY LANE	East Quincy	Co of PLUMAS	QUINCY
LVT/PF	Mixed Mun	IDYLLWILD COLLECTION STATION	P	28100 SAUNDERS MEADOW Rd	Idyllwild	Co of RIVERSIDE wst MGMT DEPT	RIVERSIDE
LVT/PF	Mixed Mun	MORENO VALLEY Trnsf & Rec FAC.	P	17700 Indian St	Moreno Valley	wst Mngmt of the Inland Valley	Hemet
LVT/PF	Green Mat	NORTH AREA Trnsf Statn	P	4450 ROSEVILLE Rd	N Highlands	Co of SACRAMENTO, Pub Works Dept.	SACRAMENTO
LVT/PF	Mixed Mun	NORTH AREA Trnsf Statn	P	4450 ROSEVILLE Rd	N Highlands	Co of SACRAMENTO, Pub Works Dept.	SACRAMENTO

LVT/PF	Wood mill	NORTH AREA Trnsf Statn	P	4450 ROSEVILLE Rd	N Highlands	Co of SACRAMENTO, Pub Works Dept.	SACRAMENTO
LVT/PF	Green Mat	S Area Trnsf Statn	P	8550 FRUITRIDGE Rd	Sacramento	Co of SACRAMENTO, Pub Works Dept.	SACRAMENTO
LVT/PF	Mixed Mun	S Area Trnsf Statn	P	8550 FRUITRIDGE Rd	Sacramento	Co of SACRAMENTO, Pub Works Dept.	SACRAMENTO
LVT/PF	Mixed Mun	HEAPS PEAK Trnsf Statn	P	HWY 18; 3 MI W of Running Springs	Lake Arrowhead		
LVT/PF	Mixed Mun	CAMP ROCK Trnsf Statn	P	CAMP ROCK Rd	Lucerne Valley	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Mixed Mun	NEWBERRY SPRINGS Trnsf Statn	P	Troy Rd and Poniente Drive	Newberry Sprngs	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Mixed Mun	Trails End(Morongo Valley)Trnsf St.	P	10780 Malibu Trail	Morongo Valley	Co of SAN BERNARDINO wst SYSTM DIV	San Bernardino
LVT/PF	Mixed Mun	Sheep Creek Trnsf Statn	P	10130 Buckwheat Rd	Phelan	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Agricultural	Twentynine Palms Trnsf Statn	P	7501 Pinto Mountain Rd	29 Palms	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Mixed Mun	Twentynine Palms Trnsf Statn	P	7501 Pinto Mountain Rd	30 Palms	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Agricultural	Trona-Argus Trnsf Statn	P	1 mi. north Argus,and 1 mi. W Trona	Trona	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Mixed Mun	Trona-Argus Trnsf Statn	P	1 mi. north Argus,and 1 mi. W Trona	Trona	San Bernardino Co. wst System Div.	San Bernardino
LVT/PF	Sludge	FIESTA ISLAND SLUDGE PROCESSING	UP	FIESTA ISLAND ON MISSION BAY	San Diego	CITY of SAN DIEGO	SAN DIEGO
LVT/PF	Mixed Mun	VIEJAS Trnsf Statn	P	7850 CAMPBELL RANCH Rd	Alpine	Allied wst Inds, Inc.	San Diego
LVT/PF	Green Mat	Barrettt Jnctn Rural Cont. Station	P	1090 BARRETT LAKE Rd	Barrett Jct	Allied wst Inds, Inc.	San Diego
LVT/PF	Mixed Mun	Barrettt Jnctn Rural Cont. Station	P	1090 BARRETT LAKE Rd	Barrett Jct	Allied wst Inds, Inc.	San Diego
LVT/PF	Mixed Mun	BOULEVARD RURAL Cont. Station	P	41097 OLD HIGHWAY 80	Boulevard	Allied wst Inds, Inc.	San Diego
LVT/PF	Mixed Mun	CAMPO RURAL CONTAINER STATION	P	1515 BUCKMAN SPRGS RD	Campo	Allied wst Inds, Inc.	San Diego
LVT/PF	Mixed Mun	JULIAN RURAL CONTAINER STATION	P	500 PLEASANT VIEW DRIVE	Julian	Ramona Lfl Inc.	San Diego
LVT/PF	Mixed Mun	UNIVERSAL REFUSE REMOVAL Rec & T.S	P	1001 W. BRADLEY AVENUE	El Cajon	UNIVERSAL REFUSE REMOVAL	EL CAJON
LVT/PF	Green Mat	COAST wst Mngmt Trnsf Statn	P	5960 EL CAMINO REAL	Carlsbad	COAST wst Mngmt, INC.	CARLSBAD
LVT/PF	Mixed Mun	COAST wst Mngmt Trnsf Statn	P	5960 EL CAMINO REAL	Carlsbad	COAST wst Mngmt, INC.	CARLSBAD
LVT/PF	Mixed Mun	San FRANCISCO SLD wst TRAN & REC Ctr	P	501 Tunnel Avenue	San Francisco	Sanitry FILL Co	San Francisco
LVT/PF	Agricultural	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	CO of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
LVT/PF	Mixed Mun	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	CO of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
LVT/PF	Wood mill	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	Co of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
LVT/PF	Agricultural	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
LVT/PF	Mixed Mun	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
LVT/PF	Wood mill	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
LVT/PF	Wood mill	EAST STOCKTON Trnsf & Rec STN	P	2435 EAST WEBER AVENUE	Stockton	E STOCKTON Trnsf & RECYCLE STATION	STOCKTON
LVT/PF	Mixed Mun	STOCKTON SCAVENGER ASSOC Trnsf Stn	P	1240 NAVY DRIVE	Stockton	STOCKTON SCAVENGER ASSOC INC	STOCKTON
LVT/PF	Agricultural	TRACY Mat Recvry & T.S.	P	30703 S. MACARTHUR DRIVE	Tracy	REPETTO M	TRACY
LVT/PF	Mixed Mun	TRACY Mat Recvry & T.S.	P	30703 S. MACARTHUR DRIVE	Tracy	REPETTO M	TRACY
LVT/PF	Mixed Mun	BLUE LINE Trnsf, INC	P	180 OYSTER POINT BLVD	S San Francisco	S SAN FRANCISCO SCAVENGER CO	S San Frncisco
LVT/PF	Mixed Mun	SAN BRUNO Trnsf Statn	P	1271 MONTGOMERY AVENUE	San Bruno	SAN BRUNO GARBAGE Co, INC	SAN BRUNO
LVT/PF	Mixed Mun	MUSSEL ROCK Trnsf Statn	P	1680 EDGEWORTH AVENUE	Daly City	BROWNING-FERRIS Inds of CALIF, INC	Sylmar
LVT/PF	Mixed Mun	S BAYSIDE Trnsf Statn	P	225 SHOREWAY Rd	San CarLos	BROWNING-FERRIS Inds, SAN CARLos	SAN CARLos
LVT/PF	Agricultural	SANTA BARBARA Co Trnsf Statn	P	4430 CALLE REAL	Santa Barbara	CO of SANTA BARBARA Trnsf Statn	S Barbara

LVT/PF	Mixed Mun	SANTA BARBARA Co Trnsf Statn	P	4430 CALLE REAL	Santa Barbara	CO of SANTA BARBARA Trnsf Statn	S Barbara
LVT/PF	Green Mat	SAN MARTIN Trnsf Statn	P	14070 LLAGAS AVENUE	San Martin	S VALLEY REFUSE Disp Co	GILROY
LVT/PF	Mixed Mun	SAN MARTIN Trnsf Statn	P	14070 LLAGAS AVENUE	San Martin	S VALLEY REFUSE Disp Co	GILROY
LVT/PF	Mixed Mun	SUNNYVALE Mat & RECVR'Y & TRNSFR ST	P	301 CARL Rd	Sunnyvale	CITY of SUNNYVALE	SUNNYVALE
LVT/PF	Green Mat	Mission Trail Trnsf Statn	P	1060 RICHARD AVENUE	Santa Clara	Mission Trails wst systm	Santa Clara
LVT/PF	Green Mat	BEN LOMOND Trnsf Statn	P	9835 NEWELL CREEK Rd	Ben Lomond	Co of SANTA CRUZ	SANTA CRUZ
LVT/PF	Mixed Mun	BEN LOMOND Trnsf Statn	P	9835 NEWELL CREEK Rd	Ben Lomond	Co of SANTA CRUZ	SANTA CRUZ
LVT/PF	Agricultural	BURNEY Trnsf Statn	P	RT 229; Adjcnt to Co Rd7P200	Burney	Co of SHASTA Pub WORKS DEP	REDDING
LVT/PF	Mixed Mun	BURNEY Trnsf Statn	P	RT 229; Adjcnt to Co Rd7P201	Burney	Co of SHASTA Pub WORKS DEP	REDDING
LVT/PF	Mixed Mun	CITY of REDDING Trnsf Statn/MRF	P	2255 ABERNATHY LN	Redding	CITY of REDDING	REDDING
LVT/PF	Mixed Mun	OCCIDENTAL Trnsf Statn	P	4985 STOETZ LANE	Sebastopol		
LVT/PF	Mixed Mun	GUERNEVILLE Trnsf Statn	P	POCKET DRIVE	Guerneville		
LVT/PF	Agricultural	SONOMA Trnsf Statn	P	STAGE GULCH Rd	Sonoma		
LVT/PF	Mixed Mun	SONOMA Trnsf Statn	P	STAGE GULCH Rd	Sonoma		
LVT/PF	Mixed Mun	HEALDSBURG REFUSE Trnsf Statn	P	166 ALEXANDER VALLEY Rd	Healdsburg		
LVT/PF	Mixed Mun	ANNAPOLIS Trnsf Statn	P	33551 ANNAPOLIS Rd	Annapolis		
LVT/PF	Agricultural	TURLOCK SCAVENGER Co Trnsf STATI	P	1100 S WALNUT	Turlock	Turlock Trnsf Inc.	Turlock
LVT/PF	Mixed Mun	TURLOCK SCAVENGER Co Trnsf STATI	P	1100 S WALNUT	Turlock	Turlock Trnsf Inc.	Turlock
LVT/PF	Wood mill	TURLOCK SCAVENGER Co Trnsf STATI	P	1100 S WALNUT	Turlock	Turlock Trnsf Inc.	Turlock
LVT/PF	Agricultural	MODESTO Disp SVC TS/RES REC FAC	P	2769 W HATCH Rd	Modesto	MODESTO Disp SERVICE	MODESTO
LVT/PF	Mixed Mun	MODESTO Disp SVC TS/RES REC FAC	P	2769 W HATCH Rd	Modesto	MODESTO Disp SERVICE	MODESTO
LVT/PF	Wood mill	MODESTO Disp SVC TS/RES REC FAC	P	2769 W HATCH Rd	Modesto	MODESTO Disp SERVICE	MODESTO
LVT/PF	Agricultural	GILTON Res Recvry/Trnsf FAC	P	800 MCCLURE Rd	Modesto	GILTON Res Recvry Fac, INC.	MODESTO
LVT/PF	Mixed Mun	GILTON Res Recvry/Trnsf FAC	P	800 MCCLURE Rd	Modesto	GILTON Res Recvry Fac, INC.	MODESTO
LVT/PF	Wood mill	GILTON Res Recvry/Trnsf FAC	P	800 MCCLURE Rd	Modesto	GILTON Res Recvry Fac, INC.	MODESTO
LVT/PF	Agricultural	BERTOLOTTI Trnsf & Rec CENTER	P	231 FLAMINGO DRIVE	Modesto	BERTOLOTTI Trnsf & Rec	CERES
LVT/PF	Mixed Mun	BERTOLOTTI Trnsf & Rec CENTER	P	231 FLAMINGO DRIVE	Modesto	BERTOLOTTI Trnsf & Rec	CERES
LVT/PF	Wood mill	BERTOLOTTI Trnsf & Rec CENTER	P	231 FLAMINGO DRIVE	Modesto	BERTOLOTTI Trnsf & Rec	CERES
LVT/PF	Green Mat	BURNT RANCH Trnsf St	P	HWY. 299, W. of BURNT RANCH	Burnt Ranch	Co of TRINITY	Weaverville
LVT/PF	Mixed Mun	BURNT RANCH Trnsf St	P	HWY. 299, W. of BURNT RANCH	Burnt Ranch	Co of TRINITY	Weaverville
LVT/PF	Mixed Mun	HAYFORK Trnsf St	P	EAST HWY 3; S of FAIRGROUNDS	Hayfork	Co of TRINITY	Weaverville
LVT/PF	Sludge	HAYFORK Trnsf St	P	EAST HWY 3; S of FAIRGROUNDS	Hayfork	Co of TRINITY	Weaverville
LVT/PF	Green Mat	HOBEL Trnsf Statn	P	HIGHWAY 3 S of TRINITY CENTER	Trinity Center	Co of TRINITY	Weaverville
LVT/PF	Mixed Mun	HOBEL Trnsf Statn	P	HIGHWAY 3 S of TRINITY CENTER	Trinity Center	Co of TRINITY	Weaverville
LVT/PF	Agricultural	RUTH Trnsf St	P	S of Ruth Res. Adjcnt state Hiwy	Ruth	Co of TRINITY	Weaverville
LVT/PF	Mixed Mun	RUTH Trnsf St	P	S of Ruth Res. Adjcnt state Hiwy	Ruth	Co of TRINITY	Weaverville
LVT/PF	Green Mat	VAN DUZEN Trnsf Statn	P	CO Rd 511, VAN DUZEN Rd	Mad River	Co of TRINITY	Weaverville
LVT/PF	Mixed Mun	VAN DUZEN Trnsf Statn	P	CO Rd 511, VAN DUZEN Rd	Mad River	Co of TRINITY	Weaverville
LVT/PF	Agricultural	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
LVT/PF	Green Mat	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
LVT/PF	Mixed Mun	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
LVT/PF	Mixed Mun	CAL SIERRA Trnsf Statn	P	19309 INDUSTRIAL DRIVE	Sonora	CAL SIERRA Disp, INC.	STANDARD

LVT/PF	Mixed Mun	GOLD COAST Rec Fac	P	5275 COLT St	Ventura (S Bnvnt)	GOLD COAST Rec INC.	VENTURA
LVT/PF	Agricultural	DEL NORTE REGIONAL Rec & Trnsf	P	111 S Del Norte Blvd.	Oxnard	BLT ENTERPRISES of OXNARD, INC.	Oxnard
LVT/PF	Mixed Mun	DEL NORTE REGIONAL Rec & Trnsf	P	111 S Del Norte Blvd.	Oxnard	BLT ENTERPRISES of OXNARD, INC.	Oxnard
LVT/PF	Green Mat	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
LVT/PF	Mixed Mun	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
LVT/PF	Wood mill	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
LVT/PF	Mixed Mun	PONDEROSA Trnsf Statn	P	PONDEROSA WAY	Brownsville	YUBA SUTTER Disp, INC.	Mrysvl
MRF		WADHAM ENERGY, LTD.	E		Colusa		
MRF		MT DIABLO PAPER STOCK & Rec CENTER	UP	4080 MALLARD DR	Concord	CONTRA COSTA wst SERVICES, INC.	CONCORD
MRF	Mixed Mun	Rec CENTER & Trnsf Statn	P	1300 LOVERIDGE Rd	Pittsburg	CONTRA COSTA wst SERVICES, INC.	CONCORD
MRF	Mixed Mun	WERN EL DORADO Recvry systm MRF	P	4100 Dimetrics Way	Diamond Springs	WERN EL DORADO REG SYSTEM	Diamond Spr
MRF	Mixed Mun	JEFFERSON AVENUE Trnsf Statn	P	5608 VILLA AVENUE	Fresno	WERN wst Inds/wst MGMT	TORRANCE
MRF	Wood mill	JEFFERSON AVENUE Trnsf Statn	P	5608 VILLA AVENUE	Fresno	WERN wst Inds/wst MGMT	TORRANCE
MRF	Green Mat	TEHACHAPI Rec, INC	P	416 N DENNISON RD	Tehachapi	BENZ SANITATION SERVICE	TEHACHAPI
MRF	Mixed Mun	TEHACHAPI Rec, INC	P	416 N DENNISON RD	Tehachapi	BENZ SANITATION SERVICE	TEHACHAPI
MRF		MORTON Rec (MRI)	TBD	E/2, S34,T12N,R23W SBBM	Maricopa	MORTON Rec INC	TAFT
MRF	Agricultural	KCWMA wst PROCESSING Fac	P	7803 HANFORD-ARMONA RD.	Hanford	Co of KINGS WST Mngmt AUTH	HANFORD
MRF	Mixed Mun	KCWMA wst PROCESSING Fac	P	7803 HANFORD-ARMONA RD.	Hanford	Co of KINGS WST Mngmt AUTH	HANFORD
MRF	Wood mill	KCWMA wst PROCESSING Fac	P	7803 HANFORD-ARMONA RD.	Hanford	Co of KINGS WST Mngmt AUTH	HANFORD
MRF	Mixed Mun	East Los Angls Rec and Trnsf	P	1512 N. Bonnie Beach Place	City Terrace	Perdomo/BLT Enterprises L.L.C.	Oxnard
MRF	Mixed Mun	wst Recvry AND Rec Fac	P	4489 ARDINE St	S Gate	H.B.J.J. Inc. Subsidiary of USA wst	Bell Gardens
MRF	Mixed Mun	Coastal Mat Recvry Fac & TS	P	357 W. Compton Blvd.	Gardena	SI-NOR Inc. DBA: Coastal MRF & TS	Gardena
MRF	Mixed Mun	RAIL CYCLE Com Mat Recvry Fac	P	6300 E. 26TH St	Commerce	wst Mngmt INC	Gardena
MRF	Mixed Mun	CITY RUBBISH Co	P	1511 FISHBURN AVENUE	City Terrace	CITY RUBBISH Co	Los Angls
MRF	Mixed Mun	United wst Rec & Trnsf, Inc.	P	14048 E. Valley Blvd.	Industry	United wst Rec & Trnsf Inc.	Industry
MRF		CITY of POMONA MRF	TBD	2000-2200 Pomona Blvd.	Pomona		
MRF	Mixed Mun	MAMMOTH Rec Fac AND TS	P	21739 Rd 19	Chowchilla	MADERA Disp systm,INC.	MADERA
MRF	Wood mill	MARIN Sanitry SERVICE Trnsf Statn	P	1060 ANDERSEN DRIVE	San Rafael	MARIN Sanitry SERVICE	SAN RAFAEL
MRF		MRWMD Mat Recvry Fac	P	14201 Del Monte Blvd	Marina	Co of MONTEREY REGIONAL wst MGT	MARINA
MRF	Mixed Mun	NAPA GARBAGE SERVICE MRF	P	SE of end of Tower Rd, Hwy 29	Napa	NAPA GARBAGE SERVICE	NAPA
MRF	Mixed Mun	EASTERN REGIONAL MRF	P	3 miles S of Truckee, CA	Alpine Meadows	EASTERN REGIONAL Lfl INC	Tahoe
MRF	Sludge	EASTERN REGIONAL MRF	P	3 miles S of Truckee, CA	Alpine Meadows	EASTERN REGIONAL Lfl INC	Tahoe
MRF	Mixed Mun	PERRIS Mat Recvry Fac	P	1706 GOETZ Rd	Perris	CR&R INCORPORATED	STANTON
MRF	Mixed Mun	Robert A Nelson Trnsf Statn & MRF	P	Agua Mansa Rd W of Brown Ave	Rubidoux	AGUA MANSA MRF, LLC	FONTANA
MRF	Agricultural	Elder Creek Recvry and Trnsf Statio	P	8642 Elder Creek Rd	Sacramento	California wst Revoval Inds, Inc	Lodi
MRF	Green Mat	Elder Creek Recvry and Trnsf Statio	P	8642 Elder Creek Rd	Sacramento	California wst Revoval Inds, Inc	Lodi
MRF	Mixed Mun	Elder Creek Recvry and Trnsf Statio	P	8642 Elder Creek Rd	Sacramento	California wst Revoval Inds, Inc	Lodi
MRF	Agricultural	FOLSOM Mat Recvry & Compsting	P	N of NEW FOLSOM PRISON	Represa (Folsom)	PRISON INDUSTRY AUTHORITY, ST. of CALIF.	FOLSOM
MRF	Mixed Mun	FOLSOM Mat Recvry & Compsting	P	N of NEW FOLSOM PRISON	Represa (Folsom)	PRISON INDUSTRY AUTHORITY, ST. of CALIF.	FOLSOM
MRF	Mixed Mun	ADVANCE Disp Mat RECVRY FACLTY	P	17105 MESA Rd	Hesperia	ADVANCE Disp Co	HESPERIA
MRF	Mixed Mun	W VALLEY Mat RECVR'Y Fac	P	9401 N. ETIWANDA AVENUE	Fontana	BURRTEC wst Inds, INC.	FONTANA
MRF	Mixed Mun	VICTOR VALLEY MRF & Trnsf Statn	P	NW CORNER of ABBY LN & B St	Victorville	BURRTEC wst Inds, INC.	FONTANA

MRF	Mixed Mun	ESCONDIDO Res Recvry	P	1044 W. WASHINGTON AVENUE	Escondido	JEMCO EQUIPMENT CORPORATION	RAMONA
MRF	Green Mat	EDCO STATION	P	8132 COMMERCIAL St	La Mesa	EDCO Disp CORPORATION	Lemon Grove
MRF	Mixed Mun	EDCO STATION	P	8132 COMMERCIAL St	La Mesa	EDCO Disp CORPORATION	Lemon Grove
MRF	Mixed Mun	FALLBROOK Rec Fac	Pd	550 W. AVIATION Rd	Fallbrook	FALLBROOK REFUSE SERVICE	FALLBROOK
MRF	Green Mat	RAMONA MRF AND Trnsf Statn	P	324 MAPLE St	Ramona	RAMONA Disp SERVICE	RAMONA
MRF	Mixed Mun	RAMONA MRF AND Trnsf Statn	P	324 MAPLE St	Ramona	RAMONA Disp SERVICE	RAMONA
MRF	Green Mat	wst ResS TECHNOLOGY, INC., R$T.S.	P	895 EGBERT St	San Francisco	wst ResS TECHNOLOGY, INC.	San Francisco
MRF	Mixed Mun	wst ResS TECHNOLOGY, INC., R$T.S.	P	895 EGBERT St	San Francisco	wst ResS TECHNOLOGY, INC.	San Francisco
MRF	Mixed Mun	W COAST Rec Co	P	1900 17TH St	San Francisco	W COAST RECYCYCLING Co	San Francisco
MRF	Agricultural	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	Co of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
MRF	Mixed Mun	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	Co of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
MRF	Wood mill	LOVELACE Trnsf Statn	P	2323 LOVELACE Rd	Manteca	Co of SAN JOAQUIN Pub WORKS DEPT	STOCKTON
MRF	Agricultural	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
MRF	Mixed Mun	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
MRF	Wood mill	CENTRAL VALLEY wst SERVICES	P	1333 EAST TURNER Rd	Lodi	CENTRAL VALLEY wst SERVICES	LODI
MRF	Wood mill	EAST STOCKTON Trnsf & Rec STN	P	2435 EAST WEBER AVENUE	Stockton	E STOCKTON Trnsf & RECYCLE STATION	STOCKTON
MRF	Agricultural	TRACY Mat Recvry & T.S.	P	30703 S. MACARTHUR DRIVE	Tracy	REPETTO M	TRACY
MRF	Mixed Mun	TRACY Mat Recvry & T.S.	P	30703 S. MACARTHUR DRIVE	Tracy	REPETTO M	TRACY
MRF	Green Mat	ZANKER Rd CLASS III Lfl	P	705 Los ESTEROS RD	San Jose	Zanker Rd Res Mngmt, Limited	San Jose
MRF	Green Mat	BFI's RECYCLERY	P	1601 DIXON LANDING Rd	San Jose	INTERNATIONAL Disp CORPORATION	MILPITAS
MRF	Mixed Mun	BFI's RECYCLERY	P	1601 DIXON LANDING Rd	San Jose	INTERNATIONAL Disp CORPORATION	MILPITAS
MRF	Green Mat	Greenwst Recvry Fac	P	625 Charles St	San Jose	Zanker Rd Res Mngmt, Limited	San Jose
MRF	Mixed Mun	CITY of REDDING Trnsf Statn/MRF	P	2255 ABERNATHY LN	Redding	CITY of REDDING	REDDING
MRF	Agricultural	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
MRF	Green Mat	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
MRF	Mixed Mun	TULARE Co Rec	P	26951 Rd 140, VISALIA	Visalia	Bever & Pena	Visallia
MRF	Mixed Mun	CAL SIERRA Trnsf Statn	P	19309 INDUSTRIAL DRIVE	Sonora	CAL SIERRA Disp, INC.	STANDARD
MRF	Mixed Mun	GOLD COAST Rec Fac	P	5275 COLT St	Ventura (S Bnvt)	GOLD COAST Rec INC.	VENTURA
MRF		DEL NORTE REGIONAL Rec & Trnsf	P	111 S Del Norte Blvd.	Oxnard	BLT ENTERPRISES of OXNARD, INC.	Oxnard
MRF	Agricultural	DEL NORTE REGIONAL Rec & Trnsf	P	111 S Del Norte Blvd.	Oxnard	BLT ENTERPRISES of OXNARD, INC.	Oxnard
MRF	Mixed Mun	DEL NORTE REGIONAL Rec & Trnsf	P	111 S Del Norte Blvd.	Oxnard	BLT ENTERPRISES of OXNARD, INC.	Oxnard
MRF	Green Mat	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
MRF	Mixed Mun	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
MRF	Wood mill	YUBA SUTTER Disp, INC. M.R.F.	P	3001 N. LEVEE Rd	Mrysvl	YUBA SUTTER Disp, INC.	Mrysvl
SWL	Green Mat	TRI CITIES Rec & Disp FAC	P	7010 AUTO MALL PARKWAY	Fremont	OAKLAND SCAVENGER Co	OAKLAND
SWL	Sludge	TRI CITIES Rec & Disp FAC	P	7010 AUTO MALL PARKWAY	Fremont	OAKLAND SCAVENGER Co	OAKLAND
SWL	Green Mat	ALTAMONT Lfl & Res RECV'RY	P	10840 ALTAMONT PASS Rd	Livermore	wst Mngmt of ALAMEDA Co	OAKLAND
SWL	Green Mat	VASCO Rd Sanitry Lfl	P	4001 NORTH VASCO Rd	Livermore	BROWNING-FERRIS Inds of CALIF, INC	Sylmar
SWL	Agricultural	Amador Co SLF/B Vista Cls II Lfl	P	6500 Buena Vista Rd	Ione	A.C.E.S., INC.	Jackson
SWL	Sludge	Amador Co SLF/B Vista Cls II Lfl	P	6500 Buena Vista Rd	Ione	A.C.E.S., INC.	Jackson

SWL	Agricultural	ROCK CREEK Lfl	P	12021 HUNT Rd	Milton	Co of CALAVERAS	S ANDREAS
SWL	Sludge	ROCK CREEK Lfl	P	12021 HUNT Rd	Milton	Co of CALAVERAS	S ANDREAS
SWL	Agricultural	STONYFORD Disp St	P	LODOGA/STONYFORD RD	Stonyford	Co of COLUSA Pub WORKS	COLUSA
SWL	Agricultural	W CONTRA COSTA Lfl	P	PARR BLVD & GARDEN TRACT RD	Richmond	W CONTRA COSTA Sanitry Lfl INC	RICHMOND
SWL	Sludge	W CONTRA COSTA Lfl	P	PARR BLVD & GARDEN TRACT RD	Richmond	W CONTRA COSTA Sanitry Lfl INC	RICHMOND
SWL	Green Mat	ACME Lfl	P	WATERBIRD WY	Martinez	ACME FILL CORPORATION	MARTINEZ
SWL	Agricultural	KELLER CANYON Lfl	P	901 BAILEY Rd	Mulligan Hill	KELLER CANYON Lfl	PACHECO
SWL	Sludge	KELLER CANYON Lfl	P	901 BAILEY Rd	Mulligan Hill	KELLER CANYON Lfl	PACHECO
SWL	Agricultural	CRESCENT CITY Lfl	P	Hights Access Rd off Old Mill	Crescent City	DEL NORTE Solid wst MGMT. AUTH.	CRESCENT C
SWL	Sludge	CRESCENT CITY Lfl	P	Hights Access Rd off Old Mill	Crescent City	DEL NORTE Solid wst MGMT. AUTH.	CRESCENT C
SWL	Wood mill	CRESCENT CITY Lfl	P	Hights Access Rd off Old Mill	Crescent City	DEL NORTE Solid wst MGMT. AUTH.	CRESCENT C
SWL	Agricultural	UNION MINE Disp St	P	5700 UNION MINE Rd	El Dorado	EL DORADO Lfl, INC.	Diamond Spr.
SWL	Sludge	UNION MINE Disp St	P	5700 UNION MINE Rd	El Dorado	EL DORADO Lfl, INC.	Diamond Spr.
SWL	Agricultural	COALINGA Disp St	P	E of Hwy 198 & Alcade on Lost Hills	Coalinga	Co of FRESNO Pub WORKS	FRESNO
SWL	Agricultural	AMERICAN AVENUE Disp St	P	18950 W AMERICAN AV 4	Tranquillity	Co of FRESNO Pub WORKS	FRESNO
SWL	Wood mill	ORANGE AVENUE Disp INC	P	3280 S ORANGE AVE	Fresno	ORANGE AVENUE Disp, INC.	FRESNO
SWL	Agricultural	GLENN Co Lfl St	P	5 MI W of I-5 ON CO RD 33	Artois	Co of GLENN Pub WORKS, JOHN JOYCE	WILLOWS
SWL	Sludge	CUMMINGS Rd Lfl	P	END of CUMMINGS Rd	Eureka	CUMMINGS Rd Lfl	EUREKA
SWL	Agricultural	CALEXICO Solid wst Disp St	P	NEW RIVER & HWY 98	Calexico	Co of IMPERIAL Pub WORKS	EL CENTRO
SWL	Agricultural	REPub IMPERIAL Lfl	P	104 EAST ROBINSON Rd	Imperial	REPub IMPERIAL ACQUISITION CORP.	IMPERIAL
SWL	Agricultural	LONE PINE Disp St	P	CEMETERY Rd; E of TOWN	Lone Pine	Co of INYO INTEGRATED wst MGMT.	BISHOP
SWL	Agricultural	INDEPENDENCE Disp St	P	RD E of HWY 395; 1.25 MI S of town	Independence	Co of INYO INTEGRATED wst MGMT.	BISHOP
SWL	Wood mill	INDEPENDENCE Disp St	P	RD E of HWY 395; 1.25 MI S of town	Independence	Co of INYO INTEGRATED wst MGMT.	BISHOP
SWL	Agricultural	BISHOP SUNLAND	P	Sunland Dr & Sunland Indian Rs Rd	Bishop	Co of INYO INTEGRATED wst MGMT.	BISHOP
SWL	Sludge	BISHOP SUNLAND	P	Sunland Dr & Sunland Indian Rs Rd	Bishop	Co of INYO INTEGRATED wst MGMT.	BISHOP
SWL	Agricultural	ARVIN Sanitry Lfl	P	WHEELER RIDGE RD	Arvin	Co of KERN wst Mngmt DEPT.	Bakersfield
SWL	Agricultural	LosT HILLS Sanitry Lfl	P	14251 HOLLOWAY Rd	Lost Hills	Co of KERN wst Mngmt DEPT.	Bakersfield
SWL	Agricultural	KERN VALLEY Sanitry Lfl	P	9800 SIERRA WAY	Kernville	Co of KERN wst Mngmt DEPT.	Bakersfield
SWL	Agricultural	MOJAVE-ROSAMOND Sanitry Lfl	P	400 SILVER QUEEN Rd	Mojave	Co of KERN wst Mngmt DEPT.	Bakersfield
SWL	Agricultural	RIDGECREST-INYOKERN Sanitry Lfl	P	3301 BOWMAN Rd	Ridgecrest	Co of KERN wst Mngmt DEPT.	Bakersfield
SWL	Green Mat	EDWARDS AFB-MAIN BASE Lfl	P	EDWARDS A F B	Edwards AFB	US DEPT of AIR FORCE-EDWARDS AFB	EDWARDS AFB
SWL	Agricultural	AVENAL Lfl	P	201 NORTH HYDRIL Rd	Avenal	CITY of AVENAL	AVENAL
SWL	Agricultural	HANFORD Sanitry Lfl	P	SE HWY 43 & HANFORD-ARMONA rd	Hanford	Co of KINGS wst Mngmt AUTHORI	HANFORD
SWL	Wood mill	HANFORD Sanitry Lfl	P	SE HWY 43 & HANFORD-ARMONA rd	Hanford	Co of KINGS wst Mngmt AUTHORI	HANFORD
SWL	Agricultural	BASS HILL Lfl	P	HWY 395 JOHNSTONVILLE AREA	Johnstonville	Co of LASSEN Pub WORKS DEPT	SUSANVILLE
SWL	Sludge	BASS HILL Lfl	P	HWY 395 JOHNSTONVILLE AREA	Johnstonville	Co of LASSEN Pub WORKS DEPT	SUSANVILLE
SWL	Agricultural	HERLONG Disp Fac	P	Co Rd 328	Herlong	Co of LASSEN Pub WORKS DEPT	SUSANVILLE
SWL	Agricultural	SCHOLL CANYON Sanitry Lfl	P	3001 SCHOLL CANYON Rd	Glendale	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Wood mill	SCHOLL CANYON Sanitry Lfl	P	3001 SCHOLL CANYON Rd	Glendale	Co of Los Angls SANITATION DIST	WHITTIER

SWL	Agricultural	wst Mngmt of LANCASTER S LF	P	600 EAST AVENUE "F"	Lancaster	wst Mngmt of CALIFORNIA INC	LANCASTER
SWL	Agricultural	CHIQUITA CANYON Sanitry Lfl	P	29201 HENRY MAYO DRIVE	Valencia (S Clarita)	RePub Services of California I, L.L.C	Santa Fe Spr
SWL	Sludge	CHIQUITA CANYON Sanitry Lfl	P	29201 HENRY MAYO DRIVE	Valencia (S Clarita)	RePub Services of California I, L.L.C	Santa Fe Spr
SWL	Agricultural	PUENTE HILLS Lfl #6	P	2800 S WORKMAN MILL RD	Whittier	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Sludge	PUENTE HILLS Lfl #6	P	2801 S WORKMAN MILL RD	Whittier	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Wood mill	PUENTE HILLS Lfl #6	P	2802 S WORKMAN MILL RD	Whittier	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Agricultural	CALABASAS Sanitry Lfl	P	5300 LosT HILLS Rd	Agoura Hills	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Wood mill	CALABASAS Sanitry Lfl	P	5300 LosT HILLS Rd	Agoura Hills	Co of Los Angls SANITATION DIST	WHITTIER
SWL	Sludge	PEBBLY BEACH (AVALON) Disp St	P	DUMP Rd	Avalon	SEAGULL SANITATION systm	Santa Fe Spr
SWL	Wood mill	PEBBLY BEACH (AVALON) Disp St	P	DUMP Rd	Avalon	SEAGULL SANITATION systm	Santa Fe Spr
SWL	Agricultural	FAIRMEAD Solid wst Disp St	P	AVENUE 22 AT Rd 19	Chowchilla	MADERA Disp systm,INC.	MADERA
SWL	Green Mat	FAIRMEAD Solid wst Disp St	P	AVENUE 22 AT Rd 19	Chowchilla	MADERA Disp systm,INC.	MADERA
SWL	Sludge	FAIRMEAD Solid wst Disp St	P	AVENUE 22 AT Rd 19	Chowchilla	MADERA Disp systm,INC.	MADERA
SWL	Agricultural	REDWOOD Sanitry Lfl	P	NE NOVATO BTWN Santonio & RR	Novato	REDWOOD Lfl INC. SANIFILL	HOUSTON
SWL	Sludge	REDWOOD Sanitry Lfl	P	NE NOVATO BTWN Santonio & RR	Novato	REDWOOD Lfl INC. SANIFILL	HOUSTON
SWL	Wood mill	REDWOOD Sanitry Lfl	P	NE NOVATO BTWN Santonio & RR	Novato	REDWOOD Lfl INC. SANIFILL	HOUSTON
SWL	Sludge	MARIPOSA Co Sanitry Lfl	P	Dump Rd 2 MI N of Mariposa -Hwy 49	Mariposa	Co of MARIPOSA	MARIPOSA
SWL	Wood mill	UKIAH Solid wst Disp St	P	VICHY Springs rd 3 MI SW of Ukiah	Ukiah	CITY of UKIAH	UKIAH
SWL	Green Mat	HIGHWAY 59 Disp St	P	HWY 59; 6 MI N MERCED	Merced	Co of MERCED	MERCED
SWL	Wood mill	HIGHWAY 59 Disp St	P	HWY 59; 6 MI N MERCED	Merced	Co of MERCED	MERCED
SWL	Agricultural	BILLY WRIGHT Disp St	P	BILLY WRIGHT RD; 7 MI W Los Banos	Los Banos	Co of MERCED	MERCED
SWL	Sludge	ALTURAS Sanitry Lfl	P	INTERSECTION of CO #54 & #60	Alturas	Co of MODOC Pub WORKS DEPT	ALTURAS
SWL	Agricultural	WALKER Sanitry Lfl	P	EAST SIDE LANE	Walker	Co of MONO	BRIDGEPORT
SWL	Sludge	WALKER Sanitry Lfl	P	EAST SIDE LANE	Walker	Co of MONO	BRIDGEPORT
SWL	Green Mat	PUMICE VALLEY Lfl	P	HWY 120; 4 MI S MONO LAKE	Lee Vining	Co of MONO	BRIDGEPORT
SWL	Sludge	PUMICE VALLEY Lfl	P	HWY 120; 4 MI S MONO LAKE	Lee Vining	Co of MONO	BRIDGEPORT
SWL	Green Mat	BENTON CROSSING Sanitry Lfl	P	1 MI SW BENTON CROSSING	Benton	Co of MONO	BRIDGEPORT
SWL	Sludge	BENTON CROSSING Sanitry Lfl	P	1 MI SW BENTON CROSSING	Benton	Co of MONO	BRIDGEPORT
SWL	Green Mat	BENTON Sanitry Lfl	P	HWY 120 & STATE ROUTE 6	Benton	Co of MONO	BRIDGEPORT
SWL	Agricultural	LEWIS Rd Sanitry Lfl	P	LEWIS RD;2 MI W WATSNVLL	Pajaro	RURAL DISPOS-ALL SERVICE	SALINAS
SWL	Agricultural	JOHNSON CANYON Sanitry Lfl	P	2 MI E HWY 101 Johnson Canyon Rd	Gonzales	Salinas Valley Solid wst Authority	Salinas
SWL	Sludge	JOHNSON CANYON Sanitry Lfl	P	3 MI E HWY 101 Johnson Canyon Rd	Gonzales	Salinas Valley Solid wst Authority	Salinas
SWL	Agricultural	JOLON Rd Sanitry Lfl	P	3 MI S KING CITY	King City	JOLON Rd Lfl Co	KING CITY
SWL	Agricultural	CRAZY HORSE Sanitry Lfl	P	CRAZY HORSE N of PRUNEDALE	Prunedale	RURAL DISPOS-ALL SERVICE	SALINAS
SWL	Agricultural	Mont Regional Wst Mgmt Dst/Mar	P	2 MI N of MARINA; D MONTE BLVD	Marina	CO of MONTEREY REGIONAL wst MGT	MARINA
SWL	Sludge	Mont Regional Wst Mgmt Dst/Mar	P	3 MI N of MARINA; D MONTE BLVD	Marina	Co of MONTEREY REGIONAL wst MGT	MARINA
SWL	Agricultural	CLOVER FLAT Lfl	P	4380 SILVERADO Trl/3MI SE of CALST	Napa	UPPER VALLEY Rec & Disp SERVIC	ST HELENA

SWL	Sludge	CLOVER FLAT Lfl	P		Napa	UPPER VALLEY Rec & Disp SERVIC	ST HELENA
SWL	Agricultural	SANTIAGO CANYON Sanitry Lfl	P	3099 SANTIAGO CANYON Rd	Irvine	Co of ORANGE INTEG wst MGT DEPT	SANTA ANA
SWL	Agricultural	OLINDA ALPHA Sanitry Lfl	P	NE of VALENCIA A & Carbon CYN RD	Brea	Co of ORANGE INTEG wst MGT DEPT	SANTA ANA
SWL	Wood mill	OLINDA ALPHA Sanitry Lfl	P	NE of VALENCIA A & Carbon CYN RD	Brea	CO of ORANGE INTEG wst MGT DEPT	SANTA ANA
SWL	Sludge	WERN REGIONAL Lfl	P	3195 ATHENS Rd AP #17-060-02	Lincoln	W PLACER wst MGT AUTHORITY	Auburn
SWL	Agricultural	BADLANDS Disp St	P	31125 IRONWOOD AVE	Moreno Valley	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	LAMB CANYON Disp St	P	Lamb CANYON rd 3 MI S of Beaumnt	Beaumont	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	EDOM HILL Disp St	P	70-100 Edom Hill Rd	Cathedral City	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	ANZA Sanitry Lfl	P	40329 TERWILLIGER RD	Anza	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	OASIS Sanitry Lfl	P	84-505 84TH St	Oasis	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	DESERT CTR L.F.(EAGLE MOUNT)	P	7991 KAISER Rd	Desert Center	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Agricultural	BLYTHE Sanitry Lfl	P	1000 MIDLAND RD	Blythe	Co of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Sludge	METROPOLITAN WATER DISTRICT	E	33740 BOREL Rd	Winchester	SKINNER FILTRATION PLANT	WINCHESTER
SWL	Agricultural	MECCA Lfl II	P	BOX CANYON RD & GARFIELD ST	Mecca	CO of RIVERSIDE WST MGMT DEPT	RIVERSIDE
SWL	Sludge	SACRAMENTO Co Lfl (KIEFER)	P	12701 KIEFER BLVD	Rancho Cordova	CO of SACRAMENTO, Pub Works Dept.	Sacramento
SWL	Green Mat	DIXON PIT Lfl	P	8973 ELK GROVE - FLORIN Rd	Elk Grove	Super Pallet Rec Corporation	Elk Grove
SWL	Green Mat	L & D Lfl CO	P	8635 FRUITRIDGE Rd	Sacramento	L & D Lfl CO	Sacramento
SWL	Wood mill	John Smith Rd Class III Lfl	P	2650 John Smith Rd	Hollister	CO of SAN BENITO Pub WORKS DEPT	HOLLISTER
SWL	Wood mill	PFIZER, INC. Lucerne Val. INERT D.S.	E	1/4 MI w of Pfizer Lucerne Val plnt	Lucerne Valley	PFIZER INC.	Lucerne Val
SWL	Sludge	CALIFORNIA St Lfl	P	END of CALIFORNIA St	Redlands	CITY of REDLANDS	REDLANDS
SWL	Agricultural	VICTORVILLE REFUSE Disp St	P	5 MI N of Victrvll on Stoddard Wells	Victorville	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Sludge	VICTORVILLE REFUSE Disp St	P	6 MI N of Victrvll on Stoddard Wells	Victorville	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Agricultural	BARSTOW REFUSE Disp St	P	Barstow Rd 3 MI S of BARSTOW	Barstow	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Sludge	BARSTOW REFUSE Disp St	P	Barstow Rd 3 MI S of BARSTOW	Barstow	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Agricultural	COLTON REFUSE Disp St	P	Tropica Rancho 1/2 Mi w of La Cdna	Colton	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Sludge	COLTON REFUSE Disp St	P	Tropica Rancho 1/2 Mi w of La Cdna	Colton	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Wood mill	COLTON REFUSE Disp St	P	Tropica Rancho 1/2 Mi w of La Cdna	Colton	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Sludge	LANDERS Disp St	P	WINTERS RD; 4.1 MI E of HWY 247	Landers	Co of SAN BERNARDINO WST SYSTM DIV	S Bernadino
SWL	Sludge	Resrv COMPONENT TRAINING Ctr	P	FORT IRWIN MILITARY BASE	Fort Irwin (Mil Res)	US DEPT of ARMY-FORT IRWIN	FORT IRWIN
SWL	Wood mill	Mitsubishi Cement Plnt Cushenbury Llf	P	5808 STATE HIGHWAY 18	Lucerne Valley	MITSUBISHI CEMENT CORP	Lucerne Val
SWL	Agricultural	RAMONA Lfl	P	20630 PAMO RD	Ramona	Allied wst Inds, Inc.	San Diego
SWL	Sludge	RAMONA Lfl	P	20630 PAMO RD	Ramona	Allied wst Inds, Inc.	San Diego
SWL	Wood mill	RAMONA Lfl	P	20630 PAMO RD	Ramona	Allied wst Inds, Inc.	San Diego
SWL	Agricultural	BORREGO SPRINGS Lfl	P	2449 PALM CAYNON Rd	Borrego Springs	Allied wst Inds, Inc.	San Diego
SWL	Sludge	BORREGO SPRINGS Lfl	P	2449 PALM CAYNON Rd	Borrego Springs	Allied wst Inds, Inc.	San Diego
SWL	Wood mill	BORREGO SPRINGS Lfl	P	2449 PALM CAYNON Rd	Borrego Springs	Allied wst Inds, Inc.	San Diego

SWL	Agricultural	OTAY Sanitry Lfl	P	1700 MAXWELL RD	Otay (Chula Vista)	CO of SAN DIEGO Solid wst DIV	SAN DIEGO
SWL	Sludge	OTAY Sanitry Lfl	P	1700 MAXWELL RD	Otay (Chula Vista)	CO of SAN DIEGO Solid wst DIV	SAN DIEGO
SWL	Wood mill	OTAY Sanitry Lfl	P	1700 MAXWELL RD	Otay (Chula Vista)	CO of SAN DIEGO Solid wst DIV	SAN DIEGO
SWL	Agricultural	OTAY ANNEX Lfl	P	1700 MAXWELL RD	Chula Vista	Allied wst Inds, Inc.	San Diego
SWL	Green Mat	OTAY ANNEX Lfl	P	1700 MAXWELL RD	Chula Vista	Allied wst Inds, Inc.	San Diego
SWL	Sludge	OTAY ANNEX Lfl	P	1700 MAXWELL RD	Chula Vista	Allied wst Inds, Inc.	San Diego
SWL	Sludge	SYCAMORE Sanitry Lfl	P	8514 MAST BOULEVARD	Santee (San Diego)	Allied wst Inds, Inc.	San Diego
SWL	Green Mat	FRENCH CAMP Lfl	P	4599 S. MANTHEY Rd @ Downing A	Stockton	CITY of STOCKTON Pub WORKS	STOCKTON
SWL	Agricultural	FOOTHILL Sanitry Lfl	P	6484 NORTH WAVERLY Rd	Linden	FOOTHILL Sanitry Lfl INC	STOCKTON
SWL	Wood mill	FOOTHILL Sanitry Lfl	P	6484 NORTH WAVERLY Rd	Linden	FOOTHILL Sanitry Lfl INC	STOCKTON
SWL	Agricultural	FORWARD, INC	P	9999 S. Austin Rd	Manteca	FORWARD, INC.	STOCKTON
SWL	Sludge	FORWARD, INC	P	10000 S. Austin Rd	Manteca	FORWARD, INC.	STOCKTON
SWL	Agricultural	CITY of PASO ROBLES Lfl	P	HWY 46; 8 MI E of PASO ROBLES	Paso Robles	CITY of PASO ROBLES	Paso Robles
SWL	Sludge	CITY of PASO ROBLES Lfl	P	HWY 46; 8 MI E of PASO ROBLES	Paso Robles	CITY of PASO ROBLES	Paso Robles
SWL	Agricultural	COLD CANYON Lfl Solid wst DS	P	2268 CARPENTER CANYON Rd	San Luis Obispo	COLD CANYON Lfl, INC	S Luis Obispo
SWL	Agricultural	CHICAGO GRADE Lfl	P	HOMESTEAD Rd	Atascadero	JOHNSON W	TEMPLETON
SWL	Sludge	OX MOUNTAIN Sanitry Lfl	P	2 MI N-E 1/2 MOON BY ofF HWY 92	Half Moon Bay	BROWNING-FERRIS IND of CA, INC	Sylmar
SWL	Agricultural	FOXEN CANYON Sanitry Lfl	P	1.5 MI N Los Olivos FOXEN CYN RD	Los Olivos	CO of S BARBARA Pub WORKS DEP	S. Barbara
SWL	Sludge	VANDENBERG AFB Lfl	P	VANDENBERG AFB	Vandenberg AFB	US Dept. of the Air Force, 30 CES/CEVCC	Vandenbrg AFB
SWL	Agricultural	TAJIGUAS Sanitry Lfl	P	HWY 101; 23 MI W S.BARBARA	Goleta	Co of S. BARBARA Pub WORKS DEP	S. Barbara
SWL	Sludge	TAJIGUAS Sanitry Lfl	P	HWY 101; 23 MI W S.BARBARA	Goleta	Co of S. BARBARA Pub WORKS DEP	S. Barbara
SWL	Agricultural	City of SANTA MARIA Refuse Disp St	P	2065 EAST MAIN St	Santa Maria	CITY of SANTA MARIA	SANTA MARIA
SWL	Green Mat	City of SANTA MARIA Refuse Disp St	P	2065 EAST MAIN St	Santa Maria	CITY of SANTA MARIA	SANTA MARIA
SWL	Sludge	CITY of LOMPOC Sanitry Lfl	P	700 S AVALON Rd	Lompoc	CITY of LOMPOC Pub WORKS DEPT	LOMPOC
SWL	Agricultural	PACHECO PASS Sanitry Lfl	P	3665 PACHECO PASS HWY	Gilroy	S VALLEY REFUSE Disp CO	GILROY
SWL	Sludge	PACHECO PASS Sanitry Lfl	P	3665 PACHECO PASS HWY	Gilroy	S VALLEY REFUSE Disp CO	GILROY
SWL	Wood mill	PACHECO PASS Sanitry Lfl	P	3665 PACHECO PASS HWY	Gilroy	S VALLEY REFUSE Disp CO	GILROY
SWL	Sludge	NEWBY ISLAND Sanitry Lfl	P	1601 DIXON LANDING Rd	San Jose	INTERNATIONAL Disp CORP	MILPITAS
SWL	Green Mat	ZANKER Rd CLASS III Lfl	P	705 Los Esteros Rd Nr ZANKER RD	San Jose	Zanker Rd Res Man, Ltd	San Jose
SWL	Green Mat	KIRBY CANYON Recy. Disp Fac.	P	910 Coyote Creek Golf Drive	San Jose	wst Mngmt of CA Inc	Morgan Hill
SWL	Green Mat	GUADALUPE Sanitry Lfl	P	15999 GUADALUPE MINES Rd	San Jose	GUADALUPE RUBBISH DISPCO, INC	SAN JOSE
SWL	Sludge	CITY of SANTA CRUZ Sanitry Lfl	P	605 DIMEO LANE	Santa Cruz	CITY of SANTA CRUZ	SANTA CRUZ
SWL	Agricultural	CITY of WATSONVILLE Lfl	P	San Andreas rd S of BUENA VISTA	Watsonville	CITY of WATSONVILLE	Watsonville
SWL	Sludge	CITY of WATSONVILLE Lfl	P	San Andreas rd S of BUENA VISTA	Watsonville	CITY of WATSONVILLE	Watsonville
SWL	Agricultural	BUENA VISTA DRIVE Sanitry Lfl	P	150 ROUNDTREE LANE	Watsonville	Co of SANTA CRUZ	SANTA CRUZ
SWL	Green Mat	BUENA VISTA DRIVE Sanitry Lfl	P	150 ROUNDTREE LANE	Watsonville	Co of SANTA CRUZ	SANTA CRUZ
SWL	Sludge	BUENA VISTA DRIVE Sanitry Lfl	P	150 ROUNDTREE LANE	Watsonville	Co of SANTA CRUZ	SANTA CRUZ
SWL	Agricultural	ANDERSON Solid wst Disp St	P	18703 CAMBRIDGE Rd	Anderson	Anderson Solid wst, Inc.	Anderson
SWL	Sludge	ANDERSON Solid wst Disp St	P	18703 CAMBRIDGE Rd	Anderson	Anderson Solid wst, Inc.	Anderson

SWL	Wood mill	ANDERSON Solid wst Disp St	P	18703 CAMBRIDGE Rd	Anderson	Anderson Solid wst, Inc.	Anderson
SWL	Agricultural	W CENTRAL Lfl	P	14095 CLEAR CREEK Rd	Redding	CO of SHASTA Pub WORKS DEP	REDDING
SWL	Sludge	W CENTRAL Lfl	P	14095 CLEAR CREEK Rd	Redding	CO of SHASTA Pub WORKS DEP	REDDING
SWL	Sludge	BLACK BUTTE Solid wst Disp St	P	3 MI N MOUNT SHASTA CITY	Mount Shasta	Co of SISKIYOU Pub WORKS DEPT	YREKA
SWL	Agricultural	B & J DROPBOX Sanitry Lfl	P	6426 HAY Rd; 1/4 MI W HWY 113	Vacaville	B & J DROP BOX, INC.	Vacaville
SWL	Sludge	B & J DROPBOX Sanitry Lfl	P	6426 HAY Rd; 1/4 MI W HWY 113	Vacaville	B & J DROP BOX, INC.	Vacaville
SWL	Agricultural	POTRERO HILLS Lfl	P	3675 Potrero Hills Lane	Suisun City	POTRERO HILLS Lfl,INC.	FAIRFIELD
SWL	Sludge	POTRERO HILLS Lfl	P	3675 Potrero Hills Lane	Suisun City	POTRERO HILLS Lfl,INC.	FAIRFIELD
SWL	Sludge	EASTERLY wst WATER Treatmnt Plnt	E	VACA STATION Rd	Elmira	CITY of VACAVILLE Pub WORKS/UTIL	ELMIRA
SWL	Agricultural	CENTRAL Lfl	P	500 MEACHAM Rd	Petaluma		
SWL	Sludge	CENTRAL Lfl	P	500 MEACHAM Rd	Petaluma		
SWL	Wood mill	CENTRAL Lfl	P	500 MEACHAM Rd	Petaluma		
SWL	Agricultural	FINK Rd Lfl	P	4000 FINK Rd	Crows Landing	Stanislaus Co Dept. of Pub Works	Crows Landing
SWL	Sludge	FINK Rd Lfl	P	4000 FINK Rd	Crows Landing	Stanislaus Co Dept. of Pub Works	Crows Landing
SWL	Agricultural	RED BLUFF Sanitry Lfl	P	19995 PLYMIRE Rd; 2 MI nw Red Bluff	Red Bluff	CO of TEHAMA Pub WORKS DEPT	GERBER
SWL	Green Mat	RED BLUFF Sanitry Lfl	P	19996 PLYMIRE Rd; 2 MI nw Red Bluff	Red Bluff	CO of TEHAMA Pub WORKS DEPT	GERBER
SWL	Agricultural	WEAVERVILLE Lfl Disp St	P	1.5 MI NE WEAVERVILLE ofF HWY 3	Weaverville	Co of TRINITY	WEAVERVILLE
SWL	Green Mat	WEAVERVILLE Lfl Disp St	P	1.5 MI NE WEAVERVILLE ofF HWY 3	Weaverville	Co of TRINITY	WEAVERVILLE
SWL	Agricultural	TEAPOT DOME Disp St	P	AVENUE 128 AND Rd 208	Porterville	Co of TULARE	VISALIA
SWL	Agricultural	WOODVILLE Disp St	P	RD 152 AT AVE 198; 10 MI SE Tulare	Tulare	Co of TULARE	VISALIA
SWL	Agricultural	VISALIA Disp St	P	Rd 80 AT AVENUE 332	Visalia	Co of TULARE	VISALIA
SWL	Agricultural	TOLAND Rd Sanitry Lfl	P	3500 NORTH TOLAND Rd	Santa Paula	Ventura Reg. Santation Dist	VENTURA
SWL	Sludge	TOLAND Rd Sanitry Lfl	P	3500 NORTH TOLAND Rd	Santa Paula	Ventura Reg. Santation Dist	VENTURA
SWL	Sludge	SIMI VALLEY Lfl & Rec CENTER	P	111 W Los Angls AVENUE	Simi Valley	Wst MAN of CA Simi Val	SIMI VALLEY
SWL	Agricultural	YOLO Co CENTRAL Lfl	P	COUNTRY Rd 28H & Cntry rd 104	Davis		
SWL	Sludge	YOLO Co CENTRAL Lfl	P	COUNTRY Rd 28H & Cntry rd 105	Davis		
SWL	Agricultural	UNIV of CALIF DAVIS Sanitry Lfl	P	W END UCD CAMPUS ON CO RD 98	Davis	U of CA, DAVIS PHYSICAL PLANT	DAVIS
SWL	Sludge	UNIV of CALIF DAVIS Sanitry Lfl	P	W END UCD CAMPUS ON CO RD 99	Davis	U of CA, DAVIS PHYSICAL PLANT	DAVIS
SWL	Agricultural	OSTROM Rd Lfl	P	OSTROM RD. 5 MI E. of HWY. 65	Wheatland	YUBA SUTTER Disp, INC.	Mrysvl
SWL	Sludge	OSTROM Rd Lfl	P	OSTROM RD. 5 MI E. of HWY. 65	Wheatland	YUBA SUTTER Disp, INC.	Mrysvl
WWDS	Wood mill	LOUISIANA-PACIFIC Lfl	P	btwn Baggett Mrysvl Rd & Ophir Rd	Oroville	LOUISIANA PACIFIC CORP- RED BLUFF	RED BLUFF
WWDS	Wood mill	Harwood Prod. Wood wst Disp St	P	1/2 MI N of BRANSCOMB	Branscomb	HARWOOD PRODUCTS	BRANSCOMB

		TBD =to be determ
LVT/PF	Large Volume Trnsf/Proc Fac	P = Permitted
MRF	Mat Recvry Fac	Pd = Proposed
WWDS	Wood wst Disp St	UP = Unpermitted
SWL	Solid wst Lfl	E= Exempt

Appendix VI-C Biomass Power Plants in California

Table VI-C-1

Cogeneration

California Energy Commission Biolist

California Direct Combustion Biomass Facilities – November, 1999

#	Project Name	City	County	Gross (MW)	Contract (MW)	Contract Utility	Fuel	kBDT per yr.	Status	Remarks	Contact	Phone	Operated Year	Date of Shutdown
16	Louisiana Pacific, Samoa	Samoa	Humboldt	30.0	25.0	PG&E	W	484	steam	produced stream only	Jesse Sterling	707-443-7511	1980	1992
45	Diamond Walnut Power Plant	Stockton	San Joaquin	4.5	4.2	PG&E	Ag	36	open		Gary Ford	209-467-6000	1980	
63	Fibreboard Corp.	Standard	Tuolumne	3.0	3.0	PG&E	UW,W	71	closed		Jim Brisco	209-532-7141	1980	1994
42	Blue Diamond Growers Cogen	Sacramento	Sacramento	11.2	8.0	PG&E	UW,Ag	68	closed		Earl Ruby	916-446-8621	1981	
46	Wheelabrator Hudson	Anderson	Shasta	6.9	5.8	PG&E	W	54	open		Bill Carlson	530/365-9172	1982	
6	Koppers Industries	Oroville	Butte	6.0	4.8	PG&E	W	29	dismantled				1983	1996
23	Big Valley Lumber	Bieber	Lassen	7.5	3.0	PG&E	W	15	open		Marty Seuss	916-294-5226	1983	
25	Sierra Pacific Susanville	Susanville	Lassen	14.0	9.8	PG&E	W	189	open		Bob Ellery	530-378-8179	1984	1995
27	Susanville Forest Products	Susanville	Lassen	2.5	1.0	PG&E	W	32	closed		Kurt Schwartz	916-257-5808	1984	1993
3	Martell Cogeneration	Martell	Amador	20.0	9.0	PG&E	W,UW	126	open		Bill Carlson	530-365-9172	1985	
10	Auberry Energy, Inc.	Auberry	Fresno	9.0	6.0	PG&E	W,V,Ag	160	closed	phone disconnected	Doug Thompson	209-855-4001	1985	1994
33	Georgia Pacific Corp.	Fort Bragg	Mendocino	15.0	15.0	PG&E	W,UW	172	open		Art Owings	707-964-5651	1985	
40	Collins Pine Company	Chester	Plumas	12.0	10.0	PG&E	W	98	open		Jim Stewart	916-258-2111	1985	
44	California Cedar Products	Stockton	San Joaquin	0.7	N/A	N/A	W	10	closed		Patrick Lam	209-944-5800	1985	
59	Sierra Pacific Hayfork	Hayfork	Trinity	7.5	7.0	PG&E	W	85	closed		Bob Ellery	530-378-8179	1985	
60	Dinuba Energy	Dinuba	Tulare	11.5	8.3	PG&E	V,W,Ag	179	closed		Jim Schwager	209-591-8060	1985	1995
38	Sierra Pacific Lincoln	Lincoln	Placer	9.1	5.0	PG&E	W,V	91	open		Martin Law	916-645-1631	1986	
41	Sierra Pacific Quincy	Quincy	Plumas	17.5	12.5	PG&E	W	396	open		Bob Ellery	530-378-8179	1986	
48	Sierra Pacific Burney	Burney	Shasta	14.5	9.5	PG&E	W	217	open		Bob Ellery	530/378-8179	1986	
31	North Fork Energy, Inc.	North Fork	Madera	9.0	3.0	PG&E	W,Ag	145	dismantled				1987	1993
17	Pacific Lumber Company	Scotia	Humboldt	25.0	20.0	PG&E	W	419	open		John Prevost	707-764-4280	1988	
36	Soledad Energy Partnership	Soledad	Monterey	12.0	12.0	PG&E	UW,W	48	closed		Harry Hunzie	408-678-2600	1989	1994
50	Burney Forest Products	Burney	Shasta	29.0	24.0	PG&E	W	200	open		Milton Schultz	530-335-5100	1989	
53	Sierra Pacific Loyalton	Loyalton	Sierra	20.0	10.0	SPPC	W	111	open		Bob Ellery	530-378-8179	1989	
	Jackson Valley Energy	Ione	Amador	21.0	18.0	PG&E	UW,Ag	140	closed		Rollie Coombs	209-274-2407	1987	?

Key	
Ag - agricultural wastes	
An - animal wastes	
MSW - municipal solid wastes	
UW - urban wood wastes	
V - virgin wood	N/A - Not Applicable
W - wood wastes	NO - Not Obtained

Table VI-C-2
Electricity-Only

California Energy Commission Biolist

California Direct Combustion Biomass Facilities - November, 1999

#	Project Name	City	County	Gross (MW)	Contract (MW)	Contract Utility	Fuel	kBDT per yr.	Status	Remarks	Contact	Phone	Operated Year	Date of Shutdown
52	Burney Mountain Power	Burney	Shasta	11.0	9.8	PG&E	W	77	open		Larry Ingals	213-335-5434	1984	1996
5	Pacific Orville Power	Oroville	Butte	18.0	16.5	PG&E	UW,W,Ag	142	open		Joe Brown	916-532-0597	1985	
19	Ultrapower, Blue Lake	Blue Lake	Humboldt	11.4	10.5	PG&E	W	90	closed		Randy Scott	707-668-5631	1985	
26	Ogden Westwood	Westwood	Lassen	11.5	10.0	PG&E	W	75	open		Gary Pritchard	916-365-0163	1985	1994
15	Fairhaven Power Company	Eureka	Humboldt	19.0	17.3	PG&E	W	252	open		Ron Auzenne	707-445-5434	1986	
62	Sierra Power	Terra Bella	Tulare	9.4	9.4	SCE	NO	74	closed		Orley Bennet	209-535-5325	1986	1993
64	Ultrapower, Chinese Station	Jamestown	Tuolumne	25.4	22.0	PG&E	UW,W	174	open		Steve Simmons	209-984-4660	1986	
28	Chowchilla Biomass Plant I	Chowchilla	Madera	10.0	7.5	PG&E	W,Ag	24	dismantled		Bill Lax	209-665-5791	1987	1994
51	Wheelabrator Shasta Energy	Anderson	Shasta	54.9	49.7	PG&E	W,,AG,UW	384	open		Bill Carlson	530-365-9172	1987	
12	Rio Bravo Fresno	Fresno	Fresno	28.0	24.3	PG&E	UW,Ag	167	open		Dick Rodenbach	209-264-4575	1988	1994
20	Mesquite Lake Project	El Centro	Imperial	18.0	15.0	SCE	An	200	closed		Michael O'Leary	619-344-2028	1988	1994
35	El Nido Biomass Plant	El Nido	Merced	12.5	9.9	PG&E	Ag,UW	52	closed		Bill Lax	209-665-5791	1988	1994
66	Feather River Energy	Marysville	Yuba	19.8	15.0	PG&E	W,Ag	37	dismantled				1988	1994
7	Wadham Energy	Williams	Colusa	30.0	26.5	PG&E	Ag	191	open		Ed Tomeo	925-244-1100	1989	
24	Honey Lake Power	Wendel	Lassen	35.0	30.0	PG&E	W,UW	187	open		Ralph Sanders	530-254-6161	1989	
30	Madera Power Plant	Madera	Madera	28.0	25.0	PG&E	UW,Ag	120	closed		Bill Lax	209-665-5791	1989	1994
39	Ultrapower, Rocklin	Lincoln	Placer	27.0	22.0	PG&E	UW,W	134	open		Jim Hancock	916-645-3383	1989	1994
65	Woodland Biomass Power	Woodland	Yolo	28.5	22.0	PG&E	UW,W,Ag	198	open		Randy Bates	530-661-6095	1989	
11	Mendota Biomass Power	Mendota	Fresno	28.5	22.0	PG&E	UW,Ag	179	open		Bob Notoheis	209-655-4921	1990	
21	Imperial Resource Recovery	Imperial	Imperial	18.1	15.0	SCE	Ag,An,UW	126	closed				1990	
22	Delano I	Delano	Kern	31.0	27.0	SCE	UW,Ag	145	open		John Jensen	805-792-3067	1990	
29	Chowchilla Biomass Plant II	Chowchilla	Madera	12.5	9.9	PG&E	W,Ag	52	closed		Bill Lax	209-665-5791	1990	1994
43	Tracy Biomass Plant	Tracy	San Joaquin	21.5	21.0	PG&E	UW,W,Ag	131	open		Kevin Kolnowski	925-431-1431	1990	
67	Colmac Mecca Project	Mecca	Riverside	47.0	45.0	SCE	UW,Ag	270	open		Graeme Donaldson	760-396-2554	1992	
68	Delano II	Delano	Kern	22.9	22.9	SCE	UW,Ag	145	open		John Jensen	661-792-3067	1994	
	Sierra Pacific Anderson	Anderson	Shasta		4.0	PX	W	50	open		Bob Ellery	530-378-8179		

Key	
Ag - agricultural wastes	
An - animal wastes	
MSW - municipal solid wastes	
UW - urban wood wastes	
V - virgin wood	N/A - Not Applicable
W - wood wastes	NO - Not Obtained

Table VI-C-3
Steam-Only

California Energy Commission Biolist

California Direct Combustion Biomass Facilities - November, 1999

#	Project Name	City	County	Gross (MW)	Contract (MW)	Contract Utility	Fuel	kBDT per yr.	Status	Remarks	Contact	Phone	Operated Year	Date of Shutdown
9	Michigan California Lumber	Camino	El Dorado	N/A	N/A	N/A	W	82	open		Ray Laueri	916-644-2311	1970	
8	Hambro Forest Products	Crescent City	Del Norte	N/A	N/A	N/A	W	6	open		Dwayne Reichlin	707-464-6131	1974	
47	Girvan Lumber Co., Inc.	Redding	Shasta	N/A	N/A	N/A	W	4	open		Baghn Ostrander	916-244-9710	1974	
55	Hi-Ridge Lumber Company	Yreka	Siskiyou	N/A	N/A	N/A	W	7	open		Gerald Bendix	916-842-4451	1977	
18	Schmidbauer Lumber Co.	Eureka	Humboldt	N/A	N/A	N/A	W	2	open		Larry McCracken	707-443-7024	1978	
34	Masonite Corporation	Ukiah	Mendocino	N/A	N/A	N/A	W	55	open		Bill Stancer	707-462-2961	1978	
49	Central Valley	Central Valley	Shasta	N/A	N/A	N/A	W	46	closed	phone disconnected	Darryl Darmin	916-275-8812	1978	1994
32	Little Lake Industries, Inc.	Willits	Mendocino	N/A	N/A	N/A	W	4	closed		Fred Witzel	707-459-5395	1979	1992
57	Tri-Valley Growers Plant 9	Modesto	Stanislaus	N/A	N/A	N/A	W,Ag	3	open		Mike Diroll	209-578-3882	1980	
4	Louisiana Pacific, Oroville	Oroville	Butte	N/A	N/A	N/A	W	96	converted	converted to natural gas	Bill Webb	916-534-6604	1987	?
54	Stone Forest Industries	Happy Camp	Siskiyou	N/A	N/A	N/A	W	13	?		Richard Davis	916-493-2231	1987	?
61	Lindsay Olive Growers	Lindsay	Tulare	N/A	2.2	SCE	Ag	20	dismantled	elec dismantled			1987	1991
58	Crane Mills	Paskenta	Tehama	N/A	N/A	N/A	W	23	?		John Crane	916-833-5362	1989	?
1	Hudson Lumber	San Leandro	Alameda	N/A	N/A	N/A	W	6	converted	converted to natural gas	Dave Berg	510-351-5872	?	?
2	Georgia Pacific Corp.	Martell	Amador	N/A	N/A	N/A	W	22	open		Brian Bennett	209-689-1221	?	
13	Sierra Pacific Industries	Arcata	Humboldt	N/A	N/A	N/A	W	4	open		Scott Leiby	916-378-8000	?	
14	Louisiana Pacific, Arcata	Arcata	Humboldt	N/A	N/A	N/A	W	51	open		Dick Kayser	707-822-5961	?	
37	Georgia Pacific Corp.	Forest Hill	Placer	N/A	N/A	N/A	W	6	?		Joe Hughes	916-367-2241	?	?
56	Louisiana Pacific, Cloverdale	Cloverdale	Sonoma	N/A	N/A	N/A	W	10	closed	moved to Ukiah	Gary Van Patten	707-894-8952	?	?

Key	
Ag - agricultural wastes	
An - animal wastes	
MSW - municipal solid wastes	
UW - urban wood wastes	
V - virgin wood	N/A - Not Applicable
W - wood wastes	NO - Not Obtained

Appendix VI-D

Requirements for Siting a Biomass-to-Ethanol Facility in California

Biomass-to-ethanol projects will typically be permitted by local government agencies. Normally, this will mean that a city or county planning department will be the lead agency for the purposes of preparing an environmental impact report (EIR) and determining whether the project complies with the California Environmental Quality Act (CEQA). However, if the project is located on federal land, the lead agency could be a federal agency like the United States Forest Service or the Bureau of Land Management. If a power plant with a generating capacity of 50 megawatts or greater is part of the biomass-to-ethanol facility, the Energy Commission has siting jurisdiction over the entire project if the ethanol is used to supply the power plant with fuel.

The local air pollution district in which a biomass-to-ethanol facility is located will review the project proposal to determine if the facility complies with applicable air quality regulations and, if appropriate, will issue a permit to operate. With the exception of the Energy Commission which has a one-stop siting program that incorporates the review of the local air district, and other agencies, into its process, the review by the air district is separate from the land use permitting agency and may or may not occur concurrently. Other agencies may also review and issue permits for biomass-to-ethanol facilities though they will not be the lead-permitting agency for the project. They can include but are not limited to: state regional water quality control boards, fish and wildlife agencies, highway and transportation departments, and the local CUPA (certified unified program agency) for the storage and/or handling of hazardous or toxic materials.

The potential environmental impacts of biomass-to-ethanol facilities are associated with the harvest/gathering of feedstock and its transportation to the facility, as well as the construction and operation of the facility. These impacts may extend well beyond the point where they initially occur; for example, air emissions from a facility can be transported long distances to downwind receptors. The consequences or results of these impacts can be significant if left unmitigated. Thus mitigation measures, such as emission reduction credits (also known as offsets) are often necessary to ensure that significant adverse impacts are avoided.

Biomass-to-ethanol facilities generate wastewater that must be adequately treated and disposed. Wastewater streams will be high in organic and suspended solids and low in chemically and biologically available oxygen. The actual amount of wastewater generated will depend on the size of the facility, the treatment process, the quality of the water supply, and the amount of water recycling. Complete recycling of all wastewater streams from the facility is possible if capital costs associated with treatment facilities are acceptable. Wastewater disposal can be either through discharge to surface water, land, injection well, an evaporation pond, or a crystallizer. Potential project impacts should be mitigable with the options available, but the full scope of impacts is site specific and cannot be assessed without project specifics and site location. A related issue pertains to a project's water source. Any site chosen for a biomass-to-ethanol facility must have an adequate supply of water.

Construction and operation of a biomass-to-ethanol facility will generate both hazardous and nonhazardous wastes. Hazardous wastes will include those normally found in the construction and operation of similar types of industrial projects such as waste oil and grease, used solvent, contaminated clean up materials, and excess chemicals. Hazardous wastes that cannot be recycled may be sent to one of several landfills either in California or out of state specifically permitted to accept such wastes. Nonhazardous wastes from project construction are also similar to those from other industrial projects and may include scrap building materials and empty containers. In addition to normal nonhazardous wastes from facility operations such as trash, empty containers, and used packing materials, operation of a biomass-to-ethanol facility will generate solid byproducts including lignin, boiler ash, fly ash, and wastewater treatment solids. It is not expected that any of these byproducts would be classified as hazardous, although the boiler ash should be tested to ensure its nonhazardous classification. If any wastestream is classified as hazardous, a project developer must obtain a hazardous waste generation permit from the California Department of Toxic Substances Control (DTSC). Although the byproducts may be safely landfilled, alternative uses may allow them to be diverted from the wastestream.

Both the construction and operation of a biomass-to-ethanol facility can produce noise. Primary noise sources during construction come from diesel-powered trucks and construction equipment. Noise from these sources can be controlled in two ways. First, vehicles and motorized equipment are equipped with effective mufflers to limit noise emissions. Second, noisy construction work is commonly limited to daytime hours by the applicable General Plan Noise Element. The distance between a project and sensitive noise receptors (hospitals, schools, churches, libraries, or residences) can be an effective mitigation measure. If no sensitive receptors are within hearing distance of the project site, no adverse noise impacts are likely. Occasionally the presence of sensitive biological species, typically birds, may require that construction occur outside of the nesting season.

A biomass-to-ethanol facility will normally operate 24 hours a day. As such, noise emissions must be controlled to permissible nighttime levels. Some operations, such as maintenance work or fuel gathering and processing, can be performed solely during the day so that noise emissions from these operations can be limited to less stringent daytime levels. As with construction, if the distance to the nearest receptors is great enough, noise emissions should not be problematic. If receptors are nearby, operating noise emissions can be controlled by various means: equipment can be purchased that produces less noise than standard grade hardware; machinery can be placed within buildings or behind sound barriers to control noise propagation off site. Natural or man-made features such as berms or walls can be utilized to attenuate sound. Finally, the noisiest equipment can be located on the portion of the site farthest from any sensitive receptors.

An impact to a sensitive species and its habitat is often the major biological resource issue associated with a proposed project like a biomass-to-ethanol facility. Sensitive species are primarily those species designated by the California Department of Fish and Game and/or the U.S. Fish and Wildlife Service as rare, threatened or endangered, or are species that can be shown to meet the criteria for state or federal listing. Loss of habitat is the primary reason that the construction and operation of a facility, and its appurtenant linear facilities (gas, water, and transmission lines), can have significant, long-term biological resource impacts on a sensitive species. Whether a project will impact sensitive biological resources depends on site specific location issues. If there are impacts, mitigation measures can include moving the project to reduce or eliminate impacts, and/or purchasing suitable replacement habitat at some other location.

A biomass-to-ethanol facility typically will have to obtain an Authority to Construct and Permit to Operate from the local air pollution control or air quality management district. In general, granting an Authority to Construct requires air district staff to make a determination that the new air pollutant emissions from a source will neither cause a new violation nor contribute to an existing violation of any ambient air quality standards. Air quality modeling may be required for a project as will the use of best available control technology (BACT) to reduce project emissions. Offsets may also be required, though some projects would be exempt from providing offsets because certain air districts do not require projects that burn refuse-derived or biomass-derived solid waste fuel from having to provide offsets. Based upon analysis of similar emission producing facilities, it seems likely that project emissions can be successfully mitigated.

A major aspect of the analysis of the potential public health impacts of a biomass-to-ethanol facility is based upon emissions of potentially harmful substances during normal plant operations. An analysis will determine if these emissions have the potential to cause significant adverse public health impacts or to violate standards for public health protection. Such an analysis requires detailed site-specific information such as local meteorological data and terrain characteristics, in addition to detailed facility information. As with air quality, it appears likely that potential public health impacts due to project emissions could be successfully mitigated absent unique site-related issues.

Transportation and land use issues (including visual and cultural resources) are site specific in nature. Given the potential impacts of biomass-to-ethanol facilities these projects will need to be located where they comply with the local General Plan and zoning code and where the existing transportation system can accommodate the industrial traffic such a project will generate. Compliance with applicable laws and ordinances pertaining to land use and transportation will normally remove obstacles to siting a biomass-to-ethanol facility. However, proposing a project at a noncompatible site makes the siting of these facilities problematical.

Siting industrial facilities in California, such as biomass-to-ethanol facilities, requires that careful attention to be paid to the site selected for a project. Often, the most significant impacts associated with a project are site specific. Consequently, many potentially significant impacts and ultimate “show-stopping” issues can be avoided through the selection of an appropriate site. Where sites are chosen that allow industrial development that is compatible with surrounding land uses, do not impact sensitive biological resources, and where the proposed project meets air district rules and regulations, it is likely a project can comply with applicable laws, ordinances, and regulations which would enable it to be permitted.

Appendix VII-A

Evaluation of Feedstock Costs

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December 1999

1.0 Introduction

Providing sufficient feedstocks to produce ethanol is a significant constraint for most biomass to ethanol plants that could be built in California. While biomass resources are plentiful, the quantities required for a plant that produces over 20 million gallons per year of ethanol exceed 200,000 tons per year (bone dry ton -BDT basis). Constraints on supply and transportation distances become significant when the combination of available feedstocks, transportation costs, seasonal availability, and competing uses for feedstocks are taken into consideration.

This report analyzes potential biomass feedstock prices for ethanol production and describes scenarios for ethanol production from biomass. The composition and price of feedstocks are estimated. Transportation costs are determined for various size ethanol plants. The amount of feedstock required for ethanol production is then determined for different plant size scenarios.

Four categories of biomass feedstocks were considered for the Evaluation of Biomass-To-Ethanol Fuel Potential in California. This Appendix provides the assumptions on feedstocks costs used in Chapter VII, Economic Evaluation. The following feedstock categories were analyzed:

- Forest Material
- Agricultural Residue
- Urban Waste
- Waste Paper
- Energy Crops

Table 1-1 shows ethanol production scenarios that were considered for economic analysis in Appendix VII. A mix of feedstock materials was estimated for each feedstock category. The effect of plant size affected several elements of the feedstock cost. Transportation costs increased as feedstock costs increased. In addition, limits on the availability of some feedstocks requires a change in the feedstock mix as ethanol production capacity increases.

This Appendix discusses the following:

- Feedstock Description
- Feedstock Costs
- Transportation Costs
- Resource Constraints

Table 1-1. Summary of Ethanol Plant Scenarios

Feedstock Category	Technology	Plant Type	Timeframe/capacity (MM gal/yr) Near	Near	Mid	Mid	Long
Credit for fraction of feedstock			Yes	No	Yes	No	No
Forest Material	2-stage dilute acid	grass roots			20, 40, 60	40	30
Forest Material	2-stage dilute acid	collocated	20		20, 40, 60	40	30
Forest Material	acid/enzyme	grass roots			40	40	30
Forest Material	acid/enzyme	collocated	20		40	40	30
Ag Residue	2-stage dilute acid	grass roots			20, 40, 60	40	30
Ag Residue B	2-stage dilute acid	grass roots				40	
Ag Residue	2-stage dilute acid	collocated	20		20, 40, 60	40	30
Ag Residue B	2-stage dilute acid	collocated				40	
Ag Residue	acid/enzyme	grass roots			40	40	30
Ag Residue B	acid/enzyme	grass roots				40	
Ag Residue	acid/enzyme	collocated	20		40	40	30
Ag Residue B	acid/enzyme	collocated				40	
Urban/Mixed	2-stage dilute acid	grass roots				30, 50, 80	30
Urban/Mixed B	2-stage dilute acid	grass roots				50	
Urban/Mixed	2-stage dilute acid	collocated				30, 50, 80	30
Urban/Mixed B	2-stage dilute acid	collocated				50	
Urban/Mixed	acid/enzyme	grass roots				50	30, 80, 200
Urban/Mixed B	acid/enzyme	grass roots				50	
Urban/Mixed	acid/enzyme	collocated				50	30
Urban/Mixed B	acid/enzyme	collocated					50
Waste Paper	2-stage dilute acid	collocated		10		10, 30	30,80
Dedicated Crops	2-stage dilute acid	grass roots					30
Dedicated Crops	2-stage dilute acid	collocated					30
Dedicated Crops	acid/enzyme	grass roots					30, 80, 200
Dedicated Crops	acid/enzyme	collocated					30

2.0 Feedstock Description

A mix of materials was estimated for different categories of biomass feedstocks. Four feedstock categories are a composite of the materials shown in Table 2-1. The fraction of each material was estimated from available resources as discussed in Chapter III.

Properties of the feedstock materials are shown in Table 2-2. The properties, based on analyses performed by NREL, include sugars, lignin, and ash. The table also shows the maximum theoretical yield for ethanol production for each material. Higher lignin and ash content reduces the ethanol yield. The highest theoretical yields correspond to paper with a high cellulose content and very low lignin content. Rice straw has the lowest theoretical yield due to its high ash content. Several feedstock materials (waste paper, yard waste, urban wood waste, and other agricultural waste) are assumed themselves to be comprised of several materials. Properties for these component materials are shown in Table 2-3.

Table 2-1. Estimated mixture of materials for model biomass feedstocks

Forest Material	**Timeframe**				
	Near	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Mix (%)**				
Lumbermill Waste	37%	39%	18%	13%	27%
Forest Slash/Thinnings	63%	61%	82%	87%	73%

Agricultural Residue	**Timeframe**					
	Near	**Mid**	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Mix (%)**					
Other Agricultural Waste	20%	20%	20%	30%	20%	20%
Rice Straw	50%	50%	50%	30%	50%	50%
Orchard Prunings	30%	30%	30%	40%	30%	30%

Urban Waste	Timeframe						
	Mid	**Mid**	**Mid**	**Mid**	**Long**	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Mix (%)**						
Segregated Waste Paper	54%	54%	0%	58%	54%	58%	80%
Yard Waste	8%	8%	30%	8%	8%	8%	4%
Urban Wood Waste	21%	21%	30%	17%	21%	17%	8%
Landscape/Tree Prunings	17%	17%	40%	17%	17%	17%	8%

Waste Paper	**Timeframe**				
	Near	**Mid**	**Mid**	**Long**	**Long**
Capacity (MM gal/yr)	**10**	**10**	**30**	**30**	**80**
Material	**Estimated Feedstock Mix (%)**				
Segregated Waste Paper	100%	100%	100%	100%	100%

Energy Crops	Timeframe		
	Long	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Mix (%)**		
Eucalyptus	100%	100%	100%

Table 2-2. Feedstock properties

Feedstock Category	Material	(Percent dry weight of unextracted feedstock)								(kg/metric ton BD feedstock)			(gal/BD ton)
		Glucan	Mannan	Galactan	Xylan	Arabinan	Total Lignin	Ash	Extractive	Total Hexose	Total Pentose	Total Carbohydrate	Theoretical Ethanol Yield
Forest Material	Lumbermill Waste	43.3	10.2	2.8	7.4	1.5	28.6	0.9	5	625.5	101.1	726.6	112.8
	Forest Slash/ Thinnings	43.3	10.2	2.8	7.4	1.5	28.6	0.9	5	625.5	101.1	726.6	112.8
Agricultural Residue	Rice Straw	32	0.2	0.9	13.8	3.4	13.1	25		367.7	195.4	563.1	87.4
	Orchard Prunings	31.2	1.4	0.8	20.5	1.9	31.2	5.8		371.1	254.5	625.5	97.1
	Other Agricultural Waste	35	4.5	1.3	16.2	1.8	30.2	4.2		453.1	204.4	657.4	102.0
Urban Waste	Waste Paper	63	2.8	0.3	7.4	0.5	13.5	9.8	0	734.4	89.3	823.7	127.8
	Newsprint	44.3	4.9	0.6	5.2	0.6	29.3	3.5	0	553.3	65.9	619.2	96.1
	Tree Prunings	35	4.5	1.3	16.2	1.8	30.2	4.2		453.1	204.4	657.4	102.0
	Urban Wood Waste	37.9	7.4	2.5	12.4	2.2	29.1	2.6	2.4	530.8	166.5	697.4	108.2
	Yard Waste	34.2	2.3	0.4	14.1	1.9	18.2	20		410.0	181.8	591.7	91.8
Waste Paper	Waste Paper	63	2.8	0.3	7.4	0.5	13.5	9.8	0	734.4	89.3	823.7	127.8
Energy Crop	Eucalyptus	36.8	2.2	1	19	1.4	28.8	1.2	9.7	444.3	231.4	675.7	104.9

Table 2-3. Estimated compositions of composite feedstock materials

Material	Component	(Percent dry weight of unextracted feedstock)								(kg/metric ton BD feedstock)			(gal/BD ton)
		Glucan	Mannan	Galactan	Xylan	Arabinan	Total Lignin	Ash	Extractive	Total Hexose	Total Pentose	Total Carbohydrate	Theoretical Ethanol Yield
Waste Paper	100%	62.99	2.78	0.33	7.41	0.45	13.53	9.82	0	734.4	89.3	823.7	127.8
Un-coated Free Sheet	30%	74.9	2.7	0.3	8.9	0	5.3	7.7		865.5	101.1	966.6	150.0
Packaging Papers	40%	66.2	3.2	0.6	6.6	0.6	15.6	0.7		777.7	81.8	859.5	133.4
Coated Paper	30%	46.8	2.3	0	7	0.7	19	24.1		545.5	87.5	633.0	98.2
Tree Chips/Other Agricultural Waste	100%	35.01	4.46	1.31	16.18	1.81	30.21	4.15	0	453.1	204.4	657.4	102.0
Almond tree prunings	70%	31.2	1.4	0.8	20.5	1.9	31.2	5.8		371.1	254.5	625.5	97.1
Radiata pine	30%	43.9	11.6	2.5	6.1	1.6	27.9	0.3		644.4	87.5	731.9	113.6
Urban Wood Waste	100%	37.9	7.4	2.5	12.4	2.2	29.1	2.6	2.4	530.8	166.5	697.4	108.2
White oak prunings		34.2	2.3	0.4	14.1	1.9	18.2	20		410.0	181.8	591.7	91.8
CO Douglas fir (debarked)	20%	43.6	13.3	4.5	6.4	4.7	24.6	0.3	4.4	682.2	126.1	808.3	125.4
CA Ponderosa pine (whole tree)	20%	42.6	10.5	3.3	7.4	1.5	28.5	0.7	4.1	626.6	101.1	727.7	112.9
CA White fir (whole tree)	20%	40.7	10.4	3.2	7.3	1.2	29.9	0.6	3.3	603.3	96.6	699.8	108.6
Almond tree prunings	40%	31.2	1.4	0.8	20.5	1.9	31.2	5.8		371.1	254.5	625.5	97.1
Yard Waste Assume white oak prunings		34.2	2.3	0.4	14.1	1.9	18.2	20		410.0	181.8	591.7	91.8

Based on the feedstock material fractions and on an estimated practical yield for ethanol production for each material, the amount of needed feedstock material was calculated for each scenario. These values are shown in Table 2-4.

The compositional data do not sum to 100 percent. Some inert material or extractives are not included while the sugar fractions of the feedstock are accurately determined. The sugar and lignin fractions were held constant and additional ash and extractives were assumed for the economic analysis in Appendix VII-B.

Table 2-4. Feedstock material tonnage required for each scenario (wet basis)

Forest Material	**Timeframe**				
	Near	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**17.4**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Tonnage (thousand tons)**				
Lumbermill Waste	123	134	131	134	118
Forest Slash/Thinnings	226	226	599	964	344

Agricultural Residue	**Timeframe**					
	Near	**Mid**	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Tonnage (thousand tons)**					
Other Agricultural Waste	92	90	179	260	269	110
Rice Straw	233	227	455	263	682	280
Orchard Prunings	138	134	269	347	403	166

Urban Waste	Timeframe						
	Mid	**Mid**	**Mid**	**Mid**	**Long**	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Tonnage (thousand tons)**						
Segregated Waste Paper	222	370	0	634	166	473	1565
Yard Waste	45	74	309	119	33	86	106
Urban Wood Waste	117	195	309	252	87	188	212
Landscape/Tree Prunings	95	157	412	252	71	188	212

Waste Paper	**Timeframe**				
	Near	**Mid**	**Mid**	**Long**	**Long**
Capacity (MM gal/yr)	**10**	**10**	**30**	**30**	**80**
Material	**Estimated Feedstock Tonnage (thousand tons)**				
Segregated Waste Paper	142	129	386	319	852

Energy Crops	**Timeframe**		
	Long	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Tonnage (thousand BD tons)**		
Eucalyptus	316	807	2017

Forest material

Forest material consists of lumbermill waste, forest thinnings, and residues from logging operations (forest slash). Compositions for forest material were assumed to be the same as the composition for the Quincy Library Group (QLG) mix of feedstocks shown in Table 2-2. This QLG project plans to use a mix of forest materials (Yancey).

Ethanol plants using forest material feedstock were assumed to be located next to a lumbermill, and would use the waste from that lumbermill (assumed to be 80,000 BDT/year) as feedstock material. The remainder of the feedstock would consist of forest thinnings and forest slash.

Agricultural residue

Plants operating on agricultural residue were assumed to use a mixture of orchard prunings, rice straw, and other agricultural waste. Orchard prunings are currently used as fuel for biomass power plants. The prunings consist of tree branches that are removed seasonally as well as removals of entire orchards. Constraints on agricultural burning help make this material available.

Urban waste

A mixture of urban wood waste, tree prunings, yard waste, and waste paper are urban waste feedstocks that could be used for ethanol production. Clean wood waste is currently collected for use as a feedstock for particle board manufacturing. Most urban wood waste that is currently burned in biomass power plants consists of larger branches from tree pruning and removal with very little clean wood residue from furniture and lumber operations. Urban wood waste is a limited resource for existing biomass power plants and if used as an ethanol feedstock the price and transportation distance would increase. If lignin from ethanol production proves to be a suitable fuel for biomass power plants, the lignin could replace some or all of the feedstock for power plants and eliminate the potential competition for a limited resource.

Chipped tree branches and yard waste are another potential feedstocks. These materials are either composted or used for landfill cover and are not suitable as fuels for biomass power plants. Sorting and quality control steps may need to be taken with branches and yard waste as these can quickly rot, may contain unexpected contaminants, and can have a high ash content.

Waste paper may also be available from material recovery facilities, which serve as separation and transfer stations for urban waste. Locating the ethanol plant at such a facility would reduce transport costs and disposal costs.

Many waste streams such as office waste contain a high portion of waste paper. The paper that is not recycled is more likely to be contaminated with food waste, grease, liquids, and other materials but still useable for ethanol production. There are not many competing uses for contaminated paper. Several facilities may handle up to 360 tons of paper per day. This quantity is sufficient for a small ethanol plant. The largest MRFs in Southern California process 4,000 tons per day of MSW and over 1,000 tons/day of waste paper could be available at one location. Supplemental feedstocks such as yard waste and tree chips as well as urban wood waste, if available, would provide sufficient material for a 30 MM gal/year plant.

Energy Crops

This study used eucalyptus as the energy crop in the economic analysis, based primarily on its ability to grow well without irrigation. Another potential advantage of eucalyptus (and other woody crops) is that bioremediation of groundwater contamination may allow for a dual use, which would improve the economics. Energy crops with irrigation requirements, such as hybrid poplar and sugar-based crops such as sugar beets, sweet sorghum, and sugar cane, were not considered.

3.0 Feedstock Costs

Of the variables evaluated, the cost of the feedstock has a very important effect on the economics of ethanol production. Production economics were analyzed for feedstocks with and without subsidies shown in the main report. Materials that could potentially be subsidized (forest thinnings, rice straw, and waste paper) were estimated to make up 30 to 70 percent of the feedstock from an ethanol plant.

The cost of feedstocks was obtained from several sources. The California Energy Commission (CEC) documented the results of a biomass feedstock model for DOE in 1994 (Tiangco 1998). This study uses a production cost model to determine the cost of forest material, energy crops, rice straw, and other biomass materials. The cost estimates are based on a life cycle analysis of labor, land, fuel, financing, and equipment costs. CEC and NREL also completed a study of biomass. This study examines recent biomass feedstocks that might be suitable for ethanol production.

Table 3-1 summarizes the cost for biomass feedstock materials, excluding transportation costs. Table 3-2 shows feedstock costs including transportation costs. (Transportation costs are discussed in Section 4 of this Appendix.) The potential credit that was estimated for each feedstock is shown in Table 3-3. The total value of feedstock credits, and the value per gallon of ethanol produced, varies with plant size. Figures 3-1 and 3-2 show this variation resulting from a $30/BD ton forest thinning credit for plants using forest material feedstock in $/year and $/gal, respectively. Costs for each of the four categories of feedstock materials were estimated as a composite of the mix of available feedstocks in Table 3-4.

With the forest materials case, forest thinnings supplement lumbermill waste as a feedstock. Lumbermill waste is valued at $20/ton. Lumbermill waste is used as fuel to generate electric power or steam for lumbermill operations. For facilities that are not collocated with a biomass power plant, lumbermill waste is sold for uses such as animal bedding.

Forest thinnings are more expensive and add to the cost of the feedstock. Subsidized forest thinnings were considered as feedstocks since efforts are currently underway to use forest thinning practices as a means of reducing fire risk. Other competing uses for forest thinnings could raise the price of the material; however, very large quantities are under consideration for ethanol production.

Some rice straw qualifies for a tax credit if it is reused. This fraction of the agricultural material feedstocks was considered as one that could potentially qualify for continued subsidies. Orchard prunings are also used as feedstocks for biomass power plants. The use of this material for ethanol production could cause an increase in the price for such materials unless the supply is carefully assessed.

Similarly, urban wood waste is also used as a feedstock for power plants. The cost of urban wood waste fuel has risen to $50/ton in the past when it was in short supply for biomass power plants. The amount of wood waste and tree waste is limited so additional waste material was assumed to come from waste paper.

Currently, most forms of recycled paper are very costly. For example the price of recycled newspaper is about $100/ton. Using waste paper as a feedstock has a potential value for cities or materials recycling facilities (MRF) that must dispose of waste materials in landfills. A MRF must dispose of waste material and pay approximately $20 in tipping fees and up to $15 in transportation. Therefore using the material for ethanol production would save a MRF $35 per ton which could be used to process and sort the waste paper. The economics were evaluated for cases where the ethanol plant was located at a MRF. A feedstock cost of -$10 per ton was assumed for smaller 10 million gal/year plants. For larger plants, it was assumed that waste paper would need to be transported from another facility with an increase in transportation costs. Ethanol production costs were also evaluated over a range of feedstock prices. The largest MRFs could provide enough waste paper for over 30 million gallons per year of ethanol without relying on the transport of waste paper from other facilities. For smaller 10 million gallon per year ethanol facilities located at MSW facilities, transportation costs were assumed to be zero for waste materials. A MRF can also recover a fraction of the waste paper that it collects and sell it as mixed paper. The market for waste paper has varied from no value to over $40/ton. Such uses of waste paper would compete with ethanol production.

Table 3-1. Feedstock material cost (without transportation cost)

Forest Material	**Timeframe**				
	Near	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Cost ($/BD ton)**				
Lumbermill Waste	20	20	20	20	20
Forest Slash/Thinnings	34	34	34	34	34

Agricultural Residue	**Timeframe**					
	Near	**Mid**	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Cost ($/BD ton)**					
Other Agricultural Waste	5	5	5	5	5	5
Rice Straw	18	18	18	18	18	18
Orchard Prunings	23	23	23	23	23	23

Urban Waste	**Timeframe**						
	Mid	**Mid**	**Mid**	**Mid**	**Long**	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Cost ($/BD ton)**						
Segregated Waste Paper	10	10	N/A	10	10	10	10
Yard Waste	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Urban Wood Waste	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Landscape/Tree Prunings	5	5	5	5	5	5	5

Waste Paper	**Timeframe**				
	Near	**Mid**	**Mid**	**Long**	**Long**
Capacity (MM gal/yr)	**10**	**10**	**30**	**30**	**80**
Material	**Estimated Feedstock Cost ($/BD ton)**				
Segregated Waste Paper	-10	-10	-10	-10	-10

Energy Crops	**Timeframe**		
	Long	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Cost ($/BD ton)**		
Eucalyptus	36	36	36

Table 3-2. Feedstock material cost (including transportation cost)

Forest Material	Timeframe				
	Near	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Cost ($/BD ton)**				
Lumbermill Waste	20	20	20	20	20
Forest Slash/Thinnings	43.6	43.5	47.5	50.4	45.5

Agricultural Residue	Timeframe					
	Near	Mid	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Cost ($/BD ton)**					
Other Agricultural Waste	13.4	13.4	13.4	13.4	13.4	13.4
Rice Straw	27.9	27.9	30.1	28.4	31.7	28.9
Orchard Prunings	31	31	31	31	31	31

Urban Waste	Timeframe						
	Mid	Mid	Mid	Mid	Long	Long	Long
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Cost ($/BD ton)**						
Segregated Waste Paper	10/14.9[1]	15.7	N/A	16.8	10/14.9[1]	16.8	20.1
Yard Waste	2.5/9.2[2]	10.2	10.2	11.7	2.5/9.2[2]	11.7	16.2
Urban Wood Waste	10.5/17.6[3]	18.6	18.6	20.2	10.5/17.6[3]	20.2	24.9
Landscape/Tree Prunings	5/12.1[4]	13.1	13.1	14.7	5/12.1[4]	14.7	19.4

Waste Paper	Timeframe				
	Near	Mid	Mid	Long	Long
Capacity (MM gal/yr)	**10**	**10**	**30**	**30**	**80**
Material	**Estimated Feedstock Cost ($/BD ton)**				
Segregated Waste Paper	-10	-10	-4.3	-4.3	-4.3

Energy Crops	Timeframe		
	Long	Long	Long
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Cost ($/BD ton)**		
Eucalyptus	41.8	43.6	46.3

[1]$10/BD ton for grass roots plant, $14.9/BD ton for collocated plant.
[2]$2.5/BD ton for grass roots plant, $9.2/BD ton for collocated plant.
[3]$10.5/BD ton for grass roots plant, $17.6/BD ton for collocated plant.
[4]$5/BD ton for grass roots plant, $12.1/BD ton for collocated plant.

Table 3-3. Feedstock material credit

Forest Material	**Timeframe**				
	Near	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Credit ($/BD ton)**				
Lumbermill Waste	0	0	0	0	0
Forest Slash/Thinnings	30	30	0/30[1]	30	0

Agricultural Residue	**Timeframe**					
	Near	**Mid**	**Mid**	**Mid**	**Mid**	**Long**
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Credit ($/BD ton)**					
Other Agricultural Waste	0	0	0	0	0	0
Rice Straw	15	15	15	0	15	0
Orchard Prunings	0	0	0	0	0	0

Urban Waste	**Timeframe**						
	Mid	**Mid**	**Mid**	**Mid**	**Long**	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Credit ($/BD ton)**						
Segregated Waste Paper	0	0	0	0	0	0	0
Yard Waste	0	0	0	0	0	0	0
Urban Wood Waste	0	0	0	0	0	0	0
Landscape/Tree Prunings	0	0	0	0	0	0	0

Waste Paper	**Timeframe**				
	Near	**Mid**	**Mid**	**Long**	**Long**
Capacity (MM gal/yr)	**10**	**10**	**30**	**30**	**80**
Material	**Estimated Feedstock Credit ($/BD ton)**				
Segregated Waste Paper	0	0	0	0	0

Energy Crops	**Timeframe**		
	Long	**Long**	**Long**
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Credit ($/BD ton)**		
Eucalyptus	0	0	0

[1]Both Credit and non-Credit scenarios were analyzed.

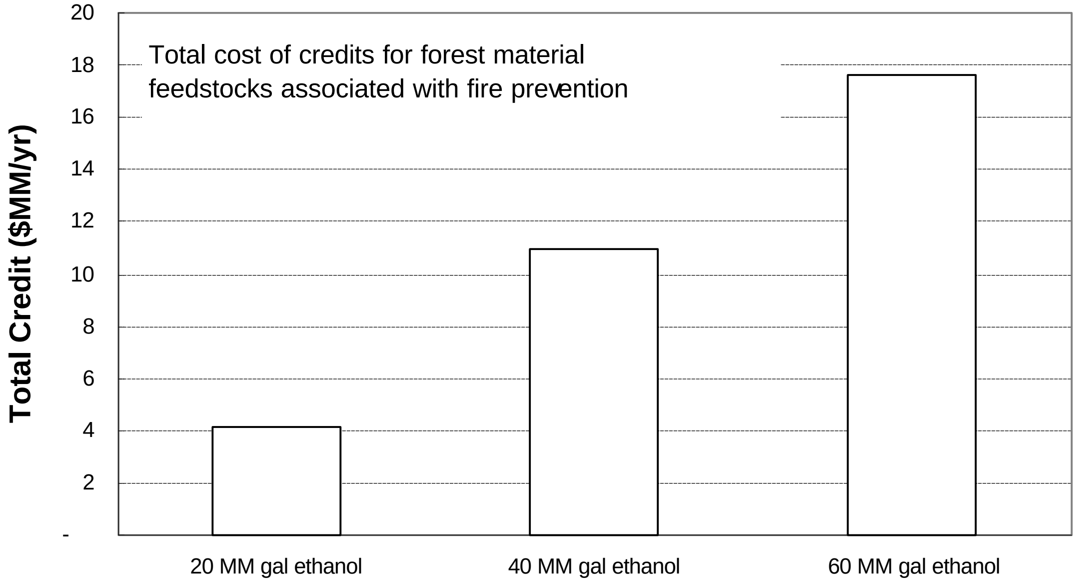

Figure 3-1. Annual credit value for ethanol plants using forest material feedstock

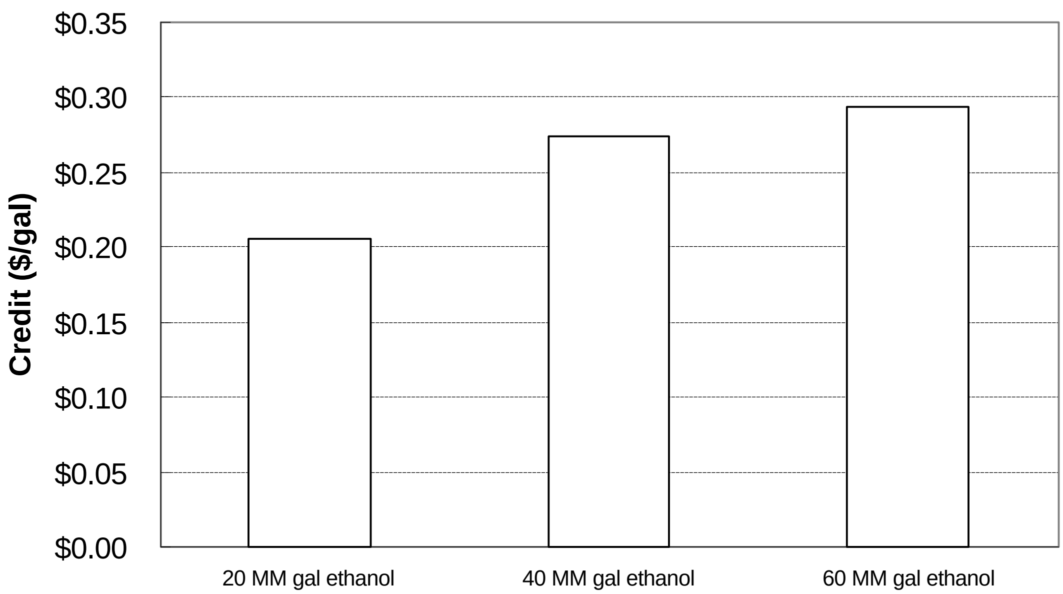

Figure 3-2. Value of credit per gallon for ethanol plants using forest material feedstock

Table 3-4. Summary of feedstock cost assumptions

Feedstock Category	Composite Cost ($/ton)		Feedstock Materials	Cost ($/ton)
Credit Assumption	Yes	No		
Forest Material (collocated cases)	18	42.2	Forest thinnings Lumbermill waste	47.5 20.0
Agricultural Residue	19.5	27	Other Ag. Waste Rice Straw Orchard prunings	13.4 27.9 31.0
Urban Waste	-	15.4	Separated waste paper Yard waste Urban wood waste Tree pruning chips	15.7 10.2 18.6 13.1
Waste Paper (MRF location)	-	-4.3	Separated waste paper	-4.32
Energy Crops	-	43.6	Eucalyptus	43.6

Feedstock costs for mid-term 40 to 50 MM gal/year ethanol capacity. Transportation costs vary with plant size. Larger plant sizes require more feedstock and greater transportation distances. Small urban waste plants can obtain low cost waste paper feedstocks if located with a materials recovery facility.

4.0 Transportation costs

Transportation costs were estimated based on costs of truck transport, which include a fixed loading/unloading cost per truckload, and a cost per mile of transport distance. These cost components are shown in Table 4-1.

Table 4-1. Primary components of transportation costs.

Component	Cost
Loading/unloading cost	$45 per truckload[1]
Travel cost	$3.75 per one-way mile per truckload[2]

[1]Based on one hour per truckload at $45/hr truck labor and vehicle cost. Travel cost is additive.
[2]Includes $3/mi truck labor and vehicle cost ($45/hr, 30 round-trip miles per hour average speed) and $0.75/mi fuel cost (4 mi/gal, $1.50/gal).

Feedstocks are assumed to be transported by tractor-trailers with volume capacity of 80 cubic yards and maximum load of 26 tons per truckload. All of the materials studied would exceed the volume limit before reaching the maximum weight load, so dry mass per truckload was calculated for each material based on bulk density and typical moisture content, as shown in Table 4-2. Moisture content for some materials may be higher; however, total transportation costs calculated for hauling biomass are consistent with actual transportation costs in the biomass industry.

Table 4-2. Feedstock material dry mass per truckload is a function of bulk density and moisture content

Feedstock	Bulk Density (lb/cu ft)	Mass (tons/ Truckload)	Moisture	Dry mass (BD tons/ truckload)
Forest Material				
Forest Slash/Thinnings	20	21.6	30%	15.1
Agricultural Residue				
Other Agricultural Waste	19	20.5	30%	14.4
Rice Straw	13	14.0	31%	9.7
Orchard Prunings	20	21.6	30%	15.1
Urban Waste				
Segregated Waste Paper	20	21.6	5%	20.5
Yard Waste	20	21.6	30%	15.1
Urban Wood Waste	19	20.5	30%	14.4
Landscape/Tree Prunings	19	20.5	30%	14.4
Energy Crops				
Eucalyptus	20	21.6	30%	15.1

Round-trip transport distance was calculated in one of two ways, depending on the material. For materials such as waste paper and yard waste that would be transported to the ethanol plant from a central collection point, a reasonable distance between the collection point and the hypothetical plant location was assumed. For urban waste feedstock materials, this distance increased with increasing plant size to reflect that materials would be trucked from several collection points rather than one nearby collection point.

For materials that would be gathered from an area rather than from a collection point, including forest slash and thinnings, rice straw, and eucalyptus, transport distance was derived by determining the size of the geographic area required to generate the needed quantity of material (using reasonable assumptions about material density and availability). Average one-way transport distance was then calculated from this area.

Ethanol plants using forest material feedstock were assumed to be collocated with a lumbermill, which eliminates transport costs for lumbermill waste. Small (30 MM gal/yr) grass roots ethanol plants using urban waste feedstock were assumed to be collocated with an urban waste collection center to eliminate transport costs. Larger ethanol plants were deemed to be too large to be limited to one collection center.

Tables 4-3 and 4-4 show the calculated transport distances and transport costs, respectively, for each scenario.

Table 4-3. Feedstock material transportation distances

Forest Material	Timeframe				
	Near	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Transportation Distance (one-way miles)**				
Lumbermill Waste	0	0	0	0	0
Forest Slash/Thinnings	26	26	42	54	34

Agricultural Residue	Timeframe					
	Near	Mid	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Transportation Distance (one-way miles)**					
Other Agricultural Waste	20	20	20	20	20	20
Rice Straw	14	14	19	15	23	16
Orchard Prunings	20	20	20	20	20	20

Urban Waste	Timeframe						
	Mid	Mid	Mid	Mid	Long	Long	Long
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Transportation Distance (one-way miles)**						
Segregated Waste Paper	0/15[1]	19	N/A	25	0/15[1]	25	43
Yard Waste	0/15[1]	19	19	25	0/15[1]	25	43
Urban Wood Waste	0/15[1]	19	19	25	0/15[1]	25	43
Landscape/Tree Prunings	0/15[1]	19	19	25	0/15[1]	25	43

Waste Paper	Timeframe				
	Near	Mid	Mid	Long	Long
Capacity (MM gal/yr)	**10**	**10**	**30**	**30**	**80**
Material	**Estimated Feedstock Transportation Distance (one-way miles)**				
Segregated Waste Paper	0	0	19	19	19

Energy Crops	Timeframe		
	Long	Long	Long
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Transportation Distance (one-way miles)**		
Eucalyptus	11	19	29

[1]0 miles for grass roots plant, 15 miles for collocated plant.

Table 4-4. Feedstock material transportation costs

Forest Material	Timeframe				
	Near	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**60**	**30**
Material	**Estimated Feedstock Transportation Cost ($/BD ton)**				
Lumbermill Waste	0	0	0	0	0
Forest Slash/Thinnings	9.6	9.5	13.5	16.4	11.5

Agricultural Residue	Timeframe					
	Near	Mid	Mid	Mid	Mid	Long
Capacity (MM gal/yr)	**20**	**20**	**40**	**40 (B)**	**60**	**30**
Material	**Estimated Feedstock Transportation Cost ($/BD ton)**					
Other Agricultural Waste	8.4	8.4	8.4	8.4	8.4	8.4
Rice Straw	9.9	9.9	12.1	10.4	13.7	10.9
Orchard Prunings	8	8	8	8	8	8

Urban Waste	Timeframe						
	Mid	Mid	Mid	Mid	Long	Long	Long
Capacity (MM gal/yr)	**30**	**50**	**50 (B)**	**80**	**30**	**80**	**200**
Material	**Estimated Feedstock Transportation Cost ($/BD ton)**						
Segregated Waste Paper	0/4.9[1]	5.7	N/A	6.8	0/4.9[1]	6.8	10.1
Yard Waste	0/6.7[2]	7.7	7.7	9.2	0/6.7[2]	9.2	13.7
Urban Wood Waste	0/7.1[3]	8.1	8.1	9.7	0/7.1[3]	9.7	14.4
Landscape/Tree Prunings	0/7.1[3]	8.1	8.1	9.7	0/7.1[3]	9.7	14.4

Waste Paper	Timeframe				
	Near	Mid	Mid	Long	Long
Capacity (MM gal/yr)	**10**	**10**	**30**	**30**	**80**
Material	**Estimated Feedstock Cost ($/BD ton)**				
Segregated Waste Paper	0	0	5.7	5.7	5.7

Energy Crops	Timeframe		
	Long	Long	Long
Capacity (MM gal/yr)	**30**	**80**	**200**
Material	**Estimated Feedstock Transportation Cost ($/BD ton)**		
Eucalyptus	5.8	7.6	10.3

[1]$0/BD ton for grass roots plant, $4.9/BD ton for collocated plant.
[2]$0/BD ton for grass roots plant, $6.7/BD ton for collocated plant.
[3]$0/BD ton for grass roots plant, $7.1/BD ton for collocated plant.

The transport costs and distances derived for this study are fairly consistent with those used in previous studies (Tiangco).

5.0 Resource Constraints

The quantities of available biomass, competing uses, and transportation distances affect the cost of feedstocks. The mix of feedstocks for an ethanol plant must be managed to deal with seasonal availability of feedstocks and to avoid price spikes. The following evaluates constraints on the availability of biomass feedstocks.

5.1 Forest Material

The availability of forest material as feedstock at reasonable cost for ethanol production is constrained primarily by transportation costs and access. The amount of forest material needed for even the largest scenario analyzed in this study is a small fraction of the estimated amount available in California. For example, the 60 million gal/yr ethanol plant scenario requires 0.67 million BDT/yr of forest slash and forest thinnings, which is approximately 10 percent of the total amount currently available annually in California (based on current rates of forest thinning, which are presumed to be inadequate). However, transportation costs increase quickly with plant size as the plant must draw thinnings and slash from a larger geographic area, while the amount of available lumbermill waste remains fixed. In addition, collecting costs could increase significantly if acreage with poor road access is needed as a source of thinnings or slash. Figure 5-1 illustrates the potential mix of feedstocks for ethanol production and the lignin available for electric power production.

Another constraint on forest material availability is thinning frequency, which perhaps could be performed more or less frequently than the 10 years assumed in this analysis. In addition, forest slash availability is constrained by the amount of logging operations in the vicinity of the ethanol plant. Lastly, the level of support for forest thinning, translated into a credit for thinning operations, could vary over time.

5.2 Agricultural Residue

The estimated mix of agricultural feedstocks is illustrated in Figure 5-2. Alternate uses for agricultural residue affects the availability of some materials as a feedstock for ethanol production. Orchard prunings are a feedstock for biomass power production. Other agricultural materials such as spoiled fruits and vegetables are not suitable as powerplant fuels; howerver, their availability is seasonal and they tend to rot quickly. Lignin from ethanol production could provide a fuel for biomass powerplants as illustrated in Figure 5-2. This balance of lignin could allow for an efficient utilization of resources where the cellulose is first converted to ethanol.

Rice straw is seasonally available as a feedstock. 1.5 million tons per year are produced in California but not all of this material is harvested. Competing uses include bedding material for livestock. Rice straw contains a high silica content so it is likely that lignin derived from rice straw could not be burned in biomass power plants as separating the silica would be costly. Silica erodes the boiler tubes from power plants.

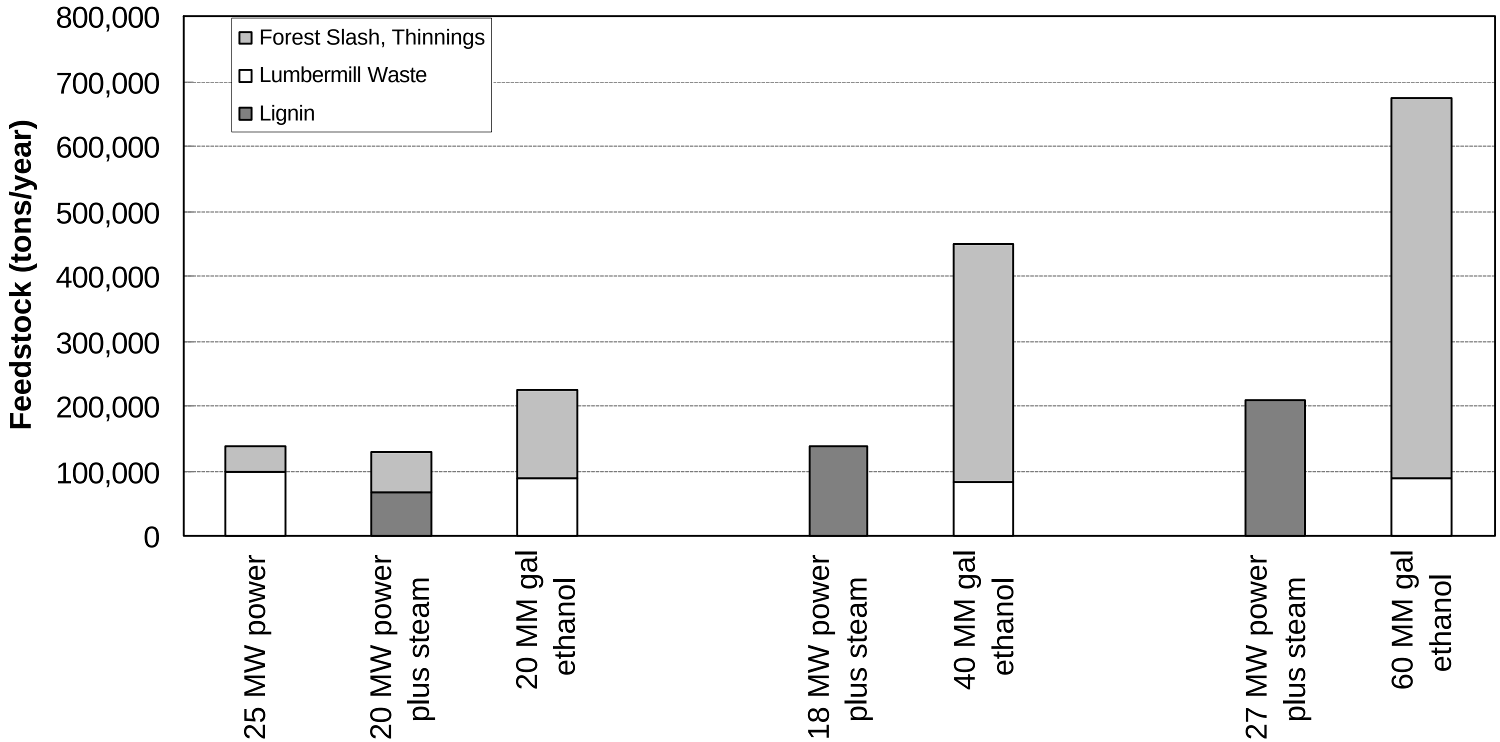

Figure 5-1. Forest materials for ethanol and biomass power production

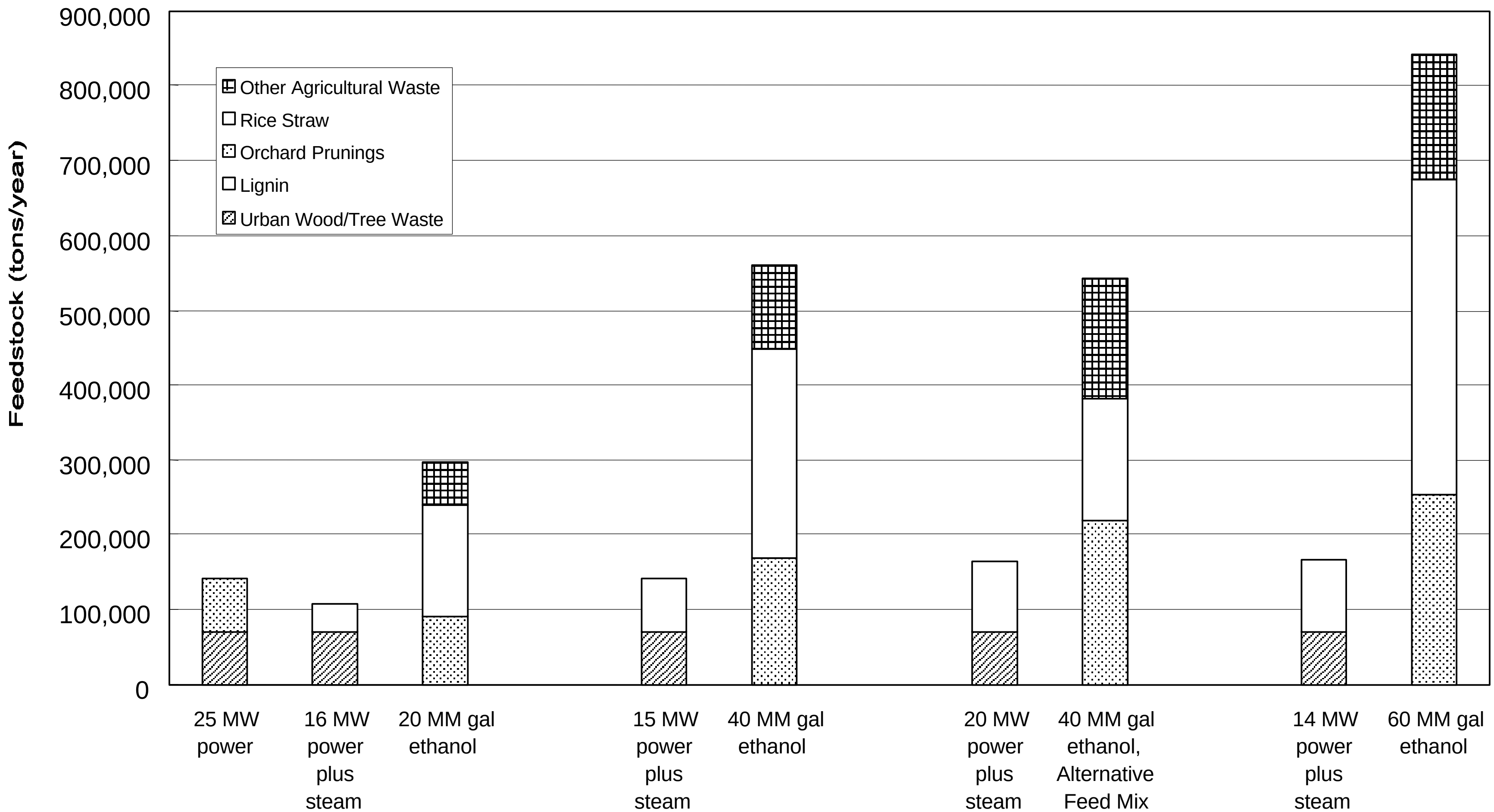

Figure 5-2. Agricultural residue feedstocks for ethanol and biomass power

If rice straw or waste paper were not subsidized, it was assumed that more tree waste and urban wood waste would need to be used as feedstocks for agricultural and urban based plants. The availability of such materials is currently limited which would be an obstacle for the economic production of ethanol. In such a case, more lignin is generated and it may be feasible to maintain the feedstock supply to a biomass power plant while using available woody feedstocks for ethanol production especially if ethanol production could be supplemented with leafy materials and other residues that are not suitable as powerplant fuel. These materials may contain high levels of ash and other contaminants. For example, yard waste may contain over 20 percent ash. Relying on a large quantity of alternative materials for ethanol production may be unrealistic. Given the large quantities of available rice straw, this material appears to be a key feedstock for ethanol plants in the 20 million gal/year and greater capacity.

5.3 Urban Waste

Alternative uses of urban waste materials limit its availability as a low cost feedstock for ethanol production. Urban woodwaste is already used as a fuel for biomass power plants. This is a lower grade of waste wood referred to as power plant fuel. Combining urban wood waste, waste paper, and other materials increases the material that would be available for ethanol production as shown in Figure 5-3. An ethanol plant could consume all of the urban wood waste burned by a biomass power plant and all of the waste paper from a MRF. Additional tree waste and yard waste could supplement these feedstocks. For ethanol plants over 30 million gallons per year, additional material would need to be brought from other MRFs or transfer stations in most cases. Additional costs for transportation as well as handling and a premium to incentivize the consistent availability of the feedstock would add to the price of the feedstock. It is not practical to make collection facilities larger and reduce tipping fees as much of the material is delivered in smaller trucks. For example, tree chips are hauled in a truck that may hold only 3 tons of material and a long drive to a large ethanol plant would increase transportation costs.

The amount of waste paper that would be available for a low cost at any one facility is limited to about 360 tons per day for larger facilities. An ethanol plant located with a material recovery facility may be able to obtain waste paper feedstocks in the range of 0 to $10 per ton after clean up costs are taken into account. Larger ethanol plants will likely need to transport feedstocks from other material recovery facilities. However, the largest MRFs would not need to transport waste paper from other facilities.

5.4 Energy Crops

The potential use of energy crops is constrained by several factors, which are discussed in Chapter IV of the main report. The primary economic constraints include the need for crops that do not require irrigation, and the fact that energy crops must be grown in close proximity to the ethanol plant to keep transport costs reasonable. This depends on having significant land nearby that can be dedicated to energy crops.

In addition, the lack of current usage of energy crops creates significant uncertainty about the costs of energy crops such as eucalyptus.

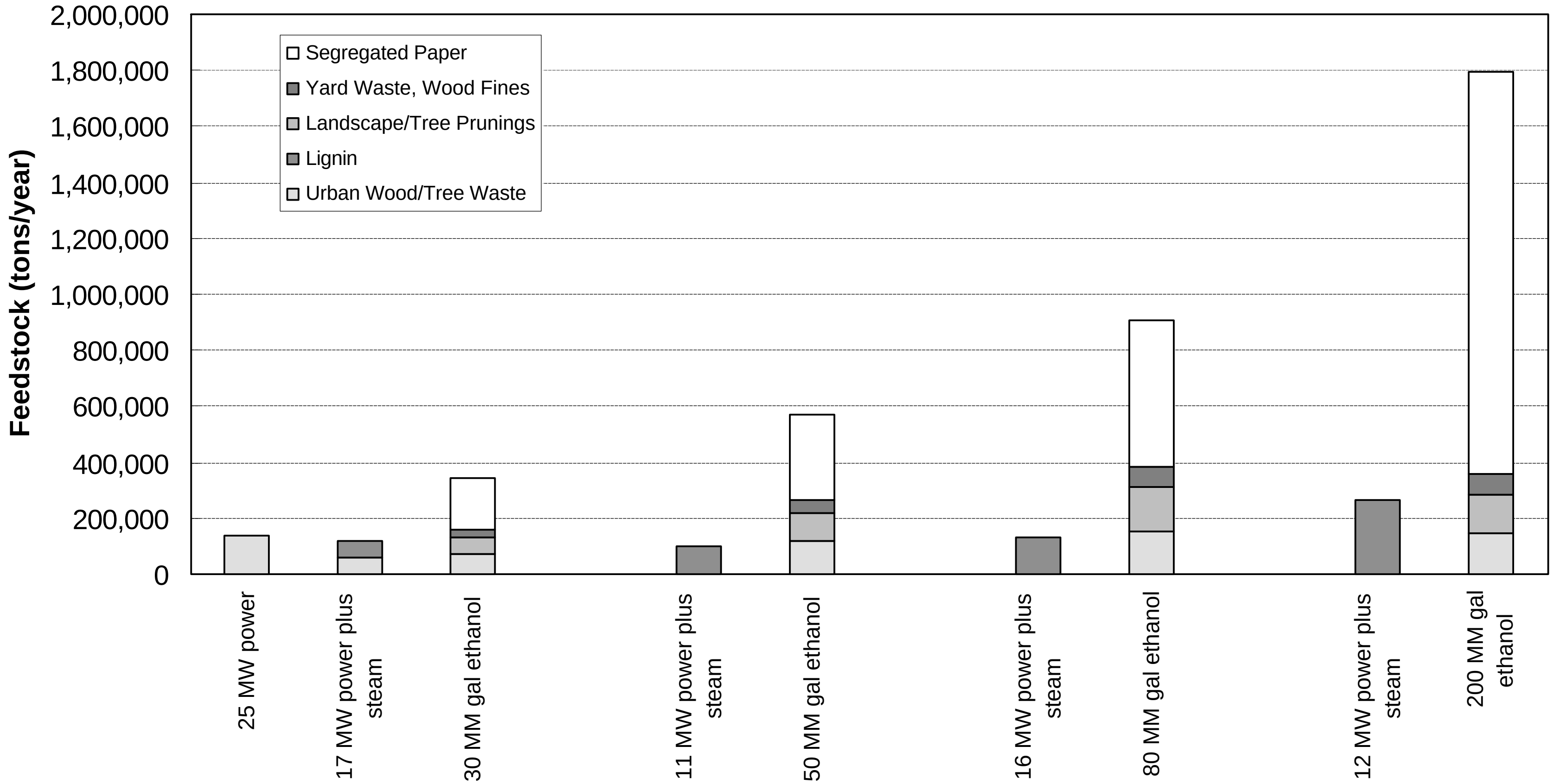

Figure 5-3. Urban waste materials for ethanol and biomass power production

5.5 Potential Ethanol Production Capacity

Table 5-1 illustrates the potential ethanol production capacity in the mid-term. If planned ethanol facilities are constructed and expanded in capacity, it appears that 170 million gallons could available in the mid-term. A large scale ethanol industry, producing 520 million gallons per year, could include four plants for each of the three feedstock categories by the year 2007. This scenario would require a well defined, secure demand for ethanol and could evolve from planned ethanol production facilities. Biomass resources for this scenario appear to be within the amount of material available in the state as well as within transportation constraints and competing demands for the feedstocks. Permitting, secure ethanol demand, and case-by-case feedstock availability would be key constraints that would limit the rapid construction of ethanol plants. A combination of plant capacities could make up the mix of mid-term ethanol supply in California. Plants over 50 million gallons per year would require significant transportation of feedstock material, but total production costs could be lower if the cost of feedstock transportation does not rise too quickly.

Table 5-1. Potential Ethanol Production Capacity

Feedstock Supplies		Large Scale No. Plants	Moderate Scale No. Plants
		4	2
Forest Material	40 MM gal/yr	160	80
Lumbermill Waste	100 M tons/year	400	200
Forest Slash/Thinnings	414 M tons/year	1656	828
		4	1
Agricultural Residue	40 MM gal/yr	160	40
Other Agricultural Waste	114 M tons/year	456	114
Rice Straw	332 M tons/year	1328	332
Orchard Prunings	179 M tons/year	716	179
		4	1
Urban Waste	50 MM gal/yr	200	50
Segregated Paper	526 M tons/year	2104	526
Urban Wood/Tree Waste	201 M tons/year	804	201
Landscape/Tree Prunings	237 M tons/year	948	237
Yard Waste, Wood Fines	101 M tons/year	404	101
		12	4
Total biomass	M tons/year	8816	2718
Total ethanol	MM gal/yr	520	170

5.6 Geographic Limitations

The location of biomass resource and available roads for transporting materials affects the transportation costs for biomass feedstocks. The Quincy Library Group evaluated the availability of forest materials for several locations in Northern California. An assessment was made of the available lumber mill waste, forest material that could be removed for fire control, and timber harvesting waste within a 25 mile radius of a candidate site. The amount of material ranged from 180,000 BD tons per year to 330,000 BD tons per year. A supply of 300,000 tons per year could support a 60 million gallon per year plant; however scale up beyond this size appears problematic for forest material plants. Obtaining greater quantities of feedstock would require a substantial increase in transportation distance. As biomass resources become scarce in one region, it becomes more cost effective to transport materials from other regions than to seek material from steeper terrain. Increased transportation on State highways will be a noticeable impact. Each additional 20 million gallons per year of ethanol production will generate approximately 45 truck round trips. This impact could be significant in areas with small rural roads.

Existing biomass power plants provide good sites for ethanol production facilities as they have materials handling and steam generation facilities that can be shared with an ethanol plant. Biomass power plants are located in close proximity to the biomass resources in California, primarily in the forested regions of Northern California where lumber resources are plentiful and along the Central Valley where agricultural wastes are available. For ethanol plants based on forest material or agricultural waste there are several plants which are candidates for collocated ethanol facilities.

Figure 5-4 shows candidate sites for ethanol plants studied by the Quincy Library Group. Each 25 mile circle indicates a region where feedstock transportation costs would be relatively low. Areas where the circles intersect would suggest limit the amount of feedstock that is available for ethanol production if multiple ethanol plants were located in close proximity.

In urban areas, there are few biomass power plants in close proximity to urban centers or MRFs. Consequently, transportation costs for urban waste and waste paper would be higher if the material needed to be shipped to a biomass power plant location. Collocating the ethanol plant at a MRF or wood waste transfer station would reduce transportation costs and help assure a more consistent supply of feedstocks. In Southern California, there are biomass power plants in Delano and San Bernadino, located 80 and 50 miles from Los Angeles. If urban wastes were used as feedstocks, more centrally located facilities might be considered to reduce transport costs.

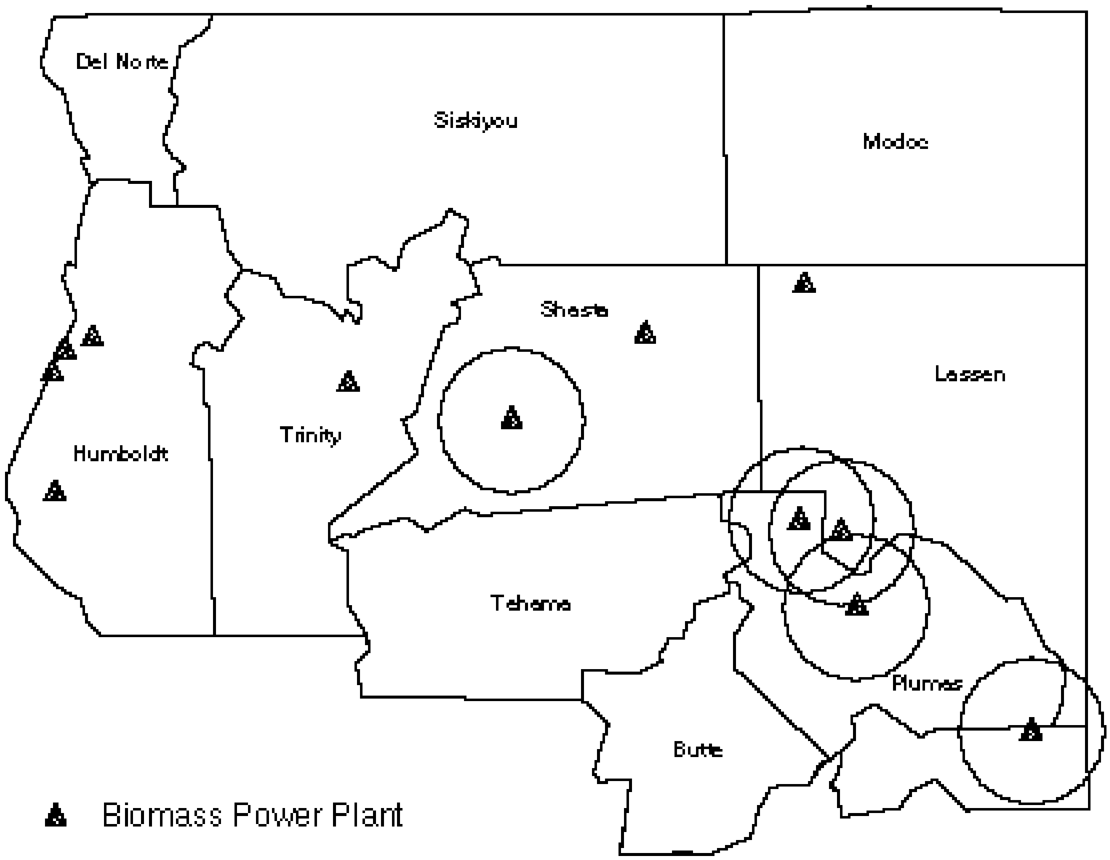

Figure 5-4. Location of Candidate Ethanol Plants with Biomass Power Plants

Appendix VII-B

EVALUATION OF ETHANOL PRODUCTION COSTS

Prepared For:

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December 1999

Table of Contents

List of Tables

List of Figures

1.0 Introduction

1.1 Parties

ProForma Systems, Inc., (ProForma), was retained by ARCADIS Geraghty & Miller (ARCADIS) on behalf of the California Energy Commission (CEC) to provide assistance related to Executive Order D-5-99 issued by California Governor Gray Davis on March 25, 1999. Part 11 of the Executive Order directs new investigations of the potential for employing ethanol, and for producing ethanol in California, in response to the phase-out of MTBE use. ProForma was retained to evaluate ethanol production economics from various feedstocks such as corn and other biomass.

This report has been prepared for the sole benefit of the CEC. Any third party in possession of the report may not rely upon its conclusions without the written consent of ProForma. ProForma conducted this analysis and prepared this report utilizing reasonable care and skill in applying methods of analysis consistent with normal industry practice. All results are based on information available at the time of review. Changes in factors upon which the review is based could affect the results. Economic forecasts are inherently uncertain because of events or combinations of events that cannot reasonably be foreseen including the actions of government, individuals, third parties and competitors. *NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE SHALL APPLY.*

The 65 biomass-to-ethanol scenarios analyzed in this report were provided to ProForma by ARCADIS. Additional information on which this report is based has been provided by others. ProForma has utilized such information without verification unless specifically noted otherwise. ProForma accepts no liability for errors or inaccuracies in information provided by others.

1.2 Purpose and Background

This report examines the economics of biomass-to-ethanol production in California and assesses the potential cost of new ethanol production in the state compared with conventional corn ethanol supply sources. A number of different production scenarios incorporating different feedstock and production process options are analyzed and other economic implications of this new industry, such as employment, are appraised.

Costs associated with conventional corn-based ethanol plants currently supplying most ethanol used as fuel in the United States are estimated to form a comparative benchmark. The most efficient of these plants use the latest wet milling processes integrated with electric power generation and food and animal feed products. Plant size, feedstock prices and the markets for co-products affect resulting ethanol prices[1].

The cost of ethanol from cellulosic biomass (non-corn and starch based feedstocks) is greatly affected by feedstock cost, and by the feedstock's physical and chemical characteristics. These characteristics determine the difficulty of converting the solid, polymeric sugars in the feedstock to soluble; fermentable sugars at high yields; and this in turn impacts capital and operating costs. The chemical composition of the feedstock determines how much ethanol, lignin and other co-products can theoretically be produced per ton of biomass. The quantity of feedstock available versus the delivered cost is also important to ethanol cost because of the economies of scale inherent in the ethanol facility construction. In general, larger facilities are more economical until the marginal cost of additional feedstock is greater than the affect of economies of scale.

Using its *Virtual Process Simulator*, ProForma has estimated the required ethanol-selling price to meet the hurdle rate specified for the various scenarios provided by ARCADIS. This price is also referred to as the Target Price as market conditions will determine the actual price of the product fuel ethanol. These scenarios and corresponding hurdle rates are listed in Appendix VII-B-1 of this report. The following variables are addressed by these scenarios:

- 2-stage dilute acid ethanol production technology versus acid/enzyme technology
- Ethanol plant size
- Stand-alone ethanol facilities versus ethanol facilities collocated with biomass power plants or material recovery facilities
- Four biomass feedstock categories (forest material, urban waste, agricultural waste, and an energy crop) with variations within each category
- Near (2002), mid (2007) and long-term (2012) timeframes
- Feedstock credits versus no credits

Three plant configurations were considered. Scenarios were developed for 30 stand-alone grass roots production facilities. Thirty additional cases included an ethanol plant collocated with a biomass power plant. Five cases include an ethanol plant located at a material recovery facility (MRF) in an urban area. The 2-stage dilute acid and the acid/enzyme ethanol production technologies and the associated process assumptions for the near-, mid- and long-term timeframes are described in detail in Sections 3.1 and 3.2. Collocation of biomass ethanol facilities with existing biomass power plants can result in significantly improved ethanol production prices. The capital cost of the ethanol facility is reduced by up to 30% due to the existing and shared infrastructure of the biomass power plant. The ethanol plant located at a MRF shares facilities for handling feedstocks. However, new wastewater treatment and steam generation equipment are required. See Section 3.3 and the references for more information about the advantages of collocation[2,3,4].

ARCADIS selected five biomass categories for analysis: forest material, urban waste, agricultural waste, and energy crops. Each of these more general biomass categories is assumed to be composed of the following biomass types:

- Forest material: lumbermill waste and forest slash and thinnings
- Urban waste: waste paper, tree prunings, urban wood waste and yard waste
- Agricultural waste: rice straw, orchard prunings, and “other agricultural waste”
- Energy crops: eucalyptus
- Waste paper: paper from material recovery facilities

The mix of the above biomass types within each category is varied for the scenarios analyzed in accordance with the information provided by ARCADIS. In addition, the impact of credits for forest slash and rice straw is considered in several of the scenarios. The 65 scenarios analyzed herein are described in more detail in Sections 2.3 and 2.4 below.

Over the long term, it is assumed that ethanol production in California would evolve towards improvements in processing technologies and subsequently lower ethanol production costs[5,6,7,8]. As experience is gained with cellulose-based production, increased ethanol yields, reduced enzyme costs, and the opportunity for production of value added co-products would reduce the cost of ethanol production. Additional feedstocks such as energy crops and additional urban waste materials may be economic. The impacts of improved technology, production of value added co-products and reduced hurdle rates are evaluated by near-, mid-, and long-term scenarios.

The cost of ethanol production will also be assessed for various scenarios that take into account increased availability of feedstocks and reduced risks due to demonstrated ethanol technologies, which will result in the construction of larger, more economical ethanol plants.

2.0 Scenarios to be Analyzed

Scenarios provided by ARCADIS were analyzed with the ProForma *Virtual Process Simulator*. Scenarios 1 through 30 are for stand-alone ethanol facilities, while scenarios 31 through 60 are for ethanol facilities collocated with biomass power plants. Scenarios 61 through 65 are for ethanol facilities collocated with a material recovery facility. Within each of these groups, the scenarios are further subdivided by the four major feedstock categories evaluated: forest materials, urban waste, agricultural waste, and energy crops. Forest materials include lumbermill waste and forest slash and thinnings. Urban waste is comprised of waste paper, tree prunings, urban wood waste, and yard waste. Agricultural waste includes rice straw, orchard prunings, and other agricultural wastes. Eucalyptus was chosen to represent a possible energy crop in California. The compositions of these feedstocks used in this analysis are included in Appendix VII-B-2.

The costs of ethanol produced by the corn dry-milling and wet-milling processes were also estimated to form a benchmark. The resulting corn ethanol prices are affected by feedstock prices, plant size, operating costs, interest rates, the markets for co-products, and other factors.

2.1 Common Assumptions

To estimate ethanol production costs from plants not yet built requires many assumptions about the hypothetical project. Biomass feedstock composition and cost, biomass transportation costs, plant size, ethanol and other product yields, capital and operating costs, hurdle rate, facility design and construction time, corporate tax rates, and project financing are just some of the variables that will impact the final ethanol cost. The assumptions required to perform the economic analysis that are common to all of the scenarios are shown in Table 1.

TABLE 1 ASSUMPTIONS FOR BIOMASS AND CORN ETHANOL COST ESTIMATES

Parameter	**Assumed value**
Plant life	20 years
Reference year	2000
Design, construction and startup period	2 years
Owner equity	25%
Loan term	10 years
Loan interest rate	8%
Hurdle rate	30% in 2002, 25% in 2007, and 20% in 2012
Operating days per year	350
Inflation rate	3%
Federal income tax rate	34%
State income tax rate	6%
Standard contingency, % of Fixed Capital Investment	10%
Contingency for under-developed design, % of Fixed Capital	15% in 2002, 7.5% in 2007, and 3.75% in 2012

In addition, lignin residue is assumed to be a co-product, i.e., lignin is "sold" and is not burned on-site for steam and electricity production. This requires the ethanol facility to purchase electricity in all cases. For stand-alone scenarios (1-30, 61-65) the electricity price to the ethanol plant is assumed to be $0.08 per kW-hr (purchased from the "grid"). In the collocated scenarios (31-60) the assumed price for electricity is $0.043 per kW-hr (purchased from the host biomass power plant).

The lignin co-product derived from all biomass types (except rice straw and waste paper - see below) is assumed to provide a credit based on the energy content of the lignin compared to the energy content of wood (lignin and wood are assumed to compete in fuel markets). The amount of the lignin credit (in $/dry ton lignin) is the ratio of the lignin energy content (Btu/lb) to wood energy content (Btu/lb) times $24 per dry ton. The collocated scenarios are assumed to receive the entire credit. The lignin credit for the stand-alone scenarios is reduced 75% due to additional costs for lignin marketing, storage, handling and transportation that reduces the effective credit for the lignin.

Lignin derived from rice straw feedstock is assumed to have a negative credit of $10 due to the high silica content of the lignin and the resulting poor boiler fuel characteristics. This “cost” for rice straw lignin is added to the purchase price for the rice straw. Lignin and residue from waste paper at MRFs is also assumed to have a negative credit of $10. It was assumed that permitting a new waste to steam boiler in Southern California would be difficult. If a new waste to steam boiler could be permitted, the lignin would displace other materials that could also be burned for a net income. Natural gas was assumed to be the source of process steam for urban MRF based facilities. ProForma is aware that valuable co-products can be derived from the silica in rice straw, but scenarios specific to silica co-products are not included in the scenarios provided by ARCADIS. Instead, credits for “generic” co-products are calculated as possibilities in the near, mid, and long-term scenarios, with credits of $0.00, $1.00, and $7.50 per dry ton of biomass feedstock, respectively, included for these undefined co-products. See Chapter V of the main report for a discussion of biorefineries and co-products.

The midpoints of the low and high feedstock costs provided by ARCADIS were used in the modeling and economic analysis for all scenarios. Feedstock costs are listed in Appendix VII-B-1 for all scenarios. Biomass transportation costs were also provided by ARCADIS and the formulas for calculating the transportation costs are presented in Appendix VII-B-3. Approximate transportation costs are also listed in Appendix VII-B-1 for each scenario. Parametric evaluations of feedstock prices were also performed.

2.2 Corn Ethanol Modeling Assumptions

ProForma Systems modeled both corn dry milling and wet milling processes to provide comparisons with fuel ethanol produced in California from cellulose based feedstocks. Ethanol production costs for dry milling and wet milling were determined with ProForma Systems’ proprietary *Virtual Process Simulator* that allows rapid and detailed analysis of chemical and biological processes. Each corn ethanol model is based on detailed process flow diagrams for the respective ethanol production technology.

Several factors affect the economics of ethanol production from corn using the dry or wet milling process. These include corn prices, value of the co-products, and the size of the ethanol facility. Many states also have ethanol production or use incentives that improve the economics for many smaller ethanol facilities.

To estimate ethanol production costs in the near-term, the corn price is assumed to be $2.50 per bushel and the distillers’ dried grains value is assumed to be $85 per ton. For the wet milling process, the value of wet mill co-products gluten meal, gluten feed and germ are assumed to be $240, $65, and $250 per ton, respectively.

2.3 Stand-Alone Biomass Ethanol Plant Scenarios

Scenarios 1 through 30 are for stand-alone ethanol facilities. These scenarios are listed in Appendix VII-B-1. A stand-alone ethanol facility is also called a "greenfield" plant because the design and capital costs include the costs for developing a new or "greenfield" site. Costs for site development will often be higher for such items as roads, utilities, lighting, and site security compared to a developed site.

2.3.1 Scenarios 1-8, Stand-alone Ethanol Plant, Forest Material

Scenarios 1 through 8 are for stand-alone ethanol facilities utilizing forest material for ethanol production. Grass Valley, CA has been assumed to be the plant site. Approximately 80,000 dry tons per year of lumbermill waste is assumed to be utilized in scenarios 1-8. The other biomass feedstock utilized is forest slash and thinnings. The amount of forest slash and thinnings required is determined by the annual ethanol production specified for each scenario. Ethanol plant sizes of 20, 30, 40, and 60 million gallons per year are evaluated.

Two-stage dilute acid ethanol production technology has been specified for scenarios 1-5 and acid/enzyme technology for scenarios 6-8. The assumptions for the dilute acid and the acid/enzyme technologies are included in Sections 3.1 and 3.2 below.

A cost of $20 per dry ton of lumbermill waste is assumed with zero transportation cost, based on the assumption that the ethanol plant can be located in close proximity to a lumbermill. The cost for forest slash and thinnings is assumed to be $34 per dry ton. Transportation cost for forest slash and forest thinnings varies with ethanol plant size and ranges from $10 to $16 per dry ton of biomass. A credit of $30 per dry ton of forest slash and thinnings is assumed for scenarios 1, 2, 3 and 6. No subsidies are included for lumbermill waste.

Near-term (year 2002) scenarios for stand-alone ethanol facilities were not included in the analysis as it is probable that most near-term ethanol plants will be collocated with biomass power plants. See Appendix VII-B-1, Table 5 Assumptions for Scenarios 1-8, stand-alone ethanol plants, forest material feedstock.

2.3.2 Scenarios 9-18, Stand-alone Ethanol Plant, Urban Waste

Scenarios 9 through 18 are for stand-alone ethanol facilities utilizing urban waste. Chino, CA has been assumed to be the plant site. The urban waste is composed of a mix of waste paper, tree prunings, urban wood waste, and yard waste. The quantities of each are varied for the various scenarios and are listed in Appendix VII-B-1, Table 6. Ethanol plant sizes evaluated include 30, 50, 80, and 200 million gallons per year. Again only 2007 and 2012 timeframes are considered.

Two-stage dilute acid ethanol production technology has been specified for scenarios 9-13 and the acid/enzyme technology for scenarios 14-18.

The cost for waste paper is $10.00 per dry ton for all scenarios, with transportation costs ranging from $0 to $10 per dry ton. For the urban waste scenarios, waste paper would need to be transported from a MRF. Sorting and the requirements for securing a long-term supply of waste paper would result in a higher waste paper cost than for a MRF located facility (Scenarios 61-65).

The cost for tree prunings is $5 per dry ton, $10.50 for urban wood waste, and $2.50 for yard waste. Transportation costs for these feedstocks vary with ethanol plant size due to larger areas and greater distance required in general for larger quantities of feedstock. Transportation costs vary from about $7 to $14 per dry ton of feedstock.

2.3.3 Scenarios 19-26, Stand-alone Ethanol Plant, Agricultural Waste

Scenarios 19 through 26 are for stand-alone ethanol facilities utilizing agricultural waste. Woodland, CA has been assumed to be the plant site. Agricultural waste is assumed to be a mix of rice straw, orchard prunings, and "other agricultural waste." The quantities of each are varied for the various scenarios and are listed in Appendix VII-B-1, Table 7. Ethanol plant sizes evaluated include 20, 30, 40, and 60 million gallons per year. Again only the 2007 and 2012 timeframes are considered for these scenarios.

Two-stage dilute acid ethanol production technology has been specified for scenarios 19-23 and the acid/enzyme technology for scenarios 24-26.

The cost for rice straw is $18 per dry ton for all scenarios, with transportation costs ranging from about $10 to $14 per dry ton of rice straw. A credit of $15 per dry ton of rice straw is included in scenarios 19, 20, 21, and 24. There are no credits considered for orchard prunings or "other agricultural wastes."

The cost for orchard prunings is $23 per dry ton and $5 for "other agricultural wastes." Transportation costs for these feedstocks range from $8 to $9 per dry ton.

2.3.4 Scenarios 27-30, Stand-alone Ethanol Plant, Energy Crop

Scenarios 27 through 30 are for stand-alone ethanol facilities utilizing eucalyptus as a representative energy crop. No plant location is specified. Ethanol plant sizes evaluated include 30, 80, and 200 million gallons per year. Only the 2012 time frame is considered due to the time required to grow an energy crop such as eucalyptus.

Two-stage dilute acid ethanol production technology has been specified for scenario 27 and acid/enzyme technology for scenarios 28-30.

The assumed cost for eucalyptus is $36 per dry ton for all scenarios, with transportation costs ranging from about $5 to $11 per dry ton depending upon plant size and the required feedstock collection area and transportation distance. No feedstock credits are included for energy crops. See Table 8, Appendix VII-B-1.

2.4 Collocated Biomass Ethanol Plant Scenarios

Scenarios 31 through 60 are for collocated ethanol facilities. These scenarios are listed in Appendix VII-B-1, Table 9 through Table 12. Collocation of ethanol facilities with existing biomass power plants can result in significant capital and operating cost reductions for the ethanol facility and increased revenues for the biomass power plant. The assumptions related to collocation and the resulting cost reductions are discussed in Section 3.3.

2.4.1 Scenarios 31-40, Collocated Ethanol Plant, Forest Material

Scenarios 31 through 40 are for collocated ethanol facilities utilizing forest material for ethanol production. The assumptions are similar, but not the same in all cases, as those for the stand-alone forest material ethanol plants. Grass Valley, CA is again assumed to be the plant site.

Approximately 80,000 dry tons per year of lumbermill waste is assumed to be utilized in scenarios 31-40. The amount of forest slash and thinnings is varied to meet the annual ethanol production rate specified for each scenario. Ethanol plant sizes of 20, 30, 40, and 60 million gallons per year are evaluated.

Two-stage dilute acid ethanol production technology has been specified for scenarios 31-36 and acid/enzyme technology for scenarios 37-40.

A cost of $20 per dry ton of lumbermill waste is assumed with zero transportation cost for scenarios 31-40. The cost for forest slash and thinnings is assumed to be $34 per dry ton. Transportation cost for forest slash and forest thinnings varies with ethanol plant size and ranges from $10 to $16 per dry ton of biomass. A credit of $30 per dry ton of forest slash and thinnings is assumed for scenarios 31-34, 37, and 38. No credits are included for lumber-mill waste.

Scenarios 31 and 37 are for the near-term (year 2002) timeframe, with the remaining scenarios for the mid (2007) and long-term (2012) timeframes.

2.4.2 Scenarios 41-48, Collocated Ethanol Plant, Urban Waste

Scenarios 41 through 48 are for collocated ethanol facilities utilizing urban waste. Chino, CA has been assumed to be the plant site. The urban waste is composed of a mix of waste paper, tree prunings, urban wood waste, and yard waste. The quantities of each are varied for the various scenarios and are listed in Appendix VII-B-1, Table 10. Ethanol plant sizes evaluated include 30, 50, and 80 million gallons per year. Only 2007 and 2012 time frames are considered.

Two-stage dilute acid ethanol production technology has been specified for scenarios 41-45 and acid/enzyme technology for scenarios 46-48.

The cost for waste paper is $10 per dry ton for all scenarios, with transportation costs ranging from about $5 to $7 per dry ton. For the urban waste scenarios, waste paper would need to be transported from a MRF. Sorting and the requirements for securing a long-term supply of waste paper would result in a higher waste paper cost than for a MRF located facility (Scenarios 61-65).

Lower costs of waste paper and other materials could be realized if the ethanol facility was collocated with a biomass power plant that burns MSW. Currently, California has 170 MW of power production capacity for facilities that burn MSW.

The cost for tree prunings is $5 per dry ton, $10.50 for urban wood waste, and $2.50 for yard waste. Transportation costs for these feedstocks vary with ethanol plant size due to larger areas and greater distances required in general for larger quantities of feedstock. Transportation costs vary from about $7 to $10 per dry ton of feedstock.

2.4.3 SCENARIOS 49-58, COLLOCATED ETHANOL PLANT, AGRICULTURAL WASTE

Scenarios 49 through 58 are for collocated ethanol facilities utilizing agricultural waste. Woodland, CA has been assumed to be the plant site. Agricultural waste is assumed to be a mix of rice straw, orchard prunings, and "other agricultural waste." The quantities of each are varied for the various scenarios and are listed in Appendix VII-B-1, Table 11. Ethanol plant sizes evaluated include 20, 30, 40, and 60 million gallons per year. Scenarios 49 and 55 are for the near-term (2002), with the remaining scenarios addressing the 2007 and 2012 time frames.

Two-stage dilute acid ethanol production technology has been specified for scenarios 49-54 and acid/enzyme technology for scenarios 55-58.

The cost for rice straw is $18 per dry ton for all scenarios, with transportation costs ranging from about $10 to $14 per dry ton of rice straw. A credit of $15 per dry ton of rice straw is included in scenarios 49-52, 55 and 56. There are no credits considered for orchard prunings or "other agricultural wastes."

The cost for orchard prunings is $23 per dry ton and $5 for "other agricultural wastes." Transportation costs for these feedstocks range from $8 to $9 per dry ton.

2.4.4 SCENARIOS 59-60, COLLOCATED ETHANOL PLANT, ENERGY CROP

Scenarios 59 and 60 are for collocated ethanol facilities utilizing eucalyptus as a representative energy crop. No plant location is specified. Ethanol plant sizes evaluated include 30 and 80 million gallons per year. Only the 2012 time frame is considered due to the time required to grow an energy crop such as eucalyptus.

Two-stage dilute acid ethanol production technology has been specified for scenario 59 and acid/enzyme technology for scenario 60.

The assumed cost for eucalyptus is $36 per dry ton for all scenarios, with transportation costs ranging from about $5 to $8 per dry ton depending upon plant size and the required feedstock collection area and transportation distance. No feedstock credits are included for energy crops. See Appendix VII-B-1, Table 12.

2.5 Material Recycling Facility/Ethanol Plant Scenarios

Scenarios 61 through 65 are for ethanol facilities located at material recovery facilities. These scenarios are listed in Appendix VII-B-1 Table 13. Locating an ethanol plant at a MRF can result in some capital cost savings. Facilities for handling the feedstock are already in place. Wastewater treatment facilities as well as a boiler for generating steam will be required. Natural gas was assumed to be the source of energy for generating steam since paper has a relatively low lignin content. Furthermore, permitting a new boiler in a California urban area would be difficult if the boiler were to burn residual lignin that may also contain waste materials such as plastic.

2.5.1 Scenarios 61-65, Ethanol Plant At Material Recovery Facility, Waste Paper

Scenarios 61 through 65 are for facilities located at MRFs. Los Angeles has been assumed to be the plant site. Loads of material containing a high fraction of waste paper can be identified at a MRF and diverted to an ethanol production facility. The scenarios are based on the two-stage dilute acid process. The cost of feedstock was assumed to be -$10/ton. Using waste paper at a MRF provides a direct reduction in landfill costs for the facility. The value of diverting this material from landfills has been estimated to be lower than -$20 per ton. Parametric analyses of feedstock costs were also performed. The costs of lignin and ash disposal were estimated at $10/ton since it is not likely that the lignin could be burned in Los Angeles. Furthermore, the lignin content of paper is much lower than that of other types of biomass.

3.0 Biomass Ethanol Production Technologies

Historically, production of ethanol has been limited to using sources of soluble sugar or starch; corn is currently the most common feedstock for ethanol production in the U.S. These forms of sugar and starch are edible and their relative value tends to be much higher than the rest of the plant, the leaves, stalks, etc. New technologies have been developed which now allow for the production of ethanol from "lignocellulosic biomass." Lignocellulosic biomass is the leafy or woody part of plants: wood, wood waste, paper, rice straw, yard waste, etc. Lignocellulosic biomass can be processed to produce sugars that can, in turn, be fermented to ethanol.

The primary components of lignocellulosic biomass are cellulose, hemicellulose, and lignin. Cellulose is the primary component of most plants and is composed of long chains of glucose, a six-carbon sugar. The cellulose is linked with the second major component of the plant biomass, hemicellulose. In hardwoods and herbaceous crops, the hemicellulose is primarily composed of the five-carbon sugar, xylose. In softwoods the hemicellulose is composed of several six-carbon sugars, primarily mannose, glucose and small amounts of galactose, in addition to the five-carbon xylose.

The last major component of biomass is lignin that gives the plant its structural strength. Lignin is the precursor to coal, has nearly the same energy content as coal, but does not contain the sulfur found in coal. Lignin is, therefore, a clean-burning source of energy that can supply the steam and electricity needs of the ethanol plant or it can be sold to others as a boiler fuel. Lignin can also be used as a high quality soil amendment.

There are several different methods for producing fermentable sugars from the cellulose and hemicellulose in biomass (gasification/fermentation technology [9] has the potential to produce ethanol from the lignin in biomass also, but this technology is not considered here). Once produced, the six carbon sugars that make up the cellulose and predominate in softwood hemicellulose can be easily fermented to ethanol[10]. Fermenting the five carbon sugars is much more difficult and will most likely require a genetically engineered microorganism to efficiently ferment the five carbon sugars that predominate the hemicellulose in hardwoods and herbaceous biomass[11].

Current technology options for producing ethanol and co-products from biomass include:

- One-stage dilute acid hydrolysis and fermentation
- Two-stage dilute acid hydrolysis and fermentation
- Concentrated acid hydrolysis and fermentation
- Dilute acid pretreatment followed by separate enzymatic hydrolysis and fermentation
- Dilute acid pretreatment followed by simultaneous saccharification and fermentation (SSF) or co-fermentation (SSCF)
- Biomass gasification and fermentation

Within each of these technology options there are many possible variations of unit operations. The point here is that all of the technology options could not be considered for this study and the economic analyses presented in this report. Adequate time and resources are not available to evaluate all of the technology options and meet the deadline for the project. Therefore, a decision was made for ProForma to model the two-stage dilute acid process and the SSCF process (referred to as "acid/enzyme" technology herein).

3.1 Two-Stage Dilute Acid Technology Assumptions

The two-stage dilute acid technology is described in Appendix VII-B-4. Numerous references are also available for this technology option[12,13] including detailed process, engineering and equipment cost data from NREL and Merrick Engineers of Denver, Colorado[14].

Assumptions specific to ethanol production utilizing two-stage dilute acid technologies are listed in Table 2 for near, mid, and long-term ethanol production scenarios. Near-term values are based on research conducted at the National Renewable Energy Laboratory. The near-term values have been demonstrated in bench- and pilot-scale tests at NREL[15]. Mid and long-term values are hypothetical values based on engineering judgment and the limits of theoretical yields for two-stage dilute acid technology using co-current hydrolysis reactors for the mid-term case and improved technology such as counter-current hydrolysis for the long-term case[16].

Fermentation of the six-carbon sugars plus xylose sugars to ethanol in the near-term case is assumed to be accomplished with a genetically engineered yeast or bacteria[17,18,19,20]. The ethanol fermentation yields for the mid- and long-term cases assume the use of an improved genetically engineered yeast or bacteria which utilizes all five biomass sugars – glucose, xylose, mannose, galactose and arabinose – with increasingly higher ethanol yields.

TABLE 2 ASSUMPTIONS FOR TWO-STAGE DILUTE ACID TECHNOLOGY

Parameter	Near-Term Value (2002)	Mid-Term Value (2007)	Long-Term Value (2012)
1st Stage Acid Hydrolysis:			
Temperature	190°C	190°C	190°C
Acid Concentration	0.7%	0.7%	0.7%
Residence Time	3 minutes	3 minutes	3 minutes
Solids Concentration	25%	25%	25%
Sugar Yields:			
Glucose	16%	16%	16%
Xylose	70%	70%	70%
Mannose	87%	87%	87%
Galactose	81%	81%	81%
Arabinose	98%	98%	98%
2nd Stage Acid Hydrolysis:			
Temperature	215°C	215°C	215°C
Acid Concentration	1.6%	1.6%	1.6%
Residence Time	70 seconds	70 seconds	70 seconds
Sugar Yields:			
Glucose	52%	58%	70%
Xylose	2%	33%	83%
Mannose	16%	62%	62%
Galactose	5%	21%	74%
Arabinose	0%	0%	0%
Overall Hydrolysis Yield:			
Glucose	60%	65%	75%
Xylose	71%	80%	95%
Mannose	89%	95%	95%
Galactose	82%	85%	95%
Arabinose	98%	98%	98%
Overall Ethanol Fermentation Yield:			
Glucose	90%	90%	95%
Xylose	75%	85%	95%
Mannose	90%	90%	95%
Galactose	90%	90%	95%
Arabinose	0%	85%	95%

3.2 Acid/Enzyme Technology Assumptions

The acid/enzyme technology is described in Appendix VII-B-5. The acid/enzyme technology selected for modeling and analysis is dilute acid pretreatment followed by simultaneous saccharification and co-fermentation (SSCF). The saccharification of cellulose is accomplished with the use of cellulase enzymes. These enzymes biologically degrade cellulose to glucose. The purchase cost or on-site production cost of these enzymes is a key parameter for the economic success of this process. On-site cellulase enzyme production has been modeled for this study. The acid/enzyme or SSCF process is described extensively in the literature[21,22,23,24,25].

Cellulase enzymes are commercially available for a variety of applications. Most of these applications do not involve extensive hydrolysis of cellulose. For example, the textile industry applications for cellulases require less than 1% hydrolysis. Ethanol production, by contrast, requires nearly complete hydrolysis. In addition, most of the commercial applications for cellulase enzymes represent higher value markets than the fuel market. For these reasons, there is quite a large leap from today's cellulase enzyme industry to the fuel ethanol industry. Most companies actively pursuing commercialization of near-term ethanol technology are choosing to begin with acid hydrolysis technologies because of the high cost of cellulase enzymes[26].

Assumptions specific to ethanol production utilizing the acid/enzyme processes are listed in Table 3 for near, mid, and long-term ethanol production scenarios. Most of the near-term values listed have been demonstrated by bench or pilot-scale tests at the National Renewable Energy Laboratory[27]. Mid and long-term values are based in most cases on NREL's technology improvement goals for 2005 and 2010[28].

Assumptions for the conversion of biomass sugars to ethanol are similar to those for the two-stage dilute acid technology with arabinose fermentation added to the near-term case. Fermentation of the five- and six-carbon sugars to ethanol for all timeframes is assumed to be accomplished with genetically engineered yeast or bacteria[29,30,3132]. The ethanol fermentation yields are assumed to increase in the mid- and long-term cases[33,34].

3.3 Collocation Assumptions

Collocating biomass ethanol facilities with existing biomass power plants can result in several interfaces that can have significant economic benefit to each facility. These interfaces can reduce capital cost of the ethanol facility, decrease fixed and variable operating costs for both facilities, create new revenue streams for existing biomass power plants, and make both facilities more competitive in their respective markets. The interfaces and corresponding economic benefits of collocating ethanol facilities with existing biomass power plants include:

a. Part or all of the biomass power plant's biomass feedstock can be diverted into the ethanol facility to recover sugars for ethanol production with subsequent return of the lignin as replacement fuel. The cost of collecting, transporting and processing feedstock for both facilities is thereby shared. This can have significant economic impacts on feedstock and operating costs.

TABLE 3 ASSUMPTIONS FOR ACID/ENZYME TECHNOLOGY

Parameter	Near-Term Value (2002)	Mid-Term Value (2007)	Long-Term Value (2012)
<u>Dilute Acid Pretreatment:</u>			
Temperature	150°C	150°C	150°C
Acid Concentration	1.5%	1.5%	1.5%
Residence Time	8 minutes	8 minutes	8 minutes
Solids Concentration	25%	25%	25%

Parameter	Near-Term Value (2002)	Mid-Term Value (2007)	Long-Term Value (2012)
Sugar Yields:			
Glucose	5%	5%	5%
Xylose	85%	85%	90%
Mannose	85%	85%	90%
Galactose	85%	85%	90%
Arabinose	85%	85%	90%
SSCF Specifications:			
Temperature	30°C	30°C	30°C
Solids Concentration	20%	25%	25%
Residence Time	7 days	3 days	2 days
Inoculum Level	10%	10%	10%
Cellulase Loading	15 FPU/g cellulose	15 FPU/g cellulose	15 FPU/g cellulose
Nutrients (CSL)	0.25%	0.20%	0.20%
Glucose Yield	80%	85%	90%
Fermentation Yields:			
Ethanol	92%	92%	95%
Xylose	85%	85%	95%
Mannose	90%	90%	95%
Galactose	90%	90%	95%
Arabinose	85%	85%	95%
Cellulase Production Specifications:			
Specific productivity	1.0 IU/g biomass/hr	4.0 IU/g biomass/hr	10 IU/g biomass/hr
Specific activity	0.5 IU/mg protein	0.7 IU/mg protein	1.0 IU/mg protein
Fermentation batch time	96 hours	84 hours	60 hours

b. Repowering the biomass power plant partially with lignin that has a higher energy density than wood chips could increase the net electrical output of the power plant by 10-18% and, thereby, increase revenue.
c. The ethanol facility can purchase steam and electricity from the biomass power plant, creating new revenue for the biomass power plant and reducing the cost of electricity and steam to the ethanol facility. This will also eliminate the ethanol facility capital investment for steam and electricity production.
d. The ethanol facility can contract with the biomass power plant to manage the biomass feedstock procurement and inventory, potentially reducing the fixed operating costs for both facilities by sharing this operation.
e. The ethanol facility can contract with the biomass power plant to manage the ethanol facility, or vice versa, reducing the fixed costs for both facilities.
f. The ethanol facility can contract with the biomass power plant to process wastewater through the power plant's wastewater treatment system.

g. The biomass power plant facility can contract to provide water for the ethanol facility, also reducing the fixed costs for both facilities, reducing capital costs to the ethanol facility as well as fixed operating costs to both facilities.
h. Use of existing biomass power plant land can reduce fixed costs for both facilities.
i. Collocating the ethanol facility at an existing biomass industrial site can reduce development costs and reduce the risks of development capital due to environmental, construction and operating permit issues.

There are currently 30 biomass power plants in California that may present collocation opportunities for biomass ethanol plants. Evaluation of each of these sites is beyond the scope of this study. Instead the assumptions listed in Table 4 were made to distinguish the collocation scenarios from the stand-alone ethanol facility scenarios.

4.0 Modeling Methodology

ProForma has developed a model for each of the ethanol production technologies analyzed in this report:

- Corn wet milling
- Corn dry milling
- Two-stage dilute acid hydrolysis and fermentation
- Acid/enzymatic hydrolysis and fermentation

The two biomass-to-ethanol models include stand-alone and collocation options. Each model utilizes ProForma's proprietary *Virtual Process Simulator* (VPS) software. The VPS software allows the user to vary any process, project or economic parameter within the model. The VPS software also allows the user to determine the ethanol cost sensitivity to any model parameter. Probabilistic and uncertainty analyses are also easily performed with the VPS software.

TABLE 4 ETHANOL FACILITY COLLOCATION ASSUMPTIONS

Capital or Operating Cost Impact	Stand-alone Ethanol Facility	Collocated Ethanol Facility
Biomass feedstock receiving and storage	New feedstock receiving and storage equipment required	Existing biomass receiving and storage equipment utilized, results in 5% reduction in total capital cost for ethanol facility
Steam and electricity use	New natural gas boiler for steam production and electricity purchased from grid	Steam and electricity are purchased from the biomass power plant
Ethanol facility infrastructure – roads, site prep., buildings, etc.	All infrastructure capital costs included	Infrastructure capital costs reduced 25% to 50% due to integrated operations with the biomass power plant
Overall capital costs	All normal capital costs included for the grassroots ethanol facility cost estimate	Ethanol facility capital costs reduced approximately 30% by collocation with biomass power plant
Ethanol facility labor charges	100% of labor charges included, approximately 30 employees required for the stand-alone ethanol facility	Direct labor charges reduced 20% by integrated biomass power and ethanol facility operations
Lignin fuel co-product	Lignin credit reduced due to marketing and transportation costs. Approx. $7/BDT lignin credit	Full value received for lignin energy from the biomass power plant. Approx. $27/BDT lignin credit
Steam production	Produced on-site with natural gas boiler at a cost of: - $1.60/1000 lbs low pressure - $3.24/1000 lbs med. press. - $4.80/1000 lbs. high press.	Purchased from biomass power plant at a cost of: - $2.00/1000 lbs low pressure - $4.00/1000 lbs med. press. - $6.00/1000 lbs. high press.
Cost of electricity	$0.080 per kW-hr from grid	$0.043 per kW-hr from biomass power plant

4.1 The ProForma Virtual Process Simulator

Ethanol production costs and process and economic sensitivities were determined with ProForma Systems' proprietary *Virtual Process Simulator* (VPS). The *Virtual Process Simulator* is an Excel™ based model that allows for rapid and detailed analysis of chemical and biological processes. For this project, ProForma has utilized its VPS models for corn wet milling, corn dry milling, two-stage dilute sulfuric acid hydrolysis of biomass, and enzymatic hydrolysis of biomass (SSCF). Each model is based on detailed process flow diagrams for the respective ethanol production technology. Stand-alone and collocated biomass ethanol facilities were analyzed with the VPS biomass models.

Each VPS model includes rigorous material and energy balance calculations. Performance parameters for complex unit operations are determined using experimental data provided by the

National Renewable Energy Laboratory and others for biomass conversion unit operations. Chemstations CHEMCAD IV™ chemical process simulator was used for material and energy balance calculations for more typical unit operations such as distillation.

The VPS model also includes equipment sizing and costing calculations for all process equipment displayed on the process flow diagrams. Process equipment purchase costs are estimated using historical cost data, ICARUS Questimate™ equipment cost estimating software, and vendor quotes. The installed cost of the process equipment is determined by applying factors to the purchased equipment costs to estimate the cost of installing the equipment as well as the cost for shipping, foundations, structural supports, and all required piping, electrical, instrumentation, insulation, painting, and spare parts.

The VPS model also includes facility capital and operating cost calculations for the ethanol facility. The capital cost estimate includes the total fixed capital investment as well as the working capital investment. The accuracy of the capital cost estimate is +30% to -15%. The operating cost estimate includes raw materials, processing materials, utilities, maintenance, operating labor, plant overhead, taxes, insurance, equipment depreciation, contingencies, and product distribution costs.

The VPS model uses a meticulous cash-flow profitability analysis to determine all commonly used indicators of project profitability, including discounted cash flow rate of return (DCFROR), also know as the internal rate of return (IRR), payback period, net present value (NPV), and simple return on investment (ROI).

VPS modeling is an efficient tool for accurate and rapid analyses of a wide variety of economic assumptions, process case studies, and sensitivity and probabilistic uncertainty analyses for R&D projects, feasibility studies and process optimization.

5.0 Corn Ethanol Production Modeling Results

To estimate ethanol production costs in the near-term, corn price is assumed to be $2.50 per bushel and the distillers’ dried grains value is assumed to be $85 per ton. For a 20 million gallon per year dry mill, the resulting production cost is $1.23 per gallon. For a 200 million gallon per year wet-mill, the near-term ethanol production cost is estimated to be $0.97 per gallon (with the value of wet mill co-products gluten meal, gluten feed and germ at $240, $65, and $250 per ton, respectively).

Figure 1 shows the sensitivity of ethanol production costs, both dry and wet milling, to corn prices. For dry milling at 20 million gallon per year plant size, ethanol costs range from $1.09 to $1.71 per gallon for corn prices from $2.00 to $4.00 per bushel. For wet milling at 200 million gallon per year plant size, ethanol costs range from $0.88 to $1.50 per gallon for corn prices from $2.00 to $4.00 per bushel.

FIGURE 1 ETHANOL COST SENSITIVITY TO CORN PRICE

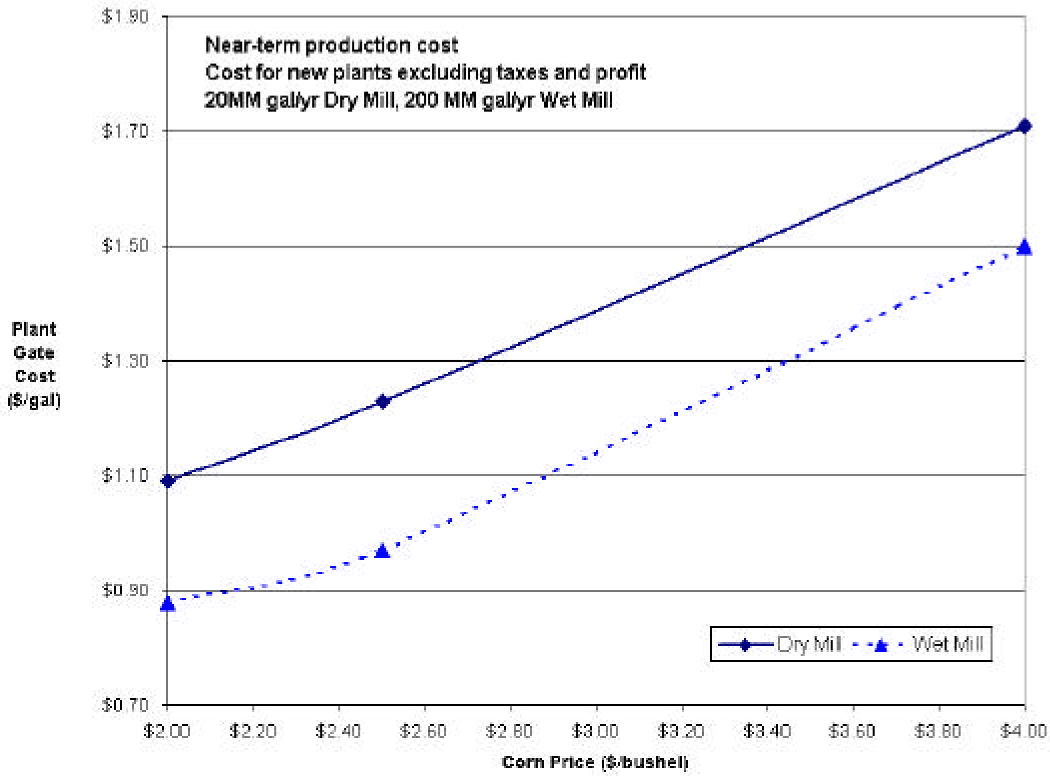
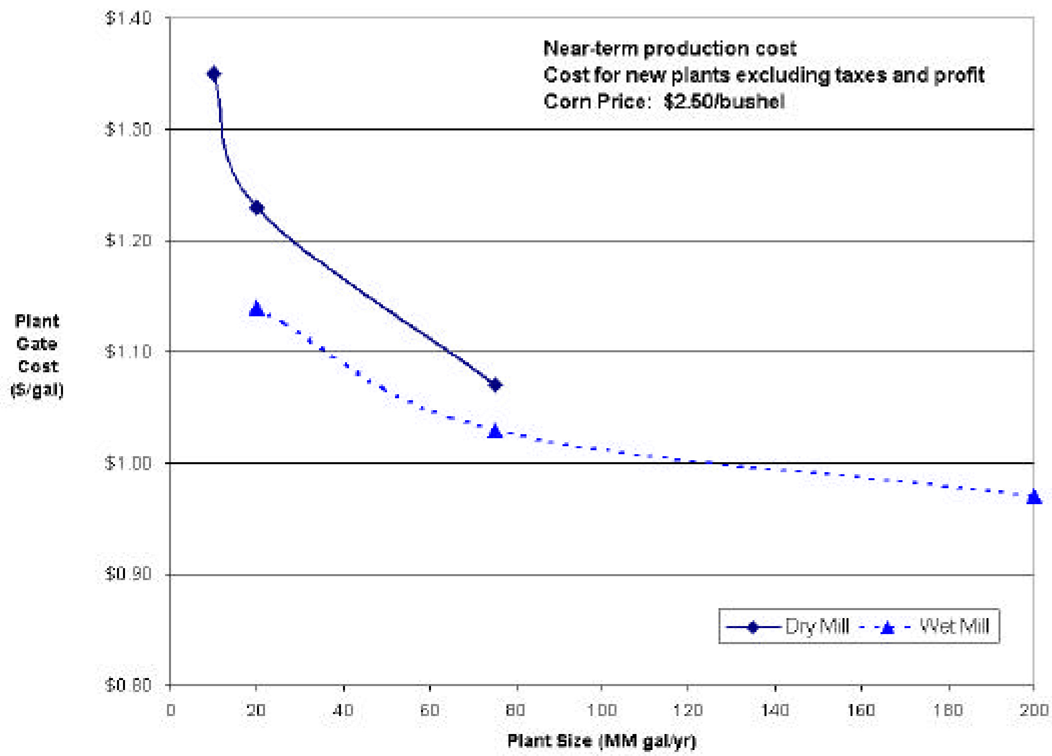


Figure 2 shows the sensitivity of ethanol production costs, to plant size. Dry mill ethanol production capacities are typically in the range of 10 to 30 million gallons per year with two existing dry mill facilities at 65 and 75 million gallons per year. Wet mills are typically much larger, ranging from 50 to 200 million gallons per year with one wet mill facility at 330 million gallons per year.

FIGURE 2 ETHANOL COST SENSITIVITY TO PLANT SIZE



With corn at $2.50 per bushel, ethanol production costs range from $1.35 to $1.07 for dry mill plant sizes from 10 to 75 million gallons per year. For wet mills ethanol production costs range from $1.14 to $0.97 per gallon for plant sizes from 20 to 200 million gallons per year.

Dry and wet milling ethanol production costs are assumed to decrease in the mid- and long-term scenarios. Improvements will likely be in the areas of increased ethanol yields per bushel of corn, the development of higher value co-products, and reduced operating costs. Dry milling ethanol production costs are estimated to be $0.98 to $1.26 per gallon in the long-term. Wet milling ethanol production costs are estimated to be $0.91 to $1.04 per gallon in the long-term.

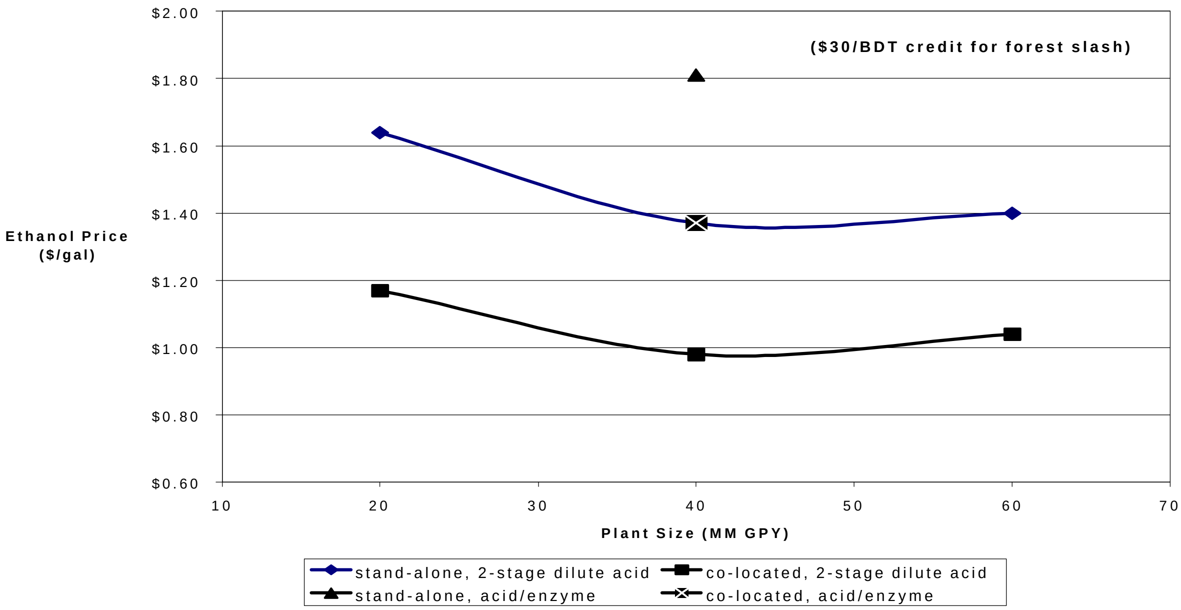
6.0 Biomass Ethanol Production Modeling Results

The ethanol process modeling and economic analysis results can be presented in many different ways. Net present value (NPV), discounted cash flow rate of return (DCFROR) or internal rate of return (IRR), ethanol production cost, and ethanol selling price required to meet a minimum hurdle rate are just a few of the ways to present the results. For this report, ARCADIS and ProForma selected the “ethanol selling price” as the method to report the modeling and economic analysis results. Hurdle rates of 30%, 25% and 20% were assumed to be reasonable rates of return on equity investment for the near-, mid- and long-term scenario timeframes, respectively. The *Virtual Process Simulator* model was then configured to solve for the ethanol-selling price that resulted in a zero NPV at the specified hurdle rate.

The modeling and economic analysis results are summarized in the tables in Appendix VII-B-6. The ethanol yield, annual feedstock requirements, average feedstock cost, total capital investment for the ethanol facility, and the minimum ethanol price required to meet the hurdle rate for each scenario are presented in Appendix VII-B-6.

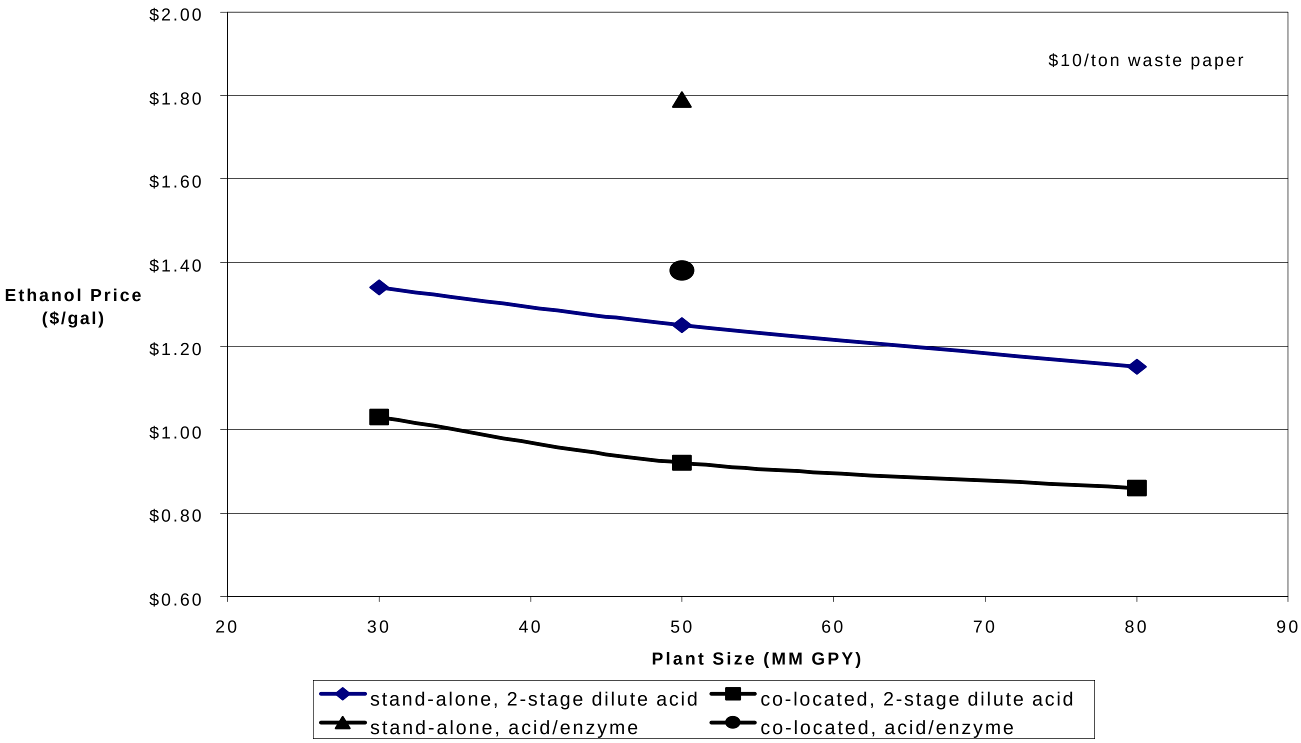
Ethanol selling prices versus ethanol plant size for the year 2007 are shown graphically in Figure 3 for forest waste, Figure 4 for urban waste, Figure 5 for agricultural waste, and Figure 6 for energy crops (long-term data is displayed for energy crops). For the forest waste (Figure 3), the ethanol price varies from $1.17 to $1.04 per gallon ethanol for the collocated 2-stage dilute acid process for plant sizes from 20 million gallons per year to 60 million gallons per year. For the stand-alone 2-stage dilute acid process, the ethanol price varies from $1.64 to $1.37 for ethanol plant sizes from 20 million gallons per year to 60 million gallons per year. A $30/BDT credit for the forest slash portion of the forest materials feedstock has been included in these scenarios.

FIGURE 3 ETHANOL PRICE VS. PLANT SIZE, FOREST MATERIALS, YEAR 2007



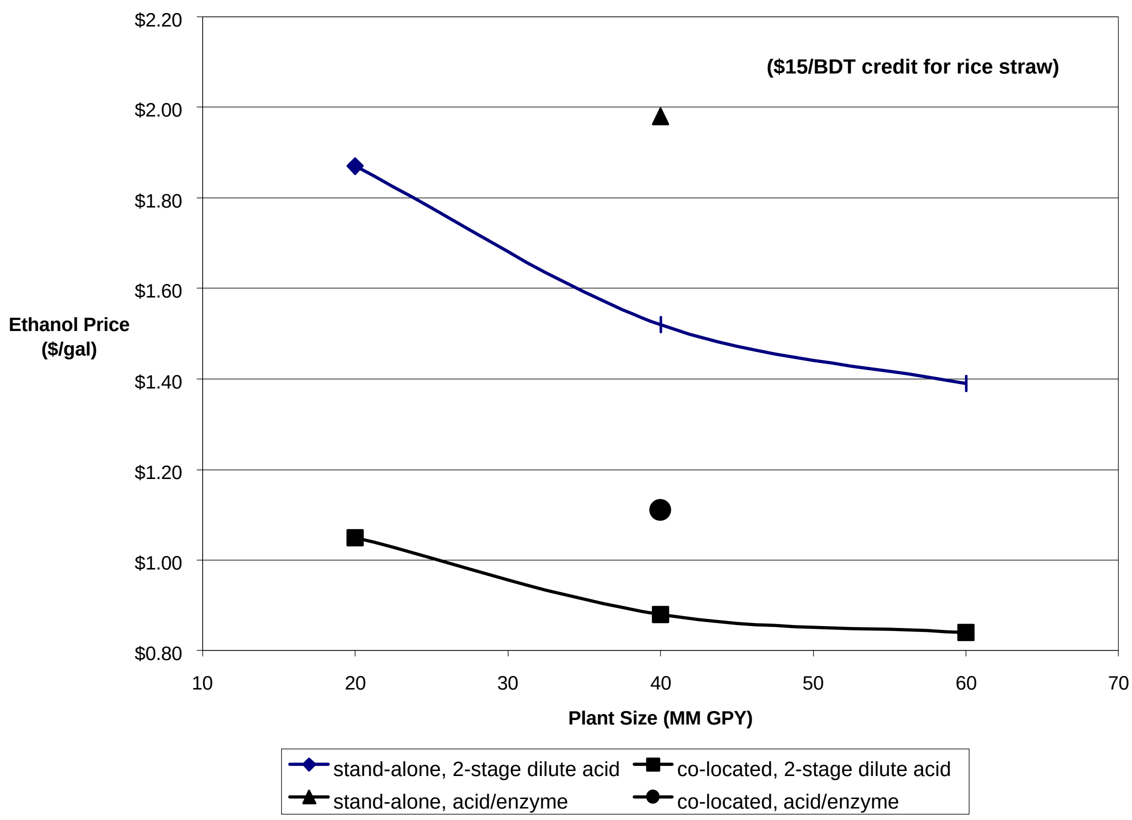
For urban waste feedstock the ethanol price varies from $1.03 to $0.86 for the collocated 2-stage dilute acid process in 2007 for plant sizes from 30 to 80 million gallons per year (Figure 4). For the stand-alone 2-stage dilute acid process with urban waste feedstock, the ethanol price varies from $1.34 to $1.15 for the range of ethanol plant sizes from 30 to 80 million gallons per year.

FIGURE 4 ETHANOL PRICE VS. PLANT SIZE, URBAN WASTE, YEAR 2007



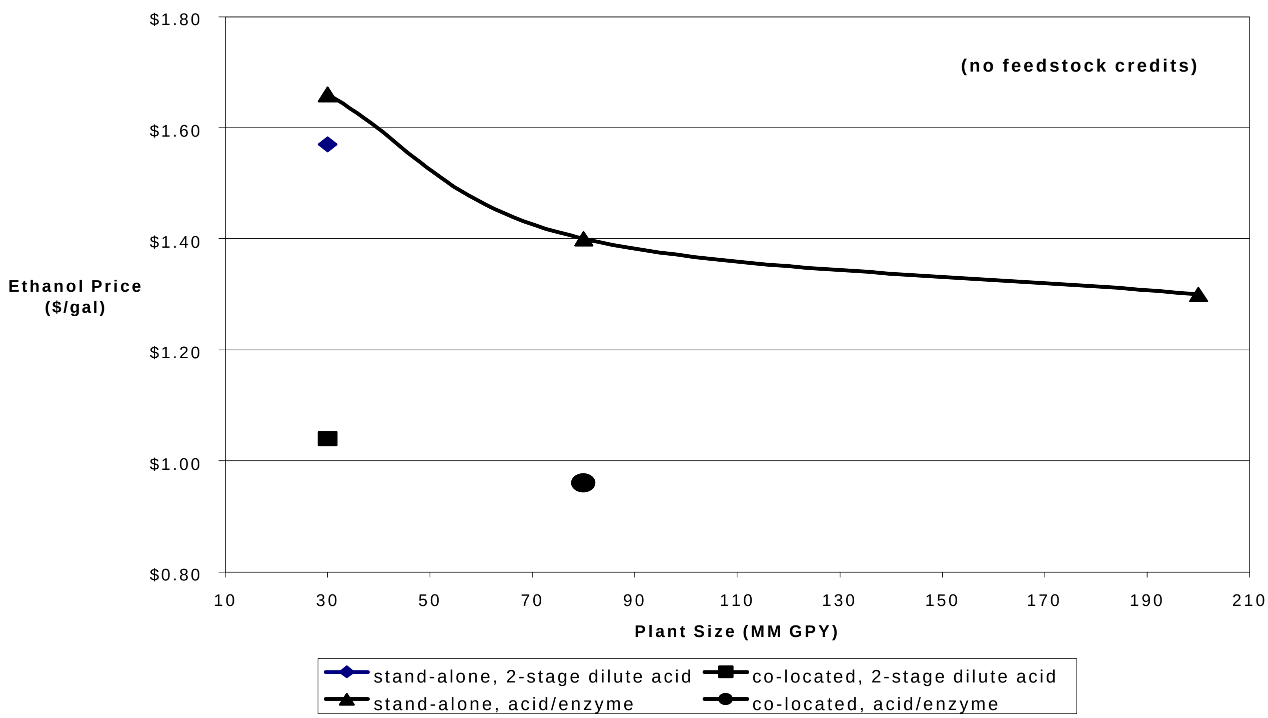
For the agricultural materials the ethanol price varies from $1.05 to $0.84 for the collocated 2-stage dilute acid process for plant sizes from 20 million gallons per year to 60 million gallons per year (Figure 5). For the stand-alone 2-stage dilute acid process with agricultural waste feedstock, the ethanol price varies from $1.87 to $1.39 for ethanol plant sizes from 20 million gallons per year to 60 million gallons per year. A $15/BDT credit for the rice straw portion of the agricultural materials feedstock has been included in these scenarios.

FIGURE 5 ETHANOL PRICE VS. PLANT SIZE, AGRICULTURAL MATERIALS, YEAR 2007



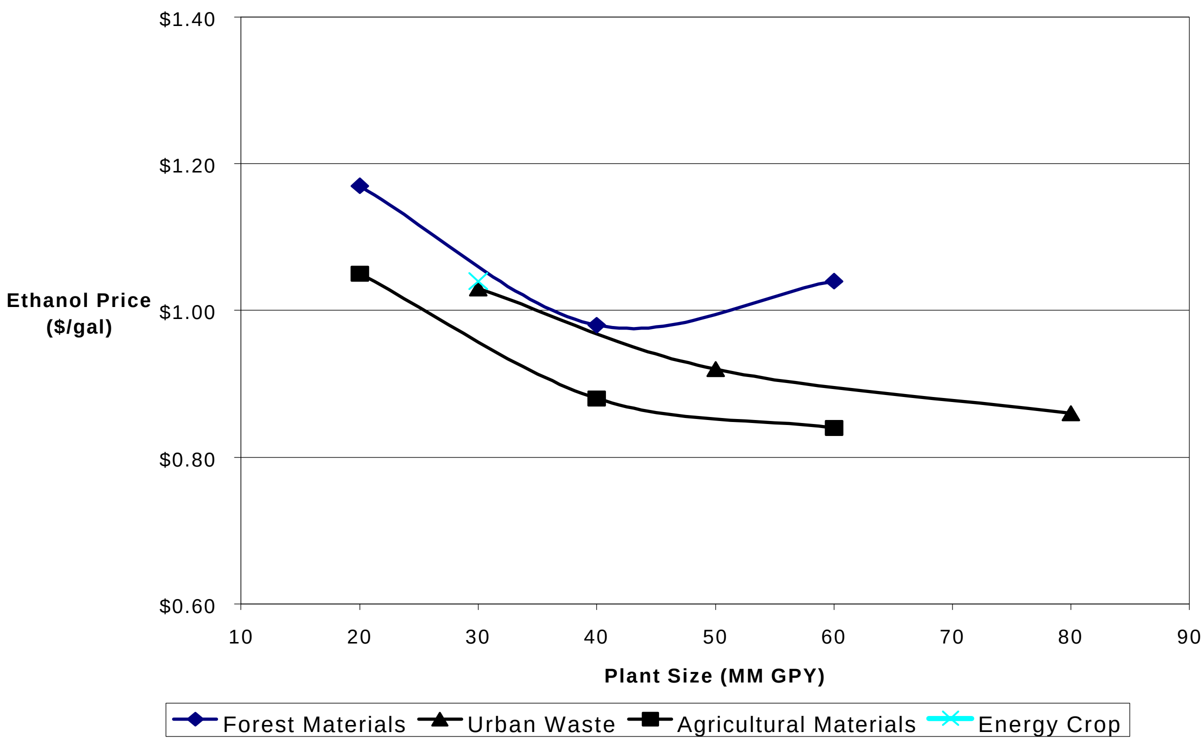
For energy crops (eucalyptus) in 2012, the ethanol price varies from $1.66 to $1.30 for the stand-alone 2-stage acid/enzyme process with eucalyptus feedstock for ethanol plant sizes from 30 million gallons per year to 200 million gallons per year (Figure 6). No feedstock credits are included.

FIGURE 6 ETHANOL PRICE VS. PLANT SIZE, ENERGY CROP, YEAR 2012



A comparison of all four feedstock types is presented in Figure 7 for the 2-stage dilute acid process and collocation scenarios. The forest material, urban waste and agricultural material ethanol price curves are the 2007 scenarios with the subsidies discussed previously. The one energy crop data point at 30 million gallons per year plant size is for 2012 with no credit.

FIGURE 7 FOUR FEEDSTOCK TYPES, 2-STAGE DILUTE ACID PROCESS, COLLOCATED SCENARIOS



A comparison of all four feedstock types is presented Figure 8 for the two-stage dilute acid process and stand-alone scenarios. The forest material, urban waste and agricultural material ethanol price curves are the 2007 scenarios with the subsidies discussed previously. The one energy crop data point at 30 million gallons per year plant size is for 2012 with no feedstock credit.

FIGURE 8 FOUR FEEDSTOCK TYPES, TWO-STAGE DILUTE ACID PROCESS, STAND-ALONE SCENARIOS

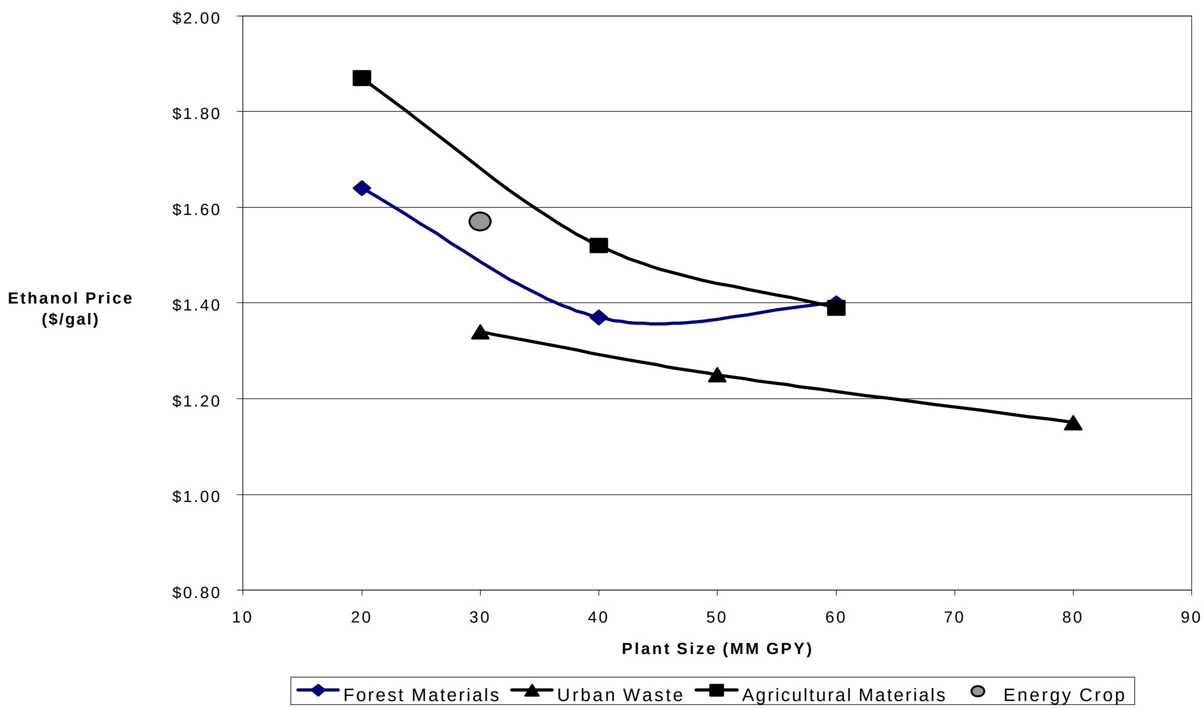
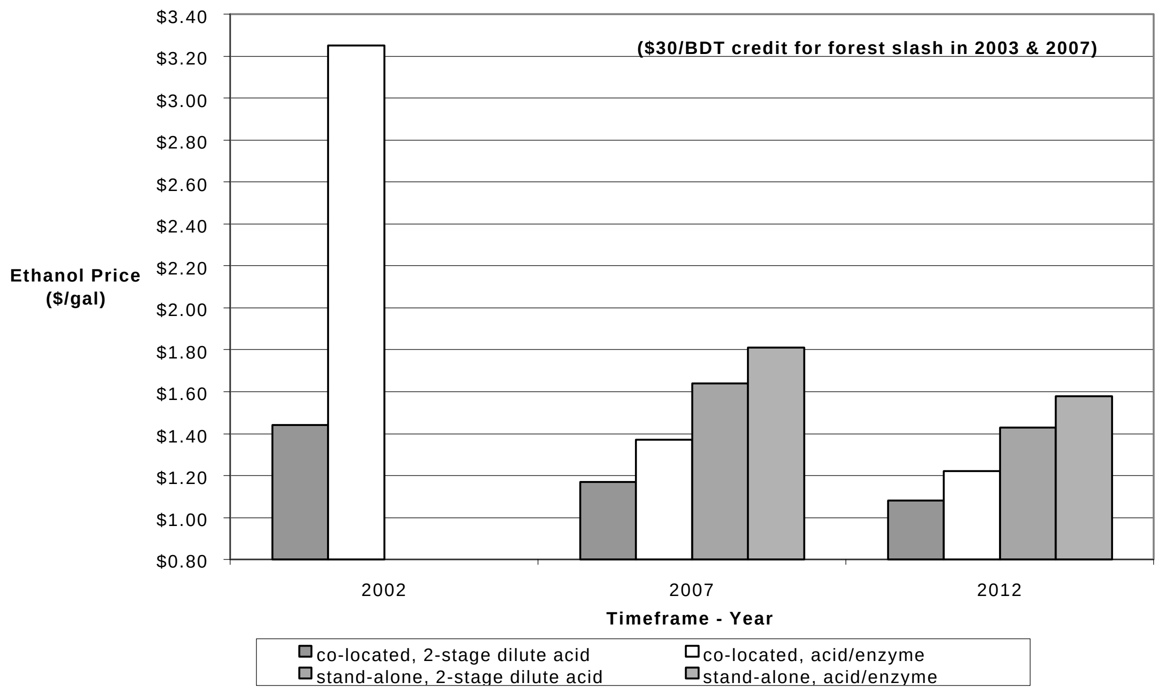


Figure 9, Figure 10, and Figure 11 show the ethanol price in the years 2002, 2007 and 2012 for collocated and stand-alone ethanol plants scenarios with both the two-stage dilute acid process and the acid/enzyme process. A general decline in ethanol price with time is seen due to the projected improvements in biomass ethanol production technologies and the lower hurdle rates for the out years. Various feedstock credits are included in these scenarios.

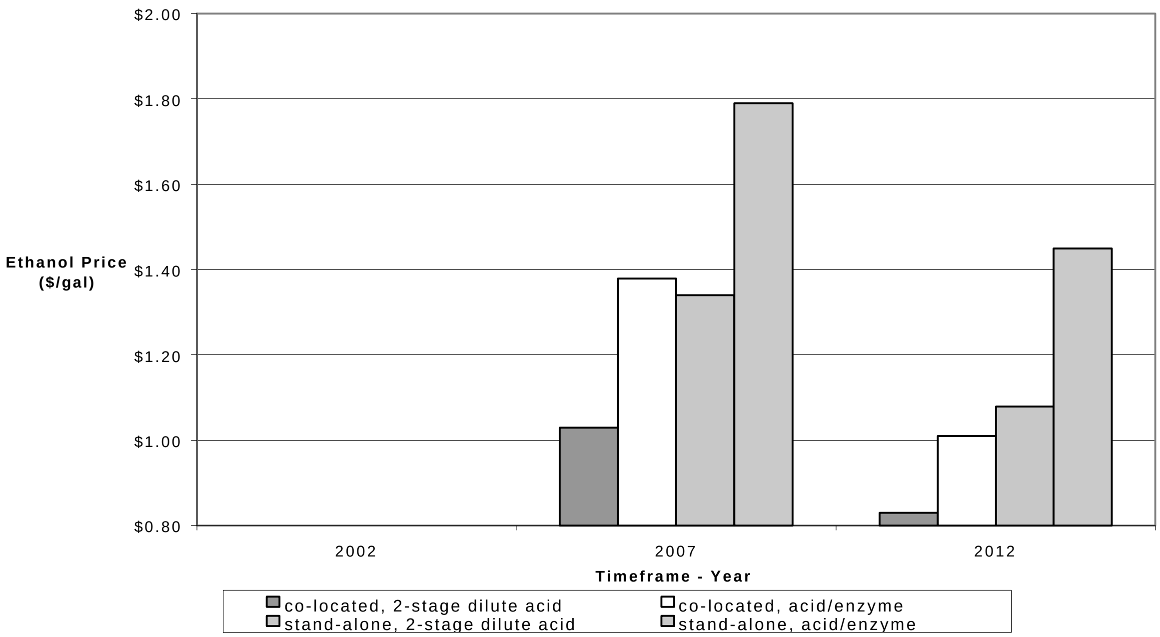
Ethanol prices versus time are shown in Figure 9 for forest material feedstock. For the collocated, two-stage dilute acid scenarios the ethanol prices are $1.44, $1.17, and $1.08 per gallon ethanol for the years 2002, 2007, and 2012, respectively. A $30/BDT credit for forest slash feedstock is included in the 2002 and 2007 scenarios, but there is no credit for the 2012 scenario. Ethanol prices for the collocated acid/enzyme scenarios are $3.25, $1.37 and $1.22.

FIGURE 9 ETHANOL PRICE VS. TIMEFRAME, FOREST MATERIALS



A similar trend is seen for urban waste feedstock in Figure 10. Scenarios for the year 2002 were not defined for urban waste so only 2007 and 2012 results are shown. The ethanol selling price for the collocated, two-stage dilute acid, urban waste feedstock scenarios are $1.03 and $0.83 per gallon ethanol for the years 2007 and 2012, respectively. The collocated acid/enzyme ethanol price is projected to decline from $1.38 in 2007 to $1.01 in 2012.

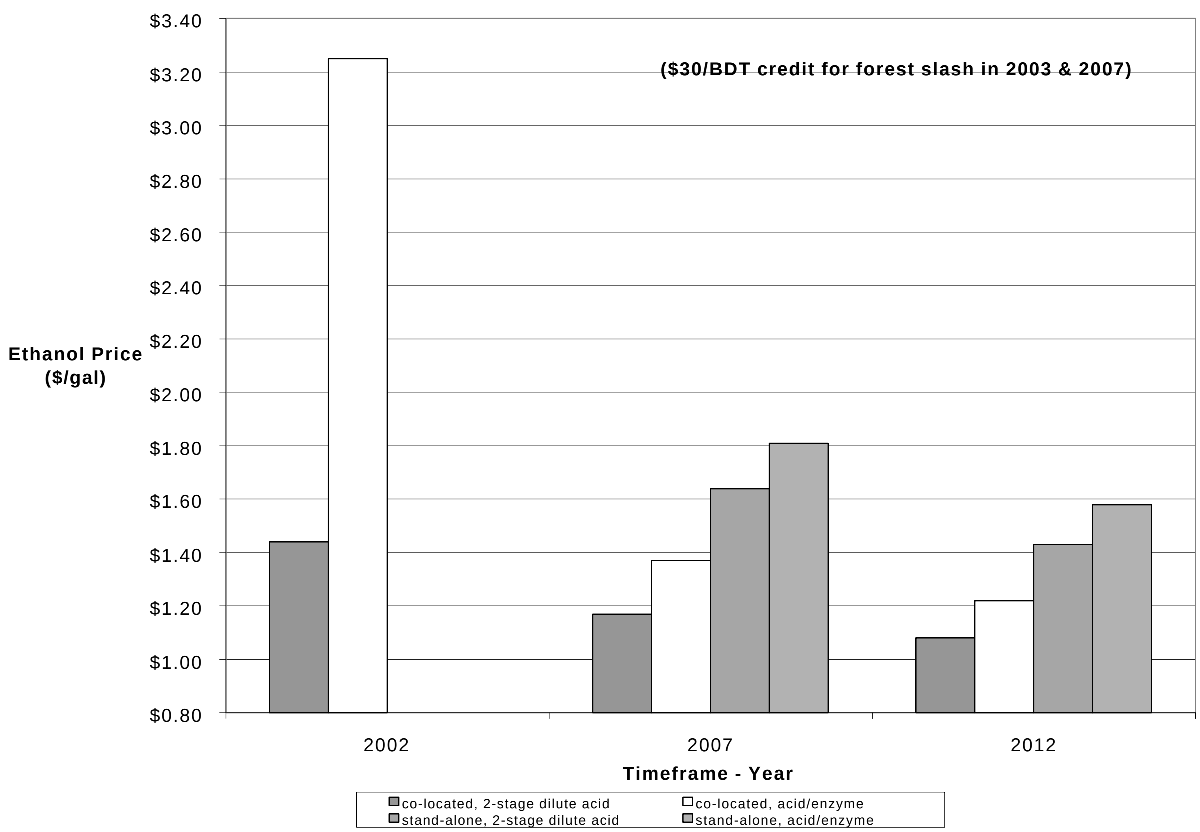
FIGURE 10 ETHANOL PRICE VS. TIMEFRAME, URBAN WASTE



Ethanol prices for agricultural waste feedstock versus time are shown in Figure 11. Collocated dilute acid ethanol prices are $1.12, $1.05 and $0.95 for 2002, 2007 and 2012, respectively. The corresponding acid/enzyme ethanol prices are $2.45, $1.11 and $1.06. A $20/BDT credit is included for the rice straw portion of the feedstock in 2002 and 2007. There is no credit in 2012.

The ethanol prices for stand-alone scenarios appear to be about $0.30 to $0.40 per gallon ethanol higher than the corresponding collocation scenarios. This is to be expected due to the significant capital cost reduction (30% less) due to the collocation assumptions described in Section 3.3.

FIGURE 11 ETHANOL PRICE VS. TIMEFRAME, AGRICULTURAL MATERIALS



Figures 12 through 15 illustrate the effect of feedstock cost on the target ethanol price. The effect of increased plant size as well as improvements in production technology between the near-term and mid-term timeframes are reflected in Figure 12. Higher capital costs for stand-alone plants result in higher production costs as shown in Figure 13. Figure 15 illustrates the effect of feedstock costs for ethanol plants located at a MRF. The cost of the near term plant is substantially higher than a midterm plant because of the higher contingency for process uncertainty, smaller plant size, and lower ethanol yields for the near term plant.

Figure 16 illustrates the potential reductions in ethanol price if value additional value added co-products are developed in the long-term. The co-product value of $7.5/ton of feedstock was assumed.

FIGURE 12 ETHANOL PRICE VS. FEEDSTOCK COST, NEAR TERM, MID TERM, FOREST MATERIALS

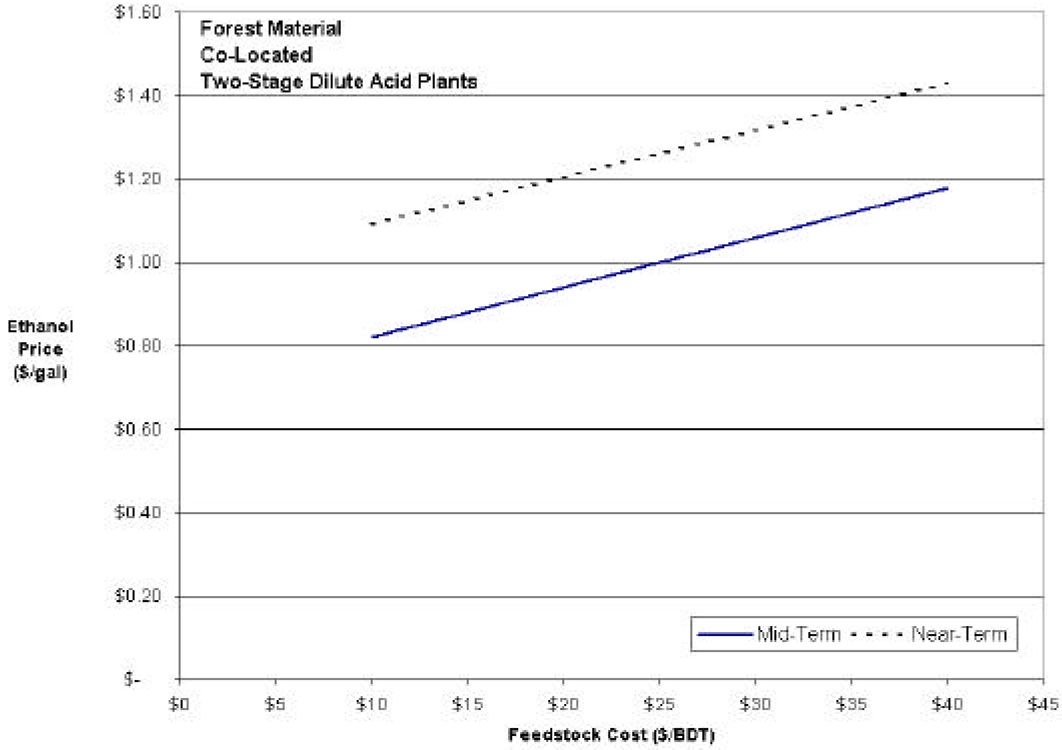


FIGURE 13 ETHANOL PRICE VS. FEEDSTOCK COST, FOREST MATERIALS, COLLOCATED VS. STAND ALONE

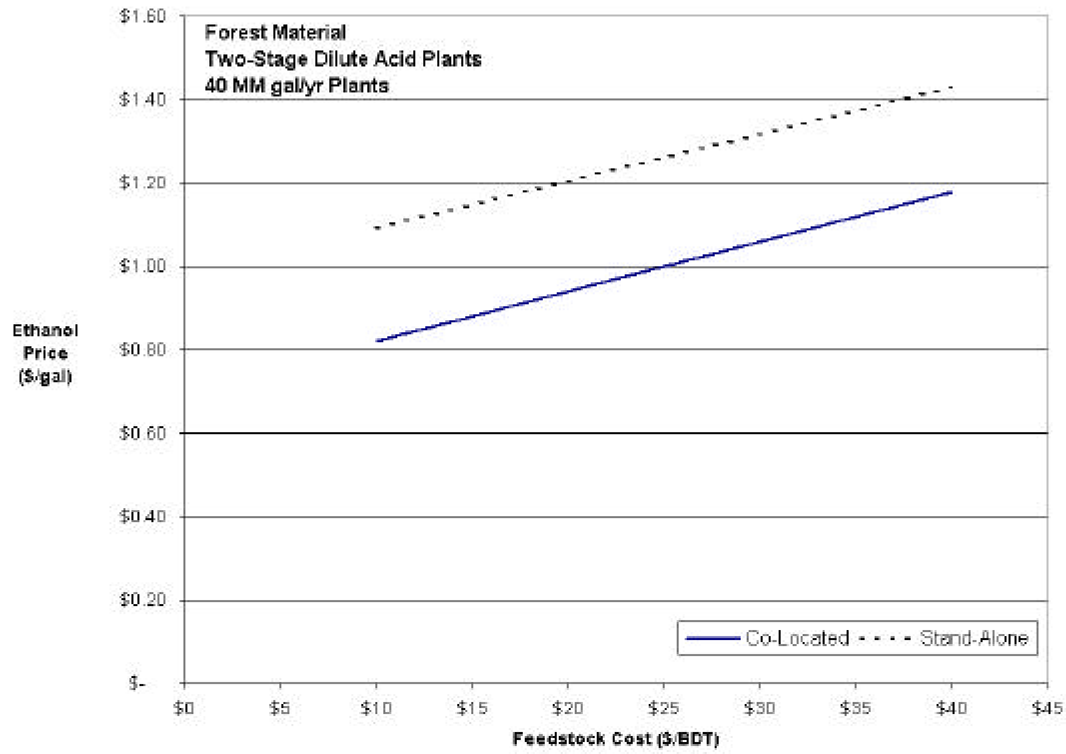


Figure 14 Ethanol Price vs. Feedstock Cost, Urban Waste Collocated

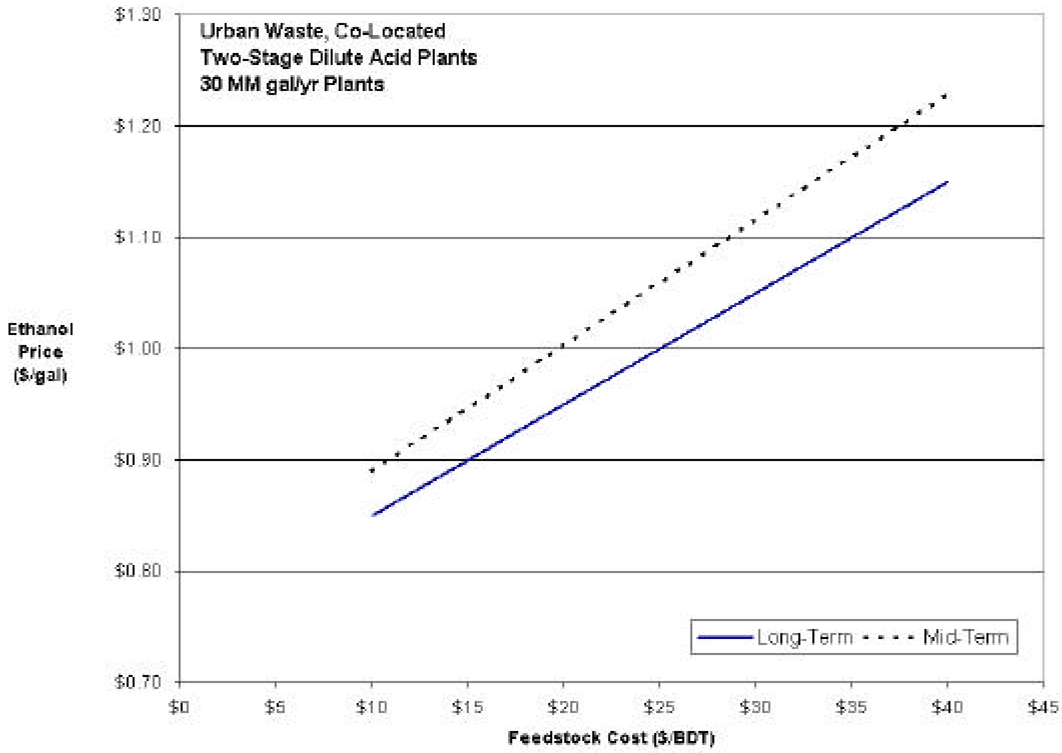


Figure 15 ETHANOL PRICE VS. FEEDSTOCK COST, WASTE PAPER LOCATED AT MRF

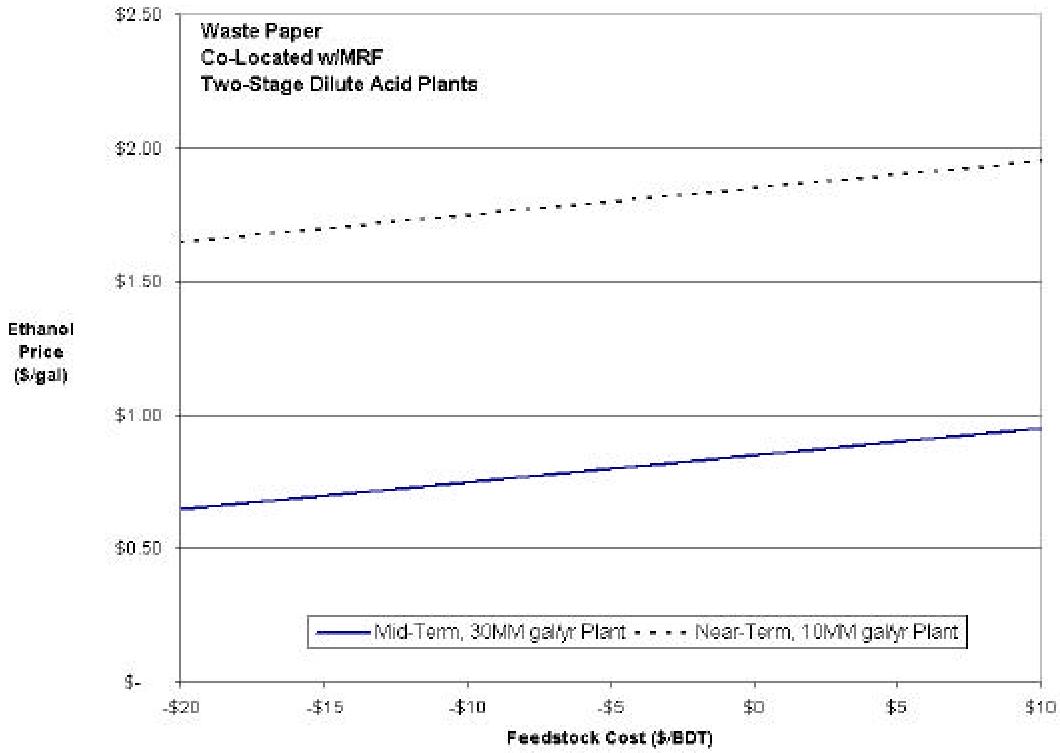
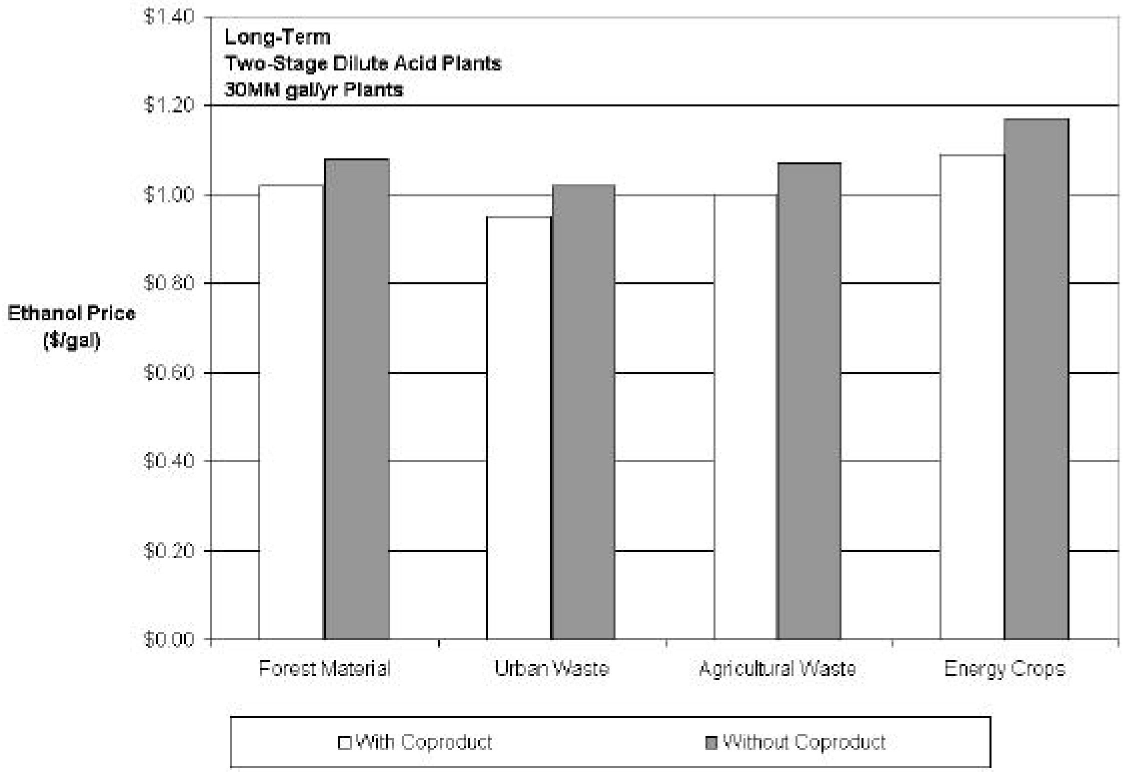


Figure 16 Ethanol Price With and Without Income from Co-products



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Appendix VII-B-1

ASSUMPTIONS FOR SCENARIOS 1 – 65

ETHANOL PRODUCTION AND ECONOMIC ANALYSIS

ProForma Systems Inc.
Golden, Colorado

TABLE 5 ASSUMPTIONS FOR SCENARIOS 1-8, STAND-ALONE ETHANOL PLANTS, FOREST MATERIAL FEEDSTOCK

case	ethanol process	year	plant size	hurdle rate	feedstock #1 lumbermill waste	feedstock #2 forest slash	feedstock #3	feedstock #4
1	two-stage dilute acid	2007	20 million GPY	25%	134,203 BDT/year $20 /BDT $0 transportation cost no credit $5/BDT lignin credit	224,900/BDT $34.00/BDT $9.5/BDT transport $30/BDT credit $5/BDT lignin credit		
2	two-stage dilute acid	2007	40 million GPY	25%	130,974 BDT/year $20/BDT $0 transportation cost no credit $5/BDT lignin credit	598,245 BDT/year $34.00/BDT $13.5/BDT transport $30/BDT credit $5/BDT lignin credit		
3	two-stage dilute acid	2007	60 million GPY	25%	134,443 BDT/year $20/BDT $0 transportation cost no credit $5/BDT lignin credit	964,001 BDT/year $34.00/BDT $26.4/BDT transport $30/BDT credit $5/BDT lignin credit		
4	two-stage dilute acid	2007	40 million GPY	25%	130,971 BDT/year $20/BDT $0 transportation cost no credit $5/BDT lignin credit	598,230 BDT/year $34.00/BDT $13.5/BDT transport no credit $5/BDT lignin credit		
5	two-stage dilute acid	2012	30 million GPY	20%	118,122 BDT/year $20/BDT $0 transportation cost no credit $5/BDT lignin credit	342,180 BDT/year $34.00/BDT $11.5/BDT transport no credit $5/BDT lignin credit		
6	acid/ enzyme	2007	40 million GPY	25%	110,818 BDT/year $20/BDT $0 transportation cost no credit $5/BDT lignin credit	506,180 BDT/year $34.00/BDT $13.5/BDT transport $30/BDT credit $5/BDT lignin credit		
7	acid/ enzyme	2007	40 million GPY	25%	110,818 BDT/year $20/BDT $0 transportation cost no credit $5/BDT lignin credit	506,180 BDT/year $34.00/BDT $13.5/BDT transport no credit $5/BDT lignin credit		
8	acid/ enzyme	2012	30 million GPY	20%	107,082 BDT/year $20/BDT $0 transportation cost no credit $5/BDT lignin credit	310,197 BDT/year $34.00/BDT $11.5/BDT transport no credit $5/BDT lignin credit		

TABLE 6 ASSUMPTIONS FOR SCENARIOS 9-18, STAND-ALONE ETHANOL PLANTS, URBAN WASTE FEEDSTOCK

case	**ethanol process**	**year**	**plant size**	**hurdle rate**	**feedstock #1 waste paper**	**feedstock #2 tree prunings**	**feedstock #3 urban wood waste**	**feedstock #4 yard waste**
9	two-stage dilute acid	2007	30 million GPY	25%	221,830 BDT/year $10.00/BDT $0/BDT transport cost no credit $5/BDT lignin credit	94,777 BDT/year $5.00/BDT $0/BDT transport cost no credit $5/BDT lignin credit	117,077 BDT/year $10.50/BDT $0/BDT transport cost no credit $5/BDT lignin credit	44,601 BDT/year $2.50/BDT $0/BDT transport cost no credit $5/BDT lignin credit
10	two-stage dilute acid	2007	50 million GPY	25%	369,716 BDT/year $10.00/BDT $5.7/BDT transport no credit $5/BDT lignin credit	157,961 BDT/year $5.00/BDT $8.1/BDT transport no credit $5/BDT lignin credit	195,128 BDT/year $10.50/BDT $8.1/BDT transport no credit $5/BDT lignin credit	74,335 BDT/year $2.50/BDT $7.7/BDT transport no credit $5/BDT lignin credit
11	two-stage dilute acid	2007	80 million GPY	25%	633,533 BDT/year $10.00/BDT $6.8/BDT transport no credit $5/BDT lignin credit	252,009 BDT/year $5.00/BDT $9.7/BDT transport no credit $5/BDT lignin credit	252,009 BDT/year $10.50/BDT $9.7/BDT transport no credit $5/BDT lignin credit	118,592 BDT/year $2.50/BDT $9.2/BDT transport no credit $5/BDT lignin credit
12	two-stage dilute acid	2007	50 million GPY	25%	no waste paper in this scenario	411,798 BDT/year $5.00/BDT $8.1/BDT transport no credit $5/BDT lignin credit	308,848 BDT/year $10.50/BDT $8.1/BDT transport no credit $5/BDT lignin credit	308,848 BDT/year $2.50/BDT $7.7/BDT transport no credit $5/BDT lignin credit
13	two-stage dilute acid	2012	30 million GPY	20%	184,190 BDT/year $10.00/BDT $0/BDT transport cost no credit $5/BDT lignin credit	78,695 BDT/year $5.00/BDT $0/BDT transport cost no credit $5/BDT lignin credit	97,211 BDT/year $10.50/BDT $0/BDT transport cost no credit $5/BDT lignin credit	37,033 BDT/year $2.50/BDT $0/BDT transport cost no credit $5/BDT lignin credit
14	acid/ enzyme	2007	50 million GPY	25%	307,383 BDT/year $10.00/BDT $5.7/BDT transport no credit $5/BDT lignin credit	131,329 BDT/year $5.00/BDT $8.1/BDT transport no credit $5/BDT lignin credit	162,230 BDT/year $10.50/BDT $8.1/BDT transport no credit $5/BDT lignin credit	61,802 BDT/year $2.50/BDT $7.7/BDT transport no credit $5/BDT lignin credit
15	acid/ enzyme	2007	50 million GPY	25%	no waste paper in this scenario	355,324 BDT/year $5.00/BDT $8.1/BDT transport no credit $5/BDT lignin credit	266,493 BDT/year $10.50/BDT $8.1/BDT transport no credit $5/BDT lignin credit	266,493 BDT/year $2.50/BDT $7.7/BDT transport no credit $5/BDT lignin credit
16	acid/ enzyme	2012	30 million GPY	20%	166,367 BDT/year $40.00/BDT $0/BDT transport cost no credit $5/BDT lignin credit	71,080 BDT/year $5.00/BDT $0/BDT transport cost no credit $5/BDT lignin credit	87,805 BDT/year $10.50/BDT $0/BDT transport cost no credit $5/BDT lignin credit	33,449 BDT/year $2.50/BDT $0/BDT transport cost no credit $5/BDT lignin credit

case	ethanol process	year	plant size	hurdle rate	feedstock #1 waste paper	feedstock #2 tree prunings	feedstock #3 urban wood waste	feedstock #4 yard waste
17	acid/ enzyme	2012	80 million GPY	20%	473,211 BDT/year $40.00/BDT $6.8/BDT transport no credit $5/BDT lignin credit	188,235 BDT/year $5.00/BDT $9.7/BDT transport no credit $5/BDT lignin credit	188,235 BDT/year $10.50/BDT $9.7/BDT transport no credit $5/BDT lignin credit	88,581 BDT/year $2.50/BDT $9.2/BDT transport no credit $5/BDT lignin credit
18	acid/ enzyme	2012	200 million GPY	20%	1,565,251 BDT/year $40.00/BDT $10.1/BDT transport no credit $5/BDT lignin credit	212,427 BDT/year $5.00/BDT $14.4/BDT transport no credit $5/BDT lignin credit	212,427 BDT/year $10.50/BDT $14.4/BDT transport no credit $5/BDT lignin credit	106,213 BDT/year $2.50/BDT $13.7/BDT transport no credit $5/BDT lignin credit

TABLE 7 ASSUMPTIONS FOR SCENARIOS 19-26, STAND-ALONE ETHANOL PLANTS, AGRICULTURAL WASTE FEEDSTOCK

case	ethanol process	year	plant size	hurdle rate	feedstock #1 rice straw	feedstock #2 orchard prunings	feedstock #3 other agri. waste	feedstock #4
19	two-stage dilute acid	2007	20 million GPY	25%	227,142 BDT/year $18.00/BDT $9.9/BDT transport $15/BDT credit $-10/BDT lignin credit	134,338 BDT/year $23.00/BDT $8/BDT transport cost no credit $5/BDT lignin credit	89,559 BDT/year $5.00/BDT $8.4/BDT transport no credit $5/BDT lignin credit	
20	two-stage dilute acid	2007	40 million GPY	25%	454,284 BDT/year $18.00/BDT $12.1/BDT transport $15/BDT credit $-10/BDT lignin credit	268,677 BDT/year $23.00/BDT $8/BDT transport cost no credit $5/BDT lignin credit	179,118 BDT/year $5.00/BDT $8.4/BDT transport no credit $5/BDT lignin credit	
21	two-stage dilute acid	2007	60 million GPY	25%	681,549 BDT/year $18.00/BDT $13.7/BDT transport $15/BDT credit $-10/BDT lignin credit	403,088 BDT/year $23.00/BDT $8/BDT transport cost no credit $5/BDT lignin credit	268,725 BDT/year $5.00/BDT $8.4/BDT transport no credit $5/BDT lignin credit	
22	two-stage dilute acid	2007	40 million GPY	25%	263,938 BDT/year $18.00/BDT $10.4/BDT transport no credit $-10/BDT lignin credit	346,890 BDT/year $23.00/BDT $8/BDT transport cost no credit $5/BDT lignin credit	260,167 BDT/year $5.00/BDT $8.4/BDT transport no credit $5/BDT lignin credit	
23	two-stage dilute acid	2012	30 million GPY	20%	280,088 BDT/year $18.00/BDT $10.9/BDT transport no credit $-10/BDT lignin credit	165,652 BDT/year $23.00/BDT $8/BDT transport cost no credit $5/BDT lignin credit	110,435 BDT/year $5.00/BDT $8.4/BDT transport no credit $5/BDT lignin credit	
24	acid/ enzyme	2007	40 million GPY	25%	393,459 BDT/year $18.00/BDT $12.1/BDT transport $20/BDT credit $-10/BDT lignin credit	232,703 BDT/year $23.00/BDT $8/BDT transport cost no credit $5/BDT lignin credit	155,135 BDT/year $5.00/BDT $8.4/BDT transport no credit $5/BDT lignin credit	
25	acid/ enzyme	2007	40 million GPY	25%	230,117 BDT/year $18.00/BDT $10.4/BDT transport no credit $-10/BDT lignin credit	302,439 BDT/year $23.00/BDT $8/BDT transport cost no credit $5/BDT lignin credit	226,829 BDT/year $5.00/BDT $8.4/BDT transport no credit $5/BDT lignin credit	
26	acid/ enzyme	2012	30 million GPY	20%	262,500 BDT/year $18.00/BDT $10.9/BDT transport no credit $-10/BDT lignin credit	155,250 BDT/year $23.00/BDT $8/BDT transport cost no credit $5/BDT lignin credit	103,500 BDT/year $5.00/BDT $8.4/BDT transport no credit $5/BDT lignin credit	

TABLE 8 ASSUMPTIONS FOR SCENARIOS 27-30, STAND-ALONE ETHANOL PLANTS, ENERGY CROP FEEDSTOCK

case	ethanol process	year	plant size	hurdle rate	feedstock #1 eucalyptus	feedstock #2	feedstock #3	feedstock #4
27	two-stage dilute acid	2012	30 million GPY	20%	492,164 BDT/year $36.00/BDT $5.8/BDT transport no credit $5/BDT lignin credit			
28	acid/ enzyme	2012	30 million GPY	20%	460,676 BDT/year $36.00/BDT $5.8/BDT transport no credit $5/BDT lignin credit			
29	acid/ enzyme	2012	80 million GPY	20%	1,229,867 BDT/year $36.00/BDT $7.6/BDT transport no credit $5/BDT lignin credit			
30	acid/ enzyme	2012	200 million GPY	20%	3,076,205 BDT/year $36.00/BDT $10.3/BDT transport no credit $5/BDT lignin credit			

TABLE 9 ASSUMPTIONS FOR SCENARIOS 31-40, COLLOCATED ETHANOL PLANTS, FOREST MATERIAL FEEDSTOCK

case	ethanol process	year	plant size	hurdle rate	feedstock #1 lumbermill waste	feedstock #2 forest slash	feedstock #3	feedstock #4
31	two-stage dilute acid	2002	20 million GPY	30%	123,789 BDT/year $20/BDT $0 transportation cost no credit $20/BDT lignin credit	225,832 BDT/year $34.00/BDT $9.6/BDT transport $30/BDT credit $20/BDT lignin credit		
32	two-stage dilute acid	2007	20 million GPY	25%	134,636 BDT/year $20/BDT $0 transportation cost no credit $20/BDT lignin credit	225,626 BDT/year $34.00/BDT $9.5/BDT transport $30/BDT credit $20/BDT lignin credit		
33	two-stage dilute acid	2007	40 million GPY	25%	131,149 BDT/year $20/BDT $0 transportation cost no credit $20/BDT lignin credit	599,047 BDT/year $34.00/BDT $13.5DT transport cost $30/BDT credit $20/BDT lignin credit		
34	two-stage dilute acid	2007	60 million GPY	25%	134,502 BDT/year $20/BDT $0 transportation cost no credit $20/BDT lignin credit	964,423 BDT/year $34.00/BDT $26.4/BDT transport $30/BDT credit $20/BDT lignin credit		
35	two-stage dilute acid	2007	40 million GPY	25%	131,149 BDT/year $20/BDT $0 transportation cost no credit $20/BDT lignin credit	599,047 BDT/year $34.00/BDT $13.5/BDT transport no credit $20/BDT lignin credit		
36	two-stage dilute acid	2012	30 million GPY	20%	118,222 BDT/year $20/BDT $0 transportation cost no credit $20/BDT lignin credit	342,469 BDT/year $34.00/BDT $11.5 transport cost no credit $20/BDT lignin credit		
37	acid/ enzyme	2002	20 million GPY	30%	116,667 BDT/year $20/BDT $0 transportation cost no credit $20/BDT lignin credit	212,838 BDT/year $34.00/BDT $9.6/BDT transport $30/BDT credit $20/BDT lignin credit		
38	acid/ enzyme	2007	40 million GPY	25%	110,834 BDT/year $20/BDT $0 transportation cost no credit $20/BDT lignin credit	506,253 BDT/year $34.00/BDT $13.5BDT transport $30/BDT credit $20/BDT lignin credit		

case	ethanol process	year	plant size	hurdle rate	feedstock #1 lumbermill waste	feedstock #2 forest slash	feedstock #3	feedstock #4
39	acid/ enzyme	2007	40 million GPY	25%	111,391 BDT/year $20/BDT $0 transportation cost no credit $20/BDT lignin credit	508,797 BDT/year $34.00/BDT $13.5/BDT transport no credit $20/BDT lignin credit		
40	acid/ enzyme	2012	30 million GPY	20%	106,847 BDT/year $20/BDT $0 transportation cost no credit $20/BDT lignin credit	309,516 BDT/year $34.00/BDT $11.5/BDT transport no credit $20/BDT lignin credit		

TABLE 10 ASSUMPTIONS FOR SCENARIOS 41-48, COLLOCATED ETHANOL PLANTS, URBAN WASTE FEEDSTOCK

case	ethanol process	year	plant size	hurdle rate	feedstock #1 waste paper	feedstock #2 tree prunings	feedstock #3 urban wood waste	feedstock #4 yard waste
41	two-stage dilute acid	2007	30 million GPY	25%	221,596 BDT/year $10.00/BDT $4.9/BDT transport no credit $20/BDT lignin credit	94,677 BDT/year $5.00/BDT $7.1/BDT transport no credit $20/BDT lignin credit	116,954 BDT/year $10.50/BDT $7.1/BDT transport no credit $20/BDT lignin credit	44,554 BDT/year $2.50/BDT $6.7/BDT transport no credit $20/BDT lignin credit
42	two-stage dilute acid	2007	50 million GPY	25%	369,609 BDT/year $10.00/BDT $5.7/BDT transport no credit $20/BDT lignin credit	157,915 BDT/year $5.00/BDT $8.1/BDT transport no credit $20/BDT lignin credit	195,071 BDT/year $10.50/BDT $8.1/BDT transport no credit $20/BDT lignin credit	74,313 BDT/year $2.50/BDT $7.7/BDT transport no credit $20/BDT lignin credit
43	two-stage dilute acid	2007	80 million GPY	25%	633,511 BDT/year $10.00/BDT $6.8/BDT transport no credit $20/BDT lignin credit	252,000 BDT/year $5.00/BDT $9.7/BDT transport no credit $20/BDT lignin credit	252,000 BDT/year $10.50/BDT $9.7/BDT transport no credit $20/BDT lignin credit	118,588 BDT/year $2.50/BDT $9.2/BDT transport no credit $20/BDT lignin credit
44	two-stage dilute acid	2007	50 million GPY	25%	no waste paper in this scenario	411,798 BDT/year $5.00/BDT $8.1/BDT transport no credit $20/BDT lignin credit	308,848 BDT/year $10.50/BDT $8.1/BDT transport no credit $20/BDT lignin credit	308,848 BDT/year $2.50/BDT $7.7/BDT transport no credit $20/BDT lignin credit
45	two-stage dilute acid	2012	30 million GPY	20%	184,190 BDT/year $10.00/BDT $4.9/BDT transport no credit $20/BDT lignin credit	78,695 BDT/year $5.00/BDT $7.1/BDT transport no credit $20/BDT lignin credit	97,211 BDT/year $10.50/BDT $7.1/BDT transport no credit $20/BDT lignin credit	37,033 BDT/year $2.50/BDT $6.7/BDT transport no credit $20/BDT lignin credit
46	acid/ enzyme	2007	50 million GPY	25%	307,383 BDT/year $10.00/BDT $5.7/BDT transport no credit $20/BDT lignin credit	131,329 BDT/year $5.00/BDT $8.1/BDT transport no credit $20/BDT lignin credit	162,230 BDT/year $10.50/BDT $8.1/BDT transport no credit $20/BDT lignin credit	61,802 BDT/year $2.50/BDT $7.7/BDT transport no credit $20/BDT lignin credit
47	acid/ enzyme	2007	50 million GPY	25%	no waste paper in this scenario	355,376 BDT/year $5.00/BDT $8.1/BDT transport no credit $20/BDT lignin credit	266,532 BDT/year $10.50/BDT $8.1/BDT transport no credit $20/BDT lignin credit	266,532 BDT/year $2.50/BDT $7.7/BDT transport no credit $20/BDT lignin credit
48	acid/ enzyme	2012	30 million GPY	20%	166,367 BDT/year $10.00/BDT $4.9/BDT transport no credit $20/BDT lignin credit	71,080 BDT/year $5.00/BDT $7.1/BDT transport no credit $20/BDT lignin credit	87,805 BDT/year $10.50/BDT $7.1/BDT transport no credit $20/BDT lignin credit	33,449 BDT/year $2.50/BDT $6.7/BDT transport no credit $20/BDT lignin credit

TABLE 11 ASSUMPTIONS FOR SCENARIOS 49-58, COLLOCATED ETHANOL PLANTS, AGRICULTURAL WASTE FEEDSTOCK

case	**ethanol process**	**year**	**plant size**	**hurdle rate**	**feedstock #1 rice straw**	**feedstock #2 orchard prunings**	**feedstock #3 other agri. waste**	**feedstock #4**
49	two-stage dilute acid	2002	20 million GPY	30%	232,737 BDT/year $18.00/BDT $9.9/BDT transport $15/BDT credit $-10/BDT lignin credit	137,647 BDT/year $23.00/BDT $8/BDT transport cost no credit $20/BDT lignin credit	91,765 BDT/year $5.00/BDT $8.4/BDT transport no credit $20/BDT lignin credit	
50	two-stage dilute acid	2007	20 million GPY	25%	227,060 BDT/year $18.00/BDT $9.9/BDT transport $15/BDT credit $-10/BDT lignin credit	134,290 BDT/year $23.00/BDT $8/BDT transport cost no credit $20/BDT lignin credit	89,527 BDT/year $5.00/BDT $8.4/BDT transport no credit $20/BDT lignin credit	
51	two-stage dilute acid	2007	40 million GPY	25%	454,538 BDT/year $18.00/BDT $12.1/BDT transport $15/BDT credit $-10/BDT lignin credit	268,827 BDT/year $23.00/BDT $8/BDT transport cost no credit $20/BDT lignin credit	179,218 BDT/year $5.00/BDT $8.4/BDT transport no credit $20/BDT lignin credit	
52	two-stage dilute acid	2007	60 million GPY	25%	681,807 BDT/year $18.00/BDT $13.7/BDT transport $15/BDT credit $-10/BDT lignin credit	403,240 BDT/year $23.00/BDT $8/BDT transport cost no credit $20/BDT lignin credit	268,827 BDT/year $5.00/BDT $8.4/BDT transport no credit $20/BDT lignin credit	
53	two-stage dilute acid	2007	40 million GPY	25%	263,938 BDT/year $18.00/BDT $10.49/BDT transport no credit $-10/BDT lignin credit	346,890 BDT/year $23.00/BDT $8/BDT transport cost no credit $20/BDT lignin credit	260,167 BDT/year $5.00/BDT $8.4/BDT transport no credit $20/BDT lignin credit	
54	two-stage dilute acid	2012	30 million GPY	20%	280,088 BDT/year $18.00/BDT $10.9/BDT transport no credit $-10/BDT lignin credit	165,652 BDT/year $23.00/BDT $8/BDT transport cost no credit $20/BDT lignin credit	110,435 BDT/year $5.00/BDT $8.4/BDT transport no credit $20/BDT lignin credit	
55	acid/ enzyme	2002	20 million GPY	30%	223,739 BDT/year $18.00/BDT $9.9/BDT transport $15/BDT credit $-10/BDT lignin credit	132,325 BDT/year $23.00/BDT $8/BDT transport cost no credit $20/BDT lignin credit	88,217 BDT/year $5.00/BDT $8.4/BDT transport no credit $20/BDT lignin credit	

case	ethanol process	year	plant size	hurdle rate	feedstock #1 rice straw	feedstock #2 orchard prunings	feedstock #3 other agri. waste	feedstock #4
56	acid/ enzyme	2007	40 million GPY	25%	393,387 BDT/year $18.00/BDT $12.1/BDT transport $15/BDT credit $-10/BDT lignin credit	232,660 BDT/year $23.00/BDT $8/BDT transport cost no credit $20/BDT lignin credit	155,107 BDT/year $5.00/BDT $8.4/BDT transport no credit $20/BDT lignin credit	
57	acid/ enzyme	2007	40 million GPY	25%	230,117 BDT/year $18.00/BDT $10.4/BDT transport no credit $-10/BDT lignin credit	302,439 BDT/year $23.00/BDT $8/BDT transport cost no credit $20/BDT lignin credit	226,829 BDT/year $5.00/BDT $8.4/BDT transport no credit $20/BDT lignin credit	
58	acid/ enzyme	2012	30 million GPY	20%	262,500 BDT/year $18.00/BDT $10.9/BDT transport no credit $-10/BDT lignin credit	155,250 BDT/year $23.00/BDT $8/BDT transport cost no credit $20/BDT lignin credit	103,500 BDT/year $5.00/BDT $8.4/BDT transport no credit $20/BDT lignin credit	

TABLE 12 ASSUMPTIONS FOR SCENARIOS 59-60, COLLOCATED ETHANOL PLANTS, ENERGY CROP FEEDSTOCK

case	ethanol process	year	plant size	hurdle rate	feedstock #1 eucalyptus	feedstock #2	feedstock #3	feedstock #4
59	two-stage dilute acid	2012	30 million GPY	20%	492,164 BDT/year $36.00/BDT $5.65/BDT transport no credit $20/BDT lignin credit			
60	acid/ enzyme	2012	80 million GPY	20%	1,236,351 BDT/year $36.00/BDT $7.2/BDT transport no credit $20/BDT lignin credit			

TABLE 13 ASSUMPTIONS FOR SCENARIOS 61-65, STAND-ALONE ETHANOL PLANTS, WASTE PAPER FEEDSTOCK

case	**ethanol process**	**year**	**plant size**	**hurdle rate**	**feedstock #1 waste paper**	**feedstock #2**	**feedstock #3**	**feedstock #4**
61	two-stage dilute acid	2002	10 million GPY	30%	141,550 BDT/year -$10.00/BDT $0/BDT transport cost no credit -$10/BDT lignin credit			
62	two-stage dilute acid	2007	10 million GPY	25%	128,635 BDT/year -$10.00/BDT $0/BDT transport cost no credit -$10/BDT lignin credit			
63	two-stage dilute acid	2007	30 million GPY	25%	385,906 BDT/year -$10.00/BDT $5.76/BDT transport no credit -$10/BDT lignin credit			
64	two-stage dilute acid	2012	30 million GPY	20%	318,930 BDT/year -$10.00/BDT $5.7/BDT transport no credit -$10/BDT lignin credit			
65	two-stage dilute acid	2012	80 million GPY	20%	851,546 BDT/year -$10.00/BDT $5.7/BDT transport no credit -$10/BDT lignin credit			

Appendix VII-B-2

BIOMASS FEEDSTOCK COMPOSITION DATA

ETHANOL PRODUCTION AND ECONOMIC ANALYSIS

ProForma Systems Inc.
Golden, Colorado

TABLE 14 BIOMASS FEEDSTOCK COMPOSITION DATA

Biomass Feedstock	Moisture	Glucan	Mannan	Galactan	Xylan	Arabinan	Total Lignin	Ash	Extractive
Lumbermill Waste	25%	43.3	10.2	2.8	7.4	1.5	28.6	1.2	5.0
Forest Slash & Thinnings	30%	43.3	10.2	2.8	7.4	1.5	28.6	1.2	5.0
Waste Paper	5%	63.0	2.8	0.3	7.4	0.5	13.5	12.5	0.0
Tree Prunings	30%	35.0	4.5	1.3	16.2	1.8	30.2	11	
Urban Wood Waste	30%	37.9	7.4	2.5	12.4	2.2	29.1	6.1	2.4
Yard Waste	30%	34.2	2.3	0.4	14.1	1.9	18.2	28.9	
Rice Straw	31%	32.0	0.2	0.9	13.8	3.4	13.1	36.6	
Orchard Prunings	30%	31.2	1.4	0.8	20.5	1.9	31.2	13	
Other Agricultural Waste	30%	35.0	4.5	1.3	16.2	1.8	30.2	11	
Eucalyptus	30%	36.8	2.2	1.0	19.0	1.4	28.8	1.1	9.7

(Units for components other than water are percent dry weight)

Appendix VII-B-3

BIOMASS TRANSPORTATION COST CALCULATIONS

ETHANOL PRODUCTION AND ECONOMIC ANALYSIS

ProForma Systems Inc.
Golden, Colorado

Biomass Transportation Cost Calculations

Data and methodology for calculating the biomass feedstock transportation costs were provided by ARCADIS Geraghty & Miller and are summarized here. Transportation costs are a function of the biomass bulk density, biomass moisture content, truck capacity, trip speed, fuel economy, etc. Round Trip Driving Cost ($/BDT/mile) and Loading/Unloading Cost ($/BDT) were provided by ARCADIS for each biomass feedstock type. These values are shown in Table 15.

For feedstocks that are harvested (forest slash, rice straw and eucalyptus) the transportation costs increase with increasing plant size according to the following equation:

$$\text{Transportation cost (\$/BDT)} = \left(\frac{X}{D \times RDF \times AF \times 4022.8} \right)^{1/2} \times TCF \times RT + L$$

Where:*
X = annual feedstock use, BDT/year
D = biomass harvest density, BDT/acre
RDF = resource density factor (ratio of harvested acres to total acres), %
AF = availability factor (percent acres harvested per year), %
TCF = transport circuity factor, miles
RT = round trip driving cost, $/BDT/mile
L = loading and unloading cost, $/BDT

*See Table 15 for values provided by ARCADIS.

The transportation costs for feedstocks that are collected by others (lumbermill waste, waste paper, tree prunings, urban wood waste, yard waste, orchard prunings and other agricultural wastes) are calculated as follows:

$$\text{Transportation cost (\$/BDT)} = TD \times RT + L$$

Where:
TD = transportation distance, miles
RT = round trip driving cost, $/BDT/mile
L = loading and unloading cost, $/BDT

Transportation distances for each feedstock are shown in Table 15.

TABLE 15 TRANSPORTATION COST INPUTS

Biomass Feedstock	**round trip driving cost ($/BDT/mi)** *RT*	**loading/ unloading cost ($/BDT)** *L*	**harvest density (BDT/acre)** *D*	**resource density factor** *RDF*	**availability factor** *AF*	**transport circuity factor (mi)** *TCF*	**transportation distance (miles)** *TD*
Lumbermill Waste	$0	$0	NA	NA	NA	NA	NA
Forest Slash & Thinnings	$0.25	$2.99	9.8	60%	9%	3	NA
Waste Paper	$0.18	$2.20	NA	NA	NA	NA	15 - 43
Tree Prunings	$0.26	$3.15	NA	NA	NA	NA	15 – 43
Urban Wood Waste	$0.26	$3.15	NA	NA	NA	NA	15 – 43
Yard Waste	$0.25	$2.99	NA	NA	NA	NA	15 – 43
Rice Straw	$0.39	$4.65	2.1	70%	30%	1.4	NA
Orchard Prunings	$0.25	$2.99	NA	NA	NA	NA	20
Other Agricultural Waste	$0.26	$3.15	NA	NA	NA	NA	20
Eucalyptus	$0.25	$2.99	7.1	70%	30%	1.4	NA

NA = Not Applicable

Appendix VII-B-4

TWO-STAGE DILUTE ACID PROCESS DESCRIPTION

ETHANOL PRODUCTION AND ECONOMIC ANALYSIS

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Dilute Sulfuric Acid Process for Ethanol Production from Biomass
– from NREL's Bioethanol Strategic Roadmap

Background

Dilute acid hydrolysis of biomass is, by far, the oldest technology for converting biomass to ethanol. As indicated earlier, the first attempt at commercializing a process for ethanol from wood was done in Germany in 1898. It involved the use of dilute acid to hydrolyze the cellulose to glucose, and was able to produce 7.6 liters of ethanol per 100 kg of wood waste (18 gal per ton). The Germans soon developed an industrial process optimized for yields of around 50 gallons per ton of biomass. This process soon found its way to the United States, culminating in two commercial plants operating in the southeast during World War I. These plants used what was called "the American Process"—a one stage dilute sulfuric acid hydrolysis. Though the yields were half that of the original German process (25 gallons of ethanol per ton versus 50), the productivity of the American process was much higher. A drop in lumber production forced the plants to close shortly after the end of World War I[1]. In the meantime, a small, but steady amount of research on dilute acid hydrolysis continued at the USDA's Forest Products Laboratory.

In 1932, the Germans developed an improved "percolation" process using dilute sulfuric acid, known as the "Scholler Process." These reactors were simple systems in which a dilute solution of sulfuric acid was pumped through a bed of wood chips. Several years into World War II, the U.S. found itself facing shortages of ethanol and sugar crops. The U.S. War Production Board reinvigorated research on wood-to-ethanol as an "insurance" measure against future worsening shortages, and even funded construction of a plant in Springfield, Oregon. The board directed the Forest Products lab to look at improvements in the Scholler Process.[2] Their work resulted in the "Madison Wood Sugar" process, which showed substantial improvements in productivity and yield over its German predecessor[3]. Problems with start up of the Oregon plant prompted additional process development work on the Madison process at TVA's Wilson Dam facility. Their pilot plant studies further refined the process by increasing yield and simplifying mechanical aspects of the process[4]. The dilute acid hydrolysis percolation reactor, culminating in the design developed in 1952, is still one of the simplest and most effective means of producing sugars from biomass. It is a benchmark against which we often compare our new ideas. In fact, such systems are still operating in Russia.

In the late 1970s, a renewed interest in this technology took hold in the U.S. because of the petroleum shortages experienced in that decade. Modeling and experimental studies on dilute hydrolysis systems were carried out during the first half of the 1980s. DOE and USDA sponsored much of this work. By 1985, most researchers recognized that, while the dilute acid percolation designs were the most practical and well understood, these systems had reached the limits of their potential. Their comparatively high glucose yields (around 70%) were achieved at the expense of producing highly dilute sugar streams. Kinetic models, based on pseudo first order kinetics, and process design work showed that the most effective designs would require both high solids concentration and some form of countercurrent flow. The former is a consequence of equipment size and energy cost and the latter is a consequence of the reactor kinetics. Both requirements involve significant equipment design problems. Studies shifted to alternative designs, such as plug flow reactors[5,6] and so-called progressing batch systems that mimicked countercurrent operation[7]. Optimal operation of the plug flow reactors required very short residence time (6 to 10 seconds) and high temperature (around 240 °C)[8]. On scale up, these systems encountered some difficulties with solids handling, even at lower-than-optimal concentrations[9]. Plug flow systems in the lab and the pilot plant produced yields of glucose of around 50%. These yields are approaching the theoretical limits for such continuous reactor systems.

Process Description

After a century of research and development, the dilute acid hydrolysis process has evolved into the general concept outlined in Figure . The hydrolysis occurs in two stages to accommodate the differences between hemicellulose and cellulose[10]. The first stage can be operated under milder conditions, which maximize yield from the more readily hydrolyzed hemicellulose. The second stage is optimized for hydrolysis of the more resistant cellulose fraction. The liquid hydrolysates are recovered from each stage and fermented to alcohol. Residual cellulose and lignin left over in the solids from the hydrolysis reactors serves as boiler fuel for electricity or steam production.

While a variety of reactor designs have been evaluated, the percolation reactors originally developed at the turn of the century are still the most reliable. Though more limited in yield than the percolation reactor, continuous cocurrent pulping reactors have been proven at industrial scale[11]. NREL recently reported results for a dilute acid hydrolysis of softwoods in which the conditions of the reactors were as follows:

- Stage 1: 0.7% sulfuric acid, 190°C, and a 3 minute residence time
- Stage 2: 0.4% sulfuric acid, 215°C, and a 3 minute residence time

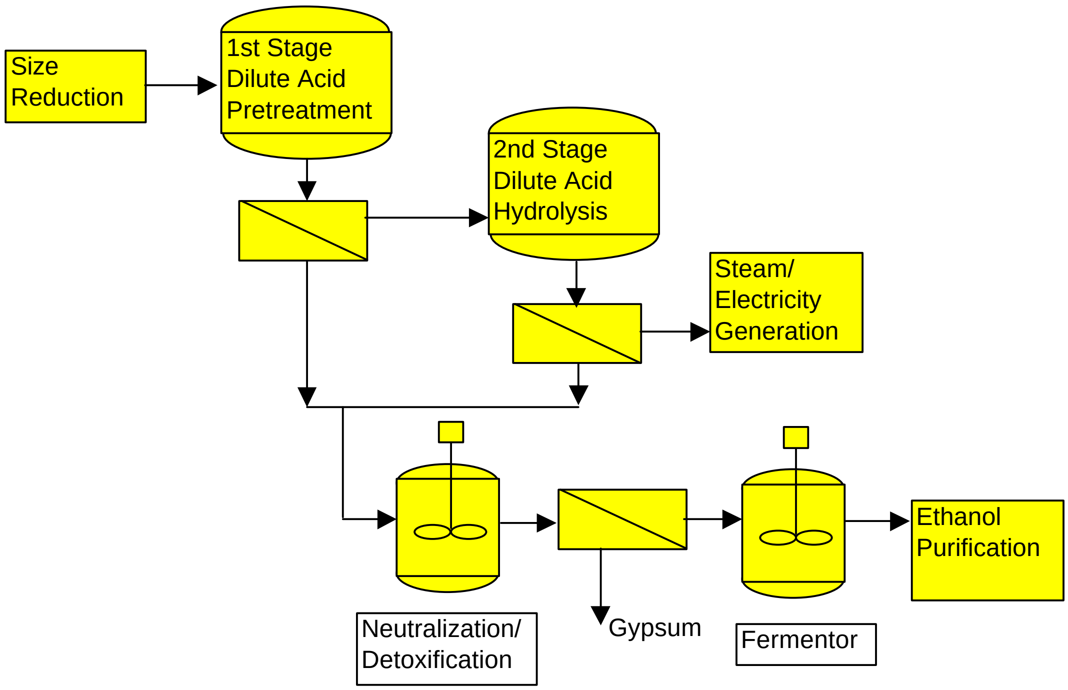

FIGURE 17: GENERAL SCHEMATIC OF TWO-STAGE DILUTE ACID HYDROLYSIS PROCESS

These bench scale tests confirmed the potential to achieve yields of 89% for mannose, 82% for galactose and 50% for glucose. Fermentation with *Saccharomyces cerevisiae* achieved ethanol conversion of 90% of the theoretical yield[12].

Commercial Status

There is quite a bit of industrial experience with the dilute acid process. As indicated earlier, Germany, Japan and Russia have operated dilute acid hydrolysis percolation plants off and on over the past 50 years. In many cases, however, these percolation designs would not survive in a completely competitive market situation. Today, companies are beginning to look at commercial opportunities for this technology, which combine recent improvements and niche opportunities to solve environmental problems.

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Appendix VII-B-5

ACID/ENZYME PROCESS DESCRIPTION

ETHANOL PRODUCTION AND ECONOMIC ANALYSIS

ProForma Systems Inc.
Golden, Colorado

Enzymatic Hydrolysis Process for Ethanol Production from Biomass

– from NREL's Bioethanol Strategic Roadmap

Background

Enzymes are the relative newcomers with respect to biomass-to-ethanol processing. While the chemistry of sugar production from wood has almost two centuries of research and development history and a hundred years of process development, enzymes for biomass hydrolysis can barely speak of fifty years of serious effort. The search for biological causes of cellulose hydrolysis did not begin in earnest until World War II. The U.S. Army mounted a basic research program to understand the causes of deterioration of military clothing and equipment in the jungles of the South Pacific—a problem that was wrecking havoc with cargo shipments during the war. This campaign resulted in the formation of the U.S. Army Natick Laboratories[1]. Out of this effort to screen thousands of samples collected from the jungle came the identification of what has become one of the most important organisms in the development of cellulase enzymes—*Trichoderma viride* (eventually *renamed Trichoderma reesei*). *T. reesei* is the ancestor of many of the most potent enzyme-producing fungi in commercial use today.

Ironically, the research on cellulases was prompted by a need to prevent their hydrolytic attack on cellulose. Today, we turn to these enzymes in hope of increasing their hydrolytic power. This turning point in the focus of cellulase research did not occur until the early 1960s, when sugars from cellulose were recognized as a possible food source,[2] echoing similar notions expressed by researchers in earlier days on acid hydrolysis research[3]. In the mid-1960s, the discovery that extracellular enzyme preparations could be made from the likes of T. reesei[4] accelerated scientific and commercial interest in cellulases. In 1973, the Army was beginning to look at cellulases as a means of converting solid waste into food and energy products[5]. By 1979, genetic enhancement of T. reesei had already produced mutant strains with up to 20 times the productivity of the original organisms isolated from New Guinea[6,7]. For roughly 20 years, cellulases made from submerged culture fungal fermentations have been commercially available. In another ironic twist, the most lucrative market cellulases today is in the textile industry, where they have found valuable niches such as in the production of "stone-washed" jeans.

The science of cellulases has come a long way since World War II. It has grown in conjunction with the monumental changes that have occurred in molecular biology, protein chemistry and enzymology over the past 50 years. It is easy to forget just how extensive this change has been. In 1876, the German researcher Wilhelm Friedrich Kuhne coined the term "enzyme." Its Greek roots simply mean "in yeast." Kuhne used it to describe the "unorganized ferment from yeast and other organisms." The debate in his time was whether the catalytic activity observed in these "ferments" could exist independently of living cells[8]. By the 1920s, evidence was mounting that these enzymes were actually proteins and that proteins were actually discrete chemical entities. But, the answer to this question had to wait for sufficiently sophisticated protein purification techniques to be developed. It was not until 1951, with the elucidation of the amino acid sequence for part of insulin, that enzymes were indisputably recognized as independent protein chemicals[9].

In many ways, however, our understanding of cellulases is in its infancy compared to other enzymes. There are some good reasons for this. Cellulase-cellulose systems involve soluble enzymes working on insoluble substrates. The jump in complexity from homogeneous enzyme-substrate systems is tremendous. It became clear fairly quickly that the enzyme known as "cellulase" was really a complex system of enzymes that work together synergistically to attack native cellulose. In 1950, this complex was crudely described as a system in which an enzyme known as "C_1" acts to decrystallize the cellulose, followed by a consortium of hydrolytic enzymes, known as "C_x" which breaks down the cellulose to sugar[10]. This early concept of cellulase activity has been modified, added to and argued about for the past forty years[11,12].

Though many researchers still talk in terms of the original model of a nonhydrolytic C_1 enzyme and a set of C_x hydrolytic enzymes, our current picture of how these enzymes work together is much more complex. Three major classes of cellulase enzymes are recognized today:

- Endoglucanases, which act randomly on soluble and insoluble glucose chains
- Exoglucanases, which include glucanhydrolases that preferentially liberate glucose monomers from the end of the cellulose chain and cellobiohydrolases that preferentially liberate cellobiose (glucose dimers) from the end of the cellulose chain
- β-glucosidases, which liberate D-glucose from cellobiose dimers and soluble cellodextrins

For a long time, researchers have recognized that these three classes of enzymes work together synergistically in a complex interplay that results in efficient decrystallization and hydrolysis of native cellulose. In reaching out to "non-scientific" audiences, promoters of cellulase research often oversimplify the basic description of how these enzymes work together to efficiently attack cellulose[13]. The danger in such oversimplifications is that they may mislead many as to the unknowns and the difficulties we still face in developing a new generation of cost effective enzymes. While our understanding of cellulase's modes of action has improved, we have much more to learn before we can efficiently develop enzyme cocktails with increased activity.

Process Description

The first application of enzymes for hydrolysis of wood in an ethanol process was obvious—simply replace the acid hydrolysis step with an enzyme hydrolysis step. This configuration, now often referred to as "separate hydrolysis and fermentation" (SHF) is shown in Figure 18.[14] Pretreatment of the biomass is required to make the cellulose more accessible to the enzymes. Many pretreatment options have been considered, including both thermal and chemical steps.

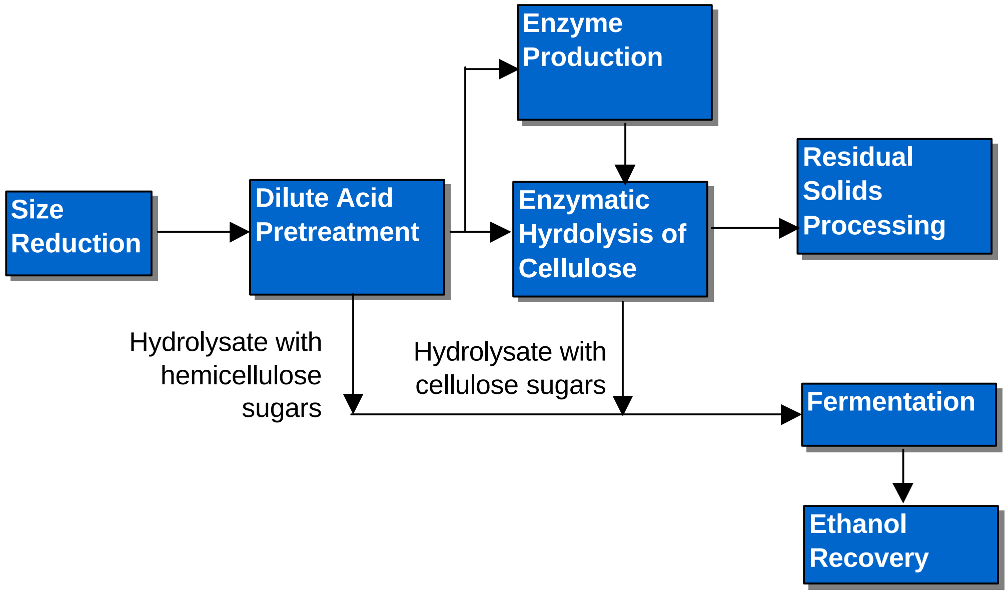

FIGURE 19: THE ENZYME PROCESS CONFIGURED AS SEPARATE HYDROLYSIS AND FERMENTATION

The most important process improvement made for the enzymatic hydrolysis of biomass was the introduction of simultaneous saccharification and fermentation (SSF), as patented by Gulf Oil Company and the University of Arkansas[15,16]. This new process scheme reduced the number of reactors involved by eliminating the separate hydrolysis reactor and, more importantly, avoiding the problem of product inhibition associated with enzymes. In the presence of glucose, β-glucosidase stops hydrolyzing cellobiose. The build up of cellobiose in turn shuts down cellulose degradation. In the SSF process scheme, cellulase enzyme and fermenting microbes are combined. As sugars are produced by the enzymes, the fermentative organisms convert them to ethanol. The SSF process has, more recently, been improved to include the cofermentation of multiple sugar substrates. This new variant of SSF, known as SSCF for Simultaneous Saccharification and CoFermentation, is shown schematically in Figure 19.

Commercial Status

As suggested earlier, cellulase enzymes are already commercially available for a variety of applications. Most of these applications do not involve extensive hydrolysis of cellulose. For example, the textile industry applications for cellulases require less than 1% hydrolysis. Ethanol production, by contrast, requires nearly complete hydrolysis. In addition, most of the commercial applications for cellulase enzymes represent higher value markets than the fuel market. For these reasons, there is quite a large leap from today's cellulase enzyme industry to the fuel ethanol industry. Our partners in commercialization of near-term ethanol technology are choosing to begin with acid hydrolysis technologies because of the high cost of cellulase enzymes.

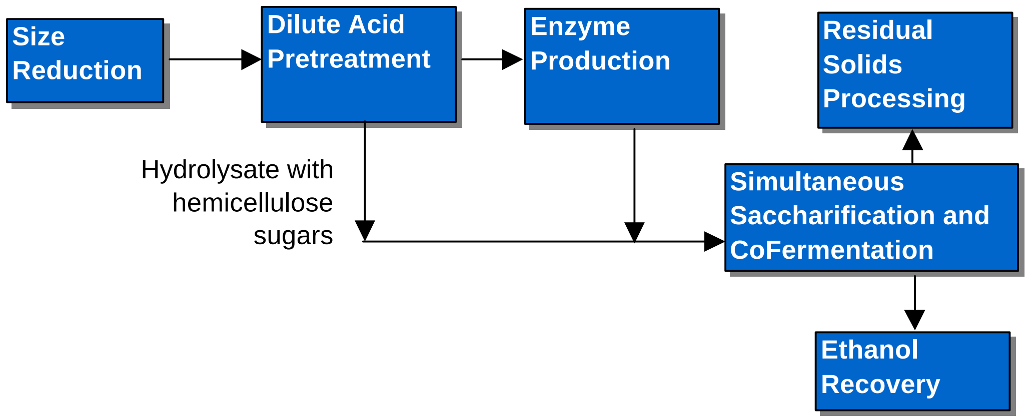

FIGURE 19: THE ENZYME PROCESS CONFIGURED FOR SIMULTANEOUS SACCHARIFICATION AND COFERMENTATION

Fermentation—a key component in all technology platforms

Description

Fermentation of sugars to ethanol is at the heart of the three hydrolysis-based technology platforms. For that reason, the discussion of this component as presented here is applicable to all three of the platforms.

The earliest attempts to utilize wood sugars from acid hydrolysis included fermentation of the sugars to ethanol. Ethanol plants operated here in the U.S. during World War I achieved yields of ethanol of around 20 to 25 gallons per dry ton of mill waste processed. This low yield is due mostly to low yields in sugar[17]. During World War II, researchers at USDA developed the "Madison Wood-sugar Process." They reported results on fermentation of Douglas-fir hydrolyzates using the yeast *Saccharomyces cerevisiae*, an industrial workhorse as far as fermentation is concerned. Like many researchers since, they struggled with problems of inhibitors in the hydrolyzate that effected yield and productivity. Removal of furfural, treating with aluminum chloride and use of large inoculum eliminated these problems. Yields of 39 to 40% of total reducing sugars were achieved in as little as 15 hours[18]. The greatest impact on yield was the inability to ferment the five carbon sugars from hemicellulose. This problem remained unresolved for several decades. In the 1980s, research on xylose fermentation began to bear fruit. A number of wild type yeasts were identified, which could convert xylose to ethanol. But, these organisms required carefully controlled levels of oxygen[19]. With the advent of powerful genetic engineering tools, we now have access to genetically engineered bacteria and yeast capable of fermenting both the five- and six- carbon sugars.[20,21,22,23,24].

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Appendix VII-B-6

MODELING RESULTS FOR TWO-STAGE DILUTE ACID AND ACID/ENZYME ETHANOL PRODUCTION TECHNOLOGIES

ETHANOL PRODUCTION AND ECONOMIC ANALYSIS

ProForma Systems Inc.
Golden, Colorado

TABLE 16 RESULTS FOR SCENARIOS 1-8, STAND-ALONE ETHANOL PLANTS, FOREST MATERIAL FEEDSTOCK

case	ethanol process	year	plant size	feedstock required (BDT/yr) (BDT/day)	ethanol yield (gal/BDT)	feedstock cost including transport and credit ($/BDT)	total capital investment	cost of production ($/gal)	ethanol selling price ($/gal)
1	two-stage dilute acid	2007	20 million GPY	258,080 737	77.4	$16.22	$80,722,000	$1.16	$1.64
2	two-stage dilute acid	2007	40 million GPY	517,000 4,477	77.4	$18.46	$119,848,000	$0.99	$1.37
3	two-stage dilute acid	2007	60 million GPY	775,630 2,216	77.4	$29.05	$157,072,000	$1.06	$1.40
4	two-stage dilute acid	2007	40 million GPY	516,990 1,477	77.4	$42.76	$121,426,000	$1.31	$1.69
5	two-stage dilute acid	2012	30 million GPY	328,120 937	91.5	$38.54	$95,362,000	$1.21	$1.43
6	acid/ enzyme	2007	40 million GPY	437,440 1,250	91.5	$17.74	$177,284,000	$1.23	$1.81
7	acid/ enzyme	2007	40 million GPY	437,440 1,250	91.5	$42.04	$178,622,000	$1.51	$2.09
8	acid/ enzyme	2012	40 million GPY	297,450 850	100.9	$38.25	$114,102,000	$1.29	$1.58

TABLE 17 RESULTS FOR SCENARIOS 9-18, STAND-ALONE ETHANOL PLANTS, URBAN WASTE FEEDSTOCK

case	**ethanol process**	**year**	**plant size**	**feedstock required (BDT/yr) (BDT/day)**	**ethanol yield (gal/BDT)**	**feedstock cost including transport and credit ($/BDT)**	**total capital investment**	**cost of production ($/gal)**	**ethanol selling price ($/gal)**
9	two-stage dilute acid	2007	30 million GPY	390,260 1,115	76.8	$8.66	$100,654,000	$0.92	$1.34
10	two-stage dilute acid	2007	50 million GPY	650,430 1,858	76.8	$15.43	$137,226,000	$0.90	$1.25
11	two-stage dilute acid	2007	80 million GPY	1,037,680 2,965	77.1	$16.61	$187,704,000	$0.84	$1.16
12	two-stage dilute acid	2007	50 million GPY	720,650 2,059	69.4	$13.88	$141,472,000	$0.92	$1.29
13	two-stage dilute acid	2012	30 million GPY	324,040 926	92.6	$8.66	$93,457,000	$0.85	$1.08
14	acid/ enzyme	2007	50 million GPY	540,770 1,545	92.4	$15.43	$221,281,000	$1.19	$1.79
15	acid/ enzyme	2007	50 million GPY	621,820 1,777	80.5	$13.88	$213,250,000	$1.18	$1.76
16	acid/ enzyme	2012	30 million GPY	292,680 836	102.6	$24.86	$115,216,000	$1.14	$1.45
17	acid/ enzyme	2012	80 million GPY	775,090 2,215	103.2	$34.01	$228,012,000	$1.05	$1.27
18	acid/ enzyme	2012	200 million GPY	1,858,740 5,311	107.6	$44.27	$475,696,000	$1.05	$1.230

TABLE 18 RESULTS FOR SCENARIOS 19-26, STAND-ALONE ETHANOL PLANTS, AGRICULTURAL WASTE FEEDSTOCK

case	ethanol process	year	plant size	feedstock required (BDT/yr) (BDT/day)	ethanol yield (gal/BDT)	feedstock cost including transport and credit ($/BDT)	total capital investment	cost of production ($/gal)	ethanol selling price ($/gal)
19	two-stage dilute acid	2007	20 million GPY	313,460 896	64.0	$18.45	$84,777,000	$1.35	$1.87
20	two-stage dilute acid	2007	40 million GPY	626,910 1,791	63.8	$19.50	$122,419,000	$1.14	$1.52
21	two-stage dilute acid	2007	60 million GPY	940,540 2,687	63.8	$20.31	$155,920,000	$1.07	$1.39
22	two-stage dilute acid	2007	40 million GPY	607,060 1,734	65.8	$24.92	$123,543,000	$1.19	$1.58
23	two-stage dilute acid	2012	30 million GPY	386,520 1,104	77.5	$26.23	$94,715,000	$1.18	$1.38
24	acid/ enzyme	2007	40 million GPY	542,970 1,551	73.6	$16.76	$184,535,000	$1.37	$1.98
25	acid/ enzyme	2007	40 million GPY	529,270 1,512	75.6	$24.81	$183,166,000	$1.44	$2.04
26	acid/ enzyme	2012	30 million GPY	362,250 1,035	82.8	$26.14	$118,060,000	$1.31	$1.60

TABLE 19 RESULTS FOR SCENARIOS 27-30, STAND-ALONE ETHANOL PLANTS, ENERGY CROP FEEDSTOCK

case	ethanol process	year	plant size	feedstock required (BDT/yr) (BDT/day)	ethanol yield (gal/BDT)	feedstock cost including transport and credit ($/BDT)	total capital investment	cost of production ($/gal)	ethanol selling price ($/gal)
27	two-stage dilute acid	2012	30 million GPY	344,510 984	87.0	$41.64	$93,806,000	$1.27	$1.57
28	acid/ enzyme	2012	30 million GPY	322,470 921	92.9	$41.55	$113,822,000	$1.37	$1.66
29	acid/ enzyme	2012	80 million GPY	860,910 2,460	92.9	$43.17	$222,224,000	$1.20	$1.40
30	acid/ enzyme	2012	200 million GPY	2,153,340 6,152	92.9	$45.60	$452,586,000	$1.15	$1.30

TABLE 20 RESULTS FOR SCENARIOS 31-40, COLLOCATED ETHANOL PLANTS, FOREST MATERIAL FEEDSTOCK

case	ethanol process	year	plant size	feedstock required (BDT/yr) (BDT/day)	ethanol yield (gal/BDT)	feedstock cost including transport and credit ($/BDT)	total capital investment	cost of production ($/gal)	ethanol selling price ($/gal)
31	two-stage dilute acid	2002	20 million GPY	250,920 717	69.3	$16.11	$62,809,000	$1.15	$1.44
32	two-stage dilute acid	2007	20 million GPY	258,920 740	77.4	$16.23	$60,182,000	$0.86	$1.17
33	two-stage dilute acid	2007	40 million GPY	517,700 1,479	77.4	$18.47	$88,479,000	$0.73	$0.98
34	two-stage dilute acid	2007	60 million GPY	775,970 2,217	77.4	$29.05	$115,046,000	$0.81	$1.04
35	two-stage dilute acid	2007	40 million GPY	517,700 1,479	77.4	$42.77	$90,061,000	$1.05	$1.31
36	two-stage dilute acid	2012	30 million GPY	728,400 938	91.5	$38.54	$69,184,000	$0.96	$1.08
37	acid/ enzyme	2002	20 million GPY	236,490 676	84.6	$15.98	$175,393,000	$2.23	$3.25
38	acid/ enzyme	2007	40 million GPY	437,500 1,250	91.5	$17.74	$138,902,000	$0.94	$1.37
39	acid/ enzyme	2007	40 million GPY	439,700 1,256	91.1	$42.06	$136,015,000	$1.17	$1.58
40	acid/ enzyme	2012	30 million GPY	296,800 848	100.9	$38.24	$86,872,000	$1.04	$1.22

TABLE 21 RESULTS FOR SCENARIOS 41-48, COLLOCATED ETHANOL PLANTS, URBAN WASTE FEEDSTOCK

case	ethanol process	year	plant size	feedstock required (BDT/yr) (BDT/day)	ethanol yield (gal/BDT)	feedstock cost including transport and credit ($/BDT)	total capital investment	cost of production ($/gal)	ethanol selling price ($/gal)
41	two-stage dilute acid	2007	30 million GPY	389,850 1,114	76.8	$14.54	$75,843,000	$0.75	$1.03
42	two-stage dilute acid	2007	50 million GPY	650,240 1,858	76.8	$15.43	$102,984,000	$0.68	$0.92
43	two-stage dilute acid	2007	80 million GPY	1,037,650 2,965	77.1	$16.61	$141,230,000	$0.64	$0.86
44	two-stage dilute acid	2007	50 million GPY	720,650 2,059	69.4	$13.88	$105,451,000	$0.68	$0.93
45	two-stage dilute acid	2012	30 million GPY	324,040 926	92.6	$14.54	$69,720,000	$0.70	$0.83
46	acid/ enzyme	2007	50 million GPY	540,770 1,545	92.4	$15.43	$175,611,000	$0.93	$1.38
47	acid/ enzyme	2007	50 million GPY	621,910 1,777	80.5	$13.88	$166,870,000	$1.07	$1.32
48	acid/ enzyme	2012	30 million GPY	292,680 836	102.6	$14.54	$87,852,000	$0.81	$1.01

TABLE 22 RESULTS FOR SCENARIOS 49-58, COLLOCATED ETHANOL PLANTS, AGRICULTURAL WASTE FEEDSTOCK

Case	ethanol process	year	plant size	feedstock required (BDT/yr) (BDT/day)	ethanol yield (gal/BDT)	feedstock cost including transport and credit ($/BDT)	total capital investment	cost of production ($/gal)	ethanol selling price ($/gal)
49	two-stage dilute acid	2002	20 million GPY	321,180 918	62.4	$18.48	$70,828,000	$1.12	$1.60
50	two-stage dilute acid	2007	20 million GPY	313,340 895	64.0	$18.45	$63,655,000	$1.05	$1.50
51	two-stage dilute acid	2007	40 million GPY	627,260 1,792	63.8	$19.51	$90,605,000	$0.88	$1.14
52	two-stage dilute acid	2007	60 million GPY	940,890 2,688	63.8	$20.32	$116,979,000	$0.84	$1.07
53	two-stage dilute acid	2007	40 million GPY	607,060 1,734	65.8	$24.92	91,896,000	$0.93	$1.19
54	two-stage dilute acid	2012	30 million GPY	386,520 1,104	77.5	$26.23	$70,130,000	$0.95	$1.05
55	acid/ enzyme	2002	20 million GPY	308,760 882	64.9	$18.43	$177,438,000	$2.45	$3.47
56	acid/ enzyme	2007	40 million GPY	542,870 1,551	73.6	$19.25	$143,535,000	$1.11	$1.56
57	acid/ enzyme	2007	40 million GPY	529,270 1,512	75.6	$24.81	$142,560,000	$1.14	$1.58
58	acid/ enzyme	2012	30 million GPY	362,250 1,035	82.8	$26.14	$88,847,000	$1.06	$1.24

TABLE 23 RESULTS FOR SCENARIOS 59-60, COLLOCATED ETHANOL PLANTS, ENERGY CROP FEEDSTOCK

case	ethanol process	year	plant size	feedstock required (BDT/yr) (BDT/day)	ethanol yield (gal/BDT)	feedstock cost including transport and credit ($/BDT)	total capital investment	cost of production ($/gal)	ethanol selling price ($/gal)
59	two-stage dilute acid	2012	30 million GPY	344,510 984	87.0	$41.64	$69,738,000	$1.04	$1.15
60	acid/ enzyme	2012	80 million GPY	865,450 2,473	92.5	$43.18	$165,815,000	$0.96	$1.08

TABLE 24 RESULTS FOR SCENARIOS 61-65, STAND-ALONE ETHANOL PLANTS, WASTE PAPER FEEDSTOCK

case	ethanol process	year	plant size	feedstock required (BDT/yr) (BDT/day)	ethanol yield (gal/BDT)	feedstock cost including transport and credit ($/BDT)	total capital investment	cost of production ($/gal)	ethanol selling price ($/gal)
61	two-stage dilute acid	2002	10 million GPY	134,470 384	74.4	-$10.00	$50,889,000	$1.00	$1.64
62	two-stage dilute acid	2007	10 million GPY	122,200 349	81.7	-$10.00	$45,257,000	$0.94	$1.39
63	two-stage dilute acid	2007	30 million GPY	366,610 1,047	81.7	-$4.30	$76,841,000	$0.60	$0.92
64	two-stage dilute acid	2001	30 million GPY	302,980 866	98.9	-$4.30	$70,945,000	$0.57	$0.80
65	two-stage dilute acid	2012	80 million GPY	808,970 2,311	98.9	-$4.30	$131,457,000	$0.43	$0.61

Appendix VII-C

Update on the Ethanol Market: Current Production Capacity, Future Supply Prospects, and Cost Estimates for California

Prepared For ARCADIS Geraghty & Miller
On behalf of the California Energy Commission

Under Subcontract No. JM60090

October 15, 1999

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ESAI

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Energy Security Analysis, Inc. (ESAI) was retained by ARCADIS Geraghty & Miller on behalf of the California Energy Commission (CEC) to provide an update of ESAI's previous work regarding the availability and cost of fuel ethanol for the California market.

The following text is a summary of the assumptions, methodology and conclusions of this update. In general, the assumptions and methodology are the same as those used by ESAI in estimating ethanol costs in the CEC's November 1998 report, *Evaluating the Cost and Supply of Alternatives to MTBE in California's Reformulated Gasoline.* New data and some minor modifications were used to provide the updated cost estimates as set forth in this report. Further details regarding calculations and methodology can be found in the accompanying appendices. This report analyzes two scenarios, with two different time periods: intermediate-term and long-term. As in the previous CEC report, the intermediate-term assumes no new capital additions to capacity are made. The long-term assumes that unlimited capital additions to capacity are possible.

The first scenario assumes that MTBE is banned in California. Ethanol must be imported from out of state (very little ethanol is currently produced in state). The second scenario posits that MTBE is banned throughout the U.S.

The intermediate-term supply curve for ethanol delivered to California under a California only ban is constructed by estimating the price at which ethanol supplies in the Midwest and other states can be bid away from gasoline blenders in those regions. Linear equations are used to estimate these breakeven prices, with an assumption of a baseline gasoline price of 62 cents/gallon and an MTBE price of 85 cents/gallon. A sensitivity is also presented for gasoline at 42 cents/gallon and 82 cents/gallon. The latest available state-by-state gasoline price data was used to determine relative state prices with reference to the 62 cents/gallon baseline price. The breakeven price at which each state values ethanol was then matched with the corresponding volume of ethanol used by each state. State ethanol usage was estimated by extrapolating the latest Federal Highway Statistics on ethanol use (1997 data) with the latest state by state gasoline usage data (Energy Information Agency 1998 data). Thus, in this report, relative state gasoline prices and ethanol volumes are different than in the previous CEC report. In addition, the most current state tax data and ethanol tax incentives are incorporated into this analysis. Illinois and Wisconsin are assumed to value ethanol as an oxygenate for RFG use in this report. As in the previous CEC report, unused U.S. capacity as well as ethanol imported through the Caribbean was considered in the supply curve.

The result is a slightly steeper supply curve than in the previous report. The first 10,000 bbl/day of ethanol can be delivered to California (assuming 15 cent/gallon transportation cost) at approximately 82 cents/gallon, ex-tax incentive ($1.36/gallon selling price). Up to 50,000 bbl/day (barrel/day)[1] would cost approximately 92 cents/gallon ex-tax incentive ($1.46/gallon selling price). And up to 100,000 bbl/day delivered to California would cost 119 cents/gallon ex-tax incentive ($1.73/gallon selling price).

[1] 1 bb – 42 gallons.

Longer-term ethanol prices can be expected to moderate to the marginal cost of production. However, this ethanol production cost will increase as more corn is used to produce ethanol (increasing the price of corn) and as the by-products (such as distiller dried grains, gluten meal and gluten feed) drop in value due to their increased supply. As in the previous CEC report, a notional production cost was estimated using various assumptions regarding baseline corn costs and by-product costs. Corn elasticity values were corrected in this report relative to the previous CEC report, which increased the rate at which corn prices increase with added ethanol usage.

The result is a cost curve which delivers ethanol to California at 69 cents/gallon ex-tax incentive ($1.23/gallon selling price) for the first 10,000 bbl/day, 75 cents/gallon ex-tax incentive ($1.29/gallon selling price) for up to 50,000 bbl/day, and 83 cents/gallon ex-tax incentive ($1.37/gallon selling price) for up to 100,000 bbl/day.

If MTBE is banned throughout the U.S., the resulting intermediate-term cost curves for ethanol delivered to California will be correspondingly higher. Assuming the oxygenate mandate remains on the books, blenders outside California would compete with California blenders for the existing ethanol supply. All ethanol in the U.S. would be valued as an oxygenate instead of as a lower value blending component for gasohol.

The resulting intermediate-term cost curve delivers ethanol to California at $1.29/gallon ex-tax incentive ($1.83/gallon selling price) for the first 10,000 bbl/day, $1.33/gallon ex-tax incentive ($1.87/gallon selling price) for up to 50,000 bbl/day, and $1.34/gallon ex-tax incentive ($1.88 selling price) for up to 100,000 bbl/day. It should be noted that this intermediate-term cost curve assumes that blenders outside California have access to the alternative oxygenates TAME and TBA. If they must use ethanol as well, then there will be a substantial imbalance between demand and supply for ethanol. The resulting bidding war for the limited supply of ethanol and upwardly spiraling price cannot be modeled.

The long-term cost curve for ethanol delivered to California under a U.S. MTBE ban is slightly higher than the long-term curve with a California only ban of MTBE, by about 2 cents/gallon per 10,000 bbl/day increment.

SectionA-1 -- Detailed descriptions of intermediate and long-term cost estimates for ethanol.

A-1.0: Ethanol availability in the U.S.

Currently, the U.S. produces about 100,000 bbl/day of fuel ethanol on an average annual basis, and imports relatively small volumes from Central America. On-line capacity in the U.S. equals 115,000 bbl/day. Therefore, the U.S. fuel ethanol industry is now operating at roughly 85 percent of capacity on an annual basis. Demand is calculated at approximately 89,000 bbl/day and there is about 26,000 bbl/day of spare capacity that could be used to supply California. This spare capacity is generally concentrated among the major producers of ethanol. While there are several ethanol plants that have shut down over the years, and might be counted as capacity that could come online to meet Californian demand, we can assume that these plants are not *currently* operating because they are not competitive. If they were competitive they would be producing at the recent market prices for ethanol ($1.00/gallon to $1.20/gallon)

A-2.0: Scenario One: MTBE Banned in California

The first scenario presumes that MTBE is eliminated in California, but that it remains a viable oxygenate for blending in other states.

A-2.1: Intermediate-term ethanol supply curve estimates

The price/volume relationships analyzed below are found in Section I, Table I-1. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

There are several blocks of ethanol supply that are available to California in the intermediate-term. First, California already consumes some ethanol. Second, there is a small volume of ethanol that can be imported from the Caribbean duty free that will be available. Third, there is unused capacity (see above). Finally, there is a finite volume of ethanol that is consumed by states with RFG programs and winter oxygenate programs, and ethanol that is blended for gasohol in the Midwest states.

According to data compiled by the Federal Highway Administration, California consumed roughly 8,800 bbl/day of ethanol on average in 1997. This is the baseline volume of ethanol available to California; it can be presumed to be available at the Los Angeles/San Francisco wholesale average price for ethanol in 1997 of $1.24/gallon.

Ethanol is blended in gasoline (primarily in the Midwest or Padd II region) where it is more economical to use than MTBE or can be blended with regular or subgrade unleaded gasoline to make a midgrade or premium gasoline.

In the intermediate-term (i.e., before substantial new ethanol capacity could be built and substantial quantities of ethanol supplied to the market), California CARB RFG blenders would have to outbid these other users of ethanol in order to secure ethanol supply and comply with Federal oxygen regulations. In other words, the price of ethanol will have to increase to the point where it is cheaper for ethanol blenders outside of California to switch to MTBE for their oxygenate use, or cheaper to buy 100 percent petroleum-based gasoline instead of using ethanol in a mix with regular unleaded gasoline (gasohol).

In order to make these comparisons, ethanol needs to be valued correctly. Ethanol's value to gasoline blenders will first depend on whether it is being used as an oxygenate in oxygenated gasoline or RFG gasoline, or whether it is being used in gasohol as a gasoline extender.

If used as an oxygenate, ethanol's value will depend on the cost of MTBE, the cost of octane and Reid Vapor Pressure (RVP). Using a 2.7 weight % oxygen level in oxygenated gasoline, ethanol's value can be expressed using the following equation[2]:

$$P_{EtOH} = (0.852\ P_{B\text{-}MTBE} - 0.923\ P_{B\text{-}EtOH} + 0.148\ P_{MTBE} - C_{EtOH})/0.077$$

Where

P_{EtOH} = Price of ethanol
$P_{B\text{-}MTBE}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with MTBE.
$P_{B\text{-}EtOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
P_{MTBE} = Price of MTBE
C_{EtOH} = Any costs associated with blending ethanol

If used as a gasoline extender, ethanol's value will depend on the retail price of gasoline, the rack price of gasoline, and the cost of octane. Using the typical 10 percent blend of ethanol found in most gasohol, ethanol's value can be expressed using the following equation:

$$P_{EtOH} = -\ (\ P_{R\text{-}MOGAS} - P_{MOGAS} - P_{R\text{-}GASOHOL} + 0.9\ P_{B\text{-}EtOH} + C_{EtOH}\ )\ /\ 0.1$$

Where

P_{EtOH} = Price of ethanol
$P_{R\text{-}MOGAS}$ = Retail (pump) price of pool gasoline
P_{MOGAS} = Rack price of pool gasoline
$P_{R\text{-}GASOHOL}$ = Retail (pump) price of gasohol
$P_{B\text{-}EtOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
C_{EtOH} = Cost associated with blending ethanol

[2] The derivations of this formula (EtOH valued as an oxygenate) and the following formula (EtOH valued as gasohol), provided by MathPro, Inc., can be found in Section B.

In order to determine the price/volume relationships, blocks of supply are identified on a state-by-state basis, using the most recently available data. Ethanol volumes consumed in each state were estimated using 1997 ethanol usage data from the October 1998 Federal Highway Administration report "Estimated Use of Gasohol" and applying this data to more recent 1998 gasoline sales data supplied by the early edition of the 1999 Energy Information Agency *Petroleum Marketing Annual*. Breakeven ethanol values (using the above linear equations) were then determined to determine the price at which these volumes would be bid away from their existing markets.

Since gasoline prices differ in each state, ethanol is valued differently according to its market. Retail and rack gasoline price data from the U.S. Energy Information Agency's *Petroleum Marketing Annual* publication were used to determine gasoline prices for all states that consume ethanol. Prices were adjusted for use in this study by basing them on a base of 62 cents/gallon pool gasoline rack price and a $1.00/gallon retail price and then adding a differential based on the relative prices found in each state. For example, Pennsylvania's rack price for gasoline was 1.3 cents/gallon higher than that of Louisiana, which had the lowest U.S. rack price; therefore, for the purposes of this study, the rack price for Pennsylvania is 63.3 (62 plus 1.3). See Section C for a ranking of state-by-state rack and retail gasoline prices.

Using the formulas expressed above, ethanol values were determined for each state. Arizona, Nevada, Washington, California, New Mexico and Colorado use ethanol primarily for winter oxygenate blending instead of as gasohol blendstock (thus the higher value for ethanol). In addition, the RFG markets of Milwaukee, Wisconsin and Chicago, Illinois primarily use ethanol as the required oxygenate (approximately 95 percent in both cases).

Several states, notably Connecticut, Idaho, Illinois, Ohio, Iowa, and South Dakota, have state incentives for ethanol use, in the form of an income tax exemption. The presence of such state subsidies increases the price at which ethanol will be bid away from these states, by 10 cents per gallon of ethanol for Connecticut, Ohio and Iowa, 10 cents for Illinois (estimated using the 2% sales exemption on a 6.25% sales tax), and 21 cents for South Dakota.

The estimated volume of ethanol sales (bbl/day) and calculated ethanol values (cents/gallon) for each state are listed in Table A-1 below:

Table A- 1 U.S. Ethanol Usage and Blending Values

State	EtOH value (cents/gal)	EtOH usage (bbl/day)		State	EtOH value (cents/gal)	EtOH usage (bbl/day)
Louisiana	65.9	59		Kentucky	70.0	451
Pennsylvania	67.2	4,300		Missouri	70.4	443
New York	67.2	1,498		New Jersey	72.8	894
Alabama	67.7	274		Connecticut	77.0	244
N. Dakota	67.7	340		Ohio	77.2	10,955
North Carolina	67.8	2,379		Iowa	80.8	3,967
Texas	67.8	3,547		Illinois RFG market	87.8	1,300
Virginia	68.2	2,325		Alaska	88.5	487
Michigan	68.2	1,895		S. Dakota	89.4	1,124
Indiana	68.6	4,605		Illinois	100.9	11,698
Maryland	68.6	187		Washington	101.7	221
Tennessee	68.6	23		Wyoming	101.9	9
West Virginia	68.9	9		Arizona	103.0	1,603
Nebraska	69.1	1,354		Wisconsin	104.1	4,747
Florida	69.5	105		New Mexico	104.5	920
Kansas	69.8	225		Colorado	104.8	4,541
Note: EtOH values assume lowest state gasoline rack price at 62 cents/gallon; MTBE price is assumed to be 85 cents/gallon. Other assumptions can be found in Section B.						

In the supply curve constructed from the above data, the block representing ethanol consumed in Minnesota is excluded from the volume that can be bid away to California blenders. Minnesota has a year-round oxygenate mandate stipulating a 2.7% minimum oxygen content in all gasoline sold in the state. According to industry sources, the language in this regulation precludes the use of MTBE, and as such, the mandate amounts to an ethanol mandate. Thus, there is approximately 13,000 bbl/day of ethanol consumed in Minnesota that cannot be bid away.

There are two other blocks of supply that need to be considered. These are volumes of ethanol imported from the Caribbean and ethanol that could be supplied by increasing U.S. utilization capacity to 100 percent.

U.S. law (the Caribbean Basin Initiative, or CBI) states that the equivalent volume of up to seven percent of U.S. ethanol production can be imported duty-free into the United States. Historically, this has been essentially unfinished ethanol from beer still/wine alcohol that is exported from the European Union, and sent to countries like Jamaica and El Salvador, where it is upgraded and sent to the U.S. Industry sources report that the ethanol is priced at approximately 60 cents/gallon, and that freight and insurance would bring the delivered price to California to almost 83 cents/gallon. With an assumed production of 115,000 bbl/day in the U.S., the Caribbean ethanol volume available is estimated at almost 9,000 bbl/day.

Since U.S. ethanol capacity is 115,000 bbl/day and the average annual consumption is 89,000 bbl/day, there is approximately 26,000 bbl/day of surplus ethanol that can be supplied to California. Because individual ethanol plant data is not available, and each plant runs on different economics, it is not possible to determine what price for ethanol would cause each plant in the U.S. to reach 100 percent of capacity.

However, it is possible to create a notional (estimated) ethanol producer's margin, and compare this to historical utilization capacity. The margin for an ethanol producer is equal to the price received for ethanol and other corn by-products (such as distiller's grains and starches) minus the cost of producing ethanol (composed mostly of corn feedstock costs). Historical price data for ethanol, corn, dried distiller grains, gluten meal and gluten feed were obtained from Hart's Publications' *Oxy Fuel News.* Typical variable and fixed cost information for both wet and dry milling ethanol producers (See Section D) were also obtained from ethanol producers. A notional margin for both wet and dry milling producers was calculated on a monthly basis for the last six years, and compared to production data from the Energy Information Agency (see Section E). According to this data, it appears that the only time that utilization rates in the U.S. reached near 100% (winter 94-95), the notional margin (averaged for both wet and dry milling producers) was approximately 40 cents/gallon.

The historical average net production cost (a weighted average for both wet and dry milling producers), according to the data used in this report, has been approximately $1.03/gallon over the past six years. Therefore, the price required to bring U.S. production to full capacity is equal to the $1.03/gallon net production cost plus 40 cents/gallon margin, or $1.43/gallon. Net of the 54 cent/gallon subsidy, this equals 89 cents/gallon.

With approximately 67,000 bbl/day of ethanol bid away from other states, 9,000 bbl/day available through the Caribbean, as well as 26,000 bbl/day available by boosting production, a supply curve can be constructed up to demand levels of 111,000 bbl/day. This is the approximate demand level that would be necessary for California if ethanol were granted a 1 psi RVP waiver, effectively allowing blenders to use up to 3.5 weight % oxygen level in CARB gasoline.

MTBE demand will fall to zero in California as a result of a ban on its use. Ordinarily this would result in a severe drop in MTBE's price, and perhaps a knock-on effect in the price of other oxygenates. However, blenders outside of California that use ethanol will need to replace oxygen or octane if ethanol is bid away; and they will most likely use MTBE. Since end-users of ethanol and MTBE will in essence be swapping demand for oxygenates, there should not be any net change in price for MTBE.

In summary, the intermediate-term supply curve for ethanol delivered to California is constructed by determining the correct ethanol value in each state that consumes the fuel, and assuming that the amount consumed by each state will be bid away by Californian end-users once the price has risen to breakeven levels above which the original consumers would find it too expensive. Minnesota ethanol is not considered, and in addition there is 9,000 bbl/day of ethanol that is available through the Caribbean, as well as 26,000 bbl/day of ethanol that is available by increasing producers' utilization rates to 100%.

Higher and Lower Gasoline Prices

If the price of gasoline and MTBE changes from the baseline assumed in this study (62 cents/gallon for gasoline and 85 cents/gallon for MTBE), then this tends to effect the price of ethanol. Sensitivities of 42 cent/gallon gasoline and 82 cent/gallon gasoline were therefore also run for this study. These are presented as charts at the end of the report. In the case of the 42 cent/gallon gasoline sensitivity, MTBE prices were adjusted downward 20 cents to 65 cents/gallon. In the case of the 82 cent/gallon gasoline sensitivity, MTBE prices were adjusted upward 20 cents to 105 cents/gallon. Over the last several years, MTBE prices have tended to average about 20-25 cents/gallon higher than gasoline prices.

Higher or lower gasoline and MTBE prices tend to push ethanol prices higher and lower. As explained in the main text of the report's appendices, if used as an oxygenate, ethanol's value will depend on the cost of MTBE, the cost of octane and Reid Vapor Pressure (RVP). If used as a gasoline extender, ethanol's value will depend on the retail price of gasoline, the rack price of gasoline, and the cost of octane.

From the point of view of the consumer, a gallon of gasohol and a gallon of gasoline should be roughly of equal value, adjusted for the lower energy content of ethanol. Therefore, higher gasoline prices will tend to push up ethanol prices. As consumers substitute gasohol for expensive regular unleaded, this tends to push up the price of ethanol. Likewise, lower gasoline prices tend to push down the price for ethanol.

A-2.2: Long-term Ethanol Cost Estimates

Within 2-3 years, added California ethanol demand would lead to an expansion of ethanol capacity in the U.S. Furthermore, the increased demand for ethanol would justify the construction of nearly 30,000 bbl/day of capacity in the U.S. that has already been planned or proposed (see Section H, Table H-3, for a listing of plants proposed to come on-line). In addition to the projects already planned, new producers will enter the market, attracted by higher intermediate-term prices and increased demand caused by a switch to ethanol consumption in California.

The long-term scenario assumes that in addition to the approximately 82,000 bbl/day of ethanol already consumed in the U.S. outside of California, additional ethanol supply would be produced to supply California's needs. Assuming that approximately 91% of ethanol will continue to be processed with corn feedstock, and that approximately 2.6 gallons of ethanol are produced from a bushel of corn, this increased demand will require additional feedstocks of up to 590 million bushels of corn if 100,000 bbl/day of ethanol were delivered to California in addition to the current demand levels outside California.

In a long-term time period, the additional required volumes of corn feedstock will be supplied in response to higher demand and higher corn prices in the intermediate-term. Additional corn production is expected to respond to the long-term supply elasticity of price for corn (the percentage change in corn supply divided by the percentage change in corn price). The U.S. Department of Agriculture (USDA) has generally used the value of 0.3 as an estimate for this value. This roughly works out to a 5-8 cent/bushel increase in price for every additional 100 million bushels of corn utilized for ethanol production. Using this elasticity value, it was possible to calculate the increasing price for corn at various volumes additional ethanol supplied to the market. Increasing corn costs will tend to increase the net production cost for ethanol production. For the purposes of this study, a baseline of $2.60/bushel was used. With additional ethanol demand (above current capacity) of 50,000 bbl/day, corn costs are expected to rise to $2.85/bushel. See Section G for detailed calculations.

It is also expected that as a result of the additional processing of corn for ethanol production, there will be a large increase in the supply of by-products, such as distillers' dried grains (DDG), corn gluten feed, corn gluten meal and corn germ. As additional volumes of these products are place on the market, it is expected that the price of these by-products will decline. Previous USDA studies have reported that an increase in ethanol production of 4.8 billion gallons would decrease corn gluten meal prices by 7 percent, corn gluten feed prices by 12.3 percent, and distillers' dried grains by 4 percent.[3]

Using this data, long-term elasticity values were calculated for each by-product of ethanol production. These elasticities were then used to determine the price of DDG, corn gluten feed, corn gluten meal, and corn germ at various volumes of ethanol supplied to the market in the long-term. See Section G for detailed calculations.

By determining the long-term price of corn and the long-term price of ethanol by-products, long-term net production costs were calculated for various volumes of ethanol. All other fixed and variable costs besides corn cost and by-product prices were held constant.

In the long-term scenario, ethanol prices are expected to decline to their marginal cost of production as calculated above. Since most production will still be located in the large corn-producing states, the transportation cost of 15 cents/gallon is held constant. Long-term ethanol prices will be lower than intermediate-term prices, but will still be upward sloping due to increasing net production costs (as a result of increasing corn costs and lower co-product revenue).

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[3] House, R., M. Peters, H. Baumes, and W.T. Disney "Ethanol and Agriculture: Effect of Increased Production on Crop and Livestock Sectors," USDA, Economic Research Service. Agricultural Economic Report Number 667. May, 1993.

The price/volume relationships analyzed below are found in Section I, Table I-2. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

A-3.0: Scenario Two: MTBE Banned in U.S.

The second scenario in this study posits that MTBE is banned not only in the state of California, but nation-wide. This will clearly boost the cost of ethanol delivered to California higher than the California-only ban scenario.

If MTBE were banned throughout the U.S., Federal RFG and winter oxygenated gasoline programs would need to switch to ethanol to replace MTBE, assuming the Federal oxygen requirement remained on the books. Of course, on an oxygen basis, ethanol barrels would not need to replace MTBE barrels one for one, as ethanol contains roughly twice the amount of oxygen as MTBE.

Besides the extra capacity existing in the U.S., there is little ethanol elsewhere that can be imported.

Brazil is the largest producer of ethanol in the world, and has a capacity of about 260,000 bbl/day. However, the U.S. would be unable, under present circumstances, to import much ethanol from Brazil. Brazil has mandated that all gasoline sold in the country contain 24% ethanol. Brazil's average gasoline consumption is about 300,000 bbl/day, and therefore the amount of mandated ethanol use is 66,000 bbl/day. In addition, however, 4 million of Brazilian cars are built to run on 100% ethanol (hydrous ethanol). The ethanol used to fuel these cars must therefore be considered dedicated ethanol, or ethanol that cannot be pulled from Brazil for use outside the country. This amounts to about 148,000 bbl/day of dedicated ethanol supply.

Therefore, in reality, there is very little Brazilian ethanol that can be supplied to the U.S. market, since 214,000 bbl/day (148,000 bbl/day + 66,000 bbl/day) is currently dedicated or mandated for use in Brazil. During the immediate-term, at most about 30,000 bbl/day of surplus ethanol could presently be supplied to the U.S. market as surplus Brazilian ethanol. While the number of cars running on 100% ethanol in Brazil is declining, overall gasoline consumption has been rising very rapidly, approaching close to 10% growth in 1997 and 6% growth in 1998. Therefore, lower ethanol use in Brazil by dedicated vehicles is being offset to a large degree by the growth of the gasoline pool. In addition, foreign ethanol that is not considered under the Caribbean Basin Initiative exemption is currently subject to a 54 cent/gallon tariff. This tariff is presumed to remain in place for the purposes of this study.

France, Italy, and Spain together produce about 30,000 bbl/day of excess wine ethanol from their combined wine industries. This ethanol, however, would also be subject to the tariff of $0.54/gallon applied against foreign produced biomass ethanol. So would other beverage grade ethanol, available in Asia and the FSU.

There are also quantities of synthetic ethanol available on the world market. However, this ethanol would not be eligible for the tax credit, as it is not a biomass fuel, and would need to be diverted from its end use as chemical feedstock.

A-3.1: Ethanol Cost Estimates, Intermediate-Term, U.S. Ban on MTBE

The U.S. consumes on an annual basis approximately 2.8 million bbl/day of reformulated gasoline, and approximately 280,000 bbl/day of oxygenated gasoline for wintertime carbon monoxide programs. Excluding California, which in the intermediate-term is assumed to demand 965,000 bbl/day of reformulated gasoline in this study, the U.S. consumes 1.84 million bbl/day of RFG. Excluding Minnesota, which consumes 130,000 bbl/day of oxygenated gasoline due to its year-round 2.7 weight % oxygen requirement, the U.S. consumes approximately 150,000 bbl/day of oxygenated wintertime gasoline. Thus, in the event of a U.S. ban on MTBE, the U.S., excluding California and Minnesota, would need to find enough oxygen to satisfy about 1.99 million bbl/day of gasoline that needs to be either oxygenated for reformulation purposes or for wintertime oxygen purposes.

In the event of a U.S.-wide ban of MTBE, gasoline blenders outside of California will see ethanol as a substitute for MTBE. Therefore, in the intermediate-term, California will need to compete for this limited ethanol supply with these outside blenders.

As ethanol is bid above its breakeven value, outside blenders will seek other substitutes, such as TAME and TBA. Presumably, MTBE capacity could be converted to TBA output in order to supply this demand. It is assumed that TAME and TBA are not banned along with MTBE, although this is a possibility, especially for TAME which is an ether with chemical properties similar to MTBE. If TAME and TBA are not available, a different, much steeper supply curve would result. This is discussed at the end of this section.

In order to make these breakeven comparisons, ethanol needs to be valued correctly. In the previous section assessing the cost of ethanol delivered to California in the intermediate-term under a California only ban of MTBE, breakeven values were calculated for blenders of ethanol within each state. Ethanol's value depended on whether it was being used as an oxygenate in oxygenated gasoline in that state, or whether it was being blended in gasohol as a gasoline extender.

In this section, a similar calculation is made. Instead of determining breakeven values needed to bid ethanol away from ethanol blenders in each state, breakeven values are calculated to determine the price necessary to outbid non-Californian blenders of RFG and oxygenated wintertime gasoline. In the case of a U.S. ban on MTBE, gasoline blenders outside California will be seeking alternate oxygenates in the marketplace to satisfy their oxygen blending requirements. These blenders will value ethanol as an oxygenate, and will bid ethanol prices above the typical Midwest gasohol value. Therefore, in order to secure delivery of ethanol to California, blenders in California will need to bid ethanol above the breakeven oxygenate value for each outside blender of RFG or wintertime oxygenated gasoline.

In the intermediate-term case scenario with MTBE banned in California only, ethanol's value outside California as an oxygenate depended on the cost of MTBE, the cost of octane and Reid Vapor Pressure (RVP). In this case, however, MTBE has been banned in the U.S., eliminating it as a useful benchmark against which to price ethanol. Ethanol's value will be determined, therefore, by other substitutable oxygenates, such as TAME and TBA.

The value of TAME and TBA can be assumed to be equal to MTBE's market value (85.4 cents/gallon in this study), minus an adjustment for octane differences, plus a 10 cent/gallon shipping and handling cost, due to the fact that these oxygenates are produced in relatively small quantities. Using an octane price of 0.7 cents/octane number, TAME is worth 3.5 cents/gallon less than MTBE (MTBE's octane level of 110 minus TAME's octane level of 105 multiplied by the octane price). TBA is worth 7 cents/gallon less than MTBE (MTBE's octane level of 110 minus TBA's octane level of 100 multiplied by the octane price). TAME's market value is therefore calculated as 91.9 cents/gallon, and TBA's value is calculated as 88.4 cents/gallon. In addition, a 4 cent/gallon differential was added to the TBA/TAME price in Padds I, II, IV, and V to account for similar differentials from Gulf Coast prices that exist today in the MTBE market.

With a benchmark value against which to value ethanol (the averaged price of TAME and TBA), breakeven prices can be calculated by RFG or oxygenated gasoline areas around the U.S.

To determine the breakeven level for ethanol in states requiring RFG gasoline the following equation is used, with the co-efficients set up to account for the volumes of ethanol and TBA/TAME required to achieve a 2.0 weight % oxygen level[4]:

$$P_{EtOH} = (0.894\ P_{B\text{-}TAME/TBA} - 0.943\ P_{B\text{-}EtOH} + 0.106\ P_{TAME/TBA} - C_{EtOH})/0.057$$

[4] This equation is similar to the equation used in Section 4.1.3.1, which is derived in Section B. In this equation and the one following it, the co-efficients for TBA/TAME is an average of the volumes required to blend TBA and TAME to a 2.0 weight % oxygen level, or a 2.7 weight % level.

Where

P_{EtOH} = Price of ethanol
$P_{B\text{-}TAME/TBA}$ = Averaged price of reformulated blendstock for oxygenate blending (RBOB) with TAME and TBA.
$P_{B\text{-}EtOH}$ = Price of reformulated blendstock for oxygenate blending (RBOB) with ethanol
$P_{TAME/TBA}$ = Averaged price of TAME and TBA
C_{EtOH} = Any costs associated with blending ethanol

In states where oxygen is needed for blending in wintertime oxygenated gasoline, a similar equation is used, with the co-efficients set up to account for the volumes of ethanol and TBA/TAME required to achieve a 2.7 weight % oxygen level:

$$P_{EtOH} = (0.858\ P_{B\text{-}TAME/TBA} - 0.923\ P_{B\text{-}EtOH} + 0.143\ P_{TAME/TBA} - C_{EtOH})/0.077$$

The price of the RBOBs used in the above equations is dependent on the price of pool gasoline (see Section B for derivation). Since gasoline prices differ in each state, ethanol will be valued differently according to its gasoline market. Rack gasoline price data from the U.S. Energy Information Agency's 1998 *Petroleum Marketing Annual* publication were used to determine gasoline prices for all states that consume reformulated or oxygenated gasoline. Prices were adjusted for use in this study by basing them on the price of pool gasoline used in the study (62 cents/gallon) and then adding a differential based on the relative prices found in each state. For example, Pennsylvania's rack price for gasoline was 1.3 cents/gallon higher than that of Louisiana, which had the lowest U.S. rack price; therefore, for the purposes of this study, the rack price for Pennsylvania is 63.3 (62 plus 1.3). See Section C for a ranking of state-by-state rack and retail gasoline prices.

Using the formulas expressed above, breakeven ethanol values were determined for each state that blends oxygen for RFG or oxygenated gasoline. The state-level incentives for ethanol use that exists in several states does not effect the breakeven ethanol values here, since the oxygenate breakeven values rise above the gasohol break even values, even with the additional incentives factored in.

Using historical data for RFG and oxygenated gasoline sales in each state (source: U.S. Energy Information Agency 1998 *Petroleum Marketing Annual*), it is possible to determine the volume of ethanol that would be required to satisfy each state's oxygen requirement. Volumes of reformulated gasoline were multiplied by 5.7% to calculate potential ethanol volumes demanded for RFG gasoline at 2.0 weight % oxygen level. Volumes of oxygenated gasoline were multiplied by 7.7 % to calculate potential ethanol volumes demanded for oxygenated gasoline at 2.7 weight % oxygen level.

The potential ethanol volumes (bbl/day) demanded by each state that requires RFG or oxygenated gasoline and price (cents/gallon) at which ethanol would be valued in each state are listed in Table A-2 below:

Table A- 2 Potential Ethanol Demand by State, and State Ethanol Values

State	RFG Demand (bbl/day)	Oxy Gasoline Demand (bbl/day)	Potential Ethanol Demand (bbl/day)	Ethanol Value (cents/gal)
New Mexico		6,524	502	95.3
Texas RFG	293,845		16,749	95.7
Arizona RFG	69,326		3,952	97.1
Montana		595	46	97.1
Utah		2,131	164	98.4
Connecticut	90,619		5,165	98.8
Massachusetts	165,931		9,458	98.8
New Jersey	271,431		15,472	99.2
Maine	31,264		1,782	99.2
New Hampshire	24,040		1,370	99.6
Rhode Island	33,950		1,935	99.8
Nevada		16,688	1,285	99.8
Texas oxy		8,307	639	100.0
Washington		36,919	2,843	100.1
Maryland	115,574		6,588	100.2
Illinois	175,438		10,000	100.6
New York	196,338		11,191	100.7
Wisconsin	46,819		2,669	100.8
Kentucky	32,160		1,833	101.1
Delaware	25,924		1,478	101.1
Oregon		23,636	1,820	101.3
Arizona oxy		23,088	1,778	101.3
Pennsylvania	87,119		4,966	101.9
Indiana	29,983		1,709	102.1
Virginia	136,074		7,756	102.4
Colorado		30,329	2,335	103.0

The supply curve for ethanol delivered to California under a U.S.-wide ban of MTBE is built up by using the above volumes, which represent the amount of ethanol that blenders outside California would potentially demand unless the price was bid above a level at which they value ethanol.

Even if 100,000 bbl/day of ethanol was bid away from the rest of the country by California (in the case of the entire state blending to a 3.5 weight % oxygen level), the rest of the U.S. could satisfy its oxygen requirements by a combination of leftover ethanol capacity, TAME, TBA, and additions to ethanol capacity.

U.S. RFG demand excluding California is estimated at about 1.84 million bbl/day. U.S. oxygenated gasoline demand excluding Minnesota is estimated at about 150,000 bbl/day. With up to 100,000 bbl/day of ethanol delivered to California, this would leave 15,000 bbl/day of spare capacity plus 9,000 bbl/day of ethanol imported from the Caribbean, for a total of about 24,000 bbl/day. This would account for approximately 421,000 bbl/day of

RFG gasoline demand at 2.0 weight % oxygen level (5.7% ethanol). Total world TAME capacity of nearly 47,000 bbl/day would account for approximately 378,000 bbl/day of RFG demand at 2.0 weight % oxygen level (12.4% TAME). And total world TBA capacity of nearly 60,000 bbl/day would account for approximately 677,000 bbl/day of RFG demand at 2.0 weight % oxygen level (8.8% TBA). Total RFG demand satisfied by these remaining oxygenates equals 1.48 million bbl/day, leaving 360,000 bbl/day of US RFG demand. In addition U.S. oxygenated gasoline demand (150,000 bbl/day) remains unsatisfied.

The remaining RFG demand of 360,000 bbl/day would require 21,000 bbl/day of ethanol at 2.0 weight % oxygen level, while oxygenated gasoline demand of 150,000 bbl/day would require 12,000 bbl/day of ethanol at 2.7 weight % oxygen level. It is assumed that this 33,000 bbl/day of ethanol capacity required to satisfy the remainder of U.S. oxygen requirements could be supplied by increasing yields of fuel ethanol at existing plants (ethanol plants have some flexibility to increase the amount of ethanol they produce at the expense of other outputs). The larger ethanol producers would most likely be the best candidates for this type of expansion, and would add to capacity as the price of ethanol increased, according to the supply curve.

If TAME and TBA are not available to satisfy the rest of U.S. RFG and oxygenated gasoline requirements, then the supply curve will be bounded. U.S. RFG demand excluding California is estimated at about 1.84 million bbl/day. At 2.0 weight % oxygen content or 5.7% ethanol volume, this equates to about 105,000 bbl/day of ethanol. U.S. oxygenated gasoline demand is approximately 280,000 bbl/day. At 2.7 weight % oxygen content or 7.7% ethanol volume, this equates to about 22,000 bbl/day of ethanol. This total demand of 127,000 bbl/day of ethanol clearly exceeds U.S. production capacity. California would have to enter a bidding war with other states for the existing supply. There is no way to model the upward spiral in price that would result from a situation of such unbalanced supply and demand in the intermediate-term.

The price/volume relationships analyzed below are found in Section I, Table I-3. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

A-3.2: Ethanol Cost Estimates, Long-Term, U.S. Ban on MTBE

The methodology for determining the long-term supply curve for ethanol under the U.S.-wide MTBE ban is similar to the case of the long-term supply curve under a California-only ban, as explained above. In addition to the ethanol projects already planned, new producers will enter the market in the long-term, attracted by higher prices for ethanol in the intermediate-term and increased demand caused by a switch to ethanol consumption in California and the U.S. during the intermediate-term.

The long-term scenario assumes that the entire country uses ethanol in addition to the additional volumes that would be produced to supply California's needs. Assuming that approximately 91% of ethanol will continue to be processed with corn feedstock, and that approximately 2.6 gallons of ethanol are produced from a bushel of corn, this increased demand will require additional feedstocks of up to 767 million bushels of corn per year for California demand of 100,000 bbl/day in addition to U.S. demand of 127,000 bbl/day.

In a long-term time period, this additional corn can be expected to be supplied in response to demand. Additional corn production is expected to respond to the long-term supply elasticity of price for corn (the percentage change in corn supply divided by the percentage change in price of corn), as explained previously in Section A-2.2. Using this elasticity value of 0.3, prices for corn were calculated at various volumes of ethanol supplied to the market. For the purposes of this study, a baseline of $2.60/bushel was used.

As explained in the California-only MTBE ban scenario, additional ethanol production is expected to result in a large increase in the supply of by-products, such as distiller's dried grains (DDG), gluten feed and gluten meal. It expected that the price of these by-products will decline as their supply increases as more corn is processed to produce ethanol. The same byproduct elasticities used in Section A-2.2, are used in this section.

Using the elasticities for the by-products of ethanol production, prices were determined for DDG, gluten feed, and gluten meal at various volumes of ethanol supplied to the market in the long-term.

By determining the long-term price of corn and the long-term price of ethanol by-products, net production costs are calculated at various volumes of ethanol. All other fixed and variable costs besides corn cost and by-product prices were held constant.

For example, using current U.S. RFG and oxygenated gasoline demand (1.84 million bbl/day and 280,000 bbl/day respectively, excluding California), the U.S. excluding California would require approximately 127,000 bbl/day of ethanol. Therefore, ethanol production would need to increase some 27,000 bbl/day from its current level of 100,000 bbl/day to satisfy this demand. This would require an additional 160 million bushels of corn feedstocks, increasing the price of corn some 7 cents/bushel from the baseline. Additional California ethanol demand on top of this would require more corn feedstocks. California ethanol demand of 50,000 bbl/day would require almost 300 million bushels of corn, and would lead to an increase in corn prices of 30 cents/bushel from the baseline.

In the long-term scenario, ethanol prices are expected to decline to their marginal cost of production as calculated above. Since most production will still be located in the large corn-producing states, the transportation cost of 15 cents/gallon remains.

The calculations for determining the long-term costs of corn and by-products are shown in Section G and the formulas for determining the production costs for ethanol producers is explained in Section D.

The price/volume relationships analyzed below are found in Section I, Table I-3. It is assumed that all subsidies including tax credits for blenders are in place throughout the country.

A-4.0: Loss of Ethanol Tax Credit

Intermediate-Term, California Ban of MTBE

Ethanol sold in the U.S. benefits from a 54 cent/gallon tax credit. Purchasers of ethanol buy the fuel at the market price, but are then allowed to claim the credit on their tax returns. Because ethanol's production costs are relatively high (on average near $1.00 per gallon, although dry milling and wet milling plants have different economics), ethanol cannot normally compete with gasoline or MTBE. The credit, however, brings its end user price to competitive levels with these fuels. Without the subsidy, it is likely that ethanol production in the U.S. would face considerable decline, perhaps to zero, because ethanol producers would still have to sell their product at least at production costs in order to avoid losing money on each unit sold. Because these production costs are considerably above the market price of competing fuels, it is likely that ethanol sales would collapse, and faced with a loss of market share, producers would shut down.

However, if MTBE is banned or there is no relief from the oxygenate mandate, refiners will still need to buy ethanol. To gauge the price effect of a removal of the 54 cent/gallon tax credit on California gasoline blenders, it is useful to estimate what type of prices would be needed to keep ethanol producers in business.

Data on production costs are not available for individual ethanol producers in the U.S. Instead a notional net production cost formula can be used, based on the cost of corn and the credits received for ethanol co-products such as distiller dried grains (DDGs), corn germ, corn gluten meal and corn gluten feed. According to interviews with industry members familiar with the ethanol industry, the most important cost segment for the typical ethanol producer is the cost of corn. Corn prices can vary substantially from state to state. Not surprisingly, the lowest corn prices in the country are found in those states with the largest amount of corn output.

The net cost of ethanol production was calculated for wet milling producers and dry milling producers in each state that produces ethanol, based on the cost of corn in each state, since this is the most germane segment of production costs. Co-product credit prices and all other expenses were assumed to remain constant in all states. Using these production costs, a cost curve for ethanol imports into California can be constructed, from lowest cost producer to highest cost producer. This cost curve estimates the prices that California gasoline blenders need to pay to induce ethanol producers to enter or stay in the marketplace and supply their fuel.

It appears that low-cost ethanol from the Caribbean, entering the U.S. duty-free, would be the first volume of ethanol available for use by California under this scenario. Minnesota's ethanol requirements (13,000 bbl/day) are first supplied by the low cost wet milling producers in Minnesota and Iowa, and California's ethanol requirements are then supplied with the remainder of ethanol production in the U.S., based on the order of relative production costs. In general, California is first supplied by the lower cost wet milling operations. Then, as the price of ethanol rises to cover the costs of production for dry-milling operations, and those states with access only to expensive corn feedstocks, ethanol is in turn supplied by these producers.

In summary, the intermediate-term supply curve for ethanol delivery to California assuming no subsidy is constructed by determining the incremental ethanol volumes that are brought into the marketplace as the price of ethanol rises to meet the costs of production in each state (which, in turn, is determined primarily by the cost of corn in each state and by wet-milling and dry-milling economics).

Intermediate-Term, U.S. Ban of MTBE

In the event of a ban on MTBE that is U.S.-wide, the intermediate-term supply curve for ethanol delivery to California without the tax credit follows a similar methodology. As explained above, the supply curve is constructed by estimating production costs from state to state where ethanol plants are located. In general, these ethanol production costs will be higher than the cost of alternative oxygenates, such as TBA and TAME. Thus as the price of ethanol rises to its production costs as California demands more and more of the fuel, blenders outside of California will react to the higher ethanol prices by turning to TBA and TAME, as these will be relatively cheaper.

The methodology for constructing the supply curve for ethanol delivered to California absent the federal subsidy under a U.S. ban of MTBE results in an identical curve as ethanol delivered to California absent the federal subsidy under a California-only ban of MTBE. Under a U.S. ban of MTBE, blenders outside California requiring oxygenates for gasoline will use a combination of available TAME, TBA, and ethanol. These outside blenders will tend to consume TBA and TAME first, as the cost for these oxygenates will be lower than the price that ethanol must reach in order to induce production from even the lowest cost producers.

It should be emphasized that this is the case only if one assumes that TAME and TBA are available, and are not banned along with MTBE. Of course, this is a possibility, as these chemicals are quite similar in nature. If TAME and TBA are not available to satisfy the rest of U.S. RFG and oxygenated gasoline requirements, then the supply curve to California will be bounded, because blenders outside California will be competing for the same limited pool of ethanol as California blenders. Again, as explained earlier, this imbalance between demand and supply would lead to an upward spiral in price. There is no way to model this.

U.S. RFG demand excluding California is estimated at about 1.84 million bbl/day. At 2.0 weight % oxygen content or 5.7% ethanol volume, this equates to about 105,000 bbl/day of ethanol. U.S. oxygenated gasoline demand is approximately 280,000 bbl/day. At 2.7

weight % oxygen content or 7.7% ethanol volume, this equates to about 22,000 bbl/day of ethanol. This total demand of 127,000 bbl/day of ethanol clearly exceeds U.S. production capacity. California would have to enter a bidding war with other states for the existing supply. There is no way to model the upward spiral in price that would result from a situation of such unbalanced supply and demand in the intermediate-term.

The price/volume relationships analyzed below are found in Section I, Table I-5.

Section B: Derivation of Breakeven Equations

There are several equations used in this report that calculate the breakeven price level for different oxygenates. They are all based on the derivation of the same equation in determining the supply curve for ethanol delivered to California in the intermediate-term (California-only ban of MTBE). This equation was developed by Mathpro, Inc.

While the equation below is used for determining the breakeven price of ethanol, it can also be used to determine the breakeven level of TAME or TBA. The co-efficients (used to determine the percentage of oxygenate needed to achieve either a 2.0 weight % or 2.7 weight % oxygen level in gasoline) will change, as will the values for the RVP and octane levels of each oxygenate.

Derivation of Equation for the value of ethanol in oxygenated gasoline

1. Initial identity

$$0.852\ P_{B\text{-}MTBE} + 0.148\ P_{MTBE} = 0.923\ P_{B\text{-}EtOH} + 0.077\ P_{EtOH} + C_{EtOH}$$

Solve for P_{EtOH} $\quad P_{EtOH} = (0.852\ P_{B\text{-}MTBE} - 0.923\ P_{B\text{-}EtOH} + 0.148\ P_{MTBE} - C_{EtOH}) / 0.077$

Where

$P_{B\text{-}MTBE}$ =	Price of reformulated blendstock for oxygenate blending (RBOB) for MTBE blending
$P_{B\text{-}EtOH}$ =	Price of reformulated blendstock for oxygenate blending (RBOB) for Ethanol blending
P_{MTBE} =	Price of MTBE
P_{EtOH} =	Price of ethanol
C_{EtOH} =	Any costs associated with ethanol blending

Co-efficients set up for ethanol and MTBE blending to achieve a 2.7 wt % oxygen level in gasoline.

2. Equations for determining change in octane in RBOBs (pool octane assumed to be 89 octane)

A. MTBE: $0.852\ O_{B\text{-}MTBE} + 0.148\ O_{MTBE} = 89$

$O_{B\text{-}MTBE} = (89 - 0.148\ O_{MTBE}) / 0.852$

$\Delta\ O_{B\text{-}MTBE} = 89 - [\ (89 - 0.148\ O_{MTBE}) / 0.852\ ]$

$\Delta\ O_{B\text{-}MTBE} = 3.65$

Where

$O_{B\text{-}MTBE}$ = Octane of RBOB used for blending MTBE (assumed equal to average pool octane)
O_{MTBE} = Octane of MTBE (110 octane)
$\Delta\ O_{B\text{-}MTBE}$ = Reduction in octane of RBOB used for blending MTBE

Co-efficients of 0.852 and 0.148 set up for MTBE blending to achieve a 2.7 weight % oxygen level

B. Ethanol: $0.923\ O_{B\text{-}EtOH} + 0.077\ O_{EtOH} = 89$

$O_{B\text{-}EtOH} = (89 - 0.077\ O_{EtOH}) / 0.923$

$\Delta\ O_{B\text{-}EtOH} = 89 - [\ (89 - 0.077\ O_{EtOH}) / 0.923\ ]$

$\Delta\ O_{B\text{-}EtOH} = 2.17$

Where

$O_{B\text{-}EtOH}$ = Octane of RBOB used for blending ethanol
O_{EtOH} = Octane of Ethanol (115 octane)
$\Delta\ O_{B\text{-}EtOH}$ = Reduction in octane of RBOB used for blending ethanol

Co-efficients of 0.923 and 0.077 set up for ethanol blending to achieve a 2.7 weight % oxygen level

3. Equations for determining change in RVP in RBOBs

A. MTBE: $0.852\ RVP_{B\text{-}MTBE} + 0.148\ RVP_{MTBE} = RVP_{POOL}$

$\Delta\ RVP_{B\text{-}MTBE} = RVP_{POOL} - [\ (RVP_{POOL} - 0.148\ RVP_{MTBE}) / 0.852\ ]$

$\Delta\ RVP_{B\text{-}MTBE} = -0.174\ RVP_{POOL} + 1.39$

Where

$RVP_{B\text{-}MTBE}$ = RVP of RBOB used for blending MTBE
RVP_{MTBE} = RVP of MTBE (8 RVP)
RVP_{POOL} = Pool gasoline RVP

B. Ethanol: $0.923\ RVP_{B\text{-}EtOH} + 0.077\ RVP_{EtOH} = RVP_{POOL}$

$$\Delta\ RVP_{B\text{-}EtOH} = RVP_{POOL} - [\ (RVP_{POOL} - 0.077\ RVP_{EtOH}\ ) / 0.923\ ]$$

$$\Delta\ RVP_{B\text{-}EtOH} = -\ 0.083\ RVP_{POOL} + 1.50$$

Where

$RVP_{B\text{-}EtOH}$ = RVP of RBOB used for blending ethanol
RVP_{EtOH} = RVP of ethanol (18 RVP)
RVP_{POOL} = Pool gasoline RVP

4. Equations for estimating value of RBOBs

A. MTBE: $P_{B\text{-}MTBE} = P_{POOL} - (P_{OCT} * \Delta\ O_{B\text{-}MTBE} + P_{RVP} * \Delta\ RVP_{MTBE}\ )$

B. Ethanol $P_{B\text{-}EtOH} = P_{POOL} - (P_{OCT} * \Delta\ O_{B\text{-}EtOH} + P_{RVP} * \Delta\ RVP_{EtOH}\ )$

Where

$P_{B\text{-}MTBE}$ = Price of RBOB used for blending MTBE
$P_{B\text{-}EtOH}$ = Price of RBOB used for blending ethanol
P_{POOL} = Price of pool gasoline
P_{OCT} = Price of octane
$\Delta\ O_{B\text{-}MTBE}$ = Reduction in octane of RBOB used for blending MTBE
$\Delta\ O_{B\text{-}EtOH}$ = Reduction in octane of RBOB used for blending ethanol
P_{RVP} = Price of RVP

NOTE: These RBOB values are plugged into the initial identity, to solve for the price of ethanol.

Note on octane prices: In determining the breakeven level of ethanol (or other oxygenates) using the equations above, the following values for octane prices were used. In scenarios that covered oxygenates used in summer, octane was assumed to be worth 1 cent per octane number. For wintertime, octane was assumed to be worth 0.4 cents per octane number. In scenarios that covered oxygenate usage on a year-round basis, a simple average was used for the octane price (0.7 cents per octane number).

Note on RVP prices: In determining the breakeven level of ethanol (or other oxygenates) using the equations above, the following values for RVP prices were used. In scenarios that covered oxygenates used in summer, RVP was assumed to be worth -0.3 cents per RVP number (RVP value is negative in the summer because blenders need to limit RVP levels to comply with air quality regulations). For wintertime, RVP was assumed to be worth 0.3

cents per RVP number. In scenarios that covered oxygenate usage on a year-round basis, a simple average was used for the RVP value (0.0 cents per RVP number).

Derivation of Equation for the value of ethanol in regular gasoline ("gasohol")

The following equation, also developed by Mathpro, Inc., estimates the value of ethanol used as a gasoline extender in regular gasoline commonly known as gasohol. This equation is used in to calculates the price at which California blenders can bid ethanol away from blenders in States that use gasohol.

1. Initial identity:

$$P_{R\text{-}MOGAS} - P_{MOGAS} = P_{R\text{-}GASOHOL} - 0.9\,P_{B\text{-}EtOH} - 0.1\,P_{EtOH} - C_{EtOH}$$

   Solve for P_{EtOH}

$$P_{EtOH} = -(P_{R\text{-}MOGAS} - P_{MOGAS} - P_{R\text{-}GASOHOL} + 0.9\,P_{B\text{-}EtOH} + C_{EtOH}) / 0.1$$

   Where P_{EtOH} = Price of ethanol
   $P_{B\text{-}EtOH}$ = Price of RBOB used for blending ethanol
   $P_{R\text{-}MOGAS}$ = Retail (pump) price of pool gasoline
   $P_{R\text{-}GASOHOL}$ = Retail (pump) price of gasohol
   P_{MOGAS} = Rack price of pool gasoline
   C_{EtOH} = Any costs associated with blending ethanol (assumed zero)

2. Equations for determining change in octane in ethanol RBOB (pool octane assumed to be 89 octane)

$$0.9\,O_{B\text{-}EtOH} + 0.1\,O_{EtOH} = 89$$

$$O_{B\text{-}EtOH} = (89 - 0.1\,O_{EtOH}) / 0.9$$

$$\Delta\,O_{B\text{-}EtOH} = 89 - [(89 - 0.1\,O_{EtOH}) / 0.9]$$

$$\Delta\,O_{B\text{-}EtOH} = 2.89$$

   Where $O_{B\text{-}EtOH}$ = Octane of RBOB used for blending ethanol
   O_{EtOH} = Octane of Ethanol (115 octane)
   $\Delta\,O_{B\text{-}EtOH}$ = Reduction in octane of RBOB used for blending ethanol

Co-efficients of 0.9 and 0.1 set up for ethanol blending to achieve a 3.5 weight % oxygen level commonly used in gasohol.

3. Equation for determining the retail price of gasohol

   The pump price of gasohol is discounted from the pump price of regular pool gasoline since the consumer must be compensated for the fact that gasohol has a lower energy content than regular gasoline. This is due to the fact that the energy density of pure ethanol is equal to roughly 3.55 million BTUs per barrel, whereas pool gasoline's energy density is equal to 5.25 million BTU's per barrel. Therefore, the ratio of ethanol to pool gasoline energy density is 0.68, which is used in the equation below, which states that gasohol's retail price must be equal to 90 percent of pool gasoline's retail price plus 10 percent of pool gasoline's retail price adjusted for the lower energy content due to the presence of the 10 percent ethanol blend:

   $P_{R\text{-}GASOHOL} = (.9 + 0.1*.68) * P_{R\text{-}MOGAS}$

4. Equations for estimating value of ethanol RBOB:

   $P_{B\text{-}EtOH} = P_{POOL} - (P_{OCT} * \Delta O_{B\text{-}EtOH})$

   Where $P_{B\text{-}EtOH}$ = Price of RBOB used for blending ethanol
   P_{POOL} = Price of pool gasoline
   P_{OCT} = Price of octane
   $\Delta O_{B\text{-}EtOH}$ = Reduction in octane of RBOB used for blending ethanol

5. After solving for the value of the ethanol RBOB and the value of gasohol, these inputs are plugged into the initial identity above, and solved for the price of ethanol. Throughout this study, the cost of blending with ethanol is assumed to be zero, and there is assumed to be zero consumer bias against ethanol.

Section C: Gasoline Price Data

State by state gasoline price data (cents/gallon)

Rack Price Data				Retail Price and Tax Data					
State	Rack Price	Delta		State	Retail	State Tax	Fed Tax	Pump Price	Delta
LA	46.9			GA	60.4	7.5	18.4	89.45	
MS	47.3	0.4		SC	60.7	16	18.4	95.10	5.65
TX	47.7	0.8		OK	60.4	17	18.4	95.80	6.35
GA	47.9	1.0		MO	60.4	17	18.4	95.80	6.35
SC	48.3	1.4		FL	65.4	13.1	18.4	96.90	7.45
FL	48.3	1.4		KS	61.5	18	18.4	97.90	8.45
NC	48.4	1.5		AR	61.5	18.6	18.4	98.50	9.05
AL	48.4	1.5		NJ	69.7	10.5	18.4	98.60	9.15
OK	48.4	1.5		TX	61.9	20	18.4	100.30	10.85
AR	48.5	1.6		IA	62.2	20	18.4	100.60	11.15
VA	48.5	1.6		TN	62.4	20	18.4	100.80	11.35
TN	48.7	1.8		KY	66.1	16.4	18.4	100.90	11.45
IN	48.9	2.0		VA	65.7	17.5	18.4	101.60	12.15
KS	48.9	2.0		IN	65.0	15	18.4	101.65	12.20
MO	48.9	2.0		NC	63.0	21.2	18.4	102.60	13.15
PA	49.1	2.2		AL	66.3	18	18.4	102.70	13.25
OH	49.3	2.4		LA	65.2	20	18.4	103.60	14.15
MI	49.7	2.8		MS	67.1	18.4	18.4	103.90	14.45
DE	50.0	3.1		NE	63.6	22.8	18.4	104.80	15.35
KY	50.1	3.2		MI	62.9	19	18.4	105.18	15.73
WI	50.4	3.5		DE	65.1	23	18.4	106.50	17.05
NE	50.4	3.5		PA	62.2	25.9	18.4	106.50	17.05
NY	50.5	3.6		VT	68.5	20	18.4	106.90	17.45
VT	50.5	3.6		NH	69.0	19.5	18.4	106.90	17.45
IL	50.6	3.7		SD	70.6	18	18.4	107.00	17.55
IA	50.8	3.9		OH	66.7	22	18.4	107.10	17.65
ND	50.9	4.0		MA	68.0	21	18.4	107.40	17.95
MD	51.1	4.2		MD	66.5	23.5	18.4	108.40	18.95
SD	51.4	4.5		WV	65.3	25.35	18.4	109.05	19.60
WV	51.6	4.7		WI	65.4	25.4	18.4	109.20	19.75
RI	51.6	4.7		ME	72.2	19	18.4	109.60	20.15
NH	51.8	4.9		IL	68.3	19	18.4	109.97	20.52
ME	52.2	5.3		ND	72.1	20	18.4	110.50	21.05
NJ	52.2	5.3		MN	72.2	20	18.4	110.60	21.15
MA	52.7	5.8		NY	67.0	22.05	18.4	110.87	21.41
CT	52.7	5.8		RI	63.8	29	18.4	111.20	21.75
MN	54.1	7.2		CT	68.0	32	18.4	118.40	28.95
CO	52.7	5.8							
NM	53.1	6.2							
OR	54.7	7.8							
AZ	54.7	7.8							
WY	55.9	9							
WA	56.1	9.2							
NV	56.5	9.6							
UT	58.1	11.2							
ID	58.5	11.6							
MT	59.6	12.7							
AK	70.4	23.5							
Source: Energy Information Administration, *Petroleum Marketing Annual 1998.*									

Section D: Derivation of Ethanol Production costs and producers' margins

Ethanol producers face differing cost structures depending on the feedstock costs (the price of corn for over 90 percent of ethanol producers) and the price producers receive for the by-products of corn milling (distillers' dried grains, corn gluten meal, corn gluten feed, corn germ, CO_2, gypsum, etc.).

In order to determine a notional net production cost for wet milling and dry milling plants, historical data was used for the prices of corn, DDG, corn gluten meal and corn gluten corn. Due to a lack of historical data for corn germ and other minor by-products, these values were held constant. Operating and fixed costs were held constant. Ethanol producers are assumed to produce roughly 2.6 gallons of ethanol from each bushel of corn. Net production cost equals gross expenses minus gross credits.

Dry Milling Operation [5]

Expenses:

- Feedstock (corn) = Corn cost ($/bushel) / 2.6
- Other costs (energy, labor, depreciation, chemicals, fixed costs): 0.625 cents/gallon

Credits:

- Distillers' dried grains (DDG)= ((DDG cost, $/ton) / 2000 lbs) * (17.35 lbs/bushel of DDG) / 2.6
- Other byproducts = 1 cent/gallon (assumed constant)

Wet Milling Operation

Expenses:

- Feedstock (corn) = Corn cost ($/bushel) / 2.6
- Other costs (energy, labor, depreciation, chemicals, fixed costs): 0.51 cents/gallon

Credits:

- Corn gluten meal: ((gluten meal cost, $/ton) / 2000 lbs) *(2.8 lbs/bushel of corn)/2.6
- Corn gluten feed: ((gluten feed cost, $/ton) / 2000 lbs) * (10 lbs/bushel of corn) / 2.6
- Corn germ: ((germ cost, $/ton) / 2000 lbs) * (4 lbs/bushel of corn) / 2.6
- Other byproducts = 1 cent/gallon (assumed constant)

[5] Notional cost structures for wet/dry milling producers provided by Arkenol, Inc.

Section E: Historical Prices for Ethanol Production

The following prices were used to construct historical ethanol net production costs using the notional formula supplied above. Historical price data for germ was not available; a constant value of $250/ton was used instead.

All other prices provided by *Hart's Publications*.

	Ethanol Price $/gallon	**Corn Price $/bu**	**Corn Price $/gallon**	**DDG ($/ton)**	**Gluten Meal $/ton**	**Gluten Feed $/ton**	**Germ $/ton**
January-92	$1.18	$2.54	$0.98	$124.00	$270.63	$105.00	$250.00
February	$1.19	$2.62	$1.01	$125.13	$271.88	$107.50	$250.00
March	$1.20	$2.67	$1.03	$123.50	$277.50	$107.50	$250.00
April	$1.24	$2.56	$0.99	$117.13	$252.50	$108.50	$250.00
May	$1.26	$2.58	$0.99	$115.38	$245.00	$106.00	$250.00
June	$1.27	$2.63	$1.01	$115.38	$247.50	$108.50	$250.00
July	$1.28	$2.47	$0.95	$120.38	$245.63	$108.50	$250.00
August	$1.33	$2.29	$0.88	$123.00	$242.70	$108.50	$250.00
September	$1.34	$2.26	$0.87	$125.25	$264.38	$108.50	$250.00
October	$1.36	$2.17	$0.84	$125.98	$270.25	$106.50	$250.00
November	$1.38	$2.17	$0.83	$126.42	$267.38	$103.00	$250.00
December	$1.29	$2.43	$0.93	$128.44	$267.50	$106.00	$250.00
January-93	$1.19	$2.30	$0.88	$129.67	$288.33	$103.50	$250.00
February	$1.15	$2.25	$0.87	$131.50	$283.40	$96.00	$250.00
March	$1.14	$2.25	$0.86	$123.55	$296.00	$97.00	$250.00
April	$1.15	$2.29	$0.88	$112.50	$288.13	$95.00	$250.00
May	$1.18	$2.26	$0.87	$106.60	$279.88	$95.00	$250.00
June	$1.18	$2.20	$0.84	$104.88	$275.63	$95.00	$250.00
July	$1.11	$2.38	$0.92	$108.17	$294.17	$95.00	$250.00
August	$1.10	$2.46	$0.95	$111.90	$313.00	$95.00	$250.00
September	$1.10	$2.40	$0.92	$113.00	$308.13	$96.50	$250.00
October	$1.11	$2.52	$0.97	$115.70	$298.45	$95.00	$250.00
November	$1.06	$2.71	$1.04	$121.38	$304.69	$92.50	$250.00
December	$1.01	$2.79	$1.07	$124.67	$313.33	$92.50	$250.00
January-94	$1.04	$3.02	$1.16	$126.00	$314.38	$97.80	$250.00
February	$1.12	$3.03	$1.16	$127.00	$298.13	$94.50	$250.00
March	$1.11	$2.88	$1.11	$124.40	$289.50	$97.00	$250.00
April	$1.10	$2.72	$1.05	$123.00	$283.75	$98.50	$250.00
May	$1.11	$2.70	$1.04	$121.75	$265.00	$101.00	$250.00
June	$1.14	$2.82	$1.08	$119.34	$262.70	$101.00	$250.00
July	$1.18	$2.40	$0.92	$121.25	$264.38	$97.50	$250.00
August	$1.22	$2.26	$0.87	$119.38	$259.38	$102.50	$250.00
September	$1.22	$2.26	$0.87	$118.90	$240.50	$102.50	$250.00
October	$1.22	$2.16	$0.83	$120.63	$225.00	$102.50	$250.00
November	$1.24	$2.18	$0.84	$118.88	$229.38	$103.50	$250.00
December	$1.25	$2.19	$0.84	$113.13	$237.50	$107.50	$250.00
January-95	$1.22	$2.27	$0.87	$108.50	$236.25	$108.50	$250.00
February	$1.20	$2.32	$0.89	$99.88	$225.63	$108.50	$250.00
March	$1.14	$2.39	$0.92	$95.10	$218.00	$108.50	$250.00
April	$1.11	$2.48	$0.95	$93.25	$210.00	$108.50	$250.00

Section E, con't: Historical Prices for Ethanol Production:

	Ethanol Price $/gallon	Corn Price $/bu	Corn Price $/gallon	DDG ($/ton)	Gluten Meal $/ton	Gluten Feed $/ton	Germ $/ton
May	$1.12	$2.56	$0.98	$93.28	$192.50	$108.50	$250.00
June	$1.10	$2.76	$1.06	$95.20	$207.50	$107.30	$250.00
July	$1.07	$2.93	$1.13	$98.13	$211.88	$108.50	$250.00
August	$1.09	$2.86	$1.10	$100.60	$228.50	$106.50	$250.00
September	$1.11	$2.95	$1.13	$106.20	$244.25	$105.50	$250.00
October	$1.13	$3.11	$1.19	$123.25	$270.63	$105.50	$250.00
November	$1.17	$3.37	$1.30	$136.70	$316.80	$105.00	$250.00
December	$1.20	$3.46	$1.33	$140.33	$332.50	$107.50	$250.00
January-96	$1.25	$3.63	$1.39	$139.88	$337.50	$107.50	$250.00
February	$1.26	$3.86	$1.48	$142.60	$343.90	$107.50	$250.00
March	$1.24	$4.03	$1.55	$145.88	$342.38	$107.50	$250.00
April	$1.28	$4.58	$1.76	$152.63	$334.88	$107.50	$250.00
May	$1.37	$4.91	$1.89	$178.70	$342.40	$107.50	$250.00
June	$1.38	$4.84	$1.86	$178.88	$323.13	$107.50	$250.00
July	$1.43	$4.80	$1.84	$161.83	$307.50	$110.00	$250.00
August	$1.53	$4.65	$1.79	$151.20	$298.00	$110.00	$250.00
September	$1.54	$3.81	$1.47	$151.50	$329.38	$108.10	$250.00
October	$1.49	$2.97	$1.14	$140.20	$344.00	$108.10	$250.00
November	$1.38	$2.69	$1.03	$136.25	$340.00	$103.50	$250.00
December	$1.28	$2.69	$1.04	$140.00	$343.13	$97.50	$250.00
January-97	$1.20	$2.67	$1.03	$147.00	$336.25	$94.00	$250.00
February	$1.20	$2.76	$1.06	$147.38	$335.63	$94.00	$250.00
March	$1.19	$2.94	$1.13	$145.13	$341.25	$85.00	$250.00
April	$1.20	$2.94	$1.13	$131.60	$343.13	$85.00	$250.00
May	$1.20	$2.81	$1.08	$121.00	$352.50	$80.00	$250.00
June	$1.14	$2.67	$1.03	$115.00	$349.25	$79.00	$250.00
July	$1.15	$2.55	$0.98	$115.50	$336.25	$81.50	$250.00
August	$1.20	$2.58	$0.99	$120.50	$345.63	$81.50	$250.00
September	$1.22	$2.57	$0.99	$120.75	$356.25	$81.50	$250.00
October	$1.22	$2.62	$1.01	$118.50	$345.50	$80.50	$250.00
November	$1.22	$2.65	$1.02	$120.75	$351.25	$74.25	$250.00
December	$1.22	$2.63	$1.01	$117.75	$352.38	$78.38	$250.00
January-98	$1.19	$2.65	$1.02	$117.50	$321.88	$77.88	$250.00
February	$1.15	$2.65	$1.02	$100.88	$295.00	$76.50	$250.00
March	$1.07	$2.66	$1.02	$92.38	$273.75	$69.75	$250.00
April	$1.03	$2.50	$0.96	$84.40	$241.50	$64.70	$250.00
May	$1.04	$2.47	$0.95	$77.50	$236.25	$64.63	$250.00

Section F: Ethanol Producers' Historical Notional Expenses, Credits and Margins

The following are notional net production costs, in $/gallon, for wet milling ethanol producers and dry milling ethanol producers, based on the prices in Section F, and the formulas provided in Section E.

	Wet Milling Operation				Dry Milling Operation			
	Expense	**Credit**	**Net**	**Margin**	**Expense**	**Credit**	**Net**	**Margin**
January-92	$1.49	$0.64	$0.84	$0.34	$1.60	$0.51	$1.09	$0.09
February	$1.52	$0.65	$0.87	$0.32	$1.63	$0.52	$1.11	$0.08
March	$1.54	$0.65	$0.89	$0.32	$1.65	$0.51	$1.14	$0.06
April	$1.50	$0.64	$0.86	$0.39	$1.61	$0.49	$1.12	$0.12
May	$1.50	$0.63	$0.87	$0.39	$1.62	$0.48	$1.13	$0.13
June	$1.52	$0.64	$0.89	$0.39	$1.64	$0.48	$1.15	$0.12
July	$1.46	$0.64	$0.82	$0.46	$1.58	$0.50	$1.07	$0.21
August	$1.39	$0.64	$0.76	$0.57	$1.51	$0.51	$0.99	$0.33
September	$1.38	$0.65	$0.73	$0.61	$1.49	$0.52	$0.98	$0.37
October	$1.35	$0.65	$0.70	$0.66	$1.46	$0.52	$0.94	$0.42
November	$1.35	$0.64	$0.71	$0.67	$1.46	$0.52	$0.94	$0.44
December	$1.44	$0.64	$0.80	$0.49	$1.56	$0.53	$1.03	$0.26
January-93	$1.39	$0.65	$0.74	$0.45	$1.51	$0.53	$0.98	$0.21
February	$1.38	$0.63	$0.74	$0.41	$1.49	$0.54	$0.95	$0.20
March	$1.37	$0.64	$0.73	$0.41	$1.49	$0.51	$0.98	$0.16
April	$1.39	$0.63	$0.76	$0.39	$1.51	$0.48	$1.03	$0.12
May	$1.38	$0.63	$0.75	$0.43	$1.50	$0.46	$1.04	$0.14
June	$1.36	$0.63	$0.73	$0.45	$1.47	$0.45	$1.02	$0.16
July	$1.43	$0.64	$0.79	$0.32	$1.54	$0.46	$1.08	$0.03
August	$1.46	$0.65	$0.81	$0.29	$1.57	$0.47	$1.10	($0.00)
September	$1.43	$0.65	$0.78	$0.31	$1.55	$0.48	$1.07	$0.03
October	$1.48	$0.64	$0.84	$0.27	$1.59	$0.49	$1.11	($0.00)
November	$1.55	$0.64	$0.92	$0.14	$1.67	$0.50	$1.16	($0.10)
December	$1.58	$0.64	$0.94	$0.07	$1.70	$0.52	$1.18	($0.18)
January-94	$1.67	$0.65	$1.02	$0.02	$1.78	$0.52	$1.26	($0.22)
February	$1.68	$0.64	$1.04	$0.08	$1.79	$0.52	$1.27	($0.15)
March	$1.62	$0.64	$0.98	$0.13	$1.73	$0.52	$1.22	($0.11)
April	$1.56	$0.64	$0.92	$0.18	$1.67	$0.51	$1.16	($0.06)
May	$1.55	$0.63	$0.92	$0.19	$1.66	$0.51	$1.16	($0.05)
June	$1.60	$0.63	$0.96	$0.17	$1.71	$0.50	$1.21	($0.07)
July	$1.44	$0.63	$0.81	$0.37	$1.55	$0.50	$1.05	$0.13
August	$1.38	$0.63	$0.75	$0.48	$1.49	$0.50	$1.00	$0.23
September	$1.38	$0.62	$0.76	$0.46	$1.50	$0.50	$1.00	$0.22
October	$1.34	$0.61	$0.73	$0.49	$1.45	$0.50	$0.95	$0.27
November	$1.35	$0.62	$0.73	$0.51	$1.46	$0.50	$0.97	$0.27
December	$1.35	$0.63	$0.72	$0.53	$1.47	$0.48	$0.99	$0.26
January-95	$1.38	$0.63	$0.75	$0.47	$1.50	$0.46	$1.03	$0.19
February	$1.40	$0.63	$0.78	$0.42	$1.52	$0.43	$1.08	$0.11
March	$1.43	$0.62	$0.81	$0.33	$1.54	$0.42	$1.13	$0.01
April	$1.46	$0.62	$0.85	$0.27	$1.58	$0.41	$1.17	($0.05)
May	$1.50	$0.61	$0.89	$0.23	$1.61	$0.41	$1.20	($0.08)
June	$1.57	$0.61	$0.96	$0.14	$1.69	$0.42	$1.27	($0.17)

Section F, con't: Ethanol Producers' Historical Notional Expenses, Credits and Margins

	Wet Milling Operation				Dry Milling Operation			
	Expense	Credit	Net	Margin	Expense	Credit	Net	Margin
July	$1.64	$0.62	$1.02	$0.05	$1.75	$0.43	$1.32	($0.25)
August	$1.61	$0.62	$0.99	$0.10	$1.73	$0.44	$1.29	($0.20)
September	$1.64	$0.63	$1.01	$0.09	$1.76	$0.45	$1.30	($0.20)
October	$1.71	$0.65	$1.06	$0.07	$1.82	$0.51	$1.31	($0.17)
November	$1.81	$0.67	$1.14	$0.03	$1.92	$0.56	$1.37	($0.20)
December	$1.84	$0.68	$1.16	$0.04	$1.96	$0.57	$1.39	($0.19)
January-96	$1.91	$0.69	$1.22	$0.03	$2.02	$0.57	$1.45	($0.20)
February	$1.99	$0.69	$1.31	-$0.05	$2.11	$0.58	$1.53	($0.28)
March	$2.06	$0.69	$1.37	-$0.13	$2.17	$0.59	$1.59	($0.35)
April	$2.27	$0.68	$1.59	-$0.30	$2.38	$0.61	$1.78	($0.49)
May	$2.40	$0.69	$1.71	-$0.34	$2.51	$0.70	$1.82	($0.45)
June	$2.37	$0.68	$1.70	-$0.31	$2.49	$0.70	$1.79	($0.41)
July	$2.36	$0.67	$1.68	-$0.26	$2.47	$0.64	$1.83	($0.40)
August	$2.30	$0.67	$1.63	-$0.10	$2.41	$0.60	$1.81	($0.28)
September	$1.98	$0.68	$1.30	$0.24	$2.09	$0.61	$1.49	$0.05
October	$1.65	$0.69	$0.96	$0.53	$1.77	$0.57	$1.20	$0.29
November	$1.55	$0.68	$0.87	$0.51	$1.66	$0.55	$1.10	$0.27
December	$1.55	$0.67	$0.88	$0.40	$1.66	$0.57	$1.09	$0.19
January-97	$1.54	$0.66	$0.88	$0.32	$1.65	$0.59	$1.06	$0.13
February	$1.57	$0.66	$0.91	$0.28	$1.69	$0.59	$1.09	$0.10
March	$1.64	$0.64	$1.00	$0.20	$1.76	$0.58	$1.17	$0.02
April	$1.64	$0.65	$1.00	$0.20	$1.76	$0.54	$1.22	($0.02)
May	$1.59	$0.64	$0.95	$0.25	$1.71	$0.50	$1.20	($0.01)
June	$1.54	$0.64	$0.90	$0.24	$1.65	$0.48	$1.17	($0.03)
July	$1.49	$0.64	$0.86	$0.30	$1.61	$0.49	$1.12	$0.03
August	$1.50	$0.64	$0.86	$0.34	$1.62	$0.50	$1.11	$0.09
September	$1.50	$0.65	$0.85	$0.37	$1.61	$0.50	$1.11	$0.11
October	$1.52	$0.64	$0.88	$0.34	$1.63	$0.50	$1.14	$0.09
November	$1.53	$0.63	$0.90	$0.32	$1.64	$0.50	$1.14	$0.08
December	$1.52	$0.64	$0.89	$0.34	$1.64	$0.49	$1.14	$0.08
January-98	$1.53	$0.62	$0.91	$0.28	$1.64	$0.49	$1.15	$0.04
February	$1.53	$0.60	$0.93	$0.22	$1.64	$0.44	$1.21	($0.06)
March	$1.54	$0.58	$0.96	$0.12	$1.65	$0.41	$1.24	($0.17)
April	$1.47	$0.55	$0.92	$0.11	$1.59	$0.38	$1.20	($0.17)
May	$1.46	$0.55	$0.91	$0.12	$1.57	$0.36	$1.21	($0.18)

Average wet milling production cost: $.95/gallon
Average dry milling production cost: $1.19/gallon

Weighted ethanol producers notional net production cost (67% wet milling, 33% dry milling): $1.03/gallon

Section G: Calculation of long-term byproduct elasticities and long-term cost of ethanol

In determining the long-term net production cost of ethanol, increased ethanol demand is assumed to increase the price of corn while decreasing the received price for ethanol production by-products, such as distillers' dried grains (DDG), corn gluten meal, corn gluten feed, and corn germ. Long-term elasticity values are used to determine the effect on the long-term prices of corn and corn byproducts.

The long-term elasticity of corn was supplied by the U.S. Department of Agriculture as 0.3. This is defined as the change in supply divided by the change in price. Roughly speaking, this equates to an increase of 5 cents/bushel for every 100 million bushels of additional corn used for ethanol production. For the by-products, secondary source data was used to estimate elasticity values. A USDA report from 1993 estimated the decrease in price of byproducts caused by an increase in ethanol demand (and thus an increase in corn processing). This report estimated that a change in ethanol production from 1.2 billion gallons to 5 billion gallons (a change of 3.8 billion gallons) over 7 years would cause the price of corn gluten meal to fall 7 percent, corn gluten feed to fall 12.3 percent, and distillers' dried grains to fall 4 percent. No estimation was provided for germ; an average of the price decline of corn gluten meal and corn gluten feed was assumed as a proxy (a decline of 7.7 percent). Wet milling production (which supplies byproducts of corn germ, corn gluten meal and corn gluten feed) was assumed to remain at 67 percent of national ethanol production, while dry milling production (which supplies byproduct of DDG) was assumed to remain at 33 percent of national ethanol production. Thus the base ethanol demand (1.2 billion gallons) and increase in ethanol demand (3.8 billion gallons) are multiplied by 0.33 for determining the change in DDG supply and 0.67 for determining the change in all other byproduct supplies. The elasticity calculations are provided below:

DDG (17.35 lbs per bushel at 10% moisture)

	Change in ethanol demand	In bushels of corn	In tons of DDG	
Change	1,254,000,000	482,307,692	4,184,019	
Base	396,000,000	152,307,692	1,321,269	
% Change in Supply			317%	
Change in Price			4%	
Elasticity ($e = \Delta P / \Delta S$)				0.0126

Gluten meal (2.88 lbs per bushel at 10% moisture)

	Change in ethanol demand	In bushels of corn	In tons of gluten meal	
Change	2,546,000,000	979,230,769	1,410,092	
Base	804,000,000	309,230,769	445,292	
% Change in Supply			317%	
Change in Price			7%	
Elasticity ($e = \Delta P / \Delta S$)				0.0221

Section G, con't: Calculation of long-term byproduct elasticity's and long-term cost of ethanol

Gluten feed (10 lbs per bushel at 12% moisture)

	Change in ethanol demand	In bushels of corn	In tons of gluten feed	
Change	2,546,000,000	979,230,769	4,896,154	
Base	804,000,000	309,230,769	1,546,154	
% Change in Supply			317%	
Change in Price			12.3%	
Elasticity (e = Δ P / Δ S)				0.0388

Germ (4 lbs per bushel at 2% moisture)

	Change in ethanol demand	In bushels of corn	In tons of germ	
Change	2,546,000,000	979,230,769	1,958,462	
Base	804,000,000	309,230,769	618,462	
% Change in Supply			317%	
Change in Price			7.7%	
Elasticity (e = Δ P / Δ S)				0.0243

In order to determine the long-term cost of ethanol, the elasticities as calculated above are applied to changes in ethanol demand. The resulting net production costs for wet millers and dry millers are calculated below. The assumptions are a base U.S. corn production level of 10.1 billion bushels, a base corn price of $2.60/bushel, and base byproduct prices of : $118.5 per ton for DDGs, $283.7 per ton for corn gluten meal, $97.4 per ton for corn gluten feed, and $250 per ton for corn germ. These base price assumptions were taken from the average historical prices provided above in Section E, excluding the period of Oct. 1995-Sept. 1996 during which corn prices were abnormally high. Three ethanol demand levels are listed below: 10,000 bbl/day, 50,000 bbl/day and 100,000 bbl/day.

Total new ethanol demand (bbl/day):	**10,000**	**50,000**	**100,000**
In gallons/year:	153,300,000	766,500,000	1,533,000,000
Additional bushels required:	58,961,538	294,807,692	589,615,385
Price reaction (Δ P = Δ S / e):	1.46%	7.30%	14.59%
Price of corn:	$2.638	$2.79	$2.979
in $/gallon of ethanol	$1.015	$1.073	$1.146

Section G, con't: Calculation of long-term byproduct elasticities and long-term cost of ethanol

Negative change in DDG price			
(Δ P = e * Δ S)	0.16%	0.81%	1.61%
Price of DDG	$118.31	$117.54	$116.58
in $/gallon of ethanol	$0.395	$0.392	$0.389
Negative change in gluten meal price			
(Δ P = e * Δ S)	0.28%	1.41%	2.82%
gluten meal price	$282.90	$279.69	$275.69
in $/gallon of ethanol	$0.157	$0.155	$0.153
Negative change in gluten feed price			
(Δ P = e * Δ S)	0.50%	2.48%	4.96%
gluten feed price	$96.91	$94.98	$92.56
in $/gallon of ethanol	$0.186	$0.183	$0.178
Negative change in germ price			
(Δ P = e * Δ S)	0.31%	1.55%	3.11%
germ price	$249.22	$246.12	$242.23
in $/gallon of ethanol	$0.192	$0.189	$0.186
Expenses (WET MILL)	$1.53	$1.58	$1.66
Credits (WET MILL)	$0.53	$0.53	$0.52
Net production cost (WET MILL)	$0.99	$1.06	$1.14
Expenses (DRY MILL)	$1.64	$1.70	$1.77
Credits (DRY MILL)	$0.39	$0.39	$0.39
Net production cost (DRY MILL)	$1.24	$1.31	$1.38
Weighted average			
(67% wet mill, 33% dry mill)	$1.07	$1.14	$1.22
Ethanol price			
minus subsidy of $.54/gallon	$0.53	$0.60	$0.68

Section H: U.S. Ethanol Plants

Table H-1 U.S. Ethanol Capacity, 1999

State	Company	Location	Million gallons per year	Barrels/day
IL	ADM	Decatur	210.0	13,699
IL	ADM	Peoria	200.0	13,046
IA	ADM	Cedar Rapids	200.0	13,046
IA	ADM	Clinton	160.0	10,437
IL	Williams Energy Services	Pekin	100.0	6,523
IN	New Energy Co. of Indiana	South Bend	85.0	5,545
NE	Minnesota Corn Processors	Columbus	80.0	5,219
NE	Cargill	Blair	75.0	4,892
IL	Midwest Grain Products	Pekin	72.2	4,712
TN	A.E. Staley	Louden	45.0	2,935
MN	Minnesota Corn Processors	Marshall	40.0	2,609
IA	Cargill	Eddyville	30.0	1,957
NE	High Plains Corp.	York	30.0	1,957
NM	High Plains Corp.	Portales	30.0	1,957
NE	AGP	Hastings	30.0	1,957
NE	Williams Energy Services	Aurora	30.0	1,957
MN	Exol Corporation - Agri Resources	Albert Lea	30.0	1,957
NE	Chief Ethanol	Hastings	29.0	1,892
KS	High Plains Corp.	Colwich	20.0	1,305
MN	Chippewa Valley Ethanol Company	Benson	18.0	1,174
MN	Corn Plus	Winnebago	17.5	1,142
MN	Heartland Corn Products	Winthrop	16.0	1,044
MN	Ethanol 2000	Bingham Lake	15.0	978
MN	Al-Corn	Claremont	15.0	978
MN	Central Minnesota Ethanol Coop	Little Falls	15.0	978
MN	Agri-Energy, LLC	Luverne	12.0	783
MN	Pro-Corn, LLC	Preston	12.0	783
MN	Minnesota Energy	Buffalo Lake	12.0	783
SD	Heartland Grain Fuels	Huron	12.0	783
ND	Alchem	Grafton	11.0	718
IA	Grain Processing Corporation	Muscatine	10.0	652
KY	Parallel Products	Louisville	10.0	652
KS	Reeve Agri-Energy	Garden City	10.0	652
SD	Heartland Grain Fuel	Aberdeen	8.0	522
MN	Morris Ag Energy	Morris	8.0	522
KS	Midwest Grain Products	Atchinson	7.2	470
SD	Broin Enterprises	Scotland	7.0	457
IA	Manildra	Hamburg	7.0	457
WY	Brimm Energy Inc. (Wyoming Ethanol)	Torrington	5.0	326
WI	Eco Products of Plover, Inc.	Plover	4.0	261
WA	Georgia-Pacific Corp	Bellingham	3.5	228
ID	J.R. Simplot	Caldwell	3.0	196
ID	J.R. Simplot	Heyburn	3.0	196
CA	Golden Cheese of CA	Corona	3.0	196

Table H-2 U.S. Ethanol Capacity, 1999 (continued)

State	Company	Location	Million gallons per year	Barrels/day
MN	Kraft, Inc.	Melrose	3.0	196
CA	Parallel Products	Rancho Cucamonga	2.0	130
CO	Merrick and Co.	Golden	1.5	98
IA	Permeate Refining	Hopkinton	1.5	98
MN	Minnesota Clean Fuels	Dundas	1.5	98
KS	ESE Alchohol	Leoti	1.1	72
TX	Jonton Alcohol	Edinburg	1.1	72
WA	Pabst Brewing	Olympia	0.7	46
IL	Vienna Correctional	Vienna	0.5	33
		TOTAL	**1753.3**	**114,400**
Source: Renewable Fuels Association, company data, various other sources				

Table H-3 U.S. Ethanol Capacity, 1999 Under Construction or Engineering Phase

State	Company	Location	Million gallons/Year	Barrels/day
MO	Northeast Missouri Grain Processors	Macon	13	848
MT	American Agri-Technology	Great Falls	30	1,957
NE	Nebraska Nutrients Inc.	Sutherland	15	978
IA	Sunrise Energy Ethanol	Iowa	5	326
IL	Adkins Energy Cooperative	Lena	30	1,957
LA	BC International	Jennings	20	1,305
IA		Blairstown	9	587
		TOTAL	**122**	**7,958**
Source: Renewable Fuels Association, company data, various other sources				

Table H-4 U.S. Ethanol Capacity, 1999 Proposed or Unknown Phase

State	Company	Location	Million gallons/Year	Barrels/day
MO	Golden Triangle Energy Cooperative	St Joseph	15	978
MN	RDO	Park Rapids	15	978
MN	Dawson Project	Dawson	20	1,305
MN	Renewable Oxygenates, Inc.	Madison	15	978
CA	Arkenol	Sacramento	12	783
CA	Quincy Library Group		20	1,305
CA	Gridley Project		12	783
IL	Unknown *	Pearl City	30	1,957
WA	Unknown *		40	2,609
IL	Unknown *		100	6,523
CA	Unknown *		30	1,957
NY	Unknown *		10	652
OR	Unknown *		30	1,957
SD	Unknown *	Black Hills	12	783
		TOTAL:	**361**	**23,550**
Source: Renewable Fuels Association, company data, various other sources * Source: Williams Energy presentation before MTBE Blue Ribbon Panel				

Section I: Supply Curve Tables (Price/Volume Relationships)

Table I-1 Ethanol Delivered to California Intermediate-Term California Ban of MTBE

Incremental Volume	Cumulative Volume	Price (cents/gallon)	With 54 cent Subsidy	Delivered cost to California
8,824	8,824	69.8	123.8	123.8
4,300	13,124	67.2	121.2	136.2
1,498	14,622	67.2	121.2	136.2
9,009	23,631	60.0	114.0	136.7
274	23,906	67.7	121.7	136.7
340	24,246	67.7	121.7	136.7
2,379	26,625	67.8	121.8	136.8
3,547	30,172	67.8	121.8	136.8
2,325	32,496	68.2	122.2	137.2
1,895	34,392	68.2	122.2	137.2
4,605	38,997	68.6	122.6	137.6
187	39,183	68.6	122.6	137.6
1,354	40,537	69.1	123.1	138.1
105	40,642	69.5	123.5	138.5
225	40,867	69.8	123.8	138.8
451	41,318	70.0	124.0	139.0
443	41,761	70.4	124.4	139.4
894	42,655	72.8	126.8	141.8
244	42,900	77.0	131.0	146.0
10,955	53,855	77.2	131.2	146.2
1,300	55,155	77.7	131.7	146.7
3,967	59,121	80.8	134.8	149.8
26,524	85,646	88.7	142.7	157.7
1,124	86,770	89.4	143.4	158.4
4,541	91,310	104.9	158.9	173.9
4,747	96,057	105.0	159.0	174.0
11,698	107,755	105.2	159.2	174.2
920	108,674	105.3	159.3	174.3
1,603	110,278	106.9	160.9	175.9
221	110,498	108.3	162.3	177.3
487	110,985	122.6	176.6	191.6
Regular unleaded gasoline assumed to be 62 cents/gallon				

Table I-2 Ethanol Delivered to California Long-Term California Ban of MTBE

Incremental Volume	Cumulative Volume	Price (cents/gallon)	With 54 cent Subsidy	Delivered cost to California
10,000	10,000	53.5	107.5	122.5
10,000	20,000	55.1	109.1	124.1
10,000	30,000	56.7	110.7	125.7
10,000	40,000	58.3	112.3	127.3
10,000	50,000	59.9	113.9	128.9
10,000	60,000	61.6	115.6	130.6
10,000	70,000	63.2	117.2	132.2
10,000	80,000	64.8	118.8	133.8
10,000	90,000	66.4	120.4	135.4
10,000	100,000	68.0	122.0	137.0
10,000	110,000	69.6	123.6	138.6
10,000	120,000	71.2	125.2	140.2

Table I-3 Ethanol Delivered to California Intermediate-Term U.S. Ban of MTBE

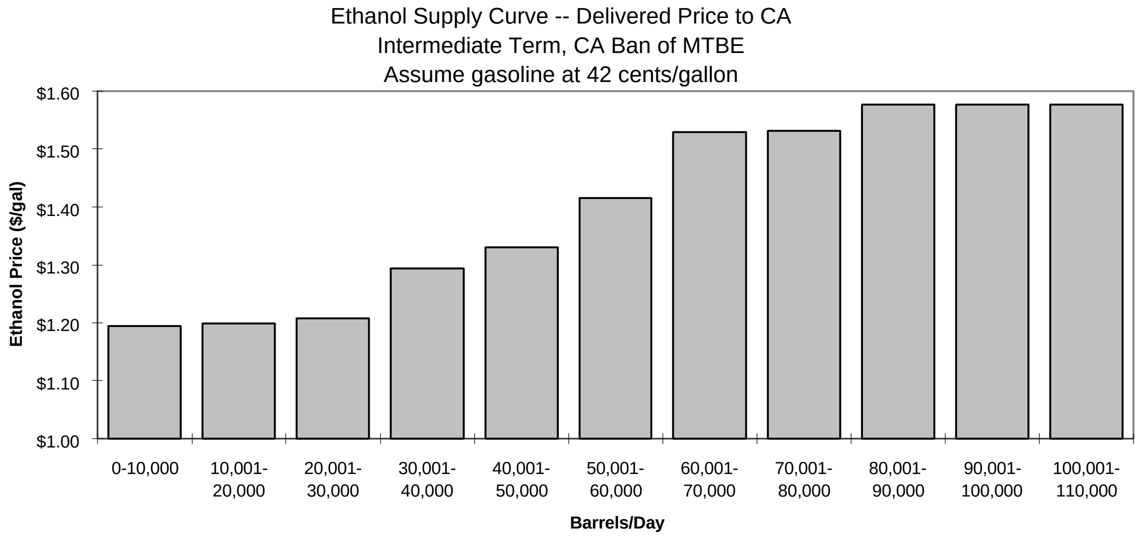
Incremental Volume	Cumulative Volume	Price (cents/gallon)	With 54 cent Subsidy	Delivered cost to California
502	502	113.8	167.8	182.8
16,749	17,252	114.3	168.3	183.3
3,952	21,203	115.6	169.6	184.6
46	21,249	115.6	169.6	184.6
164	21,413	116.9	170.9	185.9
5,165	26,578	117.4	171.4	186.4
9,458	36,036	117.4	171.4	186.4
15,472	51,508	117.8	171.8	186.8
1,782	53,290	117.8	171.8	186.8
1,370	54,660	118.2	172.2	187.2
1,935	56,595	118.4	172.4	187.4
1,285	57,880	118.3	172.3	187.3
640	58,520	118.6	172.6	187.6
2,843	61,363	118.6	172.6	187.6
6,588	67,951	118.8	172.8	187.8
10,000	77,951	119.2	173.2	188.2
11,191	89,142	119.3	173.3	188.3
2,669	91,810	119.4	173.4	188.4
1,833	93,644	119.7	173.7	188.7
1,478	95,121	119.7	173.7	188.7
1,820	96,941	119.8	173.8	188.8
1,778	98,719	119.8	173.8	188.8
4,966	103,685	120.5	174.5	189.5
1,709	105,394	120.7	174.7	189.7
7,756	113,150	121.0	175.0	190.0
2,335	115,485	121.5	175.5	190.5
Regular unleaded gasoline assumed to be 62 cents/gallon				

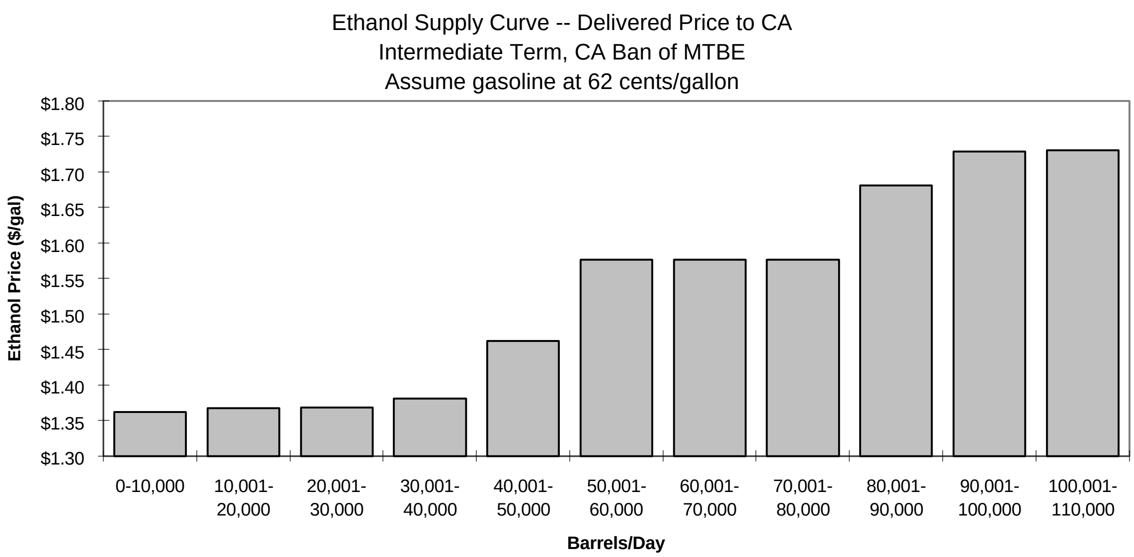
Table I-4 Ethanol Delivered to California Long-Term U.S. Ban of MTBE

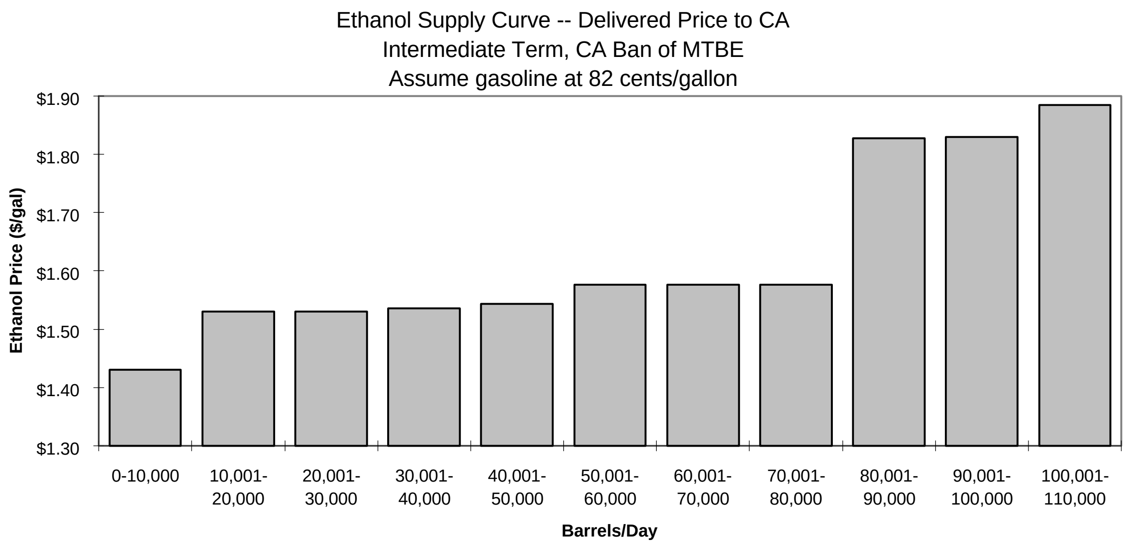
Incremental Volume	Cumulative Volume	Price (cents/gallon)	With 54 cent Subsidy	Delivered cost to California
10,000	10,000	58.3	112.3	127.3
10,000	20,000	59.9	113.9	128.9
10,000	30,000	61.6	115.6	130.6
10,000	40,000	63.2	117.2	132.2
10,000	50,000	64.8	118.8	133.8
10,000	60,000	66.4	120.4	135.4
10,000	70,000	68.0	122.0	137.0
10,000	80,000	69.6	123.6	138.6
10,000	90,000	71.2	125.2	140.2
10,000	100,000	72.8	126.8	141.8
10,000	110,000	74.5	128.5	143.5
10,000	120,000	76.1	130.1	145.1

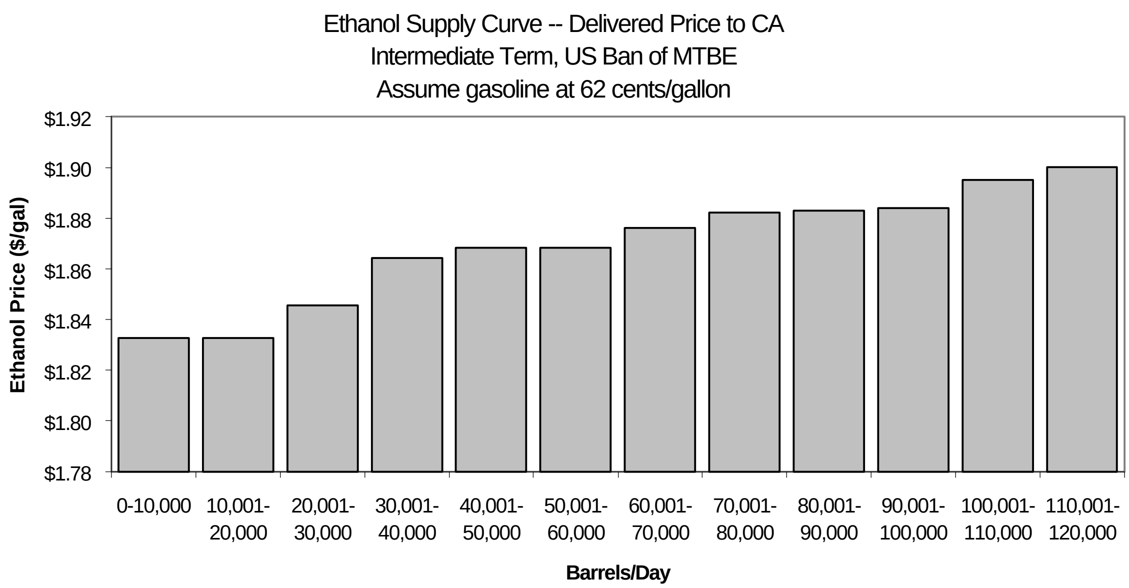
Table 1-5 Ethanol Delivered to California Intermediate-Term California Ban of MTBE No Tax Credits for Ethanol

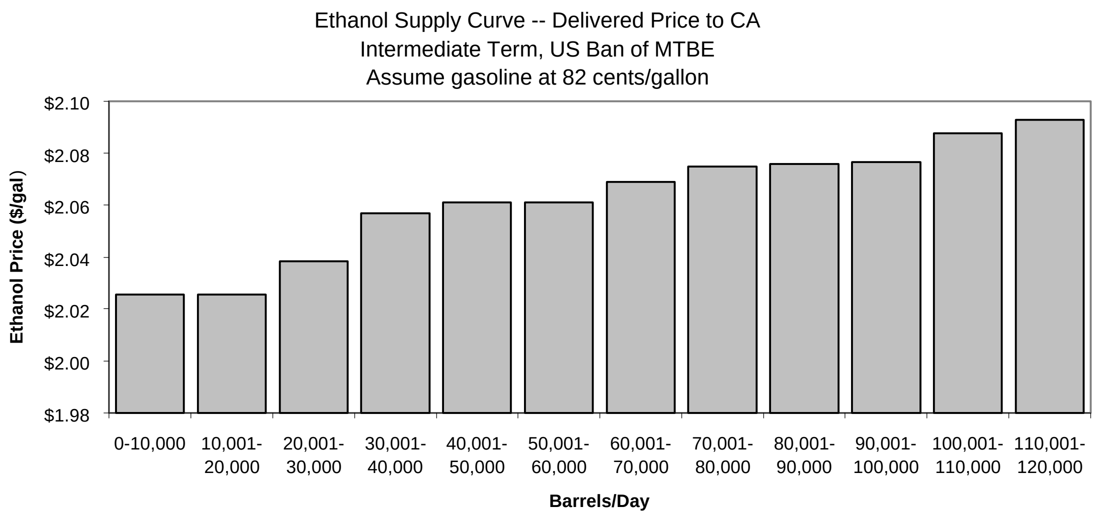
Incremental Volume	Cumulative Volume	Price (cents/gallon)	Delivered cost to California
7,700	7,700	60.0	82.7
13,050	20,750	85.3	100.3
10,111	30,861	87.6	102.6
5,545	36,406	89.0	104.0
33,268	69,674	89.7	104.7
2,740	72,414	93.1	108.1
995	73,409	104.3	119.3
5,166	78,575	107.3	122.3
652	79,227	107.3	122.3
2,348	81,575	110.8	125.8
163	81,738	110.8	125.8
2,585	84,323	112.0	127.0
7,502	91,825	113.1	128.1
1,305	93,130	113.9	128.9
815	93,945	115.2	130.2
3,725	97,670	115.6	130.6
98	97,768	117.2	132.2
652	98,420	119.1	134.1
326	98,746	122.8	137.8
1,376	100,122	122.9	137.9
1,957	102,079	123.7	138.7

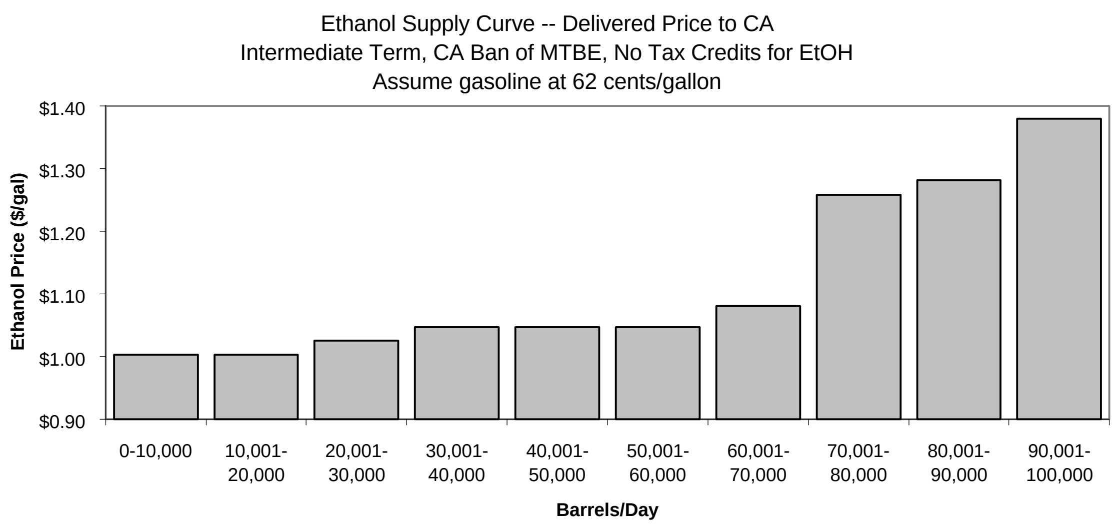

Ethanol Supply Curve -- Delivered Price to CA
Intermediate Term, CA Ban of MTBE
Assume gasoline at 42 cents/gallon
Ethanol Price ($/gal)
$1.60
$1.50
$1.40
$1.30
$1.20
$1.10
$1.00
0-10,000
10,001-20,000
20,001-30,000
30,001-40,000
40,001-50,000
50,001-60,000
60,001-70,000
70,001-80,000
80,001-90,000
90,001-100,000
100,001-110,000
Barrels/Day

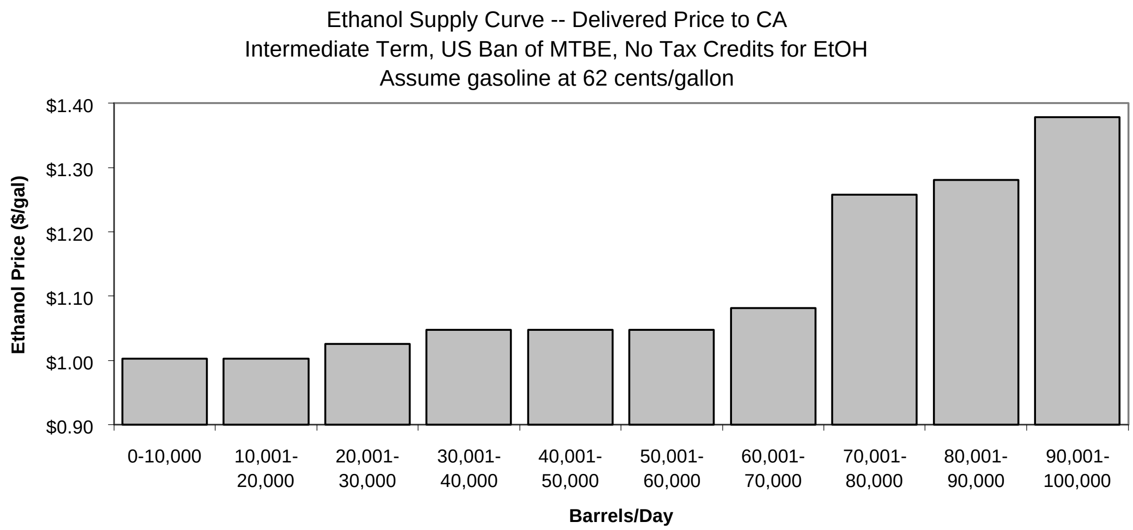

Ethanol Supply Curve -- Delivered Price to CA
Intermediate Term, CA Ban of MTBE
Assume gasoline at 62 cents/gallon
Ethanol Price ($/gal)
$1.80
$1.75
$1.70
$1.65
$1.60
$1.55
$1.50
$1.45
$1.40
$1.35
$1.30
0-10,000
10,001-20,000
20,001-30,000
30,001-40,000
40,001-50,000
50,001-60,000
60,001-70,000
70,001-80,000
80,001-90,000
90,001-100,000
100,001-110,000
Barrels/Day


Ethanol Supply Curve -- Delivered Price to CA
Intermediate Term, CA Ban of MTBE
Assume gasoline at 82 cents/gallon
Ethanol Price ($/gal)
$1.90
$1.80
$1.70
$1.60
$1.50
$1.40
$1.30
0-10,000
10,001-20,000
20,001-30,000
30,001-40,000
40,001-50,000
50,001-60,000
60,001-70,000
70,001-80,000
80,001-90,000
90,001-100,000
100,001-110,000
Barrels/Day


Ethanol Supply Curve -- Delivered Price to CA
Intermediate Term, US Ban of MTBE
Assume gasoline at 62 cents/gallon
Ethanol Price ($/gal)
$1.92
$1.90
$1.88
$1.86
$1.84
$1.82
$1.80
$1.78
0-10,000
10,001-20,000
20,001-30,000
30,001-40,000
40,001-50,000
50,001-60,000
60,001-70,000
70,001-80,000
80,001-90,000
90,001-100,000
100,001-110,000
110,001-120,000
Barrels/Day


Ethanol Supply Curve -- Delivered Price to CA
Intermediate Term, US Ban of MTBE
Assume gasoline at 82 cents/gallon
Ethanol Price ($/gal)
$2.10
$2.08
$2.06
$2.04
$2.02
$2.00
$1.98
0-10,000
10,001-20,000
20,001-30,000
30,001-40,000
40,001-50,000
50,001-60,000
60,001-70,000
70,001-80,000
80,001-90,000
90,001-100,000
100,001-110,000
110,001-120,000
Barrels/Day


Ethanol Supply Curve -- Delivered Price to CA
Intermediate Term, CA Ban of MTBE, No Tax Credits for EtOH
Assume gasoline at 62 cents/gallon
Ethanol Price ($/gal)
$1.40
$1.30
$1.20
$1.10
$1.00
$0.90
0-10,000
10,001-20,000
20,001-30,000
30,001-40,000
40,001-50,000
50,001-60,000
60,001-70,000
70,001-80,000
80,001-90,000
90,001-100,000
Barrels/Day


Ethanol Supply Curve -- Delivered Price to CA
Intermediate Term, US Ban of MTBE, No Tax Credits for EtOH
Assume gasoline at 62 cents/gallon
Ethanol Price ($/gal)
$1.40
$1.30
$1.20
$1.10
$1.00
$0.90
0-10,000
10,001-20,000
20,001-30,000
30,001-40,000
40,001-50,000
50,001-60,000
60,001-70,000
70,001-80,000
80,001-90,000
90,001-100,000
Barrels/Day

Appendix VII-D

Summary of Biomass Benefits Studies

Three different reports describing the benefits of biomass electric power plants in California were reviewed. The studies, all completed in 1997 (and cited in full at the end of this section), were done by: Natural Resources Strategic Services (NRSS) of Valencia, California for the U.S. Department of Energy and the California Energy Commission; California Biomass Energy Alliance (CBEA), work performed by Reese-Chambers Systems Consultants, submitted to the California Environmental Protection Agency; and Future Resources Associates (FRA) of Berkeley, California for the National Renewable Energy Laboratory.

All three of these studies examined the benefits to California of the operating system of biomass electric power plants, about 60 of which were built in the state from 1980 to 1996. About half of these plants continue to operate. The biomass feedstocks for these plants include wood processing residues, forest residues, agricultural residues and urban wood waste. Estimates of total biomass feedstocks consumed by the biomass power industry at its peak range from about 6 to 8 million bone dry tons per year.

<u>NRSS Study</u>

The NRSS study relied mainly on the CEC biomass data base for its statistical data on the biomass power industry. The study results are not referenced to a particular year, however, the CEC data used in the study is for the year 1991. The study describes and estimates annual dollar values for the following benefit areas: reduced air pollutant emissions from open-field burning of agricultural and forest wastes; diversion of waste materials from landfills; wildfire reduction; improved forest health; rural income and employment; and electricity generation. Simple spreadsheet models were employed to calculate benefits in each of these areas. The results are summarized in the attached table. Greenhouse gas reduction was cited as an additional benefit, but not quantified.

<u>CBEA Study</u>

The CBEA study used data from a survey of 36 biomass power plants operating as of 1994. Annual dollar values were estimated for the following benefit areas: reduced air pollutant emissions, including greenhouse gases; increased water yield from improved forest management; wildfire risk reduction; diversion of waste materials from landfills; energy diversity; and employment. A high and low range of benefits was estimated in each of these categories. The results are summarized in the attached table. Improved forest health and productivity and improved orchard productivity were cited as additional benefits but not quantified.

<u>FRA Study</u>

The FRA study provides a detailed history of the development of California's biomass power industry and generally describes the areas of environmental benefits provided by this industry. The benefit categories described include: reduced fuel loading in forests; diversion of waste materials from landfills; and reduced emissions from open burning. Employment is also discussed. No monetary valuation of benefits is included in this study.

Comparison of Estimated Benefits
(In Million $/year)

Benefit Category	**NRSS Study**	**CBEA Study** Low	High
Reduced Air Emissions		35	159
Ag Burning	15.395		
Forestry	2.020		
Greenhouse Gas Reduction	--	(incl. in air emissions)	
Diversion from Landfill Disposal		55	55
Ag	21.825		
Other	20.624		
Wildfire Reduction	23.291	17	54
Forest Health	0.560	--	
Water Yield	--	55	148
Rural Income/Employment	233.111	55	55
Electricity Generation (Energy Diversity)	156.111	29	29
Total Estimated Value of Benefits	472.932	246	500

Studies Cited

Benefits of Biomass Power in California, Natural Resource Strategic Services with assistance from Appel Consultants Inc., prepared for U.S. Dept. of Energy, Western Regional Biomass Energy Program, and California Energy Commission, August 1997.

Biomass Energy in California: Valuation of External Benefits, California Biomass Energy Alliance, submitted to California Environmental Protection Agency, December 2, 1996 (revised January 7, 1997).

The Environmental Costs and Benefits of Biomass Energy Use in California, Future Resource Associates Inc., prepared for National Renewable Energy Laboratory, May 1997.