Agriculture's Role in Energy Production: Current Levels and Future Prospects

Vernon R. Eidman[1]

There have been many changes over time in the predominant source of energy consumed by the American economy (Figure 1). Wood was the predominant source of energy through 1880. Coal surpassed wood about that time and was dominant until the late 1940s. Petroleum use increased rapidly during the first half of the 20th century and overtook coal about 1950. The use of natural gas developed somewhat later than petroleum, and also surpassed coal about 1958. Coal use declined somewhat during the middle of the 20th Century, but its use has increased in parallel with natural gas during the past 20 years (DOE, 2005a).

There is a great deal of interest in the role renewable energy sources are playing and will play in supplying the nation's energy needs. Figure 2 highlights the contribution of renewables to total supplies more clearly. Hydro electric power is about equal to all of the other renewables combined. Figure 2 also shows the Department of Energy's projected use by source to 2025. U.S. energy consumption is projected to grow over the next two decades with continued reliance on the major fossil fuels, petroleum, natural gas, and coal. The projections for nuclear electric power are relatively flat and only modest expansion of renewables can be expected over the next two decades.

What role can we expect renewables to play in future energy supplies? This paper explores part of that question, the potential for energy production from agriculture. The initial part of the paper documents the current contribution of agricultural biomass to the nation's energy supplies. The second section discusses the prospects for developments in technology and their potential impact on agriculture's potential contributions to the nation's energy supplies. Third, the paper summarizes several recent studies that estimate the amount of biomass agriculture could produce and its potential contribution to the nation's energy supplies.

Current Energy Consumption

The U.S. economy consumed a total of 99.6 quadrillion Btus during 2004 (Figure 3)[2]. This represented an increase of 1.4 quads over the total consumption for 2003 and 1.9 quads over 2002. Some of the good news is that energy consumption per capita has been relatively constant over the past 15 years, and consumption per dollar of gross domestic product has been declining since 1970 (DOE 2005b). Of the total use during 2004, 39.8 quads are from petroleum products and 23.0 quads are from natural gas. Coal accounted for 22.5 quads, almost equal to natural gas. Nuclear power made up 8.2 quads and renewables provided 6.1 quads, just over 6 percent of the total. Sixty-four percent of the petroleum (25.5 quads) and 15 percent of the natural gas (3.5 quads) was imported. Thus, the U.S. produced 70 quads and imported 29 of the total energy consumed during 2004.

[1] Professor of Applied Economics, University of Minnesota, St. Paul, MN. This paper was prepared for presentation at a conference "Energy From Agriculture: New technologies, Innovative Programs and Success Stories," December 14 -15, 2005, St. Louis, Missouri.

[2] A quadrillion is 1,000 trillion, and is referred to as a quad. The number is written as 1 followed by 15 zeros.

Now consider the breakdown of the renewables to determine what part of this total was produced from agricultural biomass. The detail provided by DOE is shown in Table 1. Of the total 6.1 quads provided by renewables, 2.7 quads, or 44 percent, are from hydroelectric power. The wood category includes wood, black liquor and other wood waste, and makes up an additional 33 percent of the renewables category. Notice that most of the wood category is used by the wood products industry, part of the industrial sector. Waste is composed of municipal solid waste, landfill gas, sludge waste, tires, agricultural byproducts, and other biomass, and accounts for 10 percent of total renewables. Most of the waste is used in the industrial and commercial sector. Alcohol is the ethanol that is used in the transportation sector for blending with gasoline, and makes up 5 percent of renewables. Geothermal and wind include the net electricity generated from these sources. The solar category includes the net electricity generation from thermal and photo voltaic. Agriculture's share of renewables includes alcohol (0.296), and much of the wind (0.143), plus a small part of the waste components. Summing, these components made up about 0.5 percent of U.S. energy use during 2004.

Another way to express agriculture's contributions to U.S. energy supplies is to calculate percentage contributed to motor fuel and electricity supplies (Table 2). The U.S. economy consumed 136 billion gallons of gasoline with additives during 2004 (DOE, 2005b). The country produced 3.4 billion gallons of ethanol during 2004, approximately 2.5 percent (on a volume basis) of total gasoline with additives. We also consumed 42.5 billion gallons of diesel fuel. The 25 million gallons of biodiesel produced made up only 0.06 percent of the total sold. Finally, the country consumed 3.953 trillion kilowatt hours of electricity during 2004. Wind power contributed about 0.36 percent of this total.

DOE projects energy use to increase about 1.4 percent per year over the next two decades, reaching 133.2 quads in 2025 (Table 3). The percentage of the total provided by renewables is projected to be about the same in 2025 as it was in 2004. The projected contribution by nuclear will be down to 6.5 percent of the total, with most of the reduction made up by petroleum and natural gas.

Energy use by sector during 2004 is shown on the right side of Figure 3. Notice that about 39 percent of the 99.6 quads is used to generate electricity and 28 percent of the total is used for transportation. The remaining 33 percent is used by the industrial, residential and commercial sectors.

Figure 3 also shows how we use each source of energy. All of nuclear and 90 percent of the coal is used to generate electricity. Two-thirds of petroleum is used by the transportation sector, while natural gas is used primarily by the industrial, residential and commercial, and electric power sectors.

Projected energy use in 2025 is given in table 4. The percentages of the total energy used for transportation and to generate electricity are projected to increase about 2.2 and 1.1 percent, respectively. These increases are offset by reductions in the percentage of total use by the industrial, and residential and commercial sectors.

Production Technologies: Current Structure and Challenges

This report considers several alternative forms of energy that can be produced from resources on farms and ranches. These are ethanol from grain, liquid fuels and electricity produced from cellulosic biomass, electricity from wind power, and methane from anaerobic digestion of manure and processing waste. A comparison of the environmental advantages and disadvantages of ethanol-gasoline and biodiesel-petroleum diesel fuel blends is presented elsewhere and is not repeated here (Eidman, 2005, and IEA, 2004). The discussion here is limited to current technologies, production costs, and challenges concerning continued development of each of these four alternatives. The potential production levels from each source are covered in the third section of the paper.

Ethanol form Grain

Industry Growth and Structure. The ethanol industry experienced a rapid rate of growth over the past 15 years, increasing from 900 million gallons in 1990 to 3.4 billion gallons in 2004. Production continues to increase and is expected to reach 4.0 billion gallons in 2005 and 5.0 billion gallons in 2006.

The growth during the late 1990s and early in this century was composed of the entry of a number of new companies building medium sized facilities. Many of the companies that initially built plants of 15 to 25 million gallons annual capacity (mmgpy) expanded them to 40 to 50 mmgpy within the past five years. With the addition of more small to medium plants, ownership of the industry capacity became more fragmented over time. In 1990 13 companies operated 17 facilities with 1.11 billion gallons of annual capacity. One firm owned 55 percent of the capacity. In mid 2005, 71 organizations operated 84 facilities with 3.7 billion gallons of annual capacity. The largest firm owned 28 percent of the capacity.

Favorable ethanol prices (Figure 4) and low corn prices have resulted in high profits over the past two years, which is attracting outside capital. Many plants have achieved return on equity of 25 to 40 percent in the past two years, with rumors of plants achieving over 60 percent. The rapid growth of the demand for ethanol, the high rates of return on capital, and the expectation that demand will continue to grow has attracted the attention of investment bankers. While most new plants coming on line are in the 40 to 60 million gallon range, a number of larger plants with 80 to 110 million gallons per year (mmgpy) capacity are also being added to the industry. Many industry observers believe the outside capital coming in may lead to consolidation of the ownership, particularly when ethanol prices decline for a period of time, reducing plant profitability. This has implications for the future ownership structure.

Marketing and management services have developed to serve the fragmented industry. Some cooperative ethanol plants have members who are obligated to deliver a specified amount of corn each year. Increasingly, however, ethanol plants purchase part to all of their feedstock on the market. They also purchase their fuel, typically natural gas, and sell their ethanol and distillers dried grains and solubles (DDGS). Oil companies do not want to deal with several 30 to 50 mmgpy plants, preferring to buy from a firm selling 300 to 500 million gallons per year. Thus, much of the procurement (of corn and natural gas) and marketing (of ethanol and DDGS) is being handled by a few firms that specialize in this area. The industry structure that has evolved is ownership of the production facilities by a large number of relatively small firms, with the marketing concentrated in the hands of a much smaller number of firms.

The rapid rate of growth in ethanol production capacity resulted from the prospects for and the realization of profitable market conditions. The expansion of the market for ethanol fuels (described below) and several government programs (described later in this article) provided enough revenue for plants during the initial years of operation to make bankers comfortable with helping finance the medium scale plants.

Economics of Ethanol Plants. The initial investment in new dry-mill ethanol plants in the upper Midwest covers the cost of the land for the plant site, permits, plant construction and working capital. This totals about $60 million for a natural gas fired plant with a name plate capacity of 40 mmgpy. The name plate-capacity is the amount the design-build firm guarantees the plant to produce. Such a plant routinely produces about 20 percent over the nameplate amount or 48 mmgpy in this case, for an average investment cost of $1.25 per gallon of annual capacity. Larger plants have somewhat lower costs per gallon of capacity. An 80 million gallon name plate capacity plant requires an initial investment of about $98 million, an average investment cost of about $1.02 per gallon of annual output. These plants produce about 2.75 gallons of anhydrous ethanol per bushel of corn (Tiffany and Eidman, 2003). Adding 2 percent denaturant results in an output of 2.81 gallons per bushel. The byproducts are 18 pounds of DDGS and 18 pounds of CO2. Some plants have a market for the CO2, but many do not and simply vent it. The cost of the feedstock has been relatively low the past two years, $2.00 per bushel or less, and with the exception of natural gas, the other operating costs have been relatively constant. The net feedstock cost (price paid for corn less the market value of DDGS) and other operating cost has been about $1.1222 per gallon for a plant producing 48 mmgpy when the natural gas price is $6.50 per million Btus. Raising the cost of natural gas to $10.50 increases the cost per gallon $0.1372, raising the cost per gallon of ethanol produced to 1.2604. Gallagher and Shapouri (2005) report very similar costs for 21 ethanol plants in 2002 if one adjusts for the changes in natural gas price.

Producing ethanol is a commodity business with wide swings in profitability, dependent largely on the price of the feedstock (primarily corn or grain sorghum), the price of ethanol, and the cost of the fuel used in the plant (typically natural gas). The sensitivity of a hypothetical plant's net margin to these three factors is illustrated in Figure 5. The annual net margin is the pretax amount that would be available to equity holders as a return and for repayment of debt.

Notice that for any given price of ethanol and natural gas, raising the price of corn reduces the plant's net margin. As this illustrates, high corn prices dramatically reduce profitability of ethanol plants. Comparing the net margin with different prices of natural gas indicates that raising the price of natural gas from $6.50 to 10.50 per million Btus reduces the net margin about $6.8 million dollars. Recent increases in natural gas prices have significantly reduced net margins. The figure also illustrates that for any given price of corn and cost of natural gas, raising the price of ethanol greatly increases the plant's net margin.

The net margins presented here do not include any subsidies paid to the plant by the state and federal governments. Receipt of subsidies would obviously increase the profitability of a plant, other things being equal. Two types of subsidies have been available from the federal government in recent years. New plants and those expanding production have been eligible for the Commodity Credit Corporation Bioenergy Program since fiscal year 2001. This program provides $150 million annually in incentive cash payments to ethanol and biodiesel producers in the U.S. that increase their purchases of agricultural commodities over the previous year's purchases and convert that commodity into increased bioenergy production. Producers with total annual production of less than 65 mmgpy are reimbursed one feedstock unit for every 2.5 units used for increased production. Those producing more than 65 mmgpy are reimbursed one feedstock unit for every 3.5 units used for increased production. A payment limitation restricts the amount of funds any single producer may obtain annually under the program to 5 percent of available funding, and payments have been prorated due to rapid industry growth. The program is scheduled to end in 2006. A second program only applies to plants producing less than 60 million gallons per year. They are allowed a 10-cent per gallon production income tax credit on up to 15 million gallons of production annually. This caps the credit at $1.5 million per year per producer. In addition to the federal programs, many states offer incentives for ethanol plants built within their borders.

Ethanol Demand. The domestic demand for fuel ethanol has developed over time largely as a result of various federal and state policies. The 1990 Clean Air Act Amendments established two major oxygenate requirements. One, implemented in 1992, requires that gasoline sold in carbon monoxide non-attainment areas must contain 2.7% oxygen. The second is the Reformulated Gasoline (RFG) program, implemented in 1995, which requires that cleaner-burning reformulated gasoline (requiring 2% oxygen) be sold in the nine worst ozone non-attainment areas. Many other cities have voluntarily adopted the RFG program. The oil industry used methyl tertiary butyl ether (MTBE) as the oxygenate of choice until concerns were raised about its pollution of groundwater. Since that time 18 states have implemented or announced bans on MTBE, greatly expanding the demand for ethanol.

Ethanol has had an exemption from Federal Excise Tax since the late 1970s. The current exemption of $ 0.51 per gallon of ethanol was extended to 2010 by the 2004 American Jobs Creation Act. The Act also provides for prorated amounts for 10% ethanol blended gasoline, oxygenated, RFG, E-85 and other uses of ethanol for transportation. The provisions of the Clean Air Act and the excise tax credit are important components of the demand for ethanol, reducing the risk for organizations building a new plant.

Some states have mandated that all gasoline sold within the state be blended with a minimum percentage of ethanol, while other states have a partial state excise tax exemption. Minnesota initiated a mandate of 10% in 1997, and Hawaii has added one effective in 2006.

These federal and state policies have resulted in three segments of the ethanol demand. A fourth is the octane enhancing demand to produce premium gasoline. The amounts of ethanol sold through each of the four segments during 2003 and 2004 are reported in Table 5. Much of the growth from 2003 to 2004 has occurred in the reformulated fuel market, as additional states have banned MTBE. Growth during 2004 was sufficiently rapid that part of the demand, approximately 160 million gallons, was filled with imports. Some imports came in through the Caribbean Initiative, which permits up to 7 % of the previous year's use to enter without duty. This is hydrated ethanol from Brazil that was converted to anhydrous ethanol and denatured in the Caribbean before being shipped to the U.S. During the peak price period, in the winter of 2004-2005, some anhydrous ethanol was imported directly from Brazil and paid the tariff of $0.54 per gallon.

The markets for ethanol in the U.S. changed dramatically when President Bush signed the Energy Policy Act of 2005. The bill provides oil companies with a great deal of flexibility in the way they use ethanol in the future. Consider four of the important provisions. 1) The Energy Bill removes the reformulated oxygenate standard 270 days after enactment, in May 2006. Refiners have lobbied for this flexibility for 6 years, indicating they can produce gasoline that meets the clean air standards with or without either MTBE or other oxygenate. 2) The bill enhanced the RFG air quality standards to protect the gains the U.S. has made in air quality. Thus oil companies will need to continue marketing reformulated gasoline. 3) The bill did not limit oil companies' liability for MTBE spills, although it gives them permission to move suits to federal courts for trial. However, because oil companies maintain the liability for MTBE spills, they may reduce the amount of MTBE produced, stimulating ethanol demand. 4) The bill imposes a renewable fuels standard that mandates that the oil industry use a minimum amount of renewable fuels per year. The minimum is 4.0 billion gallons for 2006, increasing 0.7 billion gallons per year through 2010, moving to 7.4 billion gallons in 2011 and 7.5 billion gallons in 2012. The RFS includes a credit-trading program that gives refiners RFS credits for renewable fuels blended above the baseline that have a lifespan of 12 months. This will provide oil companies a great deal of flexibility in deciding when and where to blend ethanol with gasoline.

Many in the ethanol industry feel the outlook is bright for an expanding ethanol market in the U.S. Ethanol will continue to be used as an octane enhancer, to meet air quality standards and as a fuel extender. Some argue that the RFS could expand demand more rapidly than the domestic industry can supply, significantly boosting opportunities for the countries in the region that have preferential access to U.S. markets, such as through the Caribbean Initiative, and those with low production costs that can pay the $0.54 per gallon duty.

The recent increase in petroleum and gasoline prices seems to open a new market for ethanol as a fuel extender (Figure 4). This is potentially a very large market, and one that should absorb any amount of ethanol the industry could produce in the foreseeable future. The US consumed 136 billion gallons of gasoline during 2004. The expected production levels of 4.0 and 5 billion gallons during 2005 and 2006 are only 2.9 and 3.7 percent of the consumption, respectively. If the oil industry uses ethanol as a fuel extender, the price of gasoline will effectively place a floor on the price of ethanol (net of the tax credit and blending costs).

The ethanol market may experience some abrupt swings in ethanol price as petroleum companies begin to purchase significant quantities of ethanol for nontraditional uses. This reflects the difficulty of coordinating supply with demand in a market with a predominance of mandated uses and only a small proportion of production that is available for sale as a fuel extender. The price is set by the marginal sale. When supply is in excess, the price is low. But selling more than the marginal amount available to the new customers drives the price up dramatically. Industry rumors indicate this happened in May and June of 2005, as regional gasoline companies began purchasing ethanol for use as a fuel extender (Figure 4). The additional purchases on top of the mandated demands quickly moved the price back up from its April low later in the year.

Ethanol from Lignocellulosic Biomass

The wet- and dry-mill processes referred to above produce ethanol from starch and soluble sugar. The potential to produce ethanol from these sources is limited by the resources available to produce these crops, a topic discussed in the final section of this paper. A much larger quantity of ethanol could be produced by applying new technologies that are being developed to produce ethanol from lignocellulosic biomass, the leafy or woody parts of plants. Development of these processes will enable the production of ethanol from corn stover, wheat straw, woody biomass, waste paper and wood, and other cellulosic products on a commercial scale.

The primary components of lignocellulosic biomass are cellulose, hemicellulose, and lignin. The processes being developed produce fermentable sugars from the cellulose and hemicellulose and then ferment the sugars to produce ethanol. The remaining component, lignin, is a clean-burning source of energy that can be recovered from the conversion process and burned to produce process heat and electricity.

The National Renewable Energy Laboratory (NREL) is pursuing a research program to develop a commercially viable process to produce lignocellulosic ethanol. The process they feel has the most potential is referred to as enzymatic hydrolysis. A recent study describes the process design and economics of producing ethanol from corn stover based on the co-current dilute acid prehydrolis and enzymatic hydrolsis process they are developing (Aden, et.al.,2002).

The estimated production cost of ethanol from lignocellulosic biomass is based on the study by Aden, et.al (2002). The plant is designed to process 2,205 tons (2000 metric tons) of dry organic matter per day and to operate 350 days per year. Using Aden, et.al.'s terminology, the figures here are for the th nth, n+1, n+2, etc. plants where n is 8 or 10. While earlier plants may have lower yields, much of the literature assumes the nth and later plants will achieve a conversion rate of about 68 gallons (BBI International, 2001). A plant operating 350 days per year with a conversion rate of 68 gallons per ton would produce 52.3 million gallons of anhydrous ethanol per year. Assuming 2% denaturant is added, this is equivalent to 53.4 million gallons of denatured ethanol. The future case Aden analyzed assumed a conversion rate of 89.7 gallons per ton, resulting in annual production of 70.7 million gallons of denatured ethanol. The plant is also assumed to produce an excess of 2.28 kWh of electricity per gallon of ethanol. The excess electricity is assumed t be sold to the grid at $0.041 per kWh.

The design of the plant and costs presented are based on a start-up date after 2010. The economic analysis assumes 30 months are required to complete the planning, construction and initial performance testing of the plant. The estimated project investment is $197,400,000 plus $9.9 million for operating capital. Operrating costs total $73.8 million, including the purchase of the feedstock at $30 per ton and the cellulase enzyme at $0.101 per gallon of anhydrous ethanol. The detailed costs are given by Aden, et.al (2002), Appendix D.

The cost of producing denatured ethanol is summarized in table 6, for alternative feedstock costs and alternative enzyme cost levels. The base case assumes a conversion rate of 67.8 gallons per ton, a $30 per ton cost of the feedstock and a cost of the cellulase enzyme of $0.101 per gallon. The estimated cost of ethanol with these assumptions is $1.39 per gallon. NREL reports they and their subcontractors have been successful in lowering the production cost of the cellulase enzyme to about $0.20 per gallon (Genencor International, Inc., 2004). Raising the cellulase enzyme cost to $0.20 per gallon increases the cost of denatured ethanol to $1.49 per gallon. If the cost of the feedstock is higher, say $50 per ton, the breakeven costs are increased to $1.68 per gallon with a cellulase cost of $0.101, or $1.78 per gallon with a cellulase cost of $0.20.

With the development of improved enzymes, the conversion rate is expected to increase and the enzyme cost per gallon is expected to decrease. The assumptions used by Aden et. al. (2002) are a conversion rate of 89.7 gallons per ton, a feedstock cost of $30 per ton, and an enzyme cost of $0.101 per gallon. The breakeven cost with these assumptions is $1.05 per gallon of denatured ethanol. Raising the cost of the enzyme and/or the cost of the feedstock increases the breakeven cost per gallon as shown in Table 6.

A similar analysis can be completed for other sources of lignocellulosic biomass. The conversion rates will differ based on the amount of lignin in the feedstock used, but until some plants are built it will be difficult to estimate the investment costs more accurately.

How soon can we expect to see commercial plants producing ethanol from lignocellulosic biomass using this or some modification of this new technology? A Canadian firm began producing ethanol from wheat straw in a 1 million gallon per year demonstration plant in April 2004 (Iogen Corporation, 2004). Industry sources indicate this and other companies, perhaps with access to niche sources of biomass at favorable costs, may build pilot or small scale commercial plants in the near future. If it takes 2.5 years to build a plant and bring it into production, it may be possible to have several small plants in production by 2010. As the new technology is proven, large commercial plants are expected to be constructed. Given the expected construction time of 2.5 years, it seems unlikely that we will have large-scale plants using this technology in production before 2015.

The production of a single product, ethanol, is seen as an intermediate-run technology. The longer-run objective is to develop biorefineries that integrate biomass conversion process equipment to produce fuels, power, and chemicals from biomass. The intent is to develop a plant that can take advantage of the biomass components and maximize the value derived from the biomass. If the biorefinery concept develops rapidly enough, the industry may build biorefineries, bypassing commercialization of the technology that produces only ethanol and electricity.

Biodiesel

Industry Growth and Structure: The biodiesel industry in the United States began to organize much later than ethanol, and it is in an earlier stage of industry development. Production of biodiesel increased from 0.5 million gallons in 1999 to 25 million gallons in 2004, a 50-fold increase in 5 years. The National Biodiesel Board reports 35 companies had 35 active plants in April 2005, with some of the existing companies and 14 other organizations proposing an additional 25 plants. The National Biodiesel Board estimates that current dedicated production capacity (capacity of U.S. plants that produce nothing but biodiesel) is 110 mmgpy. In addition to dedicated production capacity, there is an estimated additional 110 mmgpy of excess production capacity within the oleochemical industry. Thus the industry has the processing capacity to increase production rapidly as demand increases.

Economics of Biodiesel Plants. Haas et.al. estimate the capital and operating costs of a 10 million gallon annual capacity industrial biodiesel production facility. They assume current production practices, equipment and supply costs, and model a continuous-process vegetable oil transesterification plant with ester and glycerol recovery. The plant is assumed to partially purify the glycerol, removing methanol, fatty acids and most of the water, and sell the product (80% glycerol by mass) to industrial glycerol refiners. The analysis is based on purchasing degummed soybean oil as the feedstock.

The estimated investment costs are $11.5 million, or $1.15 per gallon of annual capacity. The operating costs are estimated to be $0.2713 and the capital costs, assuming a 10 year life and 15% rate of return on capital, are $0.2292 per gallon. Sale of the co-product, glycerol, at $0.15 per pound provides a credit of $0.128 per gallon. With the plant operating at capacity, the estimated cost per gallon ranges from $1.48 with degummed soybean oil costing $.15 per pound to$ 2.96 with degummed soybean oil costing $0.35 per pound (Table 7, col.2). The analysis assumes 7.4 pounds of virgin degummed soybean oil are required per gallon.

The feedstock cost is the largest single component of biodiesel production costs. Recycled fats and oils are less expensive than virgin oils and can also be used to produce biodiesel. Yellow grease and trap grease are the most common types. Yellow grease is recovered from used cooking oil from large scale food service operations. Renderers collect yellow and trap grease and remove the solids and water to meet industry standards. Yellow and trap grease are limited in supply, and they have other uses. For example, yellow grease is used in animal feed and also to produce soaps and detergents. Historic prices of yellow grease are about 49 % of soybean oil prices, and it is assumed the amount required to produce a gallon of biodiesel is somewhat greater, 7.65 pounds. Assuming the historic price relationship, the corresponding prices of yellow grease and the resulting cost per gallon is included in table 7, col.5. The cost per gallon ranges from $0.94 to $1.68 per gallon.The lower cost of biodiesel from yellow grease suggests that the market for biodiesel will bid up the price of yellow grease relative to soybean oil, subject to differences in the excise tax credit (discussed below).

The cost per gallon listed in columns 2 and 5 of table 7 do not include any incentive payments paid to the plant by the State and Federal Governments. Like ethanol, new biodiesel plants and those expanding production have been eligible for the Commodity Credit Corporation Bioenergy Program since fiscal 2001. Payments are based on the amount the plant processes in excess of the previous year. Payments for plants processing yellow grease are about 60 percent as much as those processing soybean oil. This program, which has contributed significantly to the profitably of biodiesel plants in recent years, is scheduled to sunset in 2006.

Biodiesel Demand. The amount of biodiesel demanded has remained relatively low because the cost of biodiesel has been and continues to be well above the wholesale price of petroleum diesel. However, several pieces of federal and state legislation are expected to enhance the demand for biodiesel. The American Jobs Creation Act of 2004 included a new tax credit for biodiesel of $1.00 per gallon for biodiesel made from virgin oils, and $0.50 per gallon for biodiesel made from nonvirgin oil, such as yellow grease. This tax credit was extended through December 31, 2008 by the Energy Policy Act of 2005. Including the excise tax credit (Columns 3 and 6, Table 7) makes biodiesel from soybean oil costing less than $0.30 per pound and biodiesel from yellow grease competitive with the price of petroleum diesel in recent months (Figure 6).

The Energy Policy Act of 1992 (EPACT) requires that a portion of the new vehicles purchased by qualified fleets be alternative-fuel vehicles (AFV). Qualified fleets include vehicles owned by state and federal agencies, and alternative fuel providers with access to alternative fuels. Law enforcement, emergency and military vehicles are excluded. The AFV requirement is 75% for Federal and State governments and 90% for alternative fuel providers. Since biodiesel can be used in diesel engines without alteration, one doesn't need to purchase an AFV to use biodiesel. EPACT rules allow a fleet operator to purchase 450 gallons of pure biodiesel for use in a heavy vehicle in lieu of an AFV purchase. A fleet operator may offset up to one-half of the AFV purchases with biodiesel purchases. This provision creates some demand for biodiesel.

A third policy may have a greater impact on biodiesel demand, however. The Environmental Pollution Control Agency recently developed a rule that will require the sulfur levels in diesel fuel to be reduced from 500 parts per million (ppm) to 15 ppm by 2006. EPA and the industry recognize that refinery changes to accomplish this reduction will greatly reduce the lubricity of petroleum diesel. Biodiesel/petroleum diesel blends of even 1 to 2 percent biodiesel can greatly improve lubricity of the resulting low sulfur fuel. Biodiesel blends of 1 or 2 % would add little to the wholesale price of fuel, and if the tax credit remains in place, it may even lower the cost.

At the state level, some states passed legislation favorable to biodiesel in recent years ranging from tax exemptions to infrastructure incentives. Minnesota enacted a statewide law requiring the state's diesel fuel to be comprised of 2 percent biodiesel. The law became effective in September 2005 when the state's biodiesel production capacity moved above 8 million gallons per year.

An important source of current biodiesel demand is for specialized uses where the air emission characteristics of biodiesel are a major advantage. These uses include marine craft and diesel engines operating in enclosed areas, such as mines. In addition, the National Biodiesel Board reports that in May 2004, more than 400 fleets associated with school districts, city governments, state governments, and federal agencies were using biodiesel. These uses are expected to grow. The policy provisions above are expected to contribute to this demand in the future. The Energy Information Agency (EIA)estimates the EPACT useage will increase to 6.5 million gallons per year by 2010. The Minnesota mandated 2% use will add about 17 million gallons of demand per year. The ultra-low - sulfur diesel rules are to be put into effect in mid 2006. EIA notes that if refiners use 1% biodiesel to improve the lubricity of diesel fuel, this will add 470 million gallons to demand by 2010.

The current use of 25 million gallons per year plus the potential markets total more than 500 million gallons per year. With the excise tax credit in place, biodiesel would also be competitive as a fuel extender, but how much can we produce from the available feedstocks?

Production Potential. The feedstock used for biodiesel production depends largely on the available supply and its price. Table 8 lists the 2000-2004 U.S. annual average production of the potential feedstocks for biodiesel. Soybean oil made up 57 percent of the total U.S. annual feedstock supply, while yellow grease and grease made up 8 percent. Other vegetable oils made up smaller percentages of the total supply and had higher prices during the past five years than soybean oil and yellow grease (Table 9). Among animal sources, inedible and edible sources made up 11 and 6 percent, respectively. Large proportions of the inedible tallow are exported, suggesting these oils may be candidates for biodiesel production. However, the animal fats are less uniform than the processed vegetable oils and require more processing to produce a uniform biodiesel product. Considering price, uniformity of product, and supply, yellow grease and soybean oil are considered to be the preferred feedstocks for biodiesel production.

Yellow grease and grease have alternative uses in livestock feed and the production of soaps. There is also the difficulty of transporting the yellow grease collected from all parts of the country to a biodiesel plant that is processing this material. Considering the alternative uses and the logistical problems, perhaps 1/2 to 2/3 of the total yellow grease and grease could be processed into biodiesel. This total would provide 172 to 228 million gallons per year.

A recent US Department of Agriculture (2002) study estimated the effect of increasing the amount of biodiesel produced from current levels to 124 million gallons in 2012. This study, conducted to analyze the effect of a renewable fuels standard for motor vehicle fuel, assumed all of the biodiesel was produced from soybean oil. The projected increase in the demand for soybean oil required to produce the biodiesel leads to an increase in the domestic price of soybean oil. The domestic price is projected to increase 17 percent over the baseline as a result of the biodiesel program. The higher price reduces other domestic uses of soybean oil and exports. Processing additional soybeans puts downward pressure on soybean meal prices, leaving the price of soybeans about 1 percent above the baseline. The change in protein prices results in minor changes in livestock production and profitability over the decade.

These data suggest the U.S. could produce 300 to 350 million gallons of biodiesel from yellow grease and soybean oil. It appears the U.S. would need to utilize other feedstocks or import other oils to process if biodiesel production is to be expanded much beyond this level.

Electricity from Wind Power

The production of electricity from wind power increased very rapidly in recent years. Total production increased from 5.6 million megawatt-hours in 2000 to 14.2 million megawatt-hours in 2004, an increase of 150 percent in four years (Table 10). In spite of this dramatic increase, wind power accounted for only 0.36 percent of total U.S. electricity production in 2004.

The wind industry and policy makers have dealt with many factors limiting opportunities to market wind power. These include many policy, economic and technical factors that interact to encourage the development of installed capacity and its use to produce electricity. Tiffany (2005) suggests these factors include:

- The Public Utilities Regulatory Policy Act (PURPA) that requires utilities to accept wind and other renewable sources of electricity at "avoided costs;"
- The federal Energy Regulatory Commission (FERC) policies that foster greater access to the grid by renewable energy;
- Strong interest on the part of individuals and groups to support the establishment of renewable power sources, including wind;
- State goals that mandate a certain proportion of electricity be purchased from local wind energy and other renewable energy sources;
- Availability of transmission lines to carry the energy generated from remote sites to the load centers;
- Reduction of regulatory barriers that inhibit utilization of wind power,
- Public investments to assess wind resources around the state;
- Increasing sophistication in the design and engineering of wind turbines;
- Greater research in the conductors capable of increasing capacity in transmission lines from remote wind sites to load centers;
- Maintaining the federal Wind production Tax Credit (PTC) which has been extended through December 31, 2007 at 1.9 cents per kWh for ten years of production;
- State wind incentive payments;
- Experience in marketing wind derived electricity to consumers as "green" energy;
- Growth in experience by lawyers in negotiating and executing power purchase agreements between wind producers and utilities; and
- Growth in experience by bankers in financing wind energy development projects.

While installing new capacity is highly dependent on all of these factors, the availability of the Production Tax Credit and access to transmission capacity are particularly important. The production Tax Credit had expired December 31, 2003 and was not renewed until October 2004. The lack of the Production Tax Credit limited new construction during 2004, but its reenactment led to much construction during 2005. Because the tax credit is to remain in place through 2007, a rapid rate of new construction also is expected during 2006 and 2007.

The production by state during 2003 is shown in table 11. Much of the concentration in wind power production was located in the West (California, Washington and Oregon), and the Midwest (Minnesota, Iowa, Colorado, Kansas, New Mexico, and Texas). Other midwestern and western states have excellent wind resources, but may be lacking transmission capacity and state incentives to encourage development.

Electricity generated from wind is noted as a clean source of power. Substituting electricity from wind power for electricity generated from fossil fuels reduces greenhouse gas emissions. The amounts of carbon dioxide, sulfur dioxide, and nitrogen oxides released in the process of producing a kilowatt hour of electricity by type of fuel are listed in Table 12.

Economics of Wind Energy A comparison of the cost of generating electricity using wind and other sources of energy was reported by the DOE (2005c). The study estimates the levelized cost in mills per kilowatt-hour (kWh) of electricity from new plants to come on line in 2015 and 2025 (Figure 7). Wind has higher capital, operation and maintenance and transmission costs than either gas- or coal- fired plants in both time periods. Wind has no fuel costs, keeping the total cost per kilowatt-hour close to the cost for natural gas and coal and below nuclear in both time periods. Nuclear is the high-cost alternative with the highest capital costs. In 2015, gas combined cycle is the lowest cost (50.67) followed by coal (51.79). Wind has an estimated cost of 55.67 mills per kilowatt, while the estimated cost for nuclear is 62.54 mills. It is noteworthy that the cost per kilowatt hour differences between gas combined cycle, coal and wind are not great, and they are highly dependent on the assumptions about future natural gas and coal prices. The analysis for 2025 assumes the price of natural gas will rise more rapidly than coal after 2010 and coal plants will become the low cost alternative for 2025. However, wind will continue to be rather competitive with coal- and gas-fired plants.

The profitability of an individual investment in a wind turbine is dependent on many factors. One of the most important is the wind resource at the site. Tiffany (2005) notes the minimum wind velocity to produce power is 10 miles per hour. The amount of power produced increases as wind speed increases until it reaches name plate capacity at about 28 miles per hour. It operates at that capacity for higher wind speeds until the “cut-out speed” is reached at about 50 miles per hour. At this speed the turbine is stopped and the blades are turned 90 degrees out of the wind and parked to prevent it from being damaged. The capacity factor of a site depends on the percentage of the time it has wind speeds in the productive range, and the strength of the wind over a typical year.

The profitability of an investment in a wind turbine depends on the price paid for the power and the state and federal subsidies available at the location. Tiffany analyses the profitability for a wind turbine in Minnesota, finding the internal rate of return ranges from 1.3% for a capacity factor of 25% to 17.3 percent for a turbine at a site with a 45 % capacity factor (Figure 8).

Limits to Development The contiguous 48 states have an ample amount of wind resources to expand electricity production from wind power to much higher levels. Elliot and Schwartz estimated that the good wind areas, which cover 6 percent of the U.S. contiguous land area, have the potential to supply 1.2 times the 2004 electricity consumption of the U.S. Much of this capacity is located in the central plains states, from Minnesota, North Dakota and Montana on the north to New Mexico and Texas on the south.

Goals for development of electricity from wind are more modest than the potential Elliot and Schwartz report. The U.S Department of Energy has set a goal of 6 percent of U.S. electricity from wind power by 2020. DOE projects total U.S electricity consumption to increase to 5.106 trillion kilowatt-hours by 2020 (DOE, 2005a). Generating 6 percent of this total would require a 21.6 fold increase in the 2004 production. While this may seem ambitious, the total is well below the 10 percent of the total considered the threshold where the intermittent nature of production becomes a problem to manage (AWEA, 2005d). To reach the 6 percent goal, the American Wind Energy Association indicates a number of factors are needed including consistent policy support and new transmission caoacity. They argue long-term consistent policy support of the federal production tax credit, currently approved through December 31, 2007, is an important component of that policy support. They also emphasize that the transmission system of the High Plains needs to be redeveloped, installing a series of new high-voltage transmission lines to transmit electricity from wind plants to population centers.

Electricity from Methane

Anaerobic digestion involves the controlled breakdown of organic wastes by bacteria in the absence of oxygen (Lazarus and Rudstrom). Acid-forming bacteria first break down organic matter into simple organic acids. Methane-forming bacteria then act on these acids, producing a gas commonly referred to as "biogas." Biogas consists of methane, carbon dioxide, water vapor, ammonia and hydrogen sulfide. The major agricultural opportunities to apply anaerobic digestion include food processing wastes and manure from livestock operations.

A small number of anaerobic digesters for livestock operations were installed on farms beginning in the 1970s. Most of the early digesters failed and few of those that were successful are in operation today because of changes in the size and ownership of the livestock operations. In mid 2005, the Environmental Protection Agency's AgStar program reported 41 digesters were in operation (EPA,2005). Eleven of these were built during the 1980s, 12 during the 1990s and the remainder over the 2000 -2002 period. Of these 41 digesters, 9 are at swine farms, 29 at dairy farms and 2 at poultry operations.

The U.S. Environmental Protection Agency's AgStar Program promotes digesters by providing technical and financial assistance to demonstration sites on commercial livestock operations around the country. The federal government provides grants to operators developing digesters under the Environmental Quality Incentives Program (EQUIP) and the Energy Systems sections of the Energy title of the Federal Farm Security Act of 2002. Many states also provide technical assistance, grants and/or loans to assist farmers building a digester.

Kramer (2005) summarizes the benefits owners in the upper Midwest reported to their operations from using anaerobic digestion. These benefits included electricity sales and offsets of electricity purchases, use of the digested solids for bedding or as a replacement for commercial fertilizer, and odor control. They reported that odor control improved the quality of life both on and off the farm, avoided complaints and perhaps lawsuits, increased operational flexibility, and permitted continuation of the operation at the site. Owners also reported a wide range of additional benefits including avoided herbicide purchases, reduced need for pest control services around the barns, and less need for lime application on fields.

The profitability of digesters is not well documented, and few of the owners interviewed by Kramer were able to quantify the economic benefits of their digesters. A recent study of a digester on an 800-cow dairy farm in Minnesota is an exception (Lazarus and Rudstrom). A heated plug-flow digester with a 130-kilowatt engine/generator to utilize the biogas was installed in August 1999. The additional investment required for a digester over a conventional manure system was $355,000 or $444 per cow.

The owners of the Minnesota dairy farm received grants and in-kind assistance of $127,500. They also received an interest free loan for $150,000 for 6 years. The remainder of the investment was financed with a combination of debt and equity capital.

The engine operated approximately 98 percent of the time from late 1999 until mid 2004, at which time it was stopped for several weeks to replace the engine. The new engine was run at reduced load for several weeks to break it in. Except for the engine replacement period, electricity generation was relatively constant at 20,000 kilowatt-hours per week, or 1,253 kwh/cow/year. The waste engine heat is captured and used to heat the dairy facility, which replaces 9.1 gallons of propane per cow per year.

The farm sold its electricity at a rate of 7.25 cents per kilowatt for the first 6 years. At the end of the 6-year period, the contract was renegotiated at 3.56 cents per kilowatt-hour. With these grants, interest free loans and revenues, the authors estimate the demonstration farm will achieve a 21percent internal rate of return on equity and the digester will contribute an annualized net present value of $5,919.

The authors also investigated the return without the subsidies and grants that are currently available. They estimated that the current investment cost of a new digester of the same type would be $530 per cow. They used the performance data actually achieved and the 2005 investment cost of $530 per cow to estimate the breakeven cost of a digester with no grants, interest free loans, or other subsidies. They estimated that a real (2005) electricity price of $.08 per Kilowatt-hour would be required to provide an 11 percent before tax return on equity.

More data is needed to analyze the profitability of various types and sizes of anaerobic digesters. The data to date suggest that anaerobic digesters may provide a way for large livestock operations and agricultural processors to deal with a major social nuisance and to generate another source of income for the business. More work is needed before we can estimate the contribution of this source of energy to savings in natural gas and LP gas and to the supply of electricity.

The Energy Information Agency (DOE, 2005a) projects a significant increase in generation of electricity from municipal waste and landfill gas. They project an increase to about 0.5% of U.S. electricity consumption from this source by 2025.

Resource Base and Potential Production

There is a great deal of interest in estimating the amount of energy that can be produced by and the likely impact on the agricultural sector. This section considers estimates from several recent studies to provide some evidence of the contribution agriculture might make to the nation’s total energy supply.

The preferred approach to estimate the amount of biomass forthcoming as markets expand is with a national supply and demand model that includes the major agricultural commodities. This type of model allocates resources to different commodities based on profitability of the alternative uses of land. Unfortunately, such a model has not been used to analyze a combination of policies that would increase the use of ethanol from grain, biodiesel from soybean oil, and lignocellulosic biomass for liquid fuel and electricity production. However, analyses of the impact from expanding specific types of biomass for energy production have been completed with national supply and demand models. The effort here is to piece three of these studies together to provide an initial picture of the amount of energy U.S. agriculture can produce. Hopefully a study that considers all of these sources within the same sector model will be completed in the near future. Such a study should clarify many of the interactions that are glossed over in the approach used here.

Ethanol and Biodiesel from Grain

A recent study assumed the amount of ethanol produced will increase from 4.2 billion gallons in 2006 to 7.0 billion gallons in 2012 to supply the renewable fuel standard (FAPRI, 2005). The assumption is that the remaining 0.5 billion gallons of the RFS will be filled by biodiesel, imported ethanol and other renewable fuels. The amount of soybean oil used to produce biodiesel increases over time, reaching 450 million pounds, enough to make 60.8 million gallons of biodiesel.

Corn used to produce ethanol increases from 1.572 billion bushels in 2006 to 2.575 billion bushels in 2012. The price of corn increases 12.6 percent over the baseline price in 2006. Soybean oil prices increase about 23 percent over the period, but the additional DDGS coming on the market limits soybean meal prices to an increase of 1 percent over the 2006 baseline price. The increase in soybean oil and relatively constant meal price results in an increase of 14 percent in the soybean price from 2006 to 2012. The higher prices for corn increase profitability of corn and the area planted to corn 3.65 million acres over the period, while the acreage of soybeans decreased 0.87 million acres. The remaining acreage for additional corn production comes from reductions in other crops, Conservation Reserve Program (CRP) acres, and idle land. The increase in the price of corn and other feed grains combined with the lower protein prices resulted in a slight increase in poultry production, a slight decrease in swine production, and very small changes in dairy and beef. The higher corn and other feed grain prices reduced government program payments about $4.196 billion in 2012 compared to 2006. The higher prices for feed grains offset the reduction in government payments, but farm expenses increase and net farm income in 2012 is projected to be about $300 million lower than in the 2006 baseline. The additional 2.8 billion gallons of ethanol produced increases the Federal Excise Tax Exemption payments $0.868 billion, partially offsetting the reduction in government farm program payments.

Bioenergy Crop Production

A second study analyzed the potential to convert cropped, idle, pasture and CRP acres to bioenergy production (De La Torre Ugarte *et. al.*, 2003). The analysis considers three bioenergy crops, switchgrass, willow, and hybrid poplar. The scenario of most interest for this discussion assumes the biomass is being managed for maximum economic production. Referred to as the production management scenario, it assumes standard fertilizer and chemical inputs with all acres of switchgrass harvested each year. The study assumes farm gate prices of $40 per dry ton of switchgrass, $42.37 per dry ton of willow, and $43.87 per dry ton of hybrid poplar. It is assumed farmers would be required to forfeit 25 percent of their CRP rental rate to receive permission to harvest the CRP acreage for biomass production.

The analysis, based on a 1999 baseline, estimated impacts for 2008. It was completed with POLYSIS, an agricultural policy simulation model of the U.S. agricultural sector. Under the production management scenario, 41.87 million acres of bioenergy crop production are planted to switchgrass, with no production of the two woody species. Of this total, 23.37 million acres are from land formerly in crop production, 12.91 million acres are from land in the CRP, 2.09 million are from idle acres and 3.49 are from pasture. The land that moves into bioenergy production comes primarily from corn, soybeans, wheat, cotton, alfalfa and other hay. The reduced production results in increased commodity prices in the range of 9 to 14 percent range for all commodities. The higher prices and the sales of switchgrass increase net farm income about $6 billion.

The production management scenario is expected to produce 188.1 million dry tons of biomass. This can be converted to ethanol, used to produce electricity, or converted to a wider range of products through biorefining.

Biomass from Crop Residue

Crop residue is another important source of biomass from agriculture. A recent study estimated supply functions for crop residue for each of five regions of the U.S. (Gallagher *et. al.*, 2003). The regions and the types of stover that are considered for harvesting are the Corn Belt (corn stover), the Great Plains (corn and sorghum stover, wheat, barley and oat straw), West Coast (corn stover, wheat, barley and oat straw), Delta (rice straw) and the Southeast (sugarcane bagasse).

The study estimates the supply of net residue available. This is the total produced less the amount needed for conservation and erosion control. Residue harvest is considered on land only if erosion is below tolerance. The required cover for erosion control was maintained on the remaining land in calculating harvestable residue.

The study assumes the residue is available for its opportunity cost. For residue fed to livestock, this is assumed to be the cost of a substitute feed, typically a low grade of hay. For other stover, the opportunity cost is assumed to be the cost of harvesting and transporting the biomass plus the cost of replacing the nutrients removed with the residue. This approach pays farmers for any costs they incurred, but it does not increase the farmer's net income.

The industry supply is the gross production less the amount needed for conservation, erosion control, and livestock feed. The estimated industry supply is 98.9 million tons for the Corn Belt and 35.5 million tons for the Great Plains. The industry supply for the other three regions is much smaller, 2.4 million tons for the West Coast, 4.6 million tons for the Delta and 3.6 million tons for the Southeast. The total for the five regions is 145.0 million tons. Gallagher *et.al.* estimate 90 percent of the total could be harvested and transported to a plant for less than $35 per ton.

Summary of Bioenergy Supplies From Agriculture

The three studies use appropriate methodologies to estimate the supplies of ethanol, bioenergy crops and crop residue. Each starts with a similar baseline, holds certain things constant and proceeds to analyze what happens if certain changes are made. Before we add them up, however, we need to make a significant adjustment in one of the totals. The FAPRI (2005) study uses and even expands the acreage planted to corn and soybeans to a total of 156.65 million acres, while the De La Torre Ugarte *et.al.* (2003)

study assumes that the acreage planted to corn and soybeans under the production management scenario is reduced to 146.7 million acres, a difference of 9.95 million acres.

Given the development of the grain ethanol industry in the U.S. it is unlikely a new bioenergy crop industry is going to bid the land away from corn and soybean production in the near future. For this reason, the analysis here begins with the land use and production levels given by the FAPRI model, and reduces the switchgrass production for the 9.95 million acres that remain in grain production. This reduces the amount of lignocellulosic biomass produced by U.S. agriculture by 57.7 million tons, reducing the amount of biomass that could be produced to 130.4 tons. Adding the amount of crop residue Gallagher *et. al* estimate could be delivered to a plant (90 percent of the total), 130.5 million tons, gives a total of 260.9 million tons.

The energy agriculture can produce from these three sources is summarized in Table 13. Converting the 260.9 tons of lignocellulosic biomass to ethanol at 89.7 gallons per ton produces 23.4 billion gallons of anhydrous ethanol. Adding 2 percent denaturant brings the denatured total to 23.9 billion gallons. Adding the ethanol from grain brings the total ethanol production to 30.9 billion gallons, 22.7 percent of the total gasoline consumption in 2004. At 76,000 Btu per gallon, it is equivalent to 2.35 quads. It is interesting to note that successful development of a lignocellulosic ethanol industry has the potential to far exceed production of ethanol from starch.

The 260 million gallons of biodiesel include 61 million gallons from soybean oil and the remainder from yellow grease. This is equivalent to 0.6 percent of the 2004 diesel fuel consumption in the U.S. and equal to .03 quads.

The plants producing ethanol from lignocellulosic biomass are expected to produce 2.28 kilowatt hours of electricity per gallon of anhydrous ethanol. This provides 53.4 million megawatt hours. If wind energy reaches 6 percent of 2004 consumption, this will total 237.2 million megawatt hours. The total electricity listed is 7.35 percent of the total consumption in 2004 and is equivalent to 2.96 quads. Summing, the energy produced from these sources totals 5.34 quads, approximately 10 times the energy produced from agricultural production in 2004.

These are more conservative estimates than many being published today. The estimates cited here are based on current crop yields and conversion technologies that are either being used or that are near to commercialization. Furthermore, they do not include energy production from forestry, which would add significantly to the total.

While these are conservative estimates, achieving them will be challenging. Producing the level of energy output listed in table 13 will require developing new markets for crop residue and bioenergy crops, and developing a lignocellulosic processing industry. They would also require a 17-fold expansion of the wind power industry.

A longer-run and, perhaps, more optimistic view of the amount of energy agriculture can produce is provided by Perlack, *et. al.,* (2005). The stated goal of the study is to show how agriculture and forestry can contribute an amount of energy equal to 30 percent of the current U.S. petroleum supply by 2030, an amount approximately equal to 1/3 of the current consumption of transportation fuels. They estimate that by 2030 agriculture (not including forestry) can provide 428 million tons of crop residue, 337 million tons of perennial crops, 87 million dry tons of grain (an amount equivalent to 3.1

billion bushels of corn), and 106 million tons of animal manure. One of the important assumptions underlying their estimates is an increase of 50 percent in the yield of corn, wheat, and other small grains, an increase of approximately 1and 2/3 percent per year. They also indicate they have not attempted to assess the economic competitiveness of the billion-ton supply they indicate can be produced.

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