BIOFUELS - AT WHAT COST?

Government support for ethanol and biodiesel in the United States

One of a series of reports addressing subsidies for biofuels in Australia, Brazil, Canada, the European Union, Switzerland and the United States.

October 2006

Prepared by:
Doug Koplow, Earth Track, Inc.
Cambridge,MA

Prepared for:
The Global Subsidies Initiative (GSI)
of the International Institute for Sustainable Development (IISD)
Geneva, Switzerland

GSI Global Subsidies Initiative

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International Institute for Sustainable Development
Head Office
161 Portage Avenue East, 6th Floor
Winnipeg, Manitoba
Canada R3B 0Y4
Tel.: +1 (204) 958-7700
Fax: +1 (204) 958-7710
Web site: http://www.iisd.org

International Institute for Sustainable Development
Global Subsidies Initiative
International Environment House 2
9 chemin de Balexert
1219 Châtelaine
Geneva, Switzerland
Telephone +41 22 917-8373
Fax +41 22 917-8054
Web site: http://www.globalsubsidies.org

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By Doug Koplow

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Abbreviations and Acronyms

2006$	U.S. dollars at their year-2006 value
ADM	Archer Daniels Midland
AFV	Alternative fuel vehicle
AMFA	Alternative Motor Fuels Act
AMT	Alternative Minimum Tax
B10	A blended fuel comprised of 10 per cent biodiesel and 90 per cent petroleum diesel
B20	A blended fuel comprised of 20 per cent biodiesel and 80 per cent petroleum diesel
B100	Pure biodiesel
CAFE	Corporate average fuel economy
CBERA	Caribbean Basin Economic Recovery Act
CCC	Commodity Credit Corporation
CO_2	Carbon dioxide
cpg	Cents per gallon
CRS	Congressional Research Service
E10	A blended fuel comprised of 10 per cent ethanol and 90 per cent gasoline
E85	A blended fuel comprised of 85 per cent ethanol and 15 per cent gasoline
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPACT92	Energy Policy Act of 1992
EPACT05	Energy Policy Act of 2005
EWG	Environmental Working Group
FFV	Flexible-fuel vehicle
GATT	General Agreement on Tariffs and Trade
GGE	Gasoline gallon equivalent
GHG	Greenhouse gas
GSI	Global Subsidies Initiative
IISD	International Institute for Sustainable Development
IRS	Internal Revenue Service
ITC	U.S. International Trade Commission | investment tax credit
JCT	Joint Committee on Taxation (of the U.S. Congress)
MACRS	Modified Accelerated Cost Recovery System
MFN	Most favored nation
MMBtu	Million British thermal units
mmgy	Million gallons per year
MTBE	Methyl tertiary-butyl ether
NAFTA	North American Free Trade Agreement
NBD	National Biodiesel Board
OECD	Organisation for Economic Co-operation and Development
OTA	Office of Technology Assessment
RFA	Renewable Fuels Association
RFS	Renewable fuels standard
TIF	Tax increment financing
USDA	U.S. Department of Agriculture
USD	U.S. Dollars
VEETC	Volumetric Ethanol Excise Tax Credit
WTO	World Trade Organization

1
Introduction

This report examines government support for ethanol and biodiesel in the United States. We have surveyed current government subsidy policies at the federal, state and, to the extent possible, local level. This analysis forms part of a multi-country effort by the Global Subsidies Initiative (GSI) to characterize and quantify subsidies to biofuels production, distribution and consumption, as well as the subsidies to producers of key factor inputs. Future work by the GSI will examine government subsidization of a range of other energy sources, including fossil fuels.

Government subsidies—at both the state and federal levels—have long played an important role in the expansion of the biofuels industry within the United States. A 1979 analysis by the now defunct Office of Technology Assessment (OTA) noted that in "…the 1980s there is a physical—though not necessarily economic—possibility of producing at least 5–10 billion gallons of ethanol per year."[1] A 1988 report by the U.S. Department of Agriculture (USDA) observed that

> [t]he fuel-ethanol industry was created by a mix of Federal and State subsidies, loan programs, and incentives. It continues to depend on Federal and State subsidies.[2]

Nearly 10 years later, the USDA's assessment had changed little. In a report issued in 1997 it stated that "[t]he most influential actors in the ethanol industry are Federal and State Governments."[3] Even the Renewable Fuels Association acknowledges that "[r]enewable fuels are produced only in countries where programs have been created to assist their production."[4]

The Energy Tax Act of 1978 introduced the first major federal subsidy to ethanol, a full exemption from the then 4¢/gallon motor fuel excise tax. In that same year, the first 20 million gallons of commercial ethanol production capacity came online.

Since that time, production capacity has grown steadily. In both the ethanol and biodiesel sectors, the pace of growth has accelerated dramatically in recent years. Currently, new capacity (new builds plus the expansion of existing plants) will increase ethanol output by nearly 50 per cent between 2006 and 2008. With respect to biodiesel, new plants will boost nameplate capacity by nearly 200 per cent.[5] State and federal policies have remained an important part of the story. In the ensuing years, many of the baseline subsidies present in the 1980s have continued to expand. Taxpayer support for biodiesel has grown as well.

Capital investment in these sectors is soaring. Since 2000, an estimated 6.5 billion[6] gallons of ethanol and nearly two billion gallons of biodiesel capacity have either entered production or are in the process of doing so. This represents an estimated capital expenditure of more than $10 billion on ethanol capacity and $1.8 billion on biodiesel. Distribution infrastructure, including terminals, retail facilities, tank trucks, rail cars and barges, during this same period adds an additional $540 million to the ethanol sector alone.[7] We were unable to identify similar information on biodiesel distribution infrastructure.

Conversion to biofuels comprises an increasingly important and rapidly growing outlet market for key feedstocks, especially corn, soybeans and sorghum. As the pace of industry growth accelerates, it is useful to re-examine questions about the role of government subsidization. VeraSun Energy Corporation, a U.S. ethanol producer that went public on U.S. stock markets this year, noted in their March 2006 filing statement with the U.S. Securities and Exchange

1 Office of Technology Assessment. *Gasohol: A Technical Memorandum*, September 1979, Washington, DC.

2 Economic Research Service, U.S. Department of Agriculture, *Ethanol: Economic and Policy Tradeoffs*. April 1988, p. 2. Agricultural Economic Report 585.

3 Crooks, Anthony. *Cooperatives and New Uses for Agricultural Products: An Assessment of the Fuel Ethanol Industry*, Rural Business-Cooperative Service, U.S. Department of Agriculture, 1997. Research report 148.

4 Renewable Fuels Association, "The Importance of Preserving the Secondary Tariff on Ethanol," 30 June 2005.

5 Ethanol calculations based on data from the RFA; biodiesel calculations based on data from the National Biodiesel Board.

6 For this study, one billion equals one thousand million, or 10^9.

7 Earth Track estimates based on data in EPA (2006a).

Commission that the "U.S. ethanol industry is highly dependent upon a myriad of federal and state legislation and regulation and any changes in legislation or regulation could materially and adversely affect our results of operations and financial position." (VeraSun, 2006: 15). Clearly, the subsidy issue remains an important one.

This analysis explores the background of historical government support, and catalogs the hundreds of programs now in place to subsidize nearly every stage of the ethanol and biodiesel supply chains. These policies are changing very rapidly, with scores of new ones under consideration at any given time. The National Biodiesel Board, for example, notes that it is tracking more than 160 pieces of legislation at the state level for biodiesel alone.[8] Wherever possible, we quantify these subsidies in an effort to estimate the total public support per gallon of biofuel produced. However, quantification is often difficult either because the subsidy's course of action is indirect (e.g., mandated use of ethanol) or because data on spending (especially at the state level) are difficult to locate. The report provides an initial approximation for these values.

Liquid biofuels have been subsidized largely on the premise that they are domestic substitutes for imported oil; they reduce greenhouse gas (GHG) emissions; and they encourage rural development. Critics of subsidization have argued that the production process of these fuels is itself fossil-fuel-intensive, obviating many of the benefits of growing the energy resource; and that there are less expensive options for both GHG mitigation and rural development. Although the most recent work (Farrell *et al.*, 2006; Hill *et al.*, 2006; U.S. EPA, 2006a) suggests some net fossil fuel displacement when biofuels replace petroleum products, the gains remain moderate, especially for corn-based ethanol. Accordingly, we provide a variety of metrics on subsidy magnitude to illustrate how much support is being provided, not only per unit of biofuel produced, but also in terms of fossil fuel displacement and greenhouse gas reductions. These values are helpful in evaluating whether other options to diversify transport fuels or mitigate climate change might be more cost-effective.

Tracking government subsidies to ethanol and biodiesel across the United States presents a major challenge. A surprising number of state governments, and many county and local ones as well, have been actively implementing a wide array of policies to support, encourage and expand the biofuels industry. Their actions have spanned a broad mix of policy types (grants; tax breaks; lending and credit enhancement programs; regulatory mandates; and funding for research, development and demonstration plants), and have targeted multiple points in the biofuels production cycle, including inputs to production, conversion, distribution and retailing, and consumption. Virtually every production input and production stage of ethanol and biodiesel is subsidized somewhere in the country; in many locations, producers can tap into multiple subsidies at once.

In addition to the wide array of policy interventions, and likely partly owing to them, the production base is undergoing massive growth, expected to double or more in only a few years. Growth in production has also been spurred by market factors such as high petroleum prices (due in part to supply insecurity), and by state-level bans on methyl tertiary-butyl ether (MTBE), a blending agent for which ethanol is one of the few readily available substitutes. The federal oxygenate standard was eliminated effective May 2006. In advance of that change refiners generally moved away from using MTBE because they felt they were no longer shielded from liability for groundwater pollution related to MTBE leaks.

The forces of a rapidly-growing production base and a proliferation of policy incentives work together to generate a growing level of public subsidization for the ethanol and biodiesel industries. Many of the existing subsidies scale linearly with production capacity or consumption levels, and the resulting rate of growth in the subsidy payments can be quite large. In addition, subsidies do not decline as the price of gasoline rises, as is the case for some subsidies benefiting petroleum and natural gas. Although the spiraling costs of the Volumetric Ethanol Excise Tax Credit in particular have led to discussions and proposals for subsidy phase-outs when oil prices are high (Bantz, 2006), there are currently no constraints in place.

At some point, the expiration of existing incentives may temper the growth in subsidization, but that point is still quite a few years off. Strong political support has maintained the key subsidies to ethanol for nearly 30 years, and we anticipate that those forces will remain. In the near term, we expect subsidy levels to rise sharply. Of particular interest is the rate of growth of 85 per cent ethanol blends (E85), for which there are a number of large state subsidies that currently apply to only a small base.

8 National Biodiesel Board, "Highlights of 2006 State Legislation Through 25 May 2006."

This report provides an overview of the support provided to ethanol and biodiesel in the United States. We have attempted to capture as many of the policy interventions as possible, but realistically acknowledge that we will have missed quite a few, and that we have been unable to quantify many of those we did identify. Despite these limitations, it is instructive to see the vast array of public support at all levels of government being showered on these industries. Aside from growing public costs, there remains a concern that productive capacity—driven by the subsidies—will grow at an unsustainable rate.

Such growth would result in a number of potentially-damaging outcomes. First, too much industry capacity could lead to a shakeout and bankruptcies. This could result in the loss of substantial public investment, and hardship in corn-intensive rural areas. Second, rapid growth in demand for feedstocks such as corn, other starches or soybeans could generate too much diversion of cropland to fuel crops; and from other uses for the fuel crops to fuel (e.g., export to the developing world). Such shifts could have important social and environmental impacts. Interestingly, while some environmental groups actively promote ethanol and biodiesel production and use, others—often those with an interest in protecting wildlife or its habitat, or who are concerned about food security—view the rapid growth of biofuels with great concern.[9]

A detailed evaluation of these issues was beyond the scope of our report. However, we are hopeful that our characterization of public support will inform the ongoing discussions of energy and agricultural policy options, and the environmental and social tradeoffs associated with a large scale-up of biofuels production.

The next chapter provides an overview of the liquid biofuels industry in the United States. Chapter 3 provides a historical overview of subsidies to this sector. Chapter 4 addresses the current subsidy picture at the federal and state levels. Chapter 5 discusses the main findings and aggregate subsidy values to ethanol and biodiesel. Readers are encouraged to review the Annex, which provides a detailed listing of the state and federal programs benefiting ethanol and biodiesel. As the report provides an overview of the largest subsidies to liquid biofuels and of the range of supports provided, the Annex contains many programs not mentioned elsewhere in the text.

1.1 Framework of the analysis

Figure 1.1 illustrates the framework used in the report to discuss subsidies provided at different points in the supply chain for biofuels, from production of feedstock crops to final consumers. Defining a baseline requires deciding how many attributes to look at, and determining what programs are too broadly cast to consider in an analysis of one particular industrial sector. In our analysis, we have focused on subsidies that affect production attributes that are significant to the cost structure of biofuels, including subsidies to producers of intermediate inputs to production, namely crop farmers. Since biofuel production systems can be energy-intensive, inclusion of subsidies to input energy would have been appropriate, but we had insufficient data to do so. More remote subsidies, such as to particular modes of transport used to ship biofuels or their feedstocks, were beyond the boundaries of this analysis.

Support to production and consumption is provided at many points in the supply chain. For the purpose of this report, the dividing line between production and consumption is taken as the point at which the biofuel leaves the manufacturing plant. The one exception is volumetric (i.e., per-gallon) subsidies provided to blenders, which are treated in this report as falling on the production side of the dividing line.

At the beginning of the supply chain are subsidies to what economists call "**intermediate inputs**"—goods and services that are consumed in the production process. The largest of these are subsidies to producers of feedstock crops used to make biofuels, particularly corn (for ethanol) and soybeans (for biodiesel). Although these subsidies do not result in a one-for-one reduction in the feedstock prices, and therefore the input costs for biofuel manufacturers, they are believed to have some depressing effect on prices. Fabiosa *et al.* (2006), for example, estimate that full liberalization of agricultural markets with the removal of trade distortions would raise world (and therefore U.S.) prices of corn by 5.7 per cent. Moreover, to the extent that production of the feedstock crops creates a demand for subsidies, the proportional share of the total subsidies to those crops used in the production of biofuels can be considered one element of the gross costs to government of promoting biofuels. (The net cost would take into account any increased taxes paid by farmers as a result of increasing their taxable incomes.)

9 Ducks Unlimited, for example, has recently pointed out that subsidies for crops, and the expansion of biofuels in particular, are contributing to conversion of former grasslands to row crops and to the loss of small wetlands in the Dakotas. See Niskanen (2006).

Subsidies to intermediate inputs are complemented by **subsidies to value-adding factors**—capital goods; labor employed directly in the production process; and land. In the case of biofuels, most of the subsidies supporting value-adding factors in the United States are linked to productive capital. These typically take the form of grants, or reduced-cost credit, for the building of biofuel manufacturing plants. Some localities are providing land for biofuel plants for free or at below market prices as well, and many others are paying, at taxpayers' expense, for upgrades of roads or rail lines servicing biofuel plants. These types of subsidies lower both the fixed costs and the investor risks of new plants, improving the return on investment.

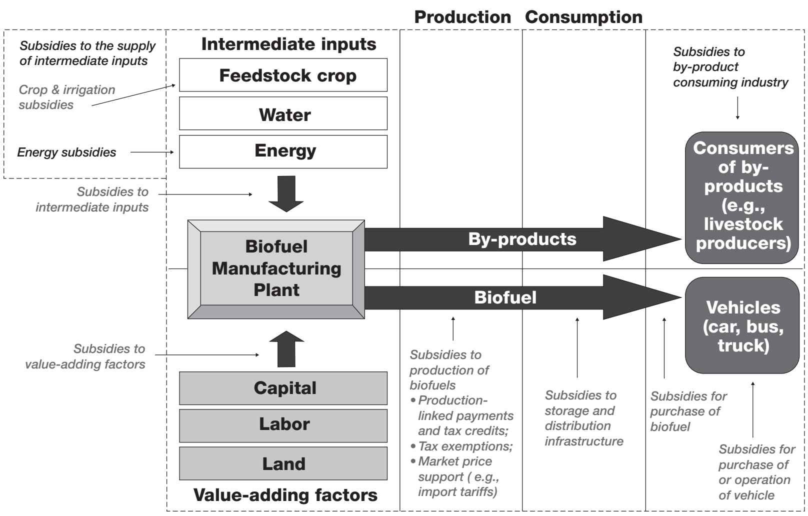
Further down the chain are **subsidies directly linked to output**. Output-linked support includes per-gallon federal tax credits to both the biodiesel and ethanol sectors. These are nominally provided to fuel blenders, and they enable those blenders to pay a higher price for the biofuels they purchase than they could without the subsidy. Production-linked subsidies are also common at the state level. Government policies that artificially elevate prices of biodiesel or ethanol are relevant here also. Import tariffs that protect domestic producers from cheaper imports are one example, impeding the ability of foreign producers to capture domestic market share. Tariffs are particularly costly to consumers at points of the country that are far from domestic biofuel production, but easily accessible to imports, most notably the east and west coasts.

Subsidies are also being provided to help reduce the costs of building or refurbishing the **storage tanks and infrastructure** required for distributing biofuels, particularly E85 (a blend of 85 per cent ethanol and 15 per cent gasoline). These help increase the availability of biofuels and reduce the total cost of supplying them to final consumers.

Subsidies and **government-procurement preferences** for the purchase of vehicles that are intended to run on biofuels increase the potential size of the market for biofuels, albeit indirectly. Nonetheless, these policies are often drivers behind other policies to increase the production or availability of biofuels. For example, having purchased flex-fuel vehicles (vehicles capable of running on ethanol-gasoline blends containing up to 85 per cent ethanol) in the past, many federal and state agencies are now requiring that these vehicles run on E85 whenever practical.

Subsidies and regulatory requirements more directly affect the demand for biofuels. **Subsidies for consumption** are minor, and have been provided mainly through government procurement programs that give preference to biofuels (such as that of the U.S. Navy for biodiesel) and assistance to school districts and municipalities that run vehicles (particularly buses) on biofuels. Of much greater influence have been so-called "renewable fuel standards," which require that a specified percentage of biofuels be used in total transport fuels consumed. Such standards, particularly if they are mandated and not just indicative targets, set a floor for the amount of biofuels that will be sold, independent of price. The exceptions are renewable fuels price standards set by a few states that apply only if the price of the biofuel remains within a certain percentage or per-gallon range of the competing petroleum-based fuel.

Figure 1.1: Subsidies provided at different points in the biofuel supply chain.



A basic understanding of core issues regarding subsidy policy is helpful in interpreting the remainder of this report. The following points are important to bear in mind:

Not just cash. Government subsidies are often thought of as cash payments from a government to a private individual or firm. While cash grants are subsidies, there are many other more complex methods that governments use to transfer value to the private sector. These include reduced tax rates; government-provided loans or insurance at below-market rates; guarantees on private loans; special requirements or bans that affect either biofuels or their substitutes; and surcharges or tariffs on competing products. While the details of these approaches can, and do, vary widely, all are used to some degree to subsidize ethanol and biodiesel in the United States.

Time-frame of the analysis. Subsidy values change annually, and can be volatile as one program is phased in or out, or as production levels or interest rates change. Our objective is to estimate an annualized subsidy value to biofuels support that is not driven by single market shifts, but rather is reflective of prevailing market trends. Estimates rely on as recent data as were available. Where programs and values shift sharply year-to-year (federal corn subsidies for example), we have used an average of multiple years rather than a single annual value. In some cases, averages include historic years. In others, such as tax expenditures where government estimates are prospective and not historical, our average value reflects prospective estimates as well.

Subsidy magnitude—cost to government versus value to recipient. Estimating the size of government subsidies can be complex. Often, estimates must be made against a baseline. For example, the baseline for taxes is that all firms pay income taxes in a particular way, with standard rates across all industries. Baselines for loan programs would be how much the government pays for the credit it uses to make subsidized loans to targeted sectors. The subsidy would be the deviation between standard and preferential tax or credit rates.

Both of the above examples represent one approach to subsidy measurement: the cost of the program to the government. However, there is a second measurement approach that estimates the value to the recipient. The value-based approach provides a more accurate metric of the level of distortions the government policies create in biofuels markets. For example, many government tax credits generate special "income" to private industry that is effectively tax-exempt. This generates an incremental subsidy value to the recipient, and is often referred to as the *outlay equivalent*. Similarly, government loans to a small, high-risk energy producer may be made at, or even slightly above, the government's cost of borrowing. However, that rate is still far below what the borrower would have been able to obtain on its own, generating an incremental *intermediation value* of the government credit support. Loan guarantees can often have quite a high intermediation value to borrowers, as they bring the effective interest rate on high-risk ventures down to the "risk-free" rate of the U.S. Treasury.

Subsidy specificity. A related issue involves subsidy policies that are available to multiple sectors of the economy. If these subsidies support key elements of ethanol production we did include them on a pro-rated basis. From the perspective of trade policy, many of these subsidies are considered "non-specific" and therefore not trade-distorting. Some economists might argue, also, that because these subsidies are offered to many industries, they benefit no single one disproportionately. For a number of reasons, we disagree.

First, some of the "general" programs actually contain special terms that do provide disproportionate benefit to liquid biofuels producers (accelerated depreciation, for example). Others, such as many state-level economic development or jobs incentives, are frequently used by the sector. As documented by Greg LeRoy, founder and director of Good Jobs First, these types of local investment incentives can be very lucrative for firms (LeRoy, 2005), in the aggregate affecting their cost structure. Finally, many of the forms of state- and local-government intermediated financing commonly provided to biofuel manufacturers, such as loan guarantees and some tax increment financing instruments, put these governments at financial risk should the operating environment for biofuels change and the borrowers default. Thus, these governments can be expected to take a higher level of interest in maintaining other, especially federal, subsidies to the sector. All of these factors make it quite important to take a holistic view of policy interventions that includes more general, as well as sector-specific, subsidies.

Subsidy magnitude—appropriate metrics. The objective of a study such as this is to inform important policy decisions. As such, no single metric tells the entire story. We provide estimates for total expenditures to support the industries, recognizing the many questions regarding fiscal prudence and overall public expenditure. We are also interested in measures of *subsidy intensity*: how much public subsidy has been spent per unit of output.

Depending on the parameter being considered, that output might be a gallon of ethanol or of biodiesel. It can also be for outputs such as petroleum or fossil fuel displacement, or greenhouse gas reduction. In our view, these latter metrics are of great interest when assessing broad policy alternatives related to environmental quality and energy security.

Market impacts. Subsidy magnitude data provide an overview of public *transfers* to the private sector. The impact that these transfers have on patterns of research, investment or production is a different issue, and one that is far more difficult to ascertain. Economists often build complex partial or general equilibrium models in an effort to answer these questions; we have not done so here. Some subsidies may have predominantly wealth effects, in that they move money from one party to another, but do not particularly affect the structure of markets to such a degree that the energy mix changes. In highly competitive global markets with open borders (which is currently not the case for biofuels), subsidies can affect the mix of suppliers (e.g., domestic versus foreign) without materially affecting the energy mix. Other subsidies can have efficiency effects, in that they do alter market equilibrium in material ways, impeding the most efficient or appropriate diversification of energy suppliers or resources. For individual policies, people (including some reviewers of this study) may hold strong opinions about the impact of a particular subsidy, and whether it affects market efficiency or merely transfers wealth. There are indeed disagreements, and the actual impact is not always self-evident. We do not try to make these evaluations in this report.

Subsidy incidence. Related to this issue of market impacts is the question of which party actually ends up benefiting from a subsidy. There is an inclination to assume that the original recipient (or target) of a subsidy program is the one who benefits. This is not always the case. A new sales tax may be shared partly by the consumer and partly by the supplier, based on their relative market power—even though each would like the other to foot the entire bill. Subsidies are no different. In our tally of transfers, we attribute subsidies to ethanol if the target is the ethanol supply chain, even if, as is often the case with the Volumetric Ethanol Excise Tax Credit, the entity that is paid the funds may be an oil company. In this case, the subsidy encourages the oil company to blend in ethanol rather than another feedstock, but the value of that credit is likely shared between multiple parties in the supply chain. As small, fragmented industries consolidate, power tends to shift to the larger players. Thus, we expect that over time, a higher percentage of all of the subsidies to ethanol and biodiesel will be captured by the larger players.

State and federal interactions. A final complication regarding tax subsidies in particular is the interaction between different tax jurisdictions. Many, though not all, federal tax breaks are accepted at the state level, reducing state taxes as well. The rules regarding what is allowed or disallowed are often state- and provision-specific. Overall, however, this particular interaction increases subsidy magnitude. Working in the opposite direction are state-level subsidies that boost taxable income on federal tax returns. This can reduce the realized benefit from the state provisions and overall tends to reduce the subsidy magnitude. Our estimates do not adjust for either of these factors. However, we estimate their impact, which is partially offsetting, to be on a net basis only a few percentage points on either side of our overall estimates.

2
Overview of Liquid Biofuels Industry in the United States

2.1 Production and capacity utilization

U.S. ethanol production has been growing steadily for more than two decades. Between 1980 and 1990, production levels more than quintupled, ending at 900 million gallons per year (mmgy). The pace of growth was slower in the 1990s, with production in 1999 roughly 60 per cent higher than at the start of the decade.

This overall growth trend occurred despite some difficult times for the industry when oil prices were low, corn prices high, or both. During the mid-1980s, 88 plants shut down, roughly a third of which were not expected to re-open. Most of the closures were small plants, however, representing only 17 per cent of industry capacity in 1986–1987 (USDA, 1988: 2). Again in the mid-1990s, ethanol production declined more than 20 per cent between 1995 and 1996. Nonetheless, by the end of the decade, growth was again robust. Annual production gains were normally in the double digits, and output more than doubled between 1999 and 2005 (from 1,470 mmgy to 3,904 mmgy).[10]

As illustrated by Table 2.1, current industry expansion is frenzied, with annual production capacity jumping by nearly 40 per cent (to five billion gallons) between January 2005 and October 2006, according to data assembled by the Renewable Fuels Association. Imports have also risen. Capacity utilization, which compares actual production with plant capacity, has tightened considerably throughout this time frame. From an 86 per cent utilization level in 1999, plant output reached well over 100 per cent of nameplate capacity in the 2003–2005 period. Havran (2006) notes that "many new plants are capable of exceeding design specifications by 10 per cent to 20 per cent or more."[11] This growth indicates strong product demand as well as continued optimization of production processes to enable sustained production levels in excess of nameplate capacity, though with some costs in higher plant wear.

New plant construction and expansions of existing plants are also growing quickly, with 3.2. billion gallons per year of capacity now in process. This would translate to a more than 60 per cent increase in plant nameplate capacity over the next two to three years. Plant sizes are rising steadily as well, with average capacity per operating plant of 34 mmgy in 1999 rising to nearly 48 mmgy currently. Some of the new plant announcements, such as 275 mmgy plants by Archers Daniel Midland (ADM) in Columbus, NE, and Cedar Rapids, IA, are a clear indication that the supply side of the ethanol market is evolving towards much larger plants (Planet Ark, 2006). This trend will have important effects both on feedstock supply and on the market power of different portions of the supply chain.

The biodiesel market remains much smaller than the market for ethanol, though its rate of growth has been faster. Annual capacity increased from a mere 0.5 million gallons in 1999 to 20 million gallons in 2003. Two years later, capacity more than tripled to 75 mmgy, and more than tripled again between 2005 and 2006, to more than 575 mmgy. Along with these 86 producing plants, there are 78 projects to build new plants or expand existing ones that are currently in process. Overall, these projects would add an additional 1,400 mmgy, nearly tripling national capacity once more.

While ethanol plant capacity utilization figures in excess of 100 per cent clearly support the logic of new plants, the data in the biodiesel sector do not tell quite so clear a story. The National Biodiesel Board estimated production capacity of biodiesel for early 2006 at 395 million gallons,[12] but actual production was only 150 million gallons, an apparent capacity utilization rate of less than 40 per cent. Yet, Leland Tong, the researcher who assembled the NBB data sets, noted that he is frequently told by plant owners that they are selling all they can produce.[13] NBB surveys also indicate high levels of new investment are continuing.

10 Renewable Fuels Association data. Note in the data above that values for output actually exceed stated production capacity in some years.

11 Since some subsidies are available only to plants with a nameplate capacity below a preset level, there may be some incentive to understate nameplate capacity.

12 National Biodiesel Board, "Estimated US Biodiesel Production," 2005.

13 Leland Tong, MARC IV Consulting, telephone conversation with Doug Koplow, 4 August 2006.

Tong's theory as to why a low utilization rate is not deterring new construction is twofold. First, he believes the utilization rates are actually higher (roughly 50 per cent) than reported, as industry members are far more willing to share information on plant capacity than on plant utilization. Second, he believes that many of these plants are still moving up the learning curve. New plants take awhile to reach full output, and plant operators continue to tweak plant operations in ways that no longer occur in the older ethanol segment.

Table 2.1: U.S. Biofuels Capacity Trends

	Ethanol			Biodiesel		
Year	Capacity (mmgy)	Capacity Utilitization	New Projects/ Existing Capacity	Capacity (mmgy)	Capacity Utilitization	New Projects/ Existing Capacity
1999	1,702	86%	4.5%	0.5	n/a	n/a
2000	1,749	93%	5.2%	2	n/a	n/a
2001	1,922	92%	3.4%	5	n/a	n/a
2002	2,347	91%	16.6%	15	n/a	n/a
2003	2,707	103%	17.8%	20	n/a	n/a
2004	3,101	110%	19.3%	25	n/a	n/a
2005	3,644	107%	20.7%	75	n/a	n/a
2006	5,047	n/a	39.8%	581	25-50%	241%

Sources and Notes:

(1) Capacity utilitization equals actual production divided by plant nameplate capacity.

(2) n/a = not available.

(3) Ethanol values calculated using data assembled by the Renewable Fuels Association, October 2006.

(4) Biodiesel data from the National Biodiesel Board, "Commercial Biodiesel Production Plants," 13 September 2006 and NBB "Estimated US Biodiesel Production," 2005. Capacity utilization based on Table 1, Urbanchuk, 2006; and Tong, 2006.

2.2 Industry concentration

The ethanol industry has historically been very concentrated, with a handful of large firms controlling most of the production capacity. For example, in 1990, the largest firm, Archer Daniels Midland (ADM), owned 55 per cent of total ethanol production capacity, with 13 firms in the industry overall. ADM's own interest in ethanol has its origins in another distortion in the U.S. agricultural market: policies that protect U.S. sugar production, thereby driving up the cost of sweeteners. In the 1970s, ADM invested heavily in factories to make high-fructose corn syrup, a low-cost, corn-based substitute for sugar that is used in soft drinks and numerous other foods. In trying to solve the problem of seasonal overcapacity in its corn syrup plants, it realized it could produce something else from corn: ethanol (Barrionuevo, 2006).

Industry growth in recent years has helped to alleviate concerns with concentration of ethanol ownership by a handful of firms. By 2004, ADM's share of production had dropped to 43 per cent, with the top five controlling 53 per cent (Yacobucci, 2004). The increasing pace of new entry helped push ADM's share down to 29 per cent by the middle of 2005, with 71 organizations (firms and cooperatives) participating in the marketplace (Eidman: 16). A 2005 analysis by the Federal Trade Commission on market concentration concluded that the entry of new plants continued to reduce the risk of concentrated ownership and, with it, the risk of non-competitive behavior (FTC: 15). The FTC noted also that because ethanol commands such a small share of the overall market for transportation fuels, even concentrated ownership of production may not result in any market power (FTC: 6).

Upon further consideration, the FTC conclusions do not seem quite so robust. First, concentrated ownership figures prominently in the political economy of subsidy creation and retention. Competitive strategy suggests that a larger proportion of the net benefits of government support will be captured by the most powerful players in the supply chain. This dynamic plays out regardless of where in the supply chain a subsidy is provided, as who initially receives the initial economic rent is not always the party that ends up with it. For example, even if higher demand for corn from ethanol production boosts corn prices, the incremental surplus tends to be captured over time not by farmers, but by larger corn processors. The greater the degree to which this capture is happening, the smaller the long-term benefits of subsidies will be for weaker players in the industry, such as small farmers.[14]

A second issue is that while ethanol constitutes a small share of overall transport fuels, it is a much larger share of the fuel additives market. The niche role ethanol plays as a blending agent in reformulated gasoline, with more market power since the demise of MTBE, provides the exact circumstance susceptible to anti-competitive behavior. This risk is compounded by the import tariffs that keep foreign ethanol from serving as a lower price ceiling for domestic suppliers. A third and final concern is that the ethanol marketing portion of the supply chain is far more concentrated than the production side, with more than 90 per cent of the ethanol produced being sold to the gasoline industry by only eight firms. Two-thirds is controlled by only three firms: ADM, Ethanol Products and the Renewable Products Marketing Group (U.S. EPA 2006: 16).

Biodiesel production is currently characterized by a few large plants and many small plants. Plants owned by farmer cooperatives and those using yellow grease as a feedstock tend to be smaller. New projects, however, are larger than the existing infrastructure (many in the 30 mmgy range), and sometimes include the same players, such as ADM. Nonetheless, the scale remains smaller than the ethanol industry. ADM's planned 85 mmgy plant in Velva, ND, for example, is to be followed by one other plant at 50 mmgy and one at 40 mmgy. Based on production levels assembled by the National Biodiesel Board, current concentration levels appear lower than those in the ethanol sector.

2.3 Summary

Although ethanol and biodiesel producers are currently selling all they can produce, and importing additional fuel to meet rising demand, the investment picture is mixed. The risk that high-demand growth could end is underscored by the two periods of retrenchment already experienced in the ethanol sector over the past 20 years.

BusinessWeek noted that banks were increasingly willing to lend up to 70 per cent of the cost of new ethanol plants, a sign of confidence in the sector. Morgan Stanley points out that some ethanol plants have even been able to borrow directly through traditional capital market debt finance (though only with below-investment-grade bonds), at a lower cost than bank lenders (More, June 2006). Similarly, *BusinessWeek* underscored some of the systematic risks of the ethanol sector, noting that "[I]nvestors in ethanol plants will find themselves at the mercy of two commodity cycles: corn and gas" (Palmeri and Pressman, May 2006).

In fact, there are three potent threats to the market position of ethanol and biodiesel. Rising feedstock prices or falling gasoline and diesel prices could certainly negatively affect the returns on biofuels. However, so too might increased imports of biofuels from abroad. In addition to ethanol from Brazilian sugar, there is increasing worldwide production of biodiesel from soybeans, palm oil, castor beans and other sources, though each feedstock has somewhat different performance properties. Ironically, even breakthroughs in cellulosic ethanol production could cause great turmoil among the investors behind the existing corn-based infrastructure.[15]

To hedge the risk of declining markets, the industry seems to expect that it can continue to rely heavily on government. This is in line with Morgan Stanley's assessment that the biggest risks to investors "are major changes in the underlying rules under which the current industry is operating" (More, June 2006). Purchase mandates, such as the Renewable Fuels Standard (RFS), set a consumption floor for renewable fuels. Though the standards do not single out corn-based ethanol (they offer higher credits to both cellulosic ethanol and biodiesel), corn-based ethanol is generally considered to be the source for most of the required purchases.[16] Increasing numbers of states have also implemented mandated consumption targets, or mandated blending ratios, for both fuels. Although the

14 David Morris at the Institute for Local Self-Reliance, a long-time proponent of incentives for biofuels, has noticed this trend. He writes that the changing ownership structure from cooperative to larger, corporate-owned plants "significantly weakens the close link between expanded ethanol production and expanded prosperity in the agricultural sector. The farmer is slipping back into his or her traditional role: supplier of raw materials to a concentrated value-added processing and manufacturing sector." (Morris, 2006).

15 We do not know the extent to which corn-based producers would be able to reconfigure plants to handle cellulosic feedstocks. One industry analyst (May 2006) thought that some parts of the production system could be retooled, but he was not sure whether doing so would be warranted economically, or what constraints feedstock proximity would create for conversion.

16 The U.S. EPA (2006) notes that even the cellulosic mandates are expected to be met with corn-based ethanol in the medium term. The statutes allow this to occur as long as 90 per cent of the process energy used in the ethanol plants is renewable.

RFS will hedge only a portion of domestic productive capacity, Greene (2006) notes that the authority to further boost mandated consumption already exists within the Energy Policy Act, and that such increases are likely.

Continued protection from imports also remains important. Although the existing supplemental tariffs on most imported ethanol expire in 2007 (mostly affecting imports from Brazil), political efforts to ensure tariff renewal are continuing. Even more aggressive policy interventions have recently been proposed to set a floor price for oil in order to protect the domestic ethanol industry.[17]

17 Richard Lugar and Vinod Khosla, "We can end oil addiction," *Washington Times*, 3 August 2006.

3
Historical Subsidies to Ethanol and Biodiesel

3.1 Evolution of federal policies supporting liquid biofuels

Subsidization of ethanol production at the federal level began with the Energy Tax Act of 1978. That Act reduced the motor fuels excise tax for ethanol-gasoline blends. Initially set at 4¢/gallon of gasohol—a blend of 10 per cent ethanol and 90 per cent gasoline, also called E10—equivalent to 40¢/gallon of pure ethanol. The exemption level thereafter changed frequently over the years (Table 3.1). It was finally replaced by the Volumetric Ethanol Excise Tax Credit (VEETC) in 2004. The General Accounting Office[18] estimated that the revenue loss from the excise-tax reduction over the 1980–2000 period was between $8.6 billion and $12.9 billion (2006$).

Table 3.1: Exemption from Motor Fuels Excise Tax for Alcohol Blends

Value on a pure ethanol basis	Period	Authority
40¢/gal	1978	Energy Tax Act of 1978
40¢/gal 40¢/gal blenders credit*		Crude Oil Windfall Profits Tax of 1980
50¢/gal 9¢/gal for ≥E85	1983	Surface Transportation Assistance Act
60¢/gal 60¢/gal blenders credit*	1984	Tax Reform Act of 1984
6¢/gal for ≥E85	1986	Tax Reform Act of 1986
54¢/gal 54¢/gal blenders credit*	1990	Omnibus Budget Reconciliation Act of 1990[19]
54¢/gal net (4.16¢/gal of 7.7% blend; 3.08¢/gal of 5.7% blend)	1992	Energy Policy Act of 1992 extended pro-rated exemptions to lower blends of ethanol E5.7 and E7.7. Ethanol blends with diesel, and ethanol produced from natural gas, also eligible.
53¢/gal 52¢/gal 51¢/gal	2001–02 2003–04 2005–07	Transportation Equity Act for the 21st Century initiated pre-scheduled reductions in the exemptions. Reduction set in 1997 by the Intermodal Surface Transportation Efficiency Act of 1997.
51¢/gal	2005	American JOBS Creation Act of 2004 replaces the excise tax exemption with a Volumetric Ethanol Excise Tax Exemption

Sources: EIA Ethanol Timeline; RFA, October 24, 2004; Duffield and Collins (2006); Gielecki *et al.* (2001); GAO/GGD-91-41; Hartley (2006).

*Blenders income tax credit is reduced by any benefit from the excise tax reduction; they are not additive.

A handful of additional federal subsidies were introduced in 1980. The Energy Security Act of 1980 initiated federally-insured loans for ethanol producers. The law allowed guarantees of up to 90 per cent of the construction cost, up to $1 million, for production capacity of less than one million gallons a year. The law also introduced price guarantees for biomass energy projects and purchase agreements for biomass energy used by federal agencies (EIA Timeline).

The Crude Oil Windfall Profits Tax Act of 1980 extended the gasohol tax exemption through the end of 1992. It also introduced a tax credit available to alcohol fuel blenders under Section 40 of the Internal Revenue Code, or to retailers in the case of sales of neat alcohol (E85 or higher). The credit boosted the effective exemption associated with the sale of higher-alcohol-content fuel blends (though still much lower than for E10). It was created to work in tandem with the excise-tax exemption, allowing alcohol blended in non-spec ratios to obtain tax credits for the amounts above that eligible for the excise-tax exemption (Hartley, 2006). As a result, it has varied in proportion to changes in the motor fuels excise tax exemption. Because Section 40 tax credits were not refundable

18 Now called the Government Accountability Office.

19 The reduction of the excise tax exemption from 60¢ to 54¢ per gallon corresponded to the introduction of the small ethanol producer credit. According to retired Joint Committee on Taxation analyst Ben Hartley, this shift was an attempt by Senator Robert Dole to redirect some of the benefits to small producers, in order to boost farm support and expand the political base for the ethanol program (Hartley, 2006).

(if credits exceeded a firm's tax liability, the taxpayer would get a rebate check), and could not offset liability under the U.S. Alternative Minimum Tax (AMT) system, the industry favored using the excise-tax exemption whenever possible.[20]

Also in 1980, alcohol production facilities were given access to tax-exempt industrial development bonds, authority that was repealed in the Tax Reform Act of 1986 (Gielecki *et al*., 2001). Access to tax-exempt bonds generated an additional $28 million a year in subsidies, based on Earth Track calculations. Since interest rate subsidies persist during the duration of the debt, these subsidies would have continued well beyond the 1986 repeal of new eligibility.

Other notable policy developments benefiting ethanol in 1980 included the placement of a supplemental import tariff of 50¢/gallon on foreign-produced ethanol in the Omnibus Reconciliation Act (RFA, 2005: 2). This tariff was increased to 60¢/gallon in the Deficit Reduction Act of 1984 (Gielecki *et al*., 2001). Industry has argued that "the secondary duty was created to offset the excise tax credit taken by the petroleum industry when ethanol, both domestic and imported, is blended with gasoline" (Schafer, 2005). Hartley (2006) notes, however, that the supplemental tariffs are punitive, since the rates are applied volumetrically to the full mixture rather than just the alcohol component benefiting from the domestic subsidy. The rates also did not contain the scheduled reductions to 51¢/gallon that were contained in the domestic legislation.

Also in 1980, the Gasohol Competition Act was enacted, and banned retaliation against ethanol re-sellers by industry competitors for selling ethanol fuels (EIA Timeline). Several states also started to subsidize ethanol around this time. For example, Minnesota introduced a 40¢/gallon ethanol blenders' credit in 1980 (phased out in 1997), as did North Dakota. An additional producer payment was established in 1986 and remains in effect today,[21] though closed to new applicants. Annual state-level subsidy payments to Minnesota's ethanol sector were above $20 million every year between 1998 and 2005. A tally of state measures carried out by the Congressional Research Service two decades ago (CRS, 1986: 80) identified incentives in place in 29 states by 1985. By 1986, state excise tax exemptions alone were costing state treasuries over $450 million per year (in dollars of 2006) in foregone tax receipts (Table 3.2).

The policies were similar to those still used today: reduced fuel-excise taxes; production tax credits; and subsidized purchases of vehicles or infrastructure capable of handling the alternative fuels. Tracking of the policies is unlikely to be consistent across sources, but there does seem to have been a decline in tax breaks for ethanol, at least through the mid-1990s. In 1997, 15 states had production or blending incentives for ethanol (Crook: 2). In 1998 it was 19, still below 1980s' levels.

Since then, the number of states providing incentives for liquid biofuel production has soared. Based on our tally, 38 states today have at least one incentive in place for ethanol or biodiesel. Some of the state-level grant and loan subsidy programs to ethanol and biodiesel appear to have existed for many years. Because these types of policies are often not included in tabulations of state subsidies, we estimate that more states subsidized ethanol in the 1980s and 1990s than is evident from the above summary data.

In 1988, federal legislation began addressing the consumption side of the alternative fuels market. The Alternative Motor Fuels Act passed that year provided credits to automakers in meeting their Corporate Average Fuel Economy (CAFE) standards when they produce cars fueled by alternative fuels, including E85 (Duffield and Collins, 10). Earning these credits was not contingent upon any particular efficiency of operation for the vehicles when using alternative fuels, or even on whether alternative fuels were actually used. Because so few vehicles getting the efficiency exemptions actually used alternative fuels (somewhat less than one per cent of the mileage, based on a 2002 Report to Congress), the rule has been estimated to have increased domestic oil demand by 80,000 barrels a day (MacKenzie *et al*., 2005).

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20 In an effort to reduce the number of taxpayers able to offset their entire tax liability due to exemptions and deductions, the United States set up a parallel Alternative Minimum Tax system that disallows many common deductions. Some tax subsidies are excluded from AMT, and thus more valuable.

21 According to Fernstrum (2006), the original payment schedule was $0.15 per gallon of ethanol and the authorized amount has changed several times, but typically has been $0.20 per gallon. Each plant was generally eligible for payments for 10 years from the time it, or a plant expansion, came on line. Payments were limited to $3 million per plant per year. The payment rate from 2004 to 2010 will be $0.19 per gallon.

Support on the consumption side continued in the Energy Policy Act of 1992 (EPACT92), which formally established E85 as an alternative transportation fuel. B100 was subsequently added by the Department of Energy, based on its authority under EPACT92. EPACT92 also established alternative-fueled vehicle mandates for government and state motor fleets, policies that have indirectly encouraged demand for the fuels over time (EIA timeline; Schnepf, May 2005).

Environmental concerns have helped improve the market position of biofuels. Ethanol is a useful fuel additive, and federal legislation has had an important influence on this market. The Clean Air Act Amendments of 1990 mandated changes to the composition of gasoline in an effort to address two specific air-pollution problems. Two types of fuels were specified: reformulated gasoline and oxygenated fuels, or "oxyfuels." Reformulated gasoline was designed to help reduce ozone-forming hydrocarbons, as well as certain air toxins in motor-vehicle emissions, and was prescribed for areas of the country suffering the most severe ozone problems. Oxyfuels were intended for use in the winter, in certain metropolitan and high-pollution areas, in order to reduce emissions of carbon monoxide. An oxygen-increasing additive, or oxygenate, was required to be added to these types of gasoline reformulations. However, the Amendments did not specify any particular oxygenate (of which there are several) for achieving these goals (Liban, 1997).

MTBE (methyl tertiary-butyl ether), a petroleum-derived additive, emerged as the oxygenate of choice, primarily because the oil industry already had more than a decade of experience using it as an octane enhancer. The Clean Air Act Amendments nonetheless also boosted demand for ethanol as one of a handful of other available oxygenates (Schnepf, May 2006). The link between oxygenates and ethanol demand continued to be fairly weak, as MTBE continued to dominate. Then, in 1994, the U.S. EPA promulgated a Renewable Oxygenate Rule that required at least 30 per cent of the oxygenates mandated under the Clean Air Act Amendments to come from renewable resources. The effect of this rule would have been to guarantee market share to ethanol. The rule was challenged by industry, however, with the support of a number of environmental groups. It was overturned in court a year later (Johnson and Libecap: 124, 125).

Additional support for developing ethanol production facilities came through the small ethanol producer tax credit, first passed in the Omnibus Budget Reconciliation Act of 1990. This tax subsidy gave certain producers a 10¢/gallon credit on their first 15 million gallons ($1.5 million per plant) produced each year. Plants with a nameplate capacity in excess of 30 million gallons a year were not eligible. This cap was doubled to 60 million gallons a year in the Energy Policy Act of 2005 (EPACT05).

Federal spending on biofuels R&D hovered between $50 and $100 million a year between 1978 and 1998 (Gielecki *et al.*, 2001). The OTA reported that direct research on ethanol within the DOE was less than $15 million/year between 1978 and 1980 (OTA, 1979, p. 64). Though it did not involve a large amount of funding, the federal government did start the Bioenergy Feedstock Development Program at Oak Ridge National Laboratory nearly 30 years ago to focus on new crops and cropping systems for energy production (Schnepf, May 2006: 13).

Federal R&D spending on biofuels has also begun to increase more recently. In addition to increases in R&D spending, the federal government has established a number of biorefinery development grants. First authorized in Section 9003 of the 2002 Farm Bill, funding has yet to be appropriated. However, EPACT05 contains a number of provisions at much higher funding levels (Duffield and Collins: 12). Though many of these programs remain unfunded, a few are slowly moving forward.

Federal subsidies to biodiesel began to pick up with the Conservation Reauthorization Act of 1998, a law that amended EPACT92 to include biodiesel fuel-use credits. These credits are earned at the rate of one per each 450 gallons of biodiesel consumed (Duffield and Collins: 10). Many states sell the credits and use the proceeds to pay for the above-market costs of using alternative fuel in their government fleets.

The American Jobs Creation Act of 2004 (JOBS Act) provided the first tax subsidies targeted directly at biodiesel, more than 25 years after similar subsidies were enacted for ethanol. The tax credit implemented follows the VEETC model, though with two separate credit levels. Virgin vegetable oils or animal fats earn a credit of $1/gallon, while waste oils earn $0.50/gallon. A year later, EPACT05 established a small biodiesel producer tax credit as well, mirroring the one for ethanol (Schnepf, May 2006).

EPA regulations may again play an important role, this time for biodiesel. Regulations to reduce sulfur (2005 for on-road use; 2010 for off-road) in diesel fuels also reduce the lubricity of the fuel. Biodiesel additions of one to two per cent can correct for this, which in theory could generate a much bigger market for biodiesel than is currently the case (Duffield and Collins: 11). However, a variety of other methods for increasing lubricity offer better and lower-cost solutions (Kojima and Johnson, 2005).

Regulatory pressures are also driving increased demand for ethanol. While the EPA's effort to mandate the use of ethanol oxygenates in the mid-1990s was reversed by the courts, a number of factors in the past few years have led to even larger gains by ethanol in the fuel additives market. In 2004, MTBE bans by the states of California, New York and Connecticut took effect, the result of concerns over groundwater contamination and MTBE carcinogenicity (Yacobucci, March 2006: 13). Nineteen other states had banned or limited the use of MTBE as of early 2006.

Two elements of EPACT05 have also accelerated the demise of MTBE. First, the industry was not granted any liability protection associated with the production of the agent. Second, oxygenate mandates were removed, based on arguments that the requirements had achieved mediocre results in improving air quality, and that there were other ways to address concerns over carbon-monoxide emissions. Effective 6 May 2006, non-oxygenated reformulated gasoline could be sold in most parts of the country (Yacobucci, March 2006: 13, 14). Despite this change, the response of refiners has not been immediate, thus some demand for ethanol as an oxygenate in reformulated gasoline remains. Moreover, with MTBE gone, ethanol remains as the main surviving competitor for increasing octane, a position that has helped further boost demand for the fuel.[22]

The Energy Policy Act of 2005 also included the first federal purchase mandates for liquid biofuels (Minnesota's mandate pre-dated federal action). Referred to as "Renewable Fuels Standards" (RFS), these provisions mandate fixed minimum consumption per year of particular specified fuels, with the mandated level rising over time. The federal RFS mandates the purchase of four billion gallons of renewable fuels in 2006, rising to 7.5 billion in 2012, with increases equivalent to the increase in gasoline demand after that. Higher credits (equal to 2.5 times those for sugar- or starch-based ethanol) are available for cellulosic ethanol until 2012, after which minimum purchase mandates take effect (Duffield and Collins: 12).[23] Biodiesel is included at a higher credit rate as well (1.5 times that for corn ethanol) because of its higher heat rate (EPA 2006b: 51). In the near term, most of the mandate is expected to be met by ethanol.

3.2 Historical data on aggregate subsidy levels to liquid biofuels

As subsidization to biodiesel is relatively recent, historical data on subsidies exist primarily for ethanol. Table 3.2 provides an overview of federal tax subsidies to ethanol between 1979 and 1986. With the exception of 1989, we did not have available data to estimate subsidies to ethanol for the entire historical period since 1979.

Much of the exhibit data were developed by the USDA (1988), though we have made a number of additions to the table. These include quantifying outlay equivalent values where appropriate (see explanation in Chapter 1); the ethanol share of corn subsidies; and estimating the outlay equivalent value of some of the tax breaks the industry received.

Table 3.2 is striking in a number of respects. First, the total financial cost of the subsidies rose steadily throughout the 1980s. This reflected a 50 per cent increase in the motor fuel excise tax exemption between 1978 and 1984, as well as steadily-mounting production levels. The financial cost of the subsidies for many of the incentives rises linearly with production levels.

22 Gallagher *et al.* (2001) projected that the MTBE ban alone could double demand for ethanol within 10 years (p. 3).

23 The U.S. Environmental Protection Agency expects that even the cellulosic mandates will be met using corn-based ethanol. The Agency notes that the definition of cellulosic in the Energy Policy Act includes ethanol made from non-cellulosic feedstocks if 90 per cent of the process energy used to operate the facility is derived from a renewable source (U.S. EPA, 2006a: 191). The EPA (2006b: 44) interprets this as referring only to thermal process energy used within the plant; internal use of electrical power or energy requirements in other portions of the supply chain would be excluded.

A second critical finding is how high the federal support was in terms of subsidy per unit of energy produced, i.e., the subsidy intensity. Some of the early-year estimates are not representative, as large capital subsidies preceded rising production over which this support could be spread. However, even as production ramped up in 1982, subsidies per million Btus (MMBtus) of ethanol averaged over $30, and close to $3 per gallon of ethanol produced (2006$). Even without the additional subsidy elements we added to the calculations shown in Table 3.2, the USDA estimated that ethanol subsidies were 15 times the subsidy per unit of energy produced as subsidies for petroleum, natural gas and coal (though on par with nuclear fission) (USDA, 1988: 28). On an outlay equivalent basis, subsidy intensities were $37 per MMBtu and $3.14 per gallon (again in 2006$).

A more comprehensive accounting of historical support would have included still more elements. Remaining gaps include the market support benefits of the then-50-cent-per-gallon secondary tariff; state and federal credit subsidies to ethanol production; state production tax credits; and research and development support. Though we do not have full details on subsidized credit, Table 3.3 does provide a snapshot of early support to the ethanol industry at the federal level. Many of these loans and guarantees ended in default.

Estimates for ethanol subsidies in 1989 (Koplow, 1993) present a similar picture, as can be seen in Table 3.4. Including outlay-equivalent benefits, ethanol subsidies were estimated at $1.3 billion (2006$). The motor fuels excise-tax exemption and accelerated depreciation benefits remained important sources of subsidy, as were federal supports to corn production.

Overall, total government support to ethanol was relatively small on a gross dollar basis, compared with subsidies to fossil fuels and nuclear fission. Also notable is that subsidy levels were down significantly from earlier in the decade. This reflected large reductions in the scope and size of subsidies previously available through investment tax credits and highly accelerated depreciation schedules, both of which were eliminated or scaled back in the Tax Reform Act of 1986. That law also cut marginal tax rates substantially, reducing the difference between revenue loss and outlay equivalent measures.

However, the subsidy intensity data continue to demonstrate extremely high levels of support to ethanol. Subsidy amounts for 1989 were $1.48 per gallon of ethanol, or $17.56 per MMBtu (both in 2006$). As in the earlier 1980s, ethanol remained more heavily subsidized on a unit output basis than other energy sources. Rates were more than 10 times that for oil, even once an adjustment is made to include defense costs for oil shipped through the Persian Gulf.[24] The second most heavily-subsidized energy resource, nuclear fission, was being subsidized at roughly half the rate of ethanol. Arguments have been made about the need for higher subsidies during the early stages of technological development, and that ethanol was a less mature technology with a smaller installed base relative to its competitors. While this line of reasoning has some merit, the differences shown in Table 3.4 are likely too large for an infant industry argument to hold.

24 Though world oil markets clearly experience less volatility as a result of U.S. military protection of Persian Gulf oil shipping lanes, estimating the taxpayer support for these activities is not straightforward. Koplow and Martin (1998) provide a detailed discussion of the issues involved, and highlight the three core missions of the military in the region. The subsidy values included here represent one-third of regional military expenses. In our view, this is much more justifiable than assigning all military costs to oil as some analysts do. However, even if all costs were assigned to oil, the subsidy intensity would remain below that of ethanol.

Table 3.2: Estimated Ethanol Industry Subsidies, 1979-1986

	1979	1980	1981	1982	1983	1984	1985	1986	
Production									
Added capacity (mmgy)	60	120	200	215	105	140	40	220	
Total production (mmgy)	20	40	75	210	375	430	625	750	
Energy content (quadrillion btu)	0.002	0.003	0.006	0.018	0.032	0.036	0.053	0.063	
Main Tax Expenditures Benefiting Ethanol (millions of nominal dollars)									
Investment tax credit	10	19	32	34	17	22	6	35	
Energy Investment tax credit	10	19	32	34	17	22	6	53	
ACRS over economic depreciation	18	35	59	63	31	41	12	64	
Tax-exempt construction bonds	0	4	11	16	19	23	24	28	
Motor Fuel Excise Tax Exemption									
Federal	0	32	34	64	210	284	476	480	
State	0	28	30	82	155	199	278	280	
Total tax expenditures	37	138	197	293	448	591	802	940	
Ethanol Share of Corn Subsidies									
Share of corn crop used in ethanol	n/a	1%	1%	2%	3%	2%	3%	3%	
Pro-rata share of corn subsidies ($mils)	0	11	10	41	286	70	116	306	
Total Subsidies to Ethanol ($mils)									**Total**
Nominal Dollars	37	149	207	334	734	661	918	1,246	4,286
2006 Dollars, revenue loss	86	321	407	616	1,296	1,125	1,513	2,007	7,370
2006 Dollars, outlay equivalent (note 1)	131	413	554	772	1,389	1,240	1,573	2,193	8,266
Marginal tax rate (state + fed) (note 2)	50%	50%	50%	50%	50%	50%	50%	50%	
Subsidy Intensity, 2006$									
Revenue loss basis									**Average, 1982 to 1986**
Per gallon produced	4.31	8.03	5.43	2.93	3.45	2.62	2.42	2.68	2.82
Per MMBtu	43.13	107.00	67.85	34.21	40.49	31.24	28.54	31.86	33.27
Outlay equivalent basis									
Per gallon produced	6.57	10.33	7.39	3.68	3.70	2.88	2.52	2.92	3.14
Per MMBtu	65.70	137.72	92.36	42.90	43.39	34.44	29.68	34.82	37.04

Notes and Sources:

(1) Outlay equivalent calculations conservatively assume incremental benefits only for the energy- and the general investment tax credits and tax exempt bonding. To the extent that corn subsidies also generate tax-exempt payments to the sector, actual support will be higher. With combined marginal rates of 50% in effect at the time, outlay equivalent values will be roughly double (revenue loss/(1-marginal rate) the revenue loss for that provision.

(2) Marginal tax rate in place during this period was 46% federal, plus an average of 4% state. This follows the approach used in USDA, *Ethanol: Economic and Policy Tradeoffs*.

(3) In addition to the subsidies shown here, ethanol also received federal R&D support and credit subsidies, as well as tax breaks and financing support within many states.

(4) Source for subsidy data: USDA, Economic Research Service, *Ethanol: Economic and Policy Tradeoffs*, April 1988, p. 27. Tax-exempt construction bonds calculated by Earth Track, Inc. based on spreads between corporate and municipal debt. Corn shares used in ethanol from USDA Economic Research Service. Corn subsidies from OECD producer subsidy equivalent data.

Table 3.3: Historical Data on Federal Credit Support for Ethanol Production Prior to 1988

Recipient	Amount ($millions)	Type	Status
I. Loan Guarantees through the Farmers Home Administration Business and Energy Program			
Clinton-Southeast Joint Venture (GA)	1.85	Guarantee	Defaulted
Idaho Fuels (ID)	0.475	Guarantee	Defaulted
Farm Fuel Production	3.8	Guarantee	Defaulted
Kentucky Agricultural Energy Co. (KY)	35.2	Guarantee, 11/84	Defaulted
American Fuel Technologies (MD)	2.5	Guarantee	Loan repaid
ADC-1 (NE)	20	Guarantee, 10/82	Sold at no loss.
Boucher Rural Products (NE)	0.28	Guarantee	Defaulted
Dawn Enterprises (ND)	20	Guarantee	Defaulted
South Point Ethanol (OH)	32	Guarantee, 5/81	Repayments were current as of source reports.
Carolina Alcohol (SC)	0.495	Guarantee	Defaulted
Sepco, Inc. (SD)	0.35	Guarantee	Defaulted
Coburn Enterprises (SD)	0.75	Guarantee	Defaulted
Elgin Alcohol Fuels, Inc. (IA)	2.6	Guarantee	Funds never disbursed.
High Plains Corp. (KS)	20	Guarantee	Funds never disbursed.
Alchem, Ltd. (ND)	8.4	Guarantee, 6/87	Repayments were current as of source reports.
II. Loan Guarantees for Ethanol Production through the DOE, Office of Alcohol Fuels			
New Energy (IN)	127	Guarantee	Defaulted March 1987; DOE paid bank and became lender. Plant survived; net DOE losses not known.
Tennol Inc. (TN)	65	Guarantee	Defaulted; DOE paid out $60m, took ownership of plant. Facility sold, dismantled, and reconfigured in 1991.
Agrifuels Refining Corp. (LA)	78.9	Guarantee	Defaulted August 1987; DOE paid $69.9m. Plant sold for salvage value less than three years later.
Circule Energy (NE)	41	Guarantee	Guarantee never approved.
Minnesota Alcohol Producers (MN)	42	Guarantee	Guarantee never approved.
Kentucky Ag. Energy Corp. (KY)	9.8	Cooperative Agreement	Bankruptcy; FmHA had planned to sell property at a loss.
South Point Ethanol (OH)	24.5	Guarantee	Repayments were current as of source reports.
Columbia Energy Resources (WA)	1.76	Cooperative Agreement	Facility was never built; DOE recovered some of the money it fronted.
III. Total Defaults	**352.3**		

Notes and Sources:

(1) Table from Doug Koplow, *Federal Energy Subsidies: Energy, Environmental, and Fiscal Impacts, Technical Appendix*, 1993. Original loan data from USDA, Office of Energy, *Fuel Ethanol and Agriculture: An Economic Assessment*, August 1986; Migdon Segal, Alcohol Fuels, Congressional Research Service, 15 July, 1988, CRS IB74087; Blanche Hamilton, USDA Farmers Home Administration, personal communication with Doug Koplow, 16 October 1992; Dan Beckman, DOE Office of Alcohol Fuels, personal communication with Doug Koplow, 19 October 1992; John A. Herrick, "Federal Financing of Green Energy: Developing Green Industry in a Changing Energy Marketplace," *Public Contract Law Journal*, Winter 2002.

(2) Defaulted loans may have been repaid in part subsequent to the compilation of source data. Similarly, plants that went over to the federal government upon default may have been resold for partial recovery of the government investment.

Table 3.4: Subsidy Magnitude and Intensity in 1989 by Fuel, 2006$

	Subsidy/MMBtu	Total ($millions)	
Conventional Electricity			Note 1
Coal	2.07	10,840	
Oil	1.70	950	
Including Persian Gulf oil defense	2.50	1,400	Note 2
Natural Gas	1.55	1,460	
Fission	8.55	15,500	
Hydro	1.01	910	
All Conventional Electricity	3.13	29,650	Note 3
Direct Consumption			
Coal	0.32	940	
Oil	0.37	11,880	
Including Persian Gulf oil defense	1.24	40,390	Note 2
Natural Gas	0.29	4,800	
Ethanol	17.56	1,290	
End-use Efficiency	0.09	1,440	

(1) Subsidies to electrical infrastructure allocated to source fuels based on shares of generation.

(2) Persian Gulf oil defense estimate appended based on Doug Koplow and Aaron Martin, *Fueling Global Warming : Federal Subsidies to Oil in the United States* (Washington, DC: Greenpeace), 1998. Estimates allocate subsidy across U.S. consumption, though in reality much of the protected oil flows to markets in Europe and Asia. Estimate was done for a different base year (1995), so will not match expenditures in 1989. However, method uses multi-year averages to provide more normalized levels of support, so will be broadly representative of federal subsidies to oil shipping that were not included in the original 1989 values.

(3) Conventional electricity totals represent weighted average of source fuels based on output energy, and excluding Persian Gulf oil defense.

(4) Subsidy estimates from Doug Koplow, *Federal Energy Subsidies: Energy, Environmental, and Fiscal Impacts* (Washington, DC: The Alliance to Save Energy), 1993.

4
Current Subsidies to Ethanol and Biodiesel

Using a standard economic classification scheme for industry support, we provide an overview of the many types of incentives now in place to support the ethanol and biodiesel industry. A complete listing of subsidy programs, as well as the details on their provisions, can be found in the Annex. The chapter itself provides illustrations rather than a catalog.

4.1 Output-linked support

Output-linked support can be provided by government interventions, such as import tariffs or purchase mandates, that raise the price of a commodity received by producers above what it would be in the absence of such interventions (market price support), as well as direct payments to producers that are linked to their levels of production. In U.S. ethanol and biodiesel markets, output-related subsidies are generally linked to gallons of fuel produced or gallons of fuel blended.

4.1.1 Market price support

Market price support refers to financial transfers to producers from consumers generated by policies that artificially elevate the price of a good. Two policies play a significant role in supporting market prices for biofuels in the United States: tariffs and purchase mandates. The import tariffs on ethanol (equivalent on an *ad valorem* basis to around 24.7 per cent)[25] are much higher than the 1.9 per cent tariff on biodiesel. Similarly, there are a number of purchase mandates that affect biodiesel markets. However, the largest program (the federal Renewable Fuels Standard) is expected to most directly affect ethanol.

4.1.1.1 Tariffs

Other nations have large and growing biofuels production capacity. Brazil stands out in the ethanol arena, with a well-established industry based on sugar-cane feedstocks. A number of countries are ramping up oilseed production for biodiesel markets as well. Some of these nations, most centrally Brazil, have the capacity to export more than they currently do into the U.S. markets. Yet, despite quite high domestic prices for biofuels in recent years, imports have remained low.

Two levels of import tariffs contribute to this outcome.[26] The applied MFN (most-favored nation) *ad valorem* tariff on imports of undenatured ethyl alcohol (80 per cent volume alcohol or higher) is 2.5 per cent, and on denatured ethyl alcohol it is 1.9 per cent. Tariffs on biodiesel (Harmonized Tariff Schedule 3824.90) were 1.9 per cent, though no imports were reported in the 2005 dataset (ITC 2006 Tariff Database).

More importantly, however, since 1980 the United States has applied an additional specific-rate tariff on ethyl alcohol intended for use as a fuel. The rate of this additional duty, initially 40¢/gallon and currently 54¢/gallon, has varied over time. It is scheduled to expire at the end of September 2007, but there are many legislators in the U.S. Congress who would like to see it extended, as in the past. Although supposedly pegged to the federal excise tax exemption (and its successor, the VEETC) to offset advantages imported ethanol received through reduced taxes, the reality has not been quite so precise. For example, although the tax credit rates have declined in recent years, the specific-rate tariff has not. In addition, while the credits are earned only on the ethyl alcohol content of the fuel, the specific-rate tariff is levied on the full volume of any denatured alcohol, including the fossil-fuel denaturant as well (Hartley, 2006). Both of these factors result in effective tariffs per unit of pure ethanol that exceed the federal tax subsidy.

25 According to an analysis carried out by the U.S. International Trade Commission in August 2006; see www.usitc.gov/tata/hts/other/rel_doc/bill_reports/documents/s-2778.pdf

26 As the U.S. industry points out, most other countries levy tariffs on ethanol imports as well. The Renewable Fuels Association has compared *ad valorem* rates among countries, and notes that the rates in Canada are five times the U.S. rate for undenatured ethyl alcohol of 2.5 per cent. In Brazil, applied MFN tariffs were until recently seven times higher, with levels 18 and 40 times those of the U.S. in the EU and Japan respectively (RFA, 2005, 3). However, if one compares both layers of tariffs (*ad valorem* and specific-rate) to the foreign *ad valorem* rates, the U.S. market does not seem quite so open.

Not all countries are subject to the specific-rate tariff on ethanol. Canada and Mexico—the United States' partners in the North American Free Trade Agreement (NAFTA)—for example, can export ethanol to the United States duty-free. An unlimited amount of ethanol from beneficiary countries of the Caribbean Basin Economic Recovery Act (CBERA) can enter the United States duty-free if it is made predominantly from local feedstocks. No CBERA country is producing its own ethanol from locally grown feedstock at present. To be exempt from tax, the transformation carried out in a CBERA country must be "substantial"; there is no consensus that dewatering alone would meet such a test, however. Similarly, there have long been discussions of large firms locating to the CBERA to dewater Brazilian ethanol and bypass the tariffs, though so far this has not happened on a large scale.

Imports of ethanol from CBERA countries may nonetheless enter free of duty under various tariff provisions, including a quota whereby imported feedstocks may be used. Under this provision, CBERA countries currently import hydrous ethanol, mainly from Brazil, and surplus wine alcohol from the European Union, dehydrate it, and export it to the United States (Bryan, 2006). Up to seven per cent of U.S. consumption may enter free of duty annually under this provision using no CBERA-origin feedstocks. Based on data from 2002–2005, imports have been less than 4.5 per cent of domestic demand, so this constraint has not been binding. The quota has never been filled and the fill rate amounted to 43 per cent in 2005. The U.S.-Central America Free Trade Agreement (CAFTA) did not change the overall level of access of CERBA-origin ethanol to the U.S. market.

4.1.1.2 Renewable fuels standards

Regulating a certain market share for any good normally drives up the price of that good. The size of the impact will depend on a variety of factors, including how large the mandated purchases are relative to what consumption would have been otherwise; the degree to which output of the good increases as prices rise; and whether competition from imports is allowed. After providing additional background on the mandates and how they interact with tariffs, we discuss their impacts on the market in light of three main attributes: direct price effects; related market-price effects; and market hedging.

At the federal level, the Energy Policy Act of 2005 (EPACT05) established a purchase mandate for liquid biofuels, known as the "Renewable Fuels Standards" (RFS). The RFS requires fixed minimum consumption per year of particular specified fuels, with the mandated level rising over time. Targets have been set at four billion gallons of renewable fuels in 2006, rising to 7.5 billion in 2012. Post-2012 increases are meant to occur at the same rate of increase as for gasoline demand. Higher credits (equal to 2.5 times those for sugar- or starch-based ethanol) are available for cellulosic ethanol until 2012, after which minimum purchase mandates take effect (Duffield and Collins: 12). Biodiesel is included at a higher credit rate as well (1.5 times that of corn ethanol) because of its higher heat rate (USEPA, 2006b: 51).

The appearance of a federal mandate in EPACT05 has not stopped states from issuing mandates of their own. Minnesota had already established a renewable fuels mandate prior to the federal RFS; it requires that gasoline sold in the state must contain 20 per cent ethanol by 2013. However, many other states have become active as well. In 2006, Iowa set a target to replace 25 per cent of all petroleum used in the formulation of gasoline with biofuels (biodiesel or ethanol). Hawaii wants 10 per cent of highway fuel use to be provided by alternative fuels by 2010; 15 per cent by 2015; and 20 per cent by 2020. Washington state has set a more modest requirement that biodiesel comprise a minimum of two per cent of annual sales within the state of diesel-like fuel, and that the ethanol content of gasoline be at least two per cent; this percentage will increase, at some point to five per cent biodiesel and 10 per cent ethanol respectively (see Annex).

At least two state-level renewable fuel blending mandates link their mandates with in-state production. Both Montana and Louisiana have made blending mandates for ethanol contingent on production of ethanol within these states reaching certain minimum levels (annual rates of output of 40 million gallons in the case of Montana and 50 million gallons in the case of Louisiana). Louisiana has also mandated that biodiesel must provide two per cent by volume of diesel fuel sold in the state within six months after in-state biodiesel production capacity reaches 10 million gallons a year.

Missouri has required that non-premium-grade gasoline sold in the state must contain 10 per cent agriculturally-derived ethanol (E-10) by 1 January 2008. However, the requirement does not apply when ethanol is more expensive than gasoline.

4.1.1.3 The combined effects of tariffs in the presence of renewable fuel standards

The effects of the tariffs on imported ethanol are twofold. The smaller effect is that the tariff acts as a tax on any imports that do enter the country. The specific-rate tariff on fuel ethanol, which under the current rules and market structure falls almost entirely on Brazil, generated tariff revenues of $53 million in 2004 and $22 million in 2005. Collections under the *ad valorem* tariff have been less than $8 million per year in recent years (ITC 2006 Tariff Database). Because of a loophole called the "manufacturer's duty drawback", however, the amount of duty actually paid on ethanol imported from countries such as Brazil and China is uncertain.[27] Some observers have estimated that the amount of the duty that ultimately does not get paid could exceed two-thirds of what otherwise would have been due (*Energy Washington Week*, 2006).[28]

The second and much more important effect of a tariff is to protect domestic markets from competition from lower-priced imports, thus allowing domestic prices to rise higher than they would otherwise. This is a much larger and more important effect, though it can be difficult to estimate. A complicating factor is that ethanol can be both a complement to gasoline when it is used as an additive, and a substitute for it when used as an extender. This makes estimating the appropriate market characteristics more difficult.

When only a tariff is in place, competition from foreign suppliers of ethanol will be reduced, but domestic manufacturers must still compete with non-ethanol alternatives, notably gasoline.[29] However, a mandate forces the use of ethanol. With a mandate but no tariff, the amount of ethanol sold domestically would be possibly higher than otherwise, but its price would be constrained by foreign competition. A mandate plus a tariff both raises the threshold price at which foreign-sourced ethanol becomes competitive, and protects domestic suppliers from being undercut by the price of gasoline.

Direct Price Effects. A number of parties have tried to estimate how much the RFS mandates alone, or in combination with import tariffs, increase domestic prices of biofuels. We present here a number of evaluations to demonstrate both the range of estimated impacts, and that the value we have integrated as a measure of market price support could be greatly underestimating its actual value.

The U.S. EPA (2006b: 150) estimated that the federal Renewable Fuels Standard as it is currently implemented would boost gasoline costs by between 0.33 and 1.05 cents per gallon (cpg) ($496 to $1,606 million a year). They estimate, nevertheless, that prices to consumers will actually decline, since more than the observed cost increases will be paid by state and federal governments through industry subsidy programs. Net of subsidies, the agency predicts consumer prices for gasoline will drop between 0.84 and 1.08 cpg (U.S. EPA, 2006b: 151). The upper end of both of these ranges models a 9.6 billion gallon market for corn-based ethanol, which we have not assumed in our other subsidy estimates. The VEETC alone on this higher level of demand would add nearly $1 billion to our subsidy totals in Chapter 5. As a result, the lower-end values of 0.33 cpg increase before subsidies and the -0.84 cpg price effects after subsidy interactions are more relevant. Urbanchuk (2003) reached similar conclusions for an analysis conducted for the Renewable Fuels Association: price increases would be more than offset through government subsidies, resulting in declines in pump prices.

The result regarding gasoline prices in both of these studies is sensitive to the degree to which state and federal subsidies to ethanol would be passed on to consumers, rather than absorbed into operating margins and profits of ethanol market participants. Ethanol prices per MMBtu are now higher than that for gasoline, suggesting that other policies supporting the domestic market (tariffs, the RFS or the MTBE ban) are generating market price support. This perspective was supported by a recent *Wall Street Journal* article (McKay, 2006). In it, James

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27 The World Bank (ESMAP, 2006) notes that an oil marketer can import ethanol as a blending component of gasoline, and obtain a refund ("draw back") on the duty paid if it exports a like-commodity within two years of paying the initial duty. Since jet fuel containing ethanol is considered a like-commodity, and counts as an export when sold for use in aircraft that depart the United States for a foreign country, this has allowed some oil marketers to count such jet-fuel exports against ethanol imports and recover the duty paid on ethanol.

28 See also www.usitc.gov/tata/hts/other/rel_doc/bill_reports/documents/s-2778.pdf

29 The price ceiling for all ethanol would be set by the energy-equivalent price of gasoline, as adjusted by any additional value of ethanol as an additive (e.g., to raise octane levels). Foreign suppliers of ethanol in that case would also be price takers, and the main difference for lower-cost foreign supplies between the situation with and without the tariff would be the market share they could capture from domestic producers, especially in coastal-state markets.

Glassman of JP Morgan was quoted as estimating that the current RFS and MTBE ban were boosting gasoline prices by as much as 60 cents a gallon. Ethanol trader Sal Gilbertie of the brokerage firm Fimat USA pegged the effects, net of subsidies, a good deal lower, at eight cents a gallon. Yet even this lower value would translate into nearly $11 billion per year in extra cost for consumers, an order of magnitude higher than the U.S. EPA's estimate.

Elobeid and Tokgoz (2006) analyzed the impact of liberalizing ethanol trade between the United States and Brazil using a multi-market international ethanol model calibrated on 2005 market data and policies, taking the United States' renewable fuel standard and Brazil's blending mandates as givens. They have been the only analysts so far that have integrated both the RFS and the tariffs into a model. Running their model they found that the removal of trade distortions would reduce U.S. domestic ethanol price by 13.6 per cent on average between 2006 and 2015 (relative to a baseline). This price decrease, in turn, would result in a 7.2 per cent decline in U.S. domestic ethanol production and a 3.6 per cent increase in consumption. These results provide a rough indication of the degree to which the import tariff, in the presence of a renewable fuels standard, increases the cost of meeting that federal renewable-fuels mandate.

Estimating market price support for a commodity ideally involves calculating the gap between the average annual unit value, or price, of the good (usually measured at the factory gate) with a reference price, usually either an average (pre-tariff) unit import price or the an export price. Since such data are not readily available for the U.S. market, we use the Elobeid and Tokgoz results to obtain a rough estimate of market price support. For the 2006–2015 period, the authors use as a baseline for the United States' annual average production of just over 7,000 gallons a year of ethanol, and measure a price gap before and after the removal of the tariff of 27¢ per gallon. Multiplying these two values yields just over $1.9 billion. This value is in line with EIA's reference case projections for average ethanol consumption during 2006–2012. Applying the same gap to the forecast production for 2006 (4.4 billion gallons) yields a very rough estimate of current market price support of around $1.2 billion.

None of the above researchers considered state-level mandates in their analyses. Nonetheless, state renewable-fuels mandates, if they are more stringent than the federal one, can increase the price distortions within particular states. If the mandates are equivalent or less stringent than federal ones, an incremental market-price support effect should not exist. However, if a state requires that specific feedstocks be used, or that a certain amount of fuel be produced locally, an incremental price effect can arise even if the percentage target does not differ from the federal mandate.

One analysis done of mandate proposals in Minnesota focused on the increased cost to consumers as the prices for biodiesel and ethanol rose higher than the equilibrium price for standard diesel and gasoline. Runge (2002) estimated biodiesel mandates would drive diesel prices up by 4.5 per cent for B2, and as much as 45 per cent for a B20 mandate. In comparison, the 8¢ per gallon estimate in McKay ($11 billion per year) was equivalent to roughly a three per cent price increase. The Minnesota Office of the Legislative Auditor predicted cost increases of 2.4¢ to 6¢ per gallon (in 2006$) under an ethanol mandate (MN OLA: 14).

Related price effects. As the demand for ethanol or biodiesel rises as a result of the mandates, prices of key inputs often rise as well—be it corn or construction services to build ethanol plants. These price shifts can have ripple effects in other product markets. An analysis of proposed federal ethanol mandates by Global Insight on behalf of the petroleum industry projected net cost increases in the feed and food sectors of up to $10 billion a year (Global Insight: 23). In stark contrast, Urbanchuk's (2003) analysis for the ethanol industry—also conducted on proposals similar, but not identical, to the RFS passed in 2005—concluded there would be no price increases. Were they to occur, rising prices can freeze out buyers in more price-sensitive markets. In biofuels, these are often grain-importing (and often poor) nations. Rising supply also increases land conversion, water consumption, and emissions, all factors that are important not to overlook. For example, the USDA's Chief Economist, Keith Collins, estimated that seven million acres now enrolled in the Department's Conservation Reserve Program could be plowed under to grow corn for ethanol. Similarly, the National Corn Growers Association notes that ethanol is a driving factor behind growers re-evaluating whether to bring land out of retirement (Donnelly, 2006).

Not all related products will increase in price, however. Co-products of surging biofuels industries are expected to experience continuing price erosion as supply increases far faster than new market uses.

Mandates as a market hedge. A third, and very important, attribute of mandates is that they greatly reduce downside risk to producers. Consider the case of ethanol. The concurrent very high prices for gasoline and elimination of MTBE mean that demand for ethanol would likely be rising regardless of the Renewable Fuels Standards. However, investors recognize that demand can be fickle. Over the longer term, industry analysts believe non-ethanol substitutes for MTBE will emerge (Hirshfeld, August 2006). Similarly, rising crop prices or falling fuel prices (or both) could greatly reduce the economic rationale for using ethanol or biodiesel.

Should this scenario occur even five to seven years hence, investors throughout the biofuels supply chain would be hurt. The mandates essentially protect a sizeable portion of the supply from not being able to sell their products during periods of market weakness. Because of the high specific tariffs on ethanol imports, the mandates are protecting primarily domestic supply. The policy shifts much of the investment market risk from the ethanol investors to the fuel consumer, and to any government lender. The subsidy value of the mandates would balloon during downturns, as the mandated ethanol or biodiesel may be substantially more expensive than regular gasoline or diesel. However, even during up-markets, the presence of the mandate makes it possible for producers to get more attractive financing terms than would otherwise be available.

4.1.2 Procurement preferences

Government-procurement preferences have become commonplace as both states and the federal government seek to spur consumption of biofuels. They are similar to mandates in structure, but far more voluntary. In fact, many of the government-procurement preferences for biofuels currently in effect are not particularly binding. Though they generally encourage the use of biofuels, the language often allows government officials wide latitude not to follow them. Most commonly, the preferences can be ignored if the preferred fuels are not readily available, or are much more expensive than standard fuels (the allowable price premiums vary by state). Others, such as Iowa's 25 per cent mandate for ethanol and biodiesel by 2010, use financial carrots rather than sticks. Retail outlets that don't meet mandate targets get reduced tax credits.

As the ability to opt out of the targeted purchases declines, the expected benefits to producers rise. For example, government-procurement rules may stipulate that biodiesel should be purchased at up to a 10 per cent price premium over standard diesel. This policy would generate a subsidy to biodiesel producers whenever officials followed it, even though such purchases may not be mandatory.

4.1.3 Payments based on current output

Many states, as well as the federal government, offer production payments or tax credits to producers of ethanol and biodiesel. These programs are normally structured to provide a pre-specified payment or tax credit for each unit (usually gallon) of output a plant produces. Blenders' credits or supplier refunds also exist in a number of places, and operate in a similar manner. Output-linked payments via the USDA's bioenergy program until recently paid a bounty per gallon of ethanol or biodiesel produced, with higher bounties for increased production. These operated through grants rather than tax credits, but were otherwise fairly similar in structure and impact.

Even with respect to production payments and tax credits, there are many variations in how they are implemented and funded. For example, the payment or credit per gallon of output varies by state, and changes over time. Some of the programs require eligible plants to pre-qualify with the government before they can claim a credit. Some cap the total payouts (or allowable tax credits) per year to all plants. This means that the early plants may absorb the entire available funds, or that the actual per-gallon subsidy received is well below the rate nominally noted in the statute. Others, such as California, which has had a generous 40¢/gallon ethanol production tax credit on its books for years (CA Code 25678), have never funded it. Nebraska appropriates funds for its Ethanol Production Incentive Cash Fund from an excise tax levied on corn and grain sorghum, currently 0.875¢ a bushel.[30]

Many states limit the size of eligible recipients, sometimes based on plant size, sometimes based on ownership shares of multiple plants. The objective of these limits is usually to focus available resources on smaller production facilities—though these smaller facilities may also have higher production costs. Often, the period of eligibility is limited as well—both in terms of when a plant must come online to partake in the program, and the number of years it can collect a producer payment once participation begins. In some states, the producer payment for a specific plant may decline to a lower level before ending completely.

30 See www.nebraskaadvantage.biz/aginnovation.htm

Finally, some states have placed geographic sourcing restrictions on their production payments in an effort to boost the benefits accruing to local farmers. Missouri's Qualified Biodiesel Incentive Fund makes monthly payments per gallon produced, but only if more than half of the feedstock comes from inside the state. Missouri's production tax credit for ethanol facilities requires that the plants be majority owned by agricultural producers engaged commercially in farming. The intent of these restrictions is clearly to keep state funding away from large, out-of-state corporations or individuals. However, we have some question as to whether they are consistent with the interstate commerce clause of the U.S. Constitution, as well as World Trade Organization (WTO) rules such as Article 3 of the Agreement on Subsidies and Countervailing Measures (which prohibits "subsidies contingent, whether solely or as one of several other conditions, upon the use of domestic over imported goods"), and Article III (national treatment) of the General Agreement on Trade and Tariffs.

4.1.3.1 Volumetric Ethanol Excise Tax Credit (VEETC)

Enacted in 2004 by the JOBS Act, the VEETC provides a tax credit based on ethanol blended into motor fuel. It replaces the partial exemption from the motor fuel excise tax that ethanol benefited from starting in 1978. Industry has advertised the benefits of the new formulation in terms of no longer reducing gasoline tax contributions into the Highway Trust Fund, which is where most of the proceeds from this tax end up. However, though revenues are more secure to highway planners, the financial cost of the provision to the U.S. Treasury remains high in either form.[31]

Earlier excise tax exemptions were set up as thresholds, with different levels of reduction for blends of *at least* 5.7, 7.7, 10 and 80 per cent ethanol. Any ethanol blend above the minimum, but below the next cut-off, would have had to rely on an alcohol fuel income tax credit (IRS Code Section 40) instead. While better than nothing, the Section 40 credits were more restrictive, and therefore less popular options. The subsidy value received by beneficiaries was generally lower, reducing the realized subsidy value to beneficiaries. The VEETC eliminated this problem, as well as enabling a faster recovery of funds than was possible under the income-tax-credit approach. Though better for industry, these changes also generate higher revenue loss to the Treasury.

The VEETC provision provides the single largest subsidy to ethanol. It is awarded without limit, and regardless of the price of gasoline, to every gallon of ethanol blended in the marketplace, domestic or imported. The subsidy cost is currently rising quite fast, mirroring the rapid increase in ethanol fuel usage. In 2005 the Joint Committee on Taxation estimated tax losses from the VEETC would average $1,440 million per year for the 2005–2009 period. Their estimate a year later was up more than 50 per cent, averaging $2,220 million per year for the 2006–2010 period, likely reflecting the rapid growth in consumption of the fuel. The U.S. Treasury, which also estimates tax expenditures, predicted a higher value than the JCT: an average of $2,650 million a year over the 2005–2011 period.

Yet demand growth seems to continue to outstrip the government estimates. Actual sales through July are on target for VEETCs worth $2,500 million for 2006, higher than projections for that year by either the JCT or the Treasury. Demand is expected to continue growing strongly in future years. Projecting the cost of this provision is not easy with such a rapidly growing market. The Renewable Fuels Standard mandates provide one stable benchmark against which to estimate VEETC subsidies. Assuming the country meets these targets, as seems likely given current growth rates, revenue losses will rise to $3.8 billion a year by 2012, when 7.5 billion gallons of ethanol must be used. The average during this period is $3.05 billion, well above current Treasury estimates, and our best guess for the cost of the VEETC to the U.S. Treasury.[32] The subsidy cost could be much higher. The reference case in EIA's *Annual Energy Outlook* projects corn ethanol consumption in 2012 at 9.64 billion gallons, well above the 7.5 billion gallon mandated level we used in our high-end subsidy estimate for the VEETC. The EIA expects the 7.5 billion gallon threshold will be passed in 2010 (U.S. EIA, 2005).

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31 There were some real distributional benefits of this change. For example, an unintended consequence of the federal excise tax exemption for gasohol was that it reduced appropriations from the Highway Trust Fund even to states that sold no gasohol. Rask (2004) estimates that between 1981 and 1996, U.S. state governments lost between $3.2 and $7.6 billion in highway funds (compared with the counterfactual of no federal tax relief on gasohol), and that some of the biggest losers were states such as Florida, New York and Pennsylvania which, during those years, sold very little fuel containing ethanol.

32 While some of this cap will be used up by biodiesel, biodiesel production and imports are currently less than 10 per cent the level of ethanol. The small market share, in combination with a variety of trends suggesting that the actual consumption of ethanol will exceed the RFS mandate by a fair margin, we expect that our estimate for ethanol will more likely be too low than too high.

Another important issue with the VEETC is whether the credits are themselves tax exempt, in part or in full. This example provides a good illustration of how tiny changes in the interpretation of the tax code can have quite large effects on the aggregate subsidy values. Were the tax credit to be includible income, the total subsidy value would simply be the revenue loss noted above. However, if the credit were not includible, the VEETC subsidy value for 2006 would rise by more than $1 billion on an outlay-equivalent basis. The total subsidy value during the 2006–2012 phase-in period of the renewable fuel standards would be roughly $9 billion higher.

Getting a clear answer as to whether the credit is includible income is not easy. Section 87 of the tax code specifically requires that tax credits for biofuels under section 40 (the income tax credits) be included in taxable income, rendering their outlay equivalent value identical to the revenue loss. The language on the VEETC is not clear. Section 2426 of the Internal Revenue Code makes numerous cross-references to section 40, mostly for definitional issues. There is no mention of Section 87.

In January of 2005, the Internal Revenue Service issued a guidance document on implementation issues related to the VEETC (IRS, 2005). Because this guidance was silent on the tax treatment of the credits, a consortium of industry groups filed comments requesting a clarification on the issue (Herman, 2005). The wording of their request indicates their inclination to treat the VEETC as not-includible in taxable income until clearly instructed to do otherwise:

> One of the major questions facing our members is whether any part of the new excise tax credit for alcohol fuel mixtures is taxable, and whether there are any circumstances in which the excise tax credit or refund (payment) must be reported as part of gross income (Herman, 2005)

An inquiry to petitioner Marilyn Herman requesting the current status of this issue went unanswered. However, an inquiry to the Joint Committee on Taxation brought confirmation that the "tax staffs (Joint Tax, Treasury, Ways & Means, and Finance) are aware of this issue and are discussing whether to recommend to the members that they enact a technical correction" (Barthold, 2006).

Given the sums involved, the sophistication of the affected entities (both in the ethanol and petroleum industry) and the real lack of guidance within existing law, it is highly probable that most of the large taxpayers are not including the VEETC in taxable income. We therefore use the outlay equivalent values for the VEETC, and the related credit for biofuels, in our high estimates for the subsidy value of this provision to industry. This generates a range of $3,570 million (using forecast demand for 2006) to $4,390 million (the average of 2006–2012 sales sufficient to meet the RFS mandate) per year. The latter value provides our high estimate for the VEETC.

To these values is a small incremental benefit by the fact that funds are accessible to the taxpayer more quickly. Standard tax credits are claimed through offsets on quarterly tax deposits. The VEETC can generally be recovered on average 35 days faster. The IRS must refund electronically-filed claims in a maximum of 20 days. While the difference in time seems small, it does generate a notable incremental benefit to the industry, since the overall magnitude of the tax credits is so large. The incremental benefit of the more rapid return of funds is estimated at $10-30 million per year for ethanol.

4.1.3.2 The Volumetric Tax Credit for Biodiesel

While the mechanics of the volumetric tax credit for biodiesel are the same as with ethanol, the volumes of fuel being produced are currently much smaller. The provision allows a tax credit of $1.00 per gallon of biodiesel produced from virgin oils or fats, and $0.50 per gallon from recovered oils or fats. The revenue loss estimates from federal sources range from $40 million per year (Treasury) to $50 million per year (JCT). To reach this upper number, one would need two-thirds of the 75 million gallons of biodiesel produced in 2005 to have come from recycled oils. In fact, the vast majority of biodiesel is currently from virgin oils, which would earn the higher tax credit rate. In addition, the pace of production is growing extremely rapidly, growth that should be incorporated into the 2005–2011 estimate range for the JCT and Treasury values.

The subsidy value of this provision can be more accurately estimated using production data on the biofuels industry. Data compiled by the biofuels industry on new plant capacity and expansions yields an estimated production capacity of nearly 1.5 billion gallons by the end of 2008. Of this, just under seven per cent is expected to be from recycled oils and fats that earn the lower credit. Assuming a capacity utilization of 75 per cent by that time (above the current estimate of 50 per cent, but well below the 110 per cent utilization in the ethanol sector), the tax credits would amount to $1,440 million per year in revenue loss or $2,060 million on an outlay-equivalent basis. Based on expected 2006 production levels of 245 million gallons (Collins, 2006), the excise tax credit would be worth $235 million on a revenue loss basis and $340 million outlay-equivalent basis. The incremental time value from rapid payout of the credit would add an additional $5–10 million a year.

4.1.3.3 The USDA Bioenergy Program

The USDA's Farm Service Agency offered targeted subsidies to ethanol and biodiesel producers through its Bioenergy Program between 2001 and 2006. The program was discontinued effective June 2006. Most payments were made for increased production, and 83 per cent of the funds overall went to ethanol. However, some payments were also made for biodiesel base production at least during 2003, 2004 and 2005, though these totaled less than $10 million across all years.

Payments were structured per gallon of energy produced, with higher bounties on increased production relative to continued base production. Bounties per gallon have varied over the course of the program depending on Congressional funding levels. For example, payments per incremental gallon of ethanol production ranged from 12¢ to 30¢ per gallon between 2001 and 2005. The range for biodiesel was from $0.51 to $1.41 per gallon during the same period. The total subsidy to these industries during the program's life was nearly $545 million, of which $118 million supported biodiesel producers. The average annual payment was $75.4 million to ethanol and $19.7 million to biodiesel.

4.1.3.4 Reduced motor fuel excise and sales taxes at the state level

Although the method of taxation varies somewhat across states (flat charges, percentage of sales prices or some mixture), many states follow the former federal approach of cutting motor fuel levies on favored fuels. These exemptions are usually granted either per gallon sold or as a percentage of the sale price. As a result, the subsidy value scales more or less proportionally as consumption of ethanol and biodiesel blends rise. Since demand for both ethanol and biodiesel is expanding extremely rapidly, by-state alternative consumption summaries compiled by the federal government (for which 2004 is the most recent) understate current subsidy levels. Where possible, we have found more recent data from state government or industry association Web sites to replace the older or estimated information.

The availability of data needed to calculate the subsidy values at the state level has other gaps as well. Fuel taxes change regularly. In any given quarter, at least a few states will change their rates. Similarly, different sources for this information also disagree. Until early 2006, there was no tracking of differential rates on biodiesel, and as of the third quarter of 2006 many states had not yet reported to the International Fuel Tax Association. We were therefore unable to estimate the subsidy value of exemptions to biodiesel. Similarly, while many states provide generous exemptions for E85, sales information are hard to come by, making revenue loss calculations difficult. We have prorated national E85 sales data (also a few years old) by the state share of E85 refueling stations. This approach enables us to generate a rough estimate, despite the limitation of implicitly assuming that all pumps dispense the same amount of fuel per year.

Finally, in states like Hawaii that exempt ethanol from percentage-based fuel taxes, the total subsidies are influenced by gasoline prices. Illinois, which has a similar program, sets this reference "price" via an administrative ruling. The sales tax is therefore uniform within the year and across the state, but will lag actual prices. Sales-tax exemptions are less visible in the standard data collections on motor fuels, but were the source of the largest subsidies in our estimates.

Based on 2004–2005 fuel consumption we estimate state sales and excise tax exemptions for biofuels to generate a subsidy of approximately $170 million per year to ethanol. This is far below the values of these exemptions in the 1980s (around $450 million per year in 2006$). However, rising demand; large new incentives, such as a full exemption from state taxes for E85 in NY and larger credits in Iowa; and rapidly growing sales of both ethanol blends and E85 suggest subsidies for 2007 and 2008 will be substantially higher. Our estimate for biodiesel is slightly over $2 million per year, a value that seems far too low given the rate of growth in biodiesel production. However, as with E85 data, information on both biodiesel tax rates and consumption levels should be far more accessible within a couple of years than it is now. Table 4.1 below provides a brief snapshot of the motor fuel tax exemptions at the state level.

One interesting aspect about the blending thresholds is that they are not always particularly firm. E85 in theory means 85 per cent or more ethanol is needed in order to get the E85 tax break. In reality, some states allow ethanol blends well below this level. Minnesota, for example, defines E85 for the purposes of its motor fuel taxes as a blend of ethanol and gasoline that "typically contains 85 per cent ethanol by volume, but at a minimum must contain 60 per cent ethanol by volume" (MN Statutes 2005, 296A.01). This definitional sleight of hand boosts the effective excise tax exemption per unit of ethanol delivered by nearly 30 per cent. In fact, the ASTM standards for E85 allow ethanol content to drop as low as 70 per cent during winter months to improve performance attributes (U.S. DOE, 2006). Thus, even state statutes that do not specify that they allow 70 per cent ethanol blends to count as E85 effectively do so if they stipulate compliance with ASTM standards.

Table 4.1: State Motor Fuel Tax Preferences for Biofuels, 2006

State	Taxes Foregone, $Millions		
	E10	E85	Description
Illinois	$91.7	$0.5	Exemption from 6.25% state sales tax if >E70 and B10. Pay tax only on 80% of proceeds for lower blends of both fuels.
Hawaii	$53.3	NQ	E10, E85, B2 and above exempt from 4% sales tax; roughly 12.5 cpg in 2005.
Iowa	$24.2	$0.03	2 cpg E10; 4 cpg E85 until $700k spent, then 2 cpg.
South Dakota	$5.3	$0.2	2 cpg E10; 12 cpg E85.
Minnesota	NA	$1.0	5.8 cpg E85.
New York	NA	$0.13	42 cpg E85;[33] 8.4 cpg B20, rising to 42 cpg for B100.
Missouri	NA	$0.2	27 cpg E85.
Others Quantified	$0.7	$0.24	
Total Quantified	**$175.2**	**$2.3**	

Other State Motor Fuel Tax Preferences Not Quantified

	E10	E85	B2
	ID (2.5 cpg) ME (2.0 cpg) MT (4.1 cpg) OK (0.2 cpg)	AR (9.8 cpg) CA (9.0 cpg) DE (1.0 cpg) FL (20 cpg) ID (2.5 cpg) IN (2.0 cpg) ME (7.6 cpg) MT (4.1 cpg) NY (42 cpg) NC (20.2 cpg) OK (1.4 cpg) PA (9.3 cpg)	HI (12.5 cpg) ID (2.5 cpg) IN (1.0 cpg) NY - B20 & above (8.4 cpg to 42 cpg for B100) NC (20.2 cpg) ND (6.6 cpg)

Sources:

Earth Track calculations based on data compiled from the following sources:

NA = Not Applicable; NQ = Not Quantified

(1) American Petroleum Institute, "State Motor Fuel Excise Tax Rates," January 2006 and July 2006 revisions.

(2) American Coalition for Ethanol, Status 2006: ACE State by State Ethanol Handbook, 2006.

(3) National Ethanol Vehicle Coalition, "Energy Content & State Motor Fuels Tax Rates," January 2006.

(4) National Conference of State Legislatures, "State Incentives for the Production and Use of Ethanol," based on RFA data, May 2005. Accessed 15 May 2006 at www.ncsl.org/programs/energy/ethinc.htm

(5) International Federal of Fuel Tax Association, Motor Fuel Tax rate matrix for Q1 2006. Downloaded on 12 May 2006 from: http://www.iftach.org/taxmatrix/charts/1Q2006.xls

(6) FTA, 2006. Federal of Tax Administrators, "Motor Fuel Excise Tax Rates, January 2006." Accessible at: www.taxadmin.org/fta/rate/motor_fl.html

(7) Various state-level statutes and press releases.

33 There are some discrepancies between state sources on the exact amount of reductions in New York (see, for example, Pataki, 2006). However, based on the low volume of current E85 sales, these do not have a material effect on totals.

4.1.3.5 Additional subsidies linked to biofuel output

A complete list of production payments and tax credits at the state level can be seen in Table 4.2 below. A variety of credits based on production, blending levels or sales are available at the state and federal level. A sampling of these other programs is given below, with a complete listing in the Annex. We estimate the state-level subsidies are worth roughly $120 million a year to the ethanol sector and $35 million a year to the biodiesel sector.

- **Federal Small Producer Tax Credit.** Ethanol and biodiesel plants that produce less than 60 million gallons per year are eligible for a 10-cents-per-gallon tax credit on the first 15 million gallons they produce. This caps the credit at $1.5 million per plant. Using industry data on plant nameplate capacity, we estimate the revenue loss from this provision to be $130 million/year for ethanol and $85 million/year for biodiesel, by 2008. Based only on plants online as of mid-2006, operating values would be lower, $90 and $27 million per year respectively. The credit amount is treated as taxable income, so there would not be an incremental outlay equivalent value. However, the credit usually is not subject to alternative minimum tax restrictions (RFA, 2006).
- **Blenders' Credits.** Tax credits may be available on a per-gallon-blended basis as well. These serve as incentives for fuel blenders to use biofuels in the products they supply to retail outlets around the state. Blenders' tax-credit programs may be run in parallel to production tax credits, but structured so that a single gallon of fuel can earn either one or the other credit.
- **Supplier tax refunds.** A program in Arkansas provides a 50¢/gallon refund to biodiesel blenders with more than one mmgy in annual capacity. This program appears quite similar to blenders' credits.

Closely related to these are the production-linked grants provided by Arkansas. These provide a 10¢/gallon bounty to biodiesel produced in the state. However, the payments are at the discretion of the Arkansas Alternative Fuels Commission, making them less reliable than other forms of subsidy.

Table 4.2: Summary of Production-linked Incentives at the State Level

State	Incentive	Fuel	Constraining Factor	Millions of USD Ethanol	Millions of USD Biodiesel	Calculation Method
ARKANSAS	50 cpg/B1; $1.00/gal B2 and higher. Supplier refund.	Biodiesel		NA	NQ	NA
ARKANSAS	50 cpg of B100 used in blending.	Biodiesel	Applies only to first 2% of gallons blended within the state.	NQ	NA	NA
CALIFORNIA	40 cpg	Ethanol and Biodiesel	Never funded.	0.0	0.0	SD
HAWAII	30 cpg PTC	Ethanol	State-wide cap of $12m/yr.	0.0		PC
ILLINOIS	5 cpg grant for retrofitting or expanding existing biofuels production facilities; 10 cpg grant for new facilities.	Both	Max. grant of $6.5m per facility.	20.0	2.4	SD (eth); MAX (biodsl)
INDIANA	2 cpg blender credit, B2 and higher.	Biodiesel >B2	Requires use of in-state feedstocks.	NA	1.3	PC, 5yr
INDIANA	$1/gal PTC of B2 or higher.	Biodiesel >B2	Only IN biodiesel eligible; per facility cap of $3-5m.	NA	2.0	PC, 5yr
INDIANA	1 cpg retailer tax credit, B2 or higher.	Biodiesel >B2	$1m statewide limit.	NA	1.0	MAX
INDIANA	12.5 cpg PTC for increasing ethanol production capacity.	Ethanol	Increase must be 40 mmgy or higher. Plant lifetime cap of $2m for 40-60mmgy; $3m if >60 mmgy.	3.4	NA	MAX, 5yr
IOWA	3 cpg to distributors of B2 if 50% of sales are B2 or higher.	Biodiesel >B2		NA	1.1	Sales
IOWA	25 cpg E85 retailer tax credit.	Ethanol (E85 only)		0.2	NA	Sales

State	Incentive	Fuel	Constraining Factor	Millions of USD Ethanol	Millions of USD Biodiesel	Calculation Method
IOWA	2.5 cpg incremental tax credit to retailers selling >60% of volume blended ethanol.	Ethanol	Credit applies only to sales in excess of 60% threshold.	12.1	NA	Sales
KANSAS	30 cpg PTC to biodiesel producers.	Biodiesel		NA	0.0	PC
KANSAS	5 cpg for pre-existing ethanol production capacity; 7.5 cpg for new capacity or expansions.	Ethanol	Max. credits of $750k/plants up to 10 mmgy; $1.125m on plants up to 15 mmgy.	4.3	NA	SD04-06
KENTUCKY	$1/gallon producer or blender tax credit.	Biodiesel	State-wide cap of $1.5m/year.	NA	1.5	MAX
MAINE	5 cpg PTC for ethanol and biodiesel producers.	Ethanol and Biodiesel		0.0	0.0	PC
MARYLAND	20 cpg PTC for ethanol produced from small grains; 5 cpg PTC for other feedstocks such as corn.	Ethanol	Credit limited to 15 mmgy, of which 10 mmgy must be small grains.	0.0	NA	PC
MARYLAND	20 cpg PTC for biodiesel from soybeans in new production capacity; 5 cpg PTC if from other feedstocks or soy from pre-existing plant.	Biodiesel	Annual cap on 2mmgy of new soy capacity; 3 mmgy from other capacity.	NA	0.0	PC
MINNESOTA	20 cpg PTC for ethanol production. New enrollments ceased in 2004.	Ethanol	Payments capped at $3m per producer per year since 2004.	20.8	NA	SD04-06
MISSISSIPPI	20 cpg PTC for ethanol producers.	Ethanol	Cap of $6m/year per producer; $37m state-wide.	0.0	NA	PC
MISSOURI	20 PTC on first 12.5 mmgy of ethanol production; 5 cpg on next 12.5 mmgy.	Ethanol	Plants must be majority-owned by local agricultural producers.	12.3	NA	PC
MISSOURI	30 cpg PTC to biodiesel producers on first 15 mmgy of production; 10 cpg on next 15 mmgy.	Biodiesel		NA	7.0	PC
MONTANA	2 cpg distributor rebate on B2 or higher.	Biodiesel >B2	Must be sourced entirely from MT feedstocks.	0.0	0.0	PC
MONTANA	10 cpg PTC for increases in biodiesel production over the prior year.	Biodiesel		NA	0.0	PC
MONTANA	20 PTC on ethanol production containing 100% MT feedstocks. Credit declines as local content falls.	Ethanol	$2m/yr per producer; $6m/year per state.	0.0	NA	PC
NEBRASKA	18.5 cpg of ethanol production up to 15.6 mmgy.	Ethanol	$2.8m per plant per year.	17.9	NA	SD04-06
NORTH DAKOTA	5 cpg blender tax credit for B5 and higher.	Biodiesel >B5		NA	NQ	NA
NORTH DAKOTA	40 cpg PTC for ethanol produced and sold in ND.	Ethanol	Plant built prior to 1995; plant cap at 900k/2 yrs if >15mmgy; at 450k/2 yrs if <15mmgy	0.5	NA	PC
NORTH DAKOTA	Producer payments tied to price of corn for increasing capacity by 50% of 10 mmgy.	Ethanol	State cap of 1.6m; plant lifetime cap of 10m.	1.6	NA	MAX
OKLAHOMA	20 cpg PTC for new capacity up to 25 mmgy prior to 2012, 10 mmgy thereafter.	Biodiesel	Per plant lifetime cap of $25m prior to 2012; $6m/plant after.	NA	3.7	PC
OKLAHOMA	20 cpg PTC for new ethanol capacity.	Ethanol		0.0	NA	PC
PENNSYLVANIA	5 cpg producer grant for ethanol producers up to 12.5 mmgy.	Ethanol		0.0	NA	PC

State	Incentive	Fuel	Constraining Factor	Millions of USD Ethanol	Millions of USD Biodiesel	Calculation Method
SOUTH DAKOTA	20 cpg PTC.	Ethanol	State-wide cap of $7m/year.	7.0	NA	MAX
TEXAS	16.8 cpg PTC (net of fees) on first 18 mmgy each of ethanol and biodiesel per plant.	Ethanol and Biodiesel		3.0	13.3	PC
VIRGINIA	10 cpg production grants for new plants or expansions of 10 mmgy or more of ethanol or biodiesel.	Ethanol and Biodiesel		0.0	0.7	PC
WISCONSIN	20 cpg PTC on first 15 mmgy of ethanol production.	Ethanol	Requires use of in-state feedstocks.	15.8	NA	PC
WYOMING	40 cpg PTC for new or expanded ethanol production facilities.	Ethanol	Caps of $2m/year for a single plant and $4m/year for the entire state.	2.0	NA	PC
TOTAL				**120.8**	**34.1**	

Sources and Notes:

(1) Data on production from the National Biodiesel Board and the Renewable Fuels Association.

(2) Data on state-level programs culled from state statutes, and associated state government explanatory materials, as well as from the trade press.

(3) Data on Minnesota compiled by Matt Heimdahl, Minnesota Taxpayers Association.

Calculation Method Key:

MAX = Cost estimated at maximum allowable; lifetime facility caps spread over five years.

NA = Not applicable.

PC = Calculation based on plant capacity data; lifetime caps spread over five years.

SD = State data on program cost, usually annual average across the 2004–06 period.

Sales = Calculations based on fuel sales within state.

4.2 Subsidies to factors of production

Value-adding factors in biofuel production include capital, labor, land and other natural resources. Each of these is addressed in turn.

4.2.1 Support for capital used in manufacturing biofuels

Scores of incentive programs have been targeted at reducing the capital cost of ethanol and biodiesel fuels. Many of these are specific to one or the other of these fuels, though others are open to a broader variety of alternative fuels, of which ethanol and biodiesel are but two. Government subsidies are often directed to encourage capital formation in a specific portion of the supply chain.

4.2.1.1 Generic subsidies to capital

The ethanol and biodiesel sector benefits from a number of important general subsidies to capital formation. Though available to a wide variety of sectors, these policies can nonetheless distort energy markets. All of them subsidize capital-intensive energy production more heavily than less capital-intensive methods. As a result, they tend to diminish the value of conservation relative to supply expansions. In addition, the small print in how they are defined can generate differential subsidies by sector.

Accelerated Deprecation

Normal accounting rules allow capital investments to be deducted from taxable income over the service life of the investment. When deductions are accelerated, corporations receive higher than normal deductions in the early years of the investment. Funds that would otherwise have gone to the IRS are retained as additional cash within the firm, and can be used for other purposes. The provision acts as an interest-free loan from the government.

Since depreciation is normally capped at 100 per cent of the invested funds (percentage depletion in minerals industries is the exception), higher deductions in early years generate lower-than-baseline deductions in later years. However, due to the time-value of money, even if the nominal deductions zero out over time, the present-value benefits can be quite large. The subsidy provided by this provision is equal to the present value of deferred taxes. With nearly $12 billion invested or in-process in ethanol and biodiesel production capacity since 2000 alone, this can be a fairly large subsidy. Note that our estimates incorporate only investments into plant capacity. For simplicity, we have not made similar calculations for investments in distribution infrastructure. These investments include terminals, retail facilities, tank trucks, rail cars and barges. During this same period, the industry spent an additional $540 million on infrastructure assets in ethanol sector alone. No estimates were available for biodiesel.[34]

The allowable depreciation period and method are set by statute, and updated regularly for statutory changes by the U.S. Internal Revenue Service. Federal legislation regularly reclassifies specific industries, or shortens the write-off period for particular sectors, as one of the many levers used to subsidize targeted groups. Production equipment for ethanol and biodiesel are classified as waste reduction and resource recovery plants (Class 49.5) under the Modified Accelerated Cost Recovery System (MACRS). This grouping that includes "assets used in the conversion of refuse or other solid waste or biomass to heat or to a solid, liquid, or gaseous fuel,"[35] and allows full deduction of plant equipment in only seven years. An additional benefit comes in the form of the highly accelerated 200 per cent declining balance method that can be used for Class 49.5, and that further front-loads deductions into the first years of plant operation.

To estimate the subsidy value of accelerated depreciation, Earth Track calculated the net increase in productive capacity from 1997 through the planned additions for 2007–2008. A multi-year evaluation is needed, as the tax subsidy accrues over many years rather than just one. The capacity increases were multiplied by the capital cost per gallon for each sector (see Table 4.3) to estimate the depreciable investment added to the sector in each year. This was scaled up to include carried interest for an assumed 12-month construction period, funds that cannot be depreciated until production at the facility begins. To reflect the lower capital cost of capacity expansions, we estimated the share of capacity additions associated with plant expansions rather than new build based on industry data on the mix for new projects. We also used somewhat lower estimates for the cost of new capacity in order to recognize the fact that only investments net of tax credits and grants can be depreciated.

The annual incremental benefit of MACRS can be measured by subtracting allowable deductions under a 30-year straight line deduction method from the depreciation deductions allowed under the accelerated approach. Between 2005 and 2015, accelerated depreciation generates tax deductions that are $5.7 billion higher than under standard depreciation for the ethanol sector, and $1.3 billion higher for the biodiesel sector. Each extra dollar of depreciation deduction allows the firms to defer payment of approximately 30¢ in state and federal taxes. This results in a net present value tax subsidy of roughly $560 million to ethanol and $175 million to biodiesel. This subsidy is equivalent to nearly 6.5 and 9.3 per cent of total invested capital in the plants generating these deductions.

It is useful to estimate the revenue loss to the Treasury using the approach commonly used in tax expenditure budgets as well. Between 2005 and 2010, the provisions reduce treasury revenues by an average of $220 million per year for ethanol production and $55 million per year in biofuels. As this estimate excludes both any investments not yet announced, and capital spending on biofuels-related infrastructure, we would expect the actual revenue loss to be higher.

General investment tax credits (ITCs) also generate subsidies for the sector. As seen in Table 4.3, federal ITCs were an important subsidy to ethanol early in its development. Federal ITCs were eliminated in the Tax Reform Act of 1986. However, the policies continue to exist in some states. Iowa, for example, has a general investment tax credit for new investment directly related to creating jobs in the state. The general ITCs do not normally get listed by the groups that track targeted subsidies to alternative energy, but can be important sources of subsidization for these activities.

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34 Earth Track estimates based on data in EPA (2006).

35 Choosing the proper grouping is not always easy. Arguments to put biofuels production facilities into a variety of other classes, though most with less favorable depreciation schedules. The choice of Asset class 49.5 also reflects input from Mark Laser at Dartmouth, who noted that based on his reading of the IRS classifications, and "discussions with colleagues from NREL and Princeton," class 49.5 seemed the proper fit (Laser, 2006). Laser also concurred that assets in this class were eligible to use the 200 per cent declining balance method.

A variant of the general ITC is the Qualified North Dakota Venture Capital Corporation. Investors are eligible for income tax credits of 25 per cent (to a maximum of $250,000). Venture capital is a now a significant source of funding for biofuels production capacity.

Table 4.3: Tax Subsidies from Accelerated Depreciation of Plant Construction

	Ethanol	Biodiesel	Notes
Weighted average cost per gallon of capacity (Note 1)	$1.21	$0.93	(1)
Invested capital, biofuels production 1997–2007 ($millions) (Note 2)	$8,450	$1,850	(2)
Excess deductions, 2005–2015, accelerated versus straight-line depreciation ($millions)	$5,715	$1,330	(3)
Net present value of deferred taxes ($millions) (Note 3)	$565	$175	(4)
NPV deferred taxes/invested capital	6.5%	9.3%	
Average annual revenue loss, 2005–2010 ($millions)	$220	$55	(5)

Notes and Sources:

(1) Reflects estimated mixture of new construction versus expansion, based on data compiled by the Renewable Fuels Association (October 2006) and the National Biodiesel Board (September 2006). Capital cost estimates for new build based on a variety of sources (S&T Consultants, *et al*, 2004; Radich, 2004; Collins, 2006; May 2006; Shapouri and Gallagher, 2005). Capital cost estimates for plant expansion (which are lower than new build) are from Shapouri and Gallagher (2005).

(2) Net additions (mmgy) in each sector per year multiplied by unit cost per gallon of capacity.

(3) Calculated as NPV of MACRS seven-year 200 per cent declining balance deductions minus NPV of those available under 30-year straight line.

(4) Net present value discounts future tax savings (liabilities) to a base year of 2005 using a real discount rate of five per cent.

(5) Estimates based only on existing and pending plants. Obviously, many new projects have yet to be announced, so actual revenue losses will be higher.

4.2.1.2 Subsidies for production-related capital

In addition to production tax credits that are linked to production and more general subsidies to capital that benefit multiple sectors of the economy, there are also targeted subsidies to biofuels capital. These include cost sharing or outright grants on production facilities to demonstrate particular biofuels-related technologies, a variety of credit subsidies, and exemptions from standard regulatory or tax requirements. Additional detail on some of these programs helps to illustrate the variation in their structure. However, the programs listed here are *examples* from a very long list of state subsidies; they are not an all-inclusive listing. A more detailed catalog can be found in the Annex. Table 4.4 provides a summary of the subsidy value associated with several of these federal programs. Because many of the items on the table are newly enacted (mostly via the EPACT05), actual spending has often not begun, and in some cases may never begin. To reflect this uncertainty, the values carried into our subsidy totals have been discounted by 50 per cent. Even with this discount, these subsidies are expected to be worth an additional $470 million. The bulk of the funding is targeted towards cellulosic ethanol.

- **Capital grants** are a common subsidy in many states. They are made to help finance production facilities, refueling or blending infrastructure, or the purchase of more expensive alternative fueled vehicles. EPACT05 Section 741 which finance conversion of school buses to alternative fuels including E85 and biodiesel, is one example at the federal level. Annual funding is around $55 million. Section 1512 authorizes grants to build cellulosic ethanol plants of $100 million in 2006, rising to $400 million in 2008.
- **Funding for demonstration projects** are a closely related subsidy to capital grants, in that government money is spent to build a specific type of capital, often a newer technology. Demonstration projects may or may not require private cost sharing, and are commonly worded to direct funding to pre-defined constituencies. The Energy Policy Act of 2005 introduced a number of large demonstration projects in the biofuels area.
  - The integrated biorefinery demonstration projects (Section 932(d)) provides $160 million over three years, with no more than $100 million available to a single facility. This project will incorporate both fuels production and bio-based chemicals. (Capital grants for biorefineries were also authorized under Section 9003 of the 2002 Farm Bill, but not funded.)
  - Section 1514 of EPACT05 provides $550 million targeting cellulosic ethanol processes.

  - Section 208 of EPACT05 provides $36 million for sugar-cane based ethanol programs. This section is a good illustration of the role of earmarks in distorting the direction of energy policy. Not only are funds restricted to sugar-cane processes (rather than the most attractive option), but the funds must be split equally between projects in Florida, Hawaii, Louisiana and Texas.
  - States have many similar examples, though they generally involve lower funding levels and some federal cost shares.
- **Credit subsidies** are a third way governments subsidize the development of ethanol and biodiesel production and infrastructure. These include loans, guarantees and access to tax-exempt debt. Some examples:
  - *Loan guarantees*. EPACT05, Section 1510 sets up loan guarantees for cellulosic or MSW-sourced ethanol production, not to exceed $250 million per facility. However, there is no stipulated cap on how many projects can benefit from these guarantees. They can cover up to 80 per cent of the project cost, and last as long as 20 years.
    - Sections 1515 and 1516 of EPACT05 is another ethanol-based loan guarantee program, but this time restricted only to sugar-based production. Maximum guarantees per project are $50 million, and initial guarantees are capped at 80 per cent of the project cost. However, the provision allows supplemental guarantees to pick up an additional 15 per cent of the project cost, reducing the private-sector investment at risk to a mere five per cent of the total. Skewed risk sharing such as this is often a contributing factor to large program losses and poor project selection.
    - Title XVII of EPACT05 is a loosely worded loan guarantee program for a wide range of "advanced energy" projects, including biomass. The Department of Energy recently announced the first set of these guarantees, up to $2 billion. Although the title primarily focuses on the production of electricity, up to 35 per cent of the biomass feedstocks can end up as gas products used as a fuel (Section 1703(a)(2)). This may open eligibility to liquid biofuels.
  - *Subsidized loans*. A state-level example of credit subsidies is the California Agricultural Industries program, which makes loans at least two per cent below the interest rate earned in the state's internal investment account. This rate is likely to be even further below the cost of borrowing for small- to mid-sized firms, generating a large intermediation benefit from the program. A variety of uses are eligible, including ethanol production facilities. Delaware has a Green Energy Fund that provides both loans and grants to facilities meeting their definition of green energy. The program does include biodiesel manufacturing facilities.
  - *Tax exempt bonds*. Hawaii has authorized $50 million of tax-exempt bonds to fund a bagasse-fed ethanol plant. Nebraska has authorized public power districts to build ethanol plants, and to use tax-exempt municipal bonds to finance their construction. New Jersey is another example, having approved $84 million in tax-exempt financing for a privately-owned ethanol plant.
- **Credit-grant hybrids.** The Iowa Renewable Fuel Fund is an example of a program that mixes elements of a grant and a loan subsidy program. Twenty per cent of the commitment is a soft-loan (basically a grant), with the remaining 80 per cent a low-interest loan. A single recipient could receive a maximum of $520,000. While insufficient to trigger development alone, programs such as this are often combined by a single recipient with other state or federal programs into a much larger pot.
- **Tax-increment financing (TIF).** TIF involves designating a particular area as an improvement zone and earmarking the increase in the expected stream of future property taxes in order to provide up-front project financing for a project. TIF financing has been used on a number of biofuels projects around the country. A variation of TIF, called skip zoning, is used in Nebraska to allow small cities to collect property taxes from nearby plants outside their normal jurisdiction to raise capital for economic development, including energy facilities.
- **Property-tax abatements and exemptions.** Some states exempt purchases of equipment related to biofuels from taxes that would otherwise be owed. These exemptions are not contingent on production levels. For

example, Louisiana exempts equipment (as well as land) used to manufacture, produce or extract B100 from state sales and use taxes. In Montana, all equipment and tools used to produce ethanol from grain are exempt from property taxes for a period of 10 years. In Oregon, ethanol plants pay a reduced rate (50 per cent of statute) on the assessed value of their plant for a period of five years. These policies reduce the private cost to build a biofuels facility.

- **Enterprise zone tax exemptions.** This is a generic subsidy that is often applied to biofuels projects. States may have variants of the program, such as the Job Opportunity Building Zones (JOBZ) program in Minnesota that has been used to support a number of ethanol plants. In general, these policies provide tax reductions or exemptions for new or expanded enterprises in particular regions.
- **Deferral of gain on sales of farm refiners to cooperatives.** Such measures allow private owners of biofuel refinery capacity to sell to farmer-owned cooperatives without incurring a capital gains tax on the sale immediately, as would normally occur. Since biodiesel production has only recently begun to grow, we estimate that the vast majority of this tax subsidy benefits ethanol. The U.S. Treasury estimates revenue losses from this provision at $100 million over 2007–2011, or $20 million/year (OMB: 287, 307). Cooperatives pay no income taxes, though distributions to taxable members are taxed at the member level. In that regard they operate similarly to limited liability companies.
- **Regulatory exemptions.** The waiver of regulatory requirements normally applied to similar industrial developments, but from which ethanol or biodiesel have been exempted, also provide a benefit equivalent to a subsidy. These exemptions can sometimes be quite surprising.
  - *Environmental impact assessment waiver*. Minnesota exempts ethanol plants with a production capacity of less than 125 mmgy from conducting an environmental impact assessment so long as the plant will be located in lower density areas (outside of the seven-county metropolitan area). Biodiesel is not covered under this statute.
  - *Waiver from certificate of needs requirements*. Also in Minnesota, large energy facilities cannot be built without receiving a certificate of need from the state. Ethanol (but not biodiesel) plants are exempt from this requirement.
  - *Use of eminent domain*. Ethanol plants in Nebraska, if not privately owned, are eligible to use the powers of eminent domain. This enables them to seize private land for their industrial process. Whether "privately owned" excludes cooperatives or public utilities is not clear from the statutory language (Nebraska statutes, Section 70-667).
  - *Underground storage-tank exemption*. Washington State exempts all B100 underground tanks from regulations pertaining to underground storage tanks. If spills are not of environmental concern, this may not be a problem.

Table 4.4: Additional Federal Programs Supporting Biofuels Research and Production Facilities

Program	Starch-Based Ethanol Millions of USD	Cellulosic Ethanol Millions of USD	Biodiesel Millions of USD
USDA Sec. 2301 Environmental quality incentives program.	NQ	NQ	NQ
Production incentives for cellulosic biofuels, reverse auction format (EPACT 942).	–	100	–
Renewable Fuel Research and Production Grants, primarily to ethanol (EPACT 1510).	25	–	–
Grants to build cellulosic conversion facilities at non-profit sites such as universities (EPACT 1511).	–	325	–
Sect. 1512, Grants to producers to help build cellulosic ethanol plants (EPACT 1512).	–	250	–
USDA Sect. 9006 Renewable Energy Systems and Energy Efficiency Improvements Funding.	1	–	1

Program	Starch-Based Ethanol Millions of USD	Cellulosic Ethanol Millions of USD	Biodiesel Millions of USD
Cellullosic ethanol loan guarantees; 4 projects up to $250m each (EPACT Sect. 1510).	–	22	–
Targeted loan guarantees to ethanol from sugar cane. Max. of $50m per project (EPACT 1516). Estimate based on 4 projects, intermediation value only.	4	–	–
EPACT Title XVII. Loan guarantees for advanced energy projects, includes biofuels (EPACT 1701-03; DOE solicitation). Estimate 15% of funding to cellulosic.	–	8	–
USDA Sec. 6401 Value-Added producer grants.	1	–	1
Sec. 971(d), Integrated bioenergy research centers. Funding via DOE's Office of Science.	12	25	12
Sugar-cane based ethanol demonstration earmarks for HI, LA, FL, TX (EPACT 208).	12	–	–
Pre-Processing and Harvesting Demonstration Grants. (EPACT 946). Improved systems for biomass to energy conversion. Split between ethanol and biodiesel.	3	–	3
Cellulosic biomass research earmarks, Mississippi State University and Oklahoma State University (EPACT 1511).	–	4	–
Advanced biofuels technologies program. Cellulosic-to-ethanol demonstration projects (EPACT 1514).	–	110	–
Integrated biorefinery demonstration projects. Includes fuel and chemicals; up to 3 projects to be funded (EPACT 932(d)).	–	27	–
2002 Farm Bill, Section 9008. USDA/DOE biomass research and development grants support a variety of rural energy options including biofuels (EESI, 2004).	3	–	–
USDA Sec. 2001 Conservation Reserve Program exceptions for energy crops.	NQ	NQ	NQ
Total subsidies	61	870	17
Discount, since most only authorized	50%	50%	50%
Total, net of discount	**30**	**435**	**8**

4.2.1.3 Subsidy stacking

One important phenomenon that is not always evident when surveying subsidies flowing to the biofuels sector is the that of subsidy stacking—the degree to which multiple sources of subsidies are tapped into, especially for financing new plants. One $71-million, 20-million-gallon-per-year ethanol plant being built in Harrison County, Ohio, for example, has been able to line up the following sources of public support:[36]

- a $500,000 United States Department of Agriculture grant;
- $600,000 in Appalachian Regional Commission grants;
- $40,000 in training funds from the Ohio Department of Development (ODOD);
- $400,000 in 629 Roadwork Development funds from ODOD;
- a $7,000,000 Ohio Water Development Authority loan,
- a $600,000 Rural Pioneer loan; and
- $36,261,024 in Ohio Air Quality Development Authority Revenue Bonds.

In short, more than 60 per cent of the plant's capital will have been provided by government-intermediated credit or grants. This plant perhaps represents an unusual case, since it is being built on a former coal mine, in an economically depressed region of Ohio. But the phenomenon of subsidy stacking itself appears to be quite common, as illustrated by the situation in Minnesota (Box 4.1).

36 Source: www.dot.state.oh.us/OHIORAIL/Project%20Briefings/January%202006/06-03%20Harrison%20Ethanol%20-%20briefing.htm. See also www.ethanolproducer.com/article.jsp?article_id=1910.

Box 4.1 Minnesota: Land o' Ethanol

Minnesota has been one of the states at the forefront of promoting ethanol production. Although it is not the leading ethanol-producer state, it perhaps leads the nation in subsidies to ethanol. These subsidies are on top of those provided by the federal government and, as elsewhere, are provided not only by the state but also by local governments.

In 1980, Minnesota enacted a law that provided a tax credit for agricultural alcohol gasoline (more commonly referred to as the "**blender's credit**"), which reduced state fuel-tax liability for blenders mixing ethanol and gasoline in Minnesota. This credit, like its federal counterpart, reduced funding for transport.[37] It was eventually phased out in 1997, by which time the cumulative loss to the state treasury was $154.5 million.

The blender's credit did little to stimulate in-state ethanol production. The way to do that, the State legislators reckoned, was to provide a direct payment for ethanol produced in the state. This **producer payment,** introduced in 1986 and administered by the Minnesota Department of Agriculture, was originally scheduled to pay $0.15 per gallon of ethanol. According to Fernstrum (2006), the authorized amount has changed several times but typically has been $0.20 per gallon. Each plant was generally eligible for payments for 10 years from the time it, or a significant expansion of the plant, came online. The annual limit for payments was initially set at $3 million per plant, and in 2004 was reduced to $1.95 million per plant. Effective 2004, the producer payment program was closed to new applicants, and all remaining payments are scheduled to terminate in 2010. The payment rate during the remaining period will be $0.19 per gallon. Through fiscal year 2006 (i.e., the year ending 30 June 2006), Minnesota ethanol plants had received over $284 million in producer payments under this scheme.[38]

But government support did not end there. In 1993, the legislature created a $3.5 million Ethanol Production Facility Loan Program to assist new ethanol producers during the construction and early production phases of their operations. These loans, for $0.5 million each, went to seven ethanol plants built in Minnesota between 1994 and 1999. The term of these loans was seven to 10 years, at an interest rate of six per cent per annum.[39] All of the loans have been repaid and the program is closed to new applicants.

All but one of the EPFLP loans went to ethanol co-operatives, owned mainly by corn producers. This reflected a conscious policy by successive Minnesota governments to favor such plants over ones owned by agri-business companies. The Stock Loan Program, though not specific to ethanol production, is another such program that has helped increase local ownership of ethanol refineries. Created in 1994 (and also administered by the Minnesota Department of Agriculture), this program has provided low-interest loans to Minnesota farmers, covering up to 45 per cent of the cost of purchasing shares of stock in value-added agricultural production facilities, including ethanol refineries. The maximum term of these loans is eight years, and loan payments of interest only are permitted for up to two years, with a fully amortized repayment schedule calculated for the remaining years. Interest on the loans is charged at the lower of either four per cent or one-half of the lender's effective rate at the time of closing.[40] Since its inception, the program has provided $1,206,000 in loans to farmers to purchase shares in Minnesota ethanol plants.

Programs administered by the Minnesota Department of Employment and Economic Development (DEED) have also been a source of financing for ethanol refineries built in the state. These include:

- Minnesota Investment Fund (formerly the Economic Recovery Grant Program) – A total of $1,935,000 has been loaned to ethanol plants under this program, which awards grants to local units of government so that they may extend loans to assist local businesses.
- Greater Minnesota Business Development Public Infrastructure Program – This DEED program, which provides grants to cities for up to 50 per cent of capital costs of public infrastructure for economic development, was the source of two recent $500,000 grants to provide infrastructure serving both the Northstar Ethanol LLC (Lake Crystal) and the Heron Lake BioEnergy ethanol refineries.
- Job Skills Partnership Grant Program – In 2004, this program provided a $131,559 grant to South Central Technical College to provide staff training through in environmental and safety issues for 150 employees of four ethanol plants owned by Broin Companies.

37 C. Sullivan, "The Ethanol Industry In Minnesota," www.house.leg.state.mn.us/hrd/issinfo/ssethnl.htm

38 Source: Minnesota Department Of Agriculture, Finance & Budget Division.

39 Minnesota Legislative Auditor, *Ethanol Programs: A Program Evaluation Report*, *Report* #97-04 (February 1997): http://www.auditor.leg.state.mn.us/PED/pedrep/9704-all.pdf (page 6).

40 *Ibid* (page 7).

These DEED programs, though important for some plants, have involved relatively small sums. Much more important has been the Job Opportunity Building Zones (JOBZ) program, established in 2003. This state-level program provides tax exemptions and credits to companies investing in areas outside the Minneapolis-St. Paul metropolitan area. The four newest ethanol plants have all applied for JOBZ assistance. The Granite Falls Energy plant, built in 2005, will receive an estimated $9 million in benefits under the JOBZ program over 2005–2015.[41] The Bushmills ethanol plant in Kandiyohi County will receive an estimated $7.7 million in JOBZ benefits, and the Northstar Ethanol LLC plant in Lake Crystal $7.5 million.[42] In 2006 the law was amended to extend tax incentive eligibility from the standard 12 to 15 years for ethanol plants enrolled between 30 April 2006 and 1 July 2007.

At the local level, an important source of investment capital has been Tax Increment Financing (TIF). Tax increment financing was the dominant form of local assistance for ethanol plants built in the 1980s and 1990s. Local governments provided a total of $19.7 million in tax increment revenues to 11 ethanol plants in Minnesota. Including other TIF-generated revenues (i.e., investment earnings, transfers, etc.), TIF revenues benefiting ethanol plants equaled $25.4 million through 2004.

Many ethanol producers have benefited from multiple subsidies. Heartland Corn Products, a cooperative with 692 members that operates an ethanol refinery that went into operation in Winthrop, MN, in 1995, received a Minnesota Investment Fund grant of $150,000, an Ethanol Production Facility Loan of $500,000, tax increment revenues worth $1.1 million and $25.8 million in state producer payments. In connection with its recent expansion from 19 mgpy to 35 mgpy, the plant will benefit from tax abatements during 2009–2013 worth $274,500 in total.

Minnesota Corn Processors, a 40-million-gallon-per-year plant purchased by Archer Daniels Midland from a cooperative for $756 million in September 2002, received more than $30 million in state producer payments (which ended in 2000), and at least $13.3 million (through 2004) in tax increment revenues (excluding bond and loan proceeds (TIF used to pay off bonds and loans), which are double-counted as revenues). Total state and local government assistance: more than $46 million.

4.2.2 Support for labor employed in the biofuels industry

Surprisingly, even labor related to biofuels production does not escape subsidization. The state of Washington, for example, allows labor employed to build biofuels production capacity, or to make biodiesel or biodiesel feedstock, to pay a reduced rate on the state's business and occupation tax.

4.2.3 Support for land used in the biofuels sector

Support for land used as sites for biofuel plants is provided by many local governments through tax-funded improvements to the sites and in some cases through out-right donation of land to the biofuel-plant owner for free. Property-tax abatements, which are commonly awarded by local governments in many states, because they exempt the tax that would otherwise be due on land as well as capital improvements to the land, can also be considered to reduce the cost of land used in biofuels production, at least if the biofuel plant owners had title to the land at the time the abatement was granted. (This subsidy would presumably be capitalized into the value of the land in any subsequent sales, however.)

In the state of Washington, biofuels production capacity pays no state or local property or leasehold taxes for six years. This apparently includes property used to make the biodiesel feedstock as well. Farm areas in general often pay reduced property tax rates to reduce the incentive of farmers to redevelop the land in higher density uses. The state of Louisiana exempts property (as well as equipment) used to manufacture, produce or extract B100 from state sales and use taxes.

4.3 Policies affecting the cost of intermediate inputs

Intermediate inputs examined include agricultural feedstocks used to produce the biofuels, water and bulk transport services. The supply chains also rely quite heavily on fossil fuel inputs, but examining subsidies to fuel inputs was beyond the scope of the analysis.

41 "State taxpayers get a share of ethanol production bill," *Star Tribune* (26 September 2006): http://www.startribune.com/10107/story/696042.html.

42 "New Plants, New JOBZ," *Ethanol Producer* (April 2004): http://www.ethanolproducer.com/article.jsp?article_id=1107&q=&page=all.

4.3.1 Subsidies for feedstocks

In 1986, when the price of corn was high, and the price of gasoline was falling, the federal government came to the aid of ethanol producers by providing them with $70 million worth of free corn (Bovard, 1995; Carney, 2006). "Corporate food stamps," is how one lawyer described it at the time. Nowadays, direct subsidies—whether in the form of money or in-kind crops—for the feedstocks used in the manufacture of liquid biofuels are uncommon. But they are not unheard of. For example, Arkansas offers an income tax credit of $15 per ton for any rice straw (in excess of 500 tons) that is used in the production of ethanol.

Otherwise, government policies in the United States support the use of key biofuel feedstocks indirectly, through farm subsidies. Because of the United States' dominance in global markets for corn and soybeans, federal government subsidies provided to these crops, especially to corn, are estimated by many analysts to keep farm-gate prices artificially low. Market prices are depressed by less than the unit value of the subsidies, but by how much will vary according to market conditions. Adding to the complexity, corn and soybean markets are linked at several points. For one, they are often grown on the same land, in rotation. Second, they both yield competing products, such as vegetable oils and protein feeds (in the case of corn, as a byproduct of producing ethanol). These interactions complicate the way in which subsidies operate across the biodiesel and ethanol sectors.

4.3.1.1 Ethanol feedstocks

The most important intermediate inputs in the production of U.S. ethanol is corn. Corn is currently the source for 90–95 per cent of domestic ethanol production, with the remainder being sorghum, barley, wheat, cheese whey and potatoes.[43] For calculating subsidies, we assume that 95 per cent of the feedstock is corn, three per cent is sorghum and others make up the remaining two per cent.[44]

Although sugar is an important feedstock in ethanol production elsewhere (e.g., Brazil), it currently plays a small role within the United States due to its expense. Current efforts to boost the usage of domestically produced sugar in U.S. ethanol production despite its high cost may be more about building a consensus on trade agreements sought by other sectors of agriculture and business than about the market viability of home-grown sugar-based ethanol.

The USDA estimates that ethanol production will consume 23 per cent of the domestic corn crop in 2014–2015, up from 12 per cent in 2004–2005 (Baker and Zahniser: 33). Other analysts believe even current diversions are significantly higher than reported by USDA. Robert Wisner, an economist at Iowa State University at Ames, pegs 2006 consumption at 20 per cent of the corn crop, and rising to 40 per cent by 2012 (Clayton, 2006).

Corn is one of the most heavily subsidized crops within the United States. The Environmental Working Group (EWG), which tracks farm subsidy payments, estimates that corn subsidies totaled nearly $42 billion between 1995 and 2004 from 12 federal programs.[45] The average annual payment during 2000–2004 was $4.5 billion.[46] Payments in 2005 spiked to $9.4 billion (Campbell, 2006). This high value reflects the somewhat unusual circumstances of 2005: two successive bumper corn harvests, and a hurricane that damaged exporting infrastructure, which led to a large build-up of surplus corn in the Midwest. Current indications for the 2006 crop year are that total subsidies for corn will be smaller than for 2005, as corn is one of the commodities which did not qualify for first installments on counter-cyclical payments because the effective prices for corn exceeded its respective target price.[47] Nonetheless, corn growers will continue to receive fixed annual payments on their 2006 harvest.

43 Schnepf (4 January 2005, p. 5) puts the figure at roughly 90 per cent. Calculations based on existing plant capacities generate values of 95 per cent and higher.

44 Data on sorghum comes from Baker and Zahniser, p. 35.

45 The included production flexibility; loan deficiency; market loss assistance; direct payments; market gains farm; advance deficiency; deficiency; counter-cyclical payment; market gains warehouse; commodity certificates; farm storage; and warehouse storage. EWG data deduct negative payments or federal recaptured amounts from the total. See http://www.ewg.org/farm for more details.

46 To the extent that demand for corn in the ethanol sector drives up corn prices, corn subsidies through countercyclical payments will fall. However, this effect is already reflected in the numbers shown here.

47 See http://www.usda.gov/wps/portal/!ut/p/_s.7_0_A/7_0_1OB?contentidonly=true&contentid=2006/10/0413.xml

Other estimates for U.S. subsidization of corn production are available from the Organisation for Economic Co-operation and Development (OECD). Their indicator, the producer support estimate (PSE), combines an even wider range of supports than is captured by the EWG (though even OECD captures only a portion of the subsidies to irrigation). OECD data estimated a total PSE for corn at $5.3 billion, $3.7 billion and $8.3 billion for 2002, 2003 and 2004 respectively. (Unfortunately, starting this year the OECD no longer reports PSE estimates for specific commodities; this change affects the OECD data for 2005.)

Pro-rating these values to ethanol, based on the share of supply diverted to fuel production, generates an estimate of expenditure on corn subsidies associated with ethanol production of between $820 million and $1.4 billion per year (see Table 4.5). As ethanol production continues to consume a larger share of the domestic corn crop, its absolute (but not per-gallon) share of corn subsidies will rise accordingly.

Table 4.5: Biofuel Share of Agricultural Subsidies to Primary Fuel Feedstocks

	Corn	Sorghum	Soy	Notes
Subsidy to crop, average for 2000-2005 ($millions/yr)	$6,840	$595	$3,250	(1)
Share of crop converted into fuel	12-20%	11-17%	1%	(2), (3)
Fuel share of crop subsidy ($millions/yr)	$820–$1,368	$65–101	$33	(4)

Notes and Sources:

(1) Values represent the average support for 2000–05. Crop subsidy values for 2000–2004 are based on the OECD Producer Support Estimate measure (available from www.oecd.org/dataoecd/44/6/35043935.xls). Subsidy values for 2005 are from Chris Campbell of the Environmental Working Group. The PSE picks up a wider range of supports than does the EWG Farm Subsidy Database, so it tends to be larger.

(2) Low-end value for the ethanol share of corn production is for 2004/05 from Baker and Zahniser (p. 33). High end estimate for 2006 from University of Iowa economist Widener (Clayton, 26 July 2006). In terms of sorghum, Eidman (p. 17) notes that ethanol production absorbed 11.3 per cent of the sorghum crop in 2004, and that 17 per cent will be required in 2006. Soy values from Ash (8 August 2006), based on 6.6 per cent of soy oil going into methyl esters in 2006 (Ash, 7 August 2006). Rapid pace of biodiesel production capacity suggests the diversion rates in coming years could be substantially higher.

(3) Soy oil is a small portion of overall mass of the soybean, which is why the fraction of crop diverted to biodiesel is small. However, the USDA projects that the oil from nearly eight per cent of the U.S. soybean crop for 2006/07 will be used to produce biodiesel (Collins, 2006).

(4) Fuel share of crop subsidy equals share of crop converted to energy multiplied by the total annual subsidy to the crop.

Table 4.5 is a simple pro-rate of corn subsidies to the ethanol sector. Table 4.6 illustrates the high correlation between large ethanol states and those capturing the bulk of federal corn subsidies, as measured by subsidy programs tracked by the Environmental Working Group. The 10 states with the largest ethanol capacity capture more than 80 per cent of all federal corn subsidies. Normalizing subsidy capture by the acres planted with corn in each of these states illustrates that many of the top ethanol producing states are capturing corn subsidies at a higher rate than the national average. The most extreme is Illinois. Farmers in that state captured nearly 30 per cent more federal corn subsidies per acre than the national average. It makes sense that the most focused states would work hard to access existing subsidies and possibly to create new ones. Nonetheless, were the demand from ethanol really driving down corn subsidies (as is sometimes argued), one would expect a different pattern.

Rising domestic use of corn in ethanol production is expected to affect the more price-sensitive sectors of corn demand first. This includes declines in corn exports to the more price-sensitive countries: Canada, Egypt, Central America and the Caribbean region (Baker and Zahniser: 33). Some increased supply is expected to come from converting lands to corn that are less suited to corn production. Baker and Zahniser suggest that many of these lands may be growing soybeans now (Baker and Zahniser, 34). However, they do not directly address how this substitution would play out if soy production were also under high demand from fuel markets.

Schnepf also expects feed costs for cattle, hog, and poultry to rise as the supply of feed diminishes. Although the corn co-products from ethanol processing would likely substitute for some of the lost feed value of corn used in ethanol processing, Schnepf notes that "about 66 per cent of the original weight of corn is consumed in processing ethanol and is no longer available for feed." (Schnepf, 2005: 10).[48] However, prices for co-products of biofuels

48 There is some disagreement among our reviewers regarding this exact value. One thought that the actual value is somewhat lower. Another noted that part of this figure reflects not conversion into usable fuel, but dispersion through emissions such as carbon dioxide.

production, for example soybean meal, sorghum glutton, and distiller's dried grains (DDG), will fall sharply as biofuels production rises.

Table 4.6: Differential Subsidy Capture Rates for Large Ethanol-producing States

State	Ethanol Production		Capture of Federal Corn Subsidies			
	Capacity (mmgy)	National Rank	% of National Total, 1994–2004	Rank, Share of National Total	Corn Subsidy/Acre of Corn Planted, 2004	Subsidy/Acre as % of Average
Iowa	1,962	1	19%	1	68.32	123%
Nebraska	1,051	2	12%	3	58.68	106%
Illinois	881	3	16%	2	71.40	128%
South Dakota	703	4	4%	8	37.20	67%
Minnesota	594	5	10%	4	52.23	94%
Indiana	392	6	8%	5	65.82	118%
Kansas	268	7	3%	9	65.82	92%
Wisconsin	228	8	4%	7	51.10	88%
Michigan	207	9	3%	11	48.89	97%
Missouri	155	10	3%	10	53.82	91%
Total top 10	6,440		81%		59.83*	108%*
National					55.6	100%

*Weighted average values for top ten, based on group share of total acreage planted with corn in 2004.

Sources:

(1) State compilation of production capacity done by the Nebraska Energy Office, and includes operating and in-process capacity as of July 2006.

(2) Corn subsidy data taken from the Environmental Working Group's Farm Subsidy Database, November 2005 update. Accessed 14 October 2006.

(3) Corn acreage planted, all uses, from USDA, *Crop Production 2005 Summary*, January 2006.

Sorghum

Although sorghum remains a relatively small feedstock for ethanol relative to corn, diversion to fuel in 2005 was nonetheless estimated at over 11 per cent, and expected to rise to 17 per cent in 2006 (Eiden, 2006). Pro-rating average annual subsidies to sorghum crops generates an incremental subsidy of $65 million to $101 million related to ethanol.

4.3.1.2 Biodiesel feedstocks

Soybeans provided between 75 and 90 per cent of the feedstock used to produce roughly 75 million gallons of biodiesel in 2005.[49] As with ethanol, the main U.S. feedstock for biodiesel differs from that in other regions. Rapeseed (canola) is the main feedstock in Europe, where biodiesel production now consumes one-third of domestic production, with imported palm oil substituting in food uses.[50] Because soy oil is a relatively small fraction of the soybean yield (roughly 80 per cent is soy meal), biofuel subsidies are unlikely to be of great benefit to soybean farmers. Though prices on soy oil will rise, prices for the bulk of their product could fall substantially (ESMAP, 2006).

USDA oil-crops analyst Mark Ash notes that 6.6 per cent of soy oil production during the first half of 2006 was converted to methyl esters for biodiesel blends (Ash, 2006). This level was expected to rise to eight per cent in 2007 (Collins, 2006). Ash estimates that currently 0.8 per cent of U.S. soybean production is used to produce methyl esters used in biodiesel (Ash, 2006) At this level, the biodiesel share of soybean subsidies is quite small, only $33 million. However, if this amount were to be realized by biodiesel producers via lower feedstock costs, it would provide an incremental support of 44¢ per gallon produced based on the 75 million gallons produced in 2005.

49 The 75 per cent value is based on production capacity compiled by Leland Tong on behalf of the National Biodiesel Board. The 90 per cent value is from Schnepf, 15 May 2006, (p. 16).

50 Loppacher and Kerr, 2005, 7; Ash and Dohlman, 25.

Anticipated high rates of growth in biodiesel production, most of which will be made from soy oil, could rapidly increase the importance of soybean subsidies to the sector. According to the Congressional Research Service,

> a small increase in demand of fats and oils for biodiesel production could quickly exhaust available feedstock supplies and push vegetable oil prices significantly higher due to the low elasticity of demand for vegetable oils in food consumption. At the same time, it would begin to disturb feed markets (Schnepf, January 2005, p. 18).

Loppacher and Kerr (p. 16, 17) highlight another issue relating to biodiesel feedstocks: differences in tariff levels for plant oils, which can skew the market. For example, rates on soybean oil are 19.1 per cent of value; on rapeseed (canola), up to 6.4 per cent, and on cotton seed oil, 5.6¢ per kilogram. By comparison, the U.S. tariff on imported crude petroleum was only 5.2¢/barrel (0.05¢/kg) in 2004. Varying tariffs by feedstock could skew market selection of biodiesel feedstocks; and comparatively high tariffs relative to those for crude petroleum could impede the ability of biofuels to compete with petroleum.

4.3.2 Water consumption in biofuels production

Water consumption is relevant to two stages of liquid biofuels production. Crop production itself can require substantial amounts of water, while ethanol production can be water-intensive as well.

4.3.2.1 Water consumption in corn production

Irrigation of corn acreage generates two important dimensions for domestic ethanol production: increased environmental harm associated with the ethanol feedstock, and an incremental set of subsidies. Even the OECD's detailed calculations of producer subsidy equivalents for agriculture do not include many of the subsidies to irrigation.

Irrigation of corn has risen steadily over time, from roughly eight per cent of the crop in 1969 to an estimated 18 per cent in 2002 (Gollehon and Quinby, 27). The largest corn producing zone, which the USDA terms the "Heartland Region,"[51] is the source of 70 per cent of the corn crop, and relies on irrigation for only about five per cent of the corn acres (Foreman, 16). However, the second largest corn producing region, termed "Prairie Gateway" by the USDA, depends heavily on irrigation to produce its 15 per cent share of the nation's corn crop. This is exactly the area into which much of the new biofuel manufacturing capacity is expanding.

Including Kansas and parts of Texas, New Mexico, Colorado, Nebraska and Oklahoma, the region contains more than 60 per cent of all irrigated corn acreage in the U.S. According to Ackerman *et al.* (p. 9, 10), the region is also located over the Ogallala Aquifer, where overdraft is a big problem. Ninety-five per cent of the water pumped from the aquifer is for crop irrigation (McReynolds, 2006). Yet, the Ogallala is considered a "fossil" water resource because annual water recharge rates are too low to meaningfully offset consumption. The U.S. Geological Survey (2003) notes that compared with levels before development, water levels have "declined more than 100 feet in some areas and the saturated thickness has been reduced by more than half in others." Until the 1980s, the federal government was "underwriting huge dam and irrigation projects for the region's farms and towns" (*The Economist*, 13 December 2001). It is likely that some of these irrigation projects have contributed to the pace of over-exploitation.

The link between the Ogallala, ethanol and subsidies is an interesting one. Sixty-five per cent of the water in the aquifer is located under Nebraska (McReynolds, 2005), and, notes the Nebraska Corn Board, an "estimated two-billion acre-feet of water (more than five times the water of Lake Erie) of easily accessible ground water from the Ogallala Aquifer lies below 59 per cent of Nebraska's land surface." (NE Corn Board, 2006) The state is also the third largest recipient of federal corn subsidies in the U.S., and the second largest ethanol producer, with more than one billion gallons of capacity (see Table 4.6). It has even created a Web site, www.ethanolsites.com, targeted at "site selectors looking for suitable sites to build ethanol (or other biofuel) plants." As shown in the Annex, the state also offers many incentives to biofuels production. Seventy per cent of corn produced in Nebraska is irrigated (NE Corn Board, 2006). The implications are of this pattern are striking. It is quite likely that a large portion of both the corn production, and the ethanol plants, are relying on fossil water from the Ogallala.

51 The Heartland Region comprises Illinois, Indiana, Iowa, and parts of Ohio, Kentucky, Missouri, Nebraska, South Dakota and Minnesota.

Putting a dollar value on this subsidy is not easy. Users pay some price for water rights in the form of higher land prices when they purchase property. However, aside from their pumping costs, farmers do not seem to pay for each gallon extracted. In addition, farmers in the Ogallala formation have the unique ability to take cost depletion on their groundwater usage. No other users of groundwater in the entire United States are allowed to deduct their depletion of groundwater resources from their taxable income. The result of a court case in 1965 (and expanded to the entire Ogallala formation in 1982), this special tax ruling generates an additional layer of public support for farming in the region.[52]

The principles of political economy hold that subsidies are captured by larger, more sophisticated market players more often than not. Irrigation subsidies seem to conform to this principle (Table 4.7). The largest farms (more than 1,000 acres in size) irrigate the largest share of their corn acres (22 per cent) of all farm sizes surveyed by USDA. Nationally, more than 35 per cent of irrigated corn acres are on the largest farms. By comparison, the smallest farms (less than 250 acres of corn) contain less than 20 per cent of the irrigated corn cropland (calculations based on Foreman: 17, 26). Larger farms also make more intensive use of herbicides, as a rate nearly 20 per cent higher than smaller farms.

Table 4.7: Use of irrigation and pesticides in U.S. Corn Production, 2001

	% Corn Acreage Irrigated	Herbicides, lbs/acre	Insecticides, lbs/acre
Variation by Region			
Heartland	5	2.3	0.1
Northern Crescent	4	2.2	0.1
Northern Great Plains	28	1.2	0.1
Prairie Gateway	61	2.2	0.2
Southern Seaboard	12	2	0.3
Variation by Corn-planted acreage			
Less than 250 acres	9	2.0	0.1
250–499 acres	10	2.1	0.1
500–749 acres	17	2.2	0.1
750–999 acres	20	2.1	0.2
1000 or more acres	22	2.5	0.1

Source: Foreman, 2006.

4.3.2.2 Water consumption in production facilities

Depending on the information source, ethanol production facilities require, net of recovery, either three gallons of water per gallon of ethanol (estimate by the Renewable Fuels Association, cited by Paul, 19 June 2006) or as much as five (Lien, June 2006). Shapouri and Gallagher (2005) peg the average consumption for plants in operation in 2002 at 4.7 gallons of water per gallon of ethanol. They note that, in theory, through recycling of the process water, new plants can attain close to zero discharge. In reality, even the industry's main trade magazine notes that water consumption per gallon of ethanol remains well above zero (Zeman, October 2006). Process water contains organic compounds and must be treated prior to disposal.

Sandia National Laboratory, which is now engaged in examining the water-energy nexus, has developed a chart comparing the gallons of water needed per million Btus of thermal energy. Irrigated soybeans for biodiesel and irrigated corn for ethanol have the highest water intensity of all options evaluated, at well more than 10,000 gallons per MMBtu. Ethanol processing is estimated at above 100 gallons/MMBtu, but higher than most of the natural gas, oil, and coal scenarios evaluated. Biodiesel processing falls within the lowest tiers of the options evaluated (Pate, 2006).

52 U.S. Court of Appeals for the 5th Circuit of the United States established this precedent in United States v. Marvin Shurbet, 347 F. 2d 103 (1985). The Internal Revenue Service formally recognized the decision in Revenue Ruling 65-296, and expanded the cost depletion rights in Revenue Ruling 82-214. We did not see evidence of groundwater depletion being allowed in other water resource areas.

Capacity expansions have begun to run into water constraints in a number of states. Minnesota is a good example, where planned expansions may quadruple water demand from 2.5 to 10 billion gallons a year, most of it from aquifers. East of the Twin Cities of Minneapolis-St. Paul, there is sufficient water, though the quality of plant discharge is a problem. West of the Twin Cities, there is less rainfall, and less-productive aquifers. Outside of the metropolitan areas, knowledge of aquifer productivity is not very good, so there may be a greater risk of building plants in areas that cannot handle the extra demand. The issue has also arisen in Iowa, where geologists feel there is enough water, but that local water tables may fall. This may increase costs to others who have to modify pump configurations or drill new wells (Paul, June 2006)

The level of benefit to industry associated with these water withdrawals warrants additional study. In the west, water rights must often be purchased, providing some incentive to minimize water consumption. However, in many other parts of the United States, surface and groundwater withdrawals are merely permitted. Fees cover the administrative oversight of the wells, but aside from pumping costs, the water itself is often free (Linquist, July 2006).

4.4 Subsidies related to consumption

There are many subsidies to investments in infrastructure used to transport, store, refueling and distribute biofuels. A separate set of policies underwrites the purchase or conversion of vehicles capable of using alternative fuels.

4.4.1 Subsidies to capital related to fuel distribution and disbursement

Getting ethanol from the refinery to the fuel pump requires considerable infrastructure, separate from that used to distribute gasoline. Pure ethanol attracts moisture, which means that it cannot be transported through pipelines built to carry only petroleum products. High ethanol blends, like E85, also have to be segregated and stored in corrosion-resistant tanks, and pumped through apparatuses with appropriate seals and gaskets. All such investment is expensive. The cost of installing an E85 pump and associated on-site tanks and equipment at a filling station, for example, can range from a few thousand dollars to over $50,000 dollars, depending on location and the amount of work involved.

Over the past two years, the federal government and many states have started to offer financial incentives to help defray some of those costs. Under EPACT05, a refueling station can obtain a tax credit that covers 30 per cent of eligible costs of depreciable property (i.e., excluding land), up to a maximum of $30,000, for installing tanks and equipment for E85. Several states also provide assistance to establish new E85 facilities at retail gasoline outlets. In addition, the law allows a portion of the cost of refueling property purchased for business purposes to be expensed immediately rather than capitalized. The U.S. Treasury estimated the total value of this subsidy at $580 million over six years, or roughly $82 million per year. However, this support goes to all alternative fuels, not just ethanol and biodiesel. An allocation based on their shares of alternative fuel refueling stations provides a reasonable proxy for overall spending on related equipment. Using this approach, we estimate that annual subsidies to ethanol distribution and disbursement are on the order of $10-14 million, and to biodiesel $6-8 million.

As with the VEETC, it is likely that these tax expenditure estimates are far too low. The eligible costs apply not only to capital equipment, but to related engineering and installation costs; and the number of installations is growing rapidly. Both factors suggest the actual subsidy could be double or more what is currently being estimated.

At the state level, infrastructure incentives are common. For example, the Illinois E85 Clean Energy Infrastructure Development Program provides grants worth up to 50 per cent of the total cost for converting an existing facility (up to a maximum of $2,000 per site) to E85 operation, or for the construction of a new refueling facility (maximum grant of up to $40,000 per facility). Florida recently created a credit against the state sales and use tax, available for costs incurred between 1 July 2006 and 30 June 2010, covering 75 per cent of all costs associated with retrofitting gasoline refueling station pumps to handle ethanol; blends as low as E10 can qualify.

Other states that offer grants or income-tax credits for the construction, upgrading or expansion of an E85 fueling or refueling facility include California, Colorado, Iowa (E85 refueling infrastructure cost share up to $325,000 per recipient), Indiana, Kansas (up to $200,000 per station), Louisiana, Maine, North Carolina, New York (up to

50 per cent of the costs), Ohio, Oregon, Rhode Island (50 per cent of capital, labor and equipment costs) and Virginia. Such is the enthusiasm at the state level for E85 filling stations that Colorado has even gone to the trouble of creating a database with the ZIP codes of owners of flex-fuel vehicles to help it identify the 30 to 40 new locations where it wants to encouraged filling-station owners to add E85 to their pump line-up (Raabe, 2006).[53]

4.4.2 Support for vehicles capable of running on ethanol

All gasoline-powered vehicles sold in the United States since the late 1970s have been able to burn gasohol, or E10. Most of the vehicles that can run on higher ethanol blends are so-called flex-fuel vehicles (FFVs), which are warranted to run on blends containing as high as 85 per cent ethanol (E85). State and federal government policies have given preference to alternative-fuel vehicles (AFVs), including FFVs, for a number of years. Many of these policies apply to a wide range of fuels besides ethanol, such as liquefied natural gas (LNG), compressed natural gas (CNG) and electricity, as well as to hybrid-electric vehicles.

At the federal level, the main policy that initially helped to increase the supply of FFVs has been the 1988 Alternative Motor Fuels Act (AMFA). AMFA provided credits to automakers in meeting their Corporate Average Fuel Economy (CAFE) standards when they produced cars fueled by alternative fuels, including E85. Earning these credits was not contingent upon any particular efficiency of operation for the vehicles when using alternative fuels, or even on whether alternative fuels were actually used.

The formula for calculating an FFV's fuel economy, nevertheless, assumed that the vehicle would run on the alternate fuel half of the time. It is only the 15 per cent of the gasoline consumed when it is burning E85, plus the gasoline consumed during the other half of the time in this theoretical vehicle operation, that figures into the credit amount for the vehicle. The total credit that an automobile manufacturer could earn towards the average fuel economy of the corporate fleet from sales of FFVs was limited to 1.2 mpg. However, even that benefit had important implications. First, it enabled a number of U.S. automobile manufacturers to avoid penalties they would have otherwise had to pay on inefficient fleets. MacKenzie *et al.* (2005) have estimated that nearly $1.6 billion in penalties were avoided in this way.

The lack of retail sales points for E85 did not change dramatically after passage of AMFA. By 2004, only 200, or 0.1 per cent, of the nation's 176,000 fueling stations sold the fuel, and almost half of those were located in just one state: Minnesota. And until the EPACT05 required automobile manufacturers to label all dual-fuel (bi-fuel and flex-fuel) vehicles to inform purchasers that the vehicle can be operated on an alternative fuel such as E85, most owners (70 per cent according to research conducted by VeraSun) of FFVs were unaware that their vehicles could run the fuel (Wallen, 2006). Consequently, very little ethanol was actually consumed in FFVs. The less efficient fleets that this provision made possible also drove up domestic demand for oil. The Union of Concerned Scientists estimated that, as a result, the loophole would increase U.S. oil consumption by about 80,000 barrels a day (equivalent to over one billion gallons annually) in 2005 alone (MacKenzie *et al.*, 2005).

Despite the perverse incentives created by AMFA, in 2005 the U.S. Congress (Section 772 of EPACT05) extended the CAFE credits for dual-fuel vehicles through 2010. It also authorized the National Highway Transport Safety Administration to consider extending the incentives through 2014.

The emergence of ethanol FFVs on the market did provide a means for federal and state agencies to meet new requirements for AFVs established by the U.S. Congress in the Energy Policy Act of 1992 (EPACT92), however. Among other provisions, EPACT92 mandated that certain government fleets of motor vehicles acquire AFVs for specified fractions (75 per cent in the case of new light-duty vehicles) when purchasing new vehicles. One result of this requirement was that, over time, the federal government acquired significant numbers of ethanol FFVs.

Several Midwestern states have since mandated higher fractions of AFVs in their fleets. Iowa, for example, has required that, by 2010, *all* light-duty vehicles not used for law enforcement procured by state agencies must be AFVs (which include vehicles able to operate on E85 or B20) or hybrid-electric vehicles, when an equivalent AFV or hybrid-electric vehicle model is available. In Illinois, state agencies are permitted to give priority to acquiring FFVs, especially hybrid-electric vehicles that are capable of using E85, as well as diesel vehicles capable of using ethanol or biodiesel. Ohio's Department of Transportation has required that all light-duty vehicle purchases must be of FFVs capable of operating on E85.

53 http://www.denverpost.com/business/ci_4118797

Support for privately owned FFVs is provided by several states in the form of rebates and tax credits for purchasing AFVs, or reductions on license fees and vehicle taxes, some of which apply to ethanol FFVs.

4.4.2.1 Support for the operation of FFVs, and for the purchase of ethanol

By the end of 2005, it has been estimated that there were almost six million FFVs on U.S. roads in the United States. That share represented less than three per cent of the total vehicle fleet (excluding motorcycles) of over 220 million.

Having acquired FFVs (perhaps in some cases unknowingly), both the federal government (Section 701 of EPACT05) and several states (e.g., Iowa, Illinois, Kentucky and New York) have also recently passed laws or issued executive orders requiring that these vehicles fill up with E85 where there are filling stations that are close enough for it to be practical to do so. Ohio has set volumetric targets for the use of ethanol: by January 2007, state fleets must begin using 60,000 gallons of E85 a year, increasing by 5,000 gallons in each subsequent year. Normally these requirements do have opt-out clauses if E85 prices rise too high, but some price premiums are allowed.

Illinois, through its Alternate Fuels Rebate Program, provides the only direct fuel subsidies for ethanol that we were able to identify. These are disbursed in the form of rebates that range from $340 to $450 a year (depending on vehicle miles traveled), for up to three years, for every flex-fuel vehicle that uses E85 at least half the time during the course of a year.

The individual states, and even some municipalities, have also provided regulatory incentives that favor alternative-fuel vehicles (AFVs). Among regulatory benefits available to alternative-fuel vehicles are the right to drive in high-occupancy vehicle (HOV) lanes, no matter how few the number of occupants in the vehicle (Arizona, California, Georgia, Utah and Virginia); the right to park in areas designated for carpool operators (Arizona); and exemptions from emissions testing (Missouri and Nevada) or certain motor-vehicle inspection programs (Ohio). New Haven, Connecticut, offers free parking at metered spots within the city for registered hybrid-electric vehicles and AFVs. Because every state develops its own definition of what vehicle types may participate in their AFV incentives, it is difficult to easily evaluate how many of these incentives apply to ethanol and biodiesel-powered vehicles.

4.4.3 Conflicts between AFV and fuel-efficiency objectives

The rush among governments to encourage owners to purchase flex-fuel vehicles, and to increase the availability of E85, sits at odds with the actual composition of the fleet. Existing vehicles within the U.S. mainly have 4.0-liter or larger engines. Indeed, the main reason why there are now over six million FFVs registered in the United States has less to do with consumer-driven demand than with the long-established policy that credits these vehicles with artificially high fuel-economy ratings.

This pattern continues despite higher energy prices of late, with relatively inefficient SUVs and pick-up trucks continuing to dominate the model mix. Of the 34 models from the 2007 year tested by the U.S. EPA, 26 (three-quarters) have 5.3-liter, V-8 engines.[54] The EPA's fuel-economy ratings show that the most parsimonious achieves a respectable 21 mpg in simulated city driving and 31 mpg in simulated highway driving. The most gas-guzzling models, however, get only 14 mpg and 18 mpg, respectively. And that is running on gasoline. Running on E85, their performance drops on average by 25 per cent.

To illustrate how these vehicles interact with the various production subsidies, Table 4.8 shows the cost to taxpayers of keeping a 2007 Chevrolet Tahoe FFV — owned by a hypothetical Mr. John Doe — tanked up with E85 over the course of a year. This particular sport-utility vehicle lies mid-range in the fuel-economy rankings for the 2007 model year.

Using EPA fuel-economy ratings (which do not fully reflect actual driving conditions), and assumptions about the mix between city and highway driving, it would cost the federal government $520 a year in tax credits were Mr. Doe's vehicle to run on E85 exclusively. Using the much poorer performance reported by Consumer Reports, Mr. Doe would be costing the government more than $700 a year. (That is $7,000 over the 10-year life of the car

54 See http://www.fueleconomy.gov/feg/byfueltype.htm

if the VEETC remains on the books for that long.) If the vehicle is refueled exclusively on locally produced E85 in any one of the states that provides its own 20¢/gallon producer tax credit (Maryland, Mississippi, Missouri, Oklahoma, South Dakota, Texas or Wisconsin), Mr. Doe's neighbors would be providing an additional $200–$277 a year in subsidies to keep his fuel tank filled. The refiners or blenders, rather than Mr. Doe, would receive this money. The exception is in Illinois, where even if he filled up with E85 only half the time, he could pocket a rebate of $340 to $450 a year, courtesy of state taxpayers.

Were all of America's six million FFVs to run on E85, the cost to the U.S. treasury would be between $3 billion and $4 billion a year (depending on the actual fuel economy of the vehicles), just in tax credits alone. Counting state incentives, the figure would rise to at least $5 billion.

Table 4.8: Annual cost to taxpayers of operating a single 2007 Chevrolet Tahoe flex-fuel vehicle exclusively on E85

Variable	Units	Value
Based on EPA rating (note 1)		
Performance, simulated city driving	miles/gallon	11
Performance, simulated highway driving	miles/gallon	15
Annual consumption of pure ethanol as E85 (note 2)	gallons	1,020
Federal tax credits for the ethanol content of E85 (note 3)	U.S. dollars	$520
State tax payments or credits for the ethanol content of E85 (note 4)	U.S. dollars	$204
Based on Consumer Reports rating (note 5)		
Performance, simulated city driving	miles/gallon	7
Performance, simulated highway driving	miles/gallon	15
Annual consumption of pure ethanol as E85 (note 2)	gallons	1,384
Federal tax credits for the ethanol content of E85 (note 3)	U.S. dollars	$706
State tax payments or credits for the ethanol content of E85 (note 4)	U.S. dollars	$277

(1) Source: www.fueleconomy.gov/feg/byfueltype.htm

(2) Using U.S. EPA standard fuel-economy assumptions of 15,000 miles driven in a year, of which 55 per cent are in cities and 45 per cent are on highways.

(3) At 51¢/gallon.

(4) At 20¢/gallon. This level of production incentive is provided only in seven states.

(5) Source: "The Ethanol Myth", *Consumer Reports*, October 2006.

4.4.4 Support for biodiesel distribution and consumption

Blends of 20 per cent biodiesel with 80 per cent petroleum diesel (B20) can generally be used in any unmodified diesel engine. Biodiesel can also be used in its pure form (B100), but it may require certain engine modifications to avoid maintenance and performance problems and some methyl esters may not be suitable for use in sub-freezing temperatures. For this reason, support for biodiesel-capable vehicles has been small, and mainly focused on public (school and municipal) buses. Some programs also target large diesel engines on privately-owned vehicles as well. These have similar objectives as the bus programs: emissions reduction as well as promotion of biofuels. Few, if any, modifications to existing storage and distribution infrastructure are required to handle biodiesel or biodiesel blends. The main costs associated with increasing the availability of biodiesel to consumers are associated with segregating the fuel and adding new pumps. Table 4.9 provides an overview of a number of these programs, as well as some new ones focused on emissions and fuel performance characterization. As with new programs for ethanol that have authorized but not appropriated spending, we have discounted the values by 50 per cent in our subsidy totals.

Table 4.9: Federal Programs Benefiting Biodiesel Consumption

Program	Starch-Based Ethanol Millions of USD	Cellulosic Ethanol Millions of USD	Biodiesel Millions of USD
Biodiesel Engine Testing program (EPACT 757).	–	–	5
Health study of fuel additives, mostly alcohol-based (EPACT 1505).	unknown	–	–
University Biodiesel Program. Study biodiesel performance in university-owned electric power generating stations (EPACT 932(f)).	–	–	unknown
EPACT Sec. 741 Clean School Bus Program (EPACT 741). Est. 20% of funding supports biodiesel.	–	–	11
USDA sec. 9002 federal procurement of biobased products.	negligible	–	negligible
Diesel truck retrofit and fleet modernization program. (EPACT 702). Est. 20% of funding supports biodiesel.	–	–	7
Diesel Emissions Reduction (EPACT 791-97). Mostly pollution controls; little fuel support.	–	–	0
Regional Bioeconomy Development Grants (EPACT 945) to fund local trade groups promoting biomass utilization.	negligible	–	negligible
Biofuels & bioproducts education and outreach (EPACT 947).	negligible	negligible	negligible
Emissions study of new fuels under RFS (EPACT 1506).	ND	–	–
Total	0	0	23
Discount, since most only authorized	50%	50%	50%
Total, net of discount	**0**	**0**	**11**

4.4.4.1 Subsidies to capital related to fuel storage and distribution

As with ethanol, numerous federal and state grants and tax incentives have been created to help fuel distributors install new infrastructure for handling, storing and dispensing pure biodiesel or biodiesel blends. At the federal level, the main incentive is through the tax credit and deduction for clean-burning vehicles and property described earlier. These provisions provide a tax credit equal to 30 per cent of the cost of alternative refueling property, up to $30,000 for business property, for biodiesel blends of B20 or higher. Immediate expensing is also available for alternative refueling property, though the credits and the expensing cannot be claimed on the same property. We estimate that this subsidy has a value of $6-8 million per year.

Most of the subsidies provided by the states are targeted at off-site storage and blending facilities—i.e., between the biodiesel manufacturer and the retail outlet. Grants or income-tax credits for expenditure on infrastructure used for blending, storing or dispensing biodiesel blends are available in several states (e.g., Florida, Indiana, Iowa, Maine, North Dakota, New York, Ohio, Oregon, Rhode Island and Virginia). No information is available on the uptake of these subsidies, however. Iowa provides cost-share grants to blenders of biodiesel covering up to 50 per cent of the costs (up to a maximum of $50,000) of adding terminal distribution facilities for biodiesel to tank farms or on-site storage at fleet refueling points. Montana offers a 15 per cent tax credit for the cost of biodiesel storage and blending equipment (up to $52,500 for a distributor and $7,500 for a retail outlet).

A few states, like Florida and North Dakota, offer grants or tax credits to retailers who adapt or add equipment to their facilities so that they can sell biodiesel blends. Florida also exempts state sales tax, rental, use, consumption, distribution and storage tax on materials used in the distribution of biodiesel (B10-B100), including infrastructure used for refueling transportation, and storage.

4.4.4.2 Support for the operation of vehicles using biodiesel, and for the purchase of biodiesel

States subsidies for the consumption of biodiesel blends are only available to public bodies, typically school districts, to help them cover the incremental cost of using those blends in the place of petroleum diesel (e.g., for school buses). Currently, Missouri, New Jersey, North Carolina and Wisconsin provide such subsidies.

Government procurement is a significant element in the market. Numerous state and local bodies have mandates to consume biodiesel blends in vehicles with diesel engines. The U.S. Army, Navy, Air Force, and Marines also use biodiesel blends (mainly B20) at bases and stations throughout the country. Most of these military installations obtain biodiesel through the Defense Energy Support Center (DESC), which coordinates the federal government's fuel purchases. DESC is the largest single purchaser of biodiesel in the country, and has been procuring B20 for its administrative vehicles since 2003.

4.5 Summary

The current subsidy picture for both ethanol and biodiesel has become more complicated in recent years. Government interventions now affect most aspects of the supply chain, and requirements for specific programs can have a dizzying array of conditions and cutoffs. An integrated picture of these supports is critical for policy makers to assess the most appropriate options for energy investment and the efficient deployment of state funds. We have captured many of these supports—an integrated compilation of credit supports being the largest gap. However, many structural changes in how this information is collected, standardized, and reported by government entities is needed if it is ever to be useful for real-time decisions on industry support.

5
Aggregate Support to Ethanol and Biodiesel

To develop a better sense of how all of the individual subsidy programs affect the overall environment for biofuels, we have compiled a number of aggregate measures of support. The aggregate data provide important insights into a variety of policy questions. These range from the financial cost of the subsidy policies to taxpayers, to estimates of the costs of achieving particular policy goals. Among arguments put forth in support of biofuels subsidies are that they help the country to diversify from fossil fuels in general, and petroleum in particular; and that they have a better environmental profile than fossil fuels. We discuss in turn total financial support to the sectors; subsidies per unit of energy output; subsidies per unit of conventional energy displaced; and the subsidy cost for greenhouse gas reductions. Policy implications and recommendations, as well as areas for additional research, are discussed in Chapter 6.

5.1 Scenarios

In a marketplace that is both growing exceedingly fast, and in which the policy environment rapidly changes, determining what inputs are most representative in areas such as production volumes or numbers of plants can be challenging. To address these challenges, we present data using two main scenarios: an annualized value; and an estimate for 2006. Both are described in detail below. In addition, for metrics where cellulosic ethanol would perform much better than starch-based systems, such as in terms of fossil fuel displacement and GHG impacts, we have simulated a third scenario for cellulosic ethanol. This is obviously hypothetical, since no production capacity exists yet. But it provides useful insights into the returns on public subsidies that are, in effect, helping to create an infrastructure for cellulosic ethanol.

Annualized value (reference volume). The annualized value is the best proxy for a normalized level of support that reflects the rapid growth the industry is now experiencing. It incorporates tax benefits for productive capacity now in-process but not yet online; and a multi-year average value for ethanol production mandates under the Renewable Fuels Standard. It is less volatile year-on-year. Because so many subsidies are tied to production volumes, the main driver of this scenario, at least in terms of total support, is production volume. However, as shown below, the production volumes do not have so much impact on subsidy intensity metrics.

The reference volume for ethanol is the average of the RFS mandate targets between 2006 and 2012, roughly six billon gallons per year. This level of production is expected to be reached in 2009 via the RFS mandate targets, and in 2008 based on the EIA's *Annual Energy Outlook* (EIA, 2005). For the 2006 estimate, a production level of 4.9 billion gallons is used, extrapolated from actual U.S. data through July compiled by the Renewable Fuels Association. For biodiesel, the reference volume is 1.4 billion gallons per year, which will be reached when plants now in process are operating at a 75 per cent capacity utilization. This is expected by 2008. The 2006 estimate assumes 245 million gallons of biodiesel production this year, based on USDA estimates (Collins, 2006).

These assumptions are conservative in three important respects. First, the Energy Information Agency expects biofuels consumption to exceed RFS mandates by a large margin (U.S. EIA, 2005). Second, it is unreasonable to think that no additional production capacity will enter the market beyond projects already announced, as the pace of construction is extremely fast and has not yet shown signs of slowing. Third, many of the state subsidies are new and apply to a small, but fast growing, base, especially for E85 and biodiesel.

2006 estimate (current production base and levels). While we believe the annualized value provides a more accurate medium-term assessment of subsidy levels, it is also important to assess whether a different picture on supports would arise if one looked at the state of the industry for 2006, with current production levels and installed capital. Thus, we have modified the annualized value to better represent support levels in 2006. From this scenario we can evaluate whether there is a substantial difference in the subsidy picture between current costs, and the average value we expect to see over the next few years.

A number of adjustments were introduced to reach the 2006 value. First, biofuel production was set to expected 2006 levels. Since production levels are linearly linked to both market price support estimates and the excise tax credits, removing expected supply growth resulted in noticeably lower total subsidy values, especially in the biodiesel sector. As shown below, the impacts of these changes on subsidy intensity metrics was much smaller. A second adjustment was to zero out the many federal research and production subsidies in the Energy Policy Act of 2005, since most have been authorized but not yet funded. Third, we scaled down benefits from accelerated depreciation and small-producer tax credits to reflect only capacity in operation as of mid-2006.

Hypothetical cellulosic case. Cellulosic ethanol is often presented as the end-goal of much of the current support to starch-based systems. Cellulosic ethanol has a much better profile than starch-based ethanol in terms of energy conversion efficiencies, fossil fuel displacement, and emissions reduction. This scenario assumes that all of the existing subsidization of ethanol (with the exception of support to crop feedstocks), would benefit cellulosic ethanol, and that it had successfully built an infrastructure with the current profile of our starch-based production system. We then evaluate subsidy intensity metrics to assess whether the incremental benefits from cellulosic ethanol are sufficient to significantly change the resultant subsidy cost per unit of fossil fuel or GHG displacement.

5.2 Total support to ethanol and biodiesel

We estimate total subsidies to ethanol will soon reach an annualized value of between $6.3 and $8.7 billion per year (Table 5.1). The corresponding value for biodiesel is $1.7 to $2.3 billion per year. For ethanol, this level of support is roughly four times what the industry received annually during the first half of the 1980s. There are no comparable historical values for biodiesel, production of which began on a large scale only recently. The difference between our current high and low estimates is primarily the result of the incremental outlay equivalent value of a number of important tax breaks that was discussed earlier in the report.

When these values are recalculated to estimate 2006 subsidy levels only, total support for both fuels declines. Total support for ethanol falls by between $1 billion and $2 billion per year, to $5.1–$6.8 billion. The final value remains high. Total support for biodiesel drops much more sharply on a percentage basis, to $0.4–$0.5 billion for 2006. This change reflects that very rapid growth in the productive base of the biodiesel sector now in process, and that is ignored in the 2006 estimate.

The totals value is dominated by the volumetric excise tax credits for both fuels. Should biofuels demand exceed the targets set out in the RFS by a large margin, subsidies would rise as well. Based on preliminary work done by Earth Track on current federal subsidies to other fuels, ethanol subsidies are larger in absolute terms than for other renewable energy resources, but remain below the absolute levels for fossil fuels and nuclear fission.

Market price support, measuring the combined price protection given to domestic producers from import tariffs and the mandated purchases under the RFS, is the second largest support element for ethanol. Subsidies to corn producers account for a surprisingly large share of total support as well. Subsidies to feedstock producers were pro-rated based on the share of crops used in the biofuels industry, and the share continues to rise for corn. For biodiesel, the federal small producer tax credit comes in as the second-largest support element, worth an estimated $85 million per year in the annualized estimate. The large proportion of smaller-capacity plants in biodiesel, in contrast with the ethanol industry, likely explains this difference. Market price support was not analyzed for biodiesel, so we do not know if that would also have been an important support element in this market sector. We suspect less so, since the tariffs on biodiesel are much lower than those applied to ethanol.

State-level subsidies comprise less than 10 per cent of the total value, based on the programs we were able to quantify. However, we expect that this share would be larger if we had access to more comprehensive data on credit support for new plant construction. In addition, exemptions from state-level excise taxes are expected to rise quickly in value as the consumption of biodiesel and E85 grow in states with large exemptions, such as New York.

Table 5.1: Estimates of total support for Ethanol and Biodiesel

	Millions of USD (note 1)			
	Ethanol		Biodiesel	
	Low	High	Low	High
Market Price Support	1,188	1,620	NQ	NQ
Output-linked Support				
Volumetric Excise Tax Credit	3,050	4,365	1,435	2,049
USDA Bioenergy Program	75	75	20	20
Reductions in state motor fuel taxes	180	180	2	2
State production, blender, retailer incentives	121	121	34	34
Federal small producer tax credit	130	130	85	85
Factors of Production - Capital				
Excess of accelerated over cost depletion	220	220	55	55
Federal grants, demonstration projects, R&D (note 2)	465	465	8	8
Credit subsidies	NQ	NQ	NQ	NQ
Deferral of gain on sale of farm refineries to coops	20	20	–	–
Support for Feedstock Producers				
Corn	820	1,368	NA	NA
Sorghum	65	101	NA	NA
Soybeans	NA	NA	33	33
Water	NQ	NQ	NQ	NA
Consumption				
Credits and expensing for clean fueled vehicles and refueling infrastructure	10	14	6	8
State vehicle purchase incentives	NQ	NQ	NQ	NQ
AFV CAFE loophole	NQ	NQ	NQ	NQ
Other federal subsidies to consumption	–	–	11	11
Total (note 3)				
Annualized value (reference volume)	6,344	8,679	1,690	2,306
2006 estimate (current production base and levels)	5,123	6,782	378	481

Notes:

(1) Primary difference between high and low estimates is inclusion of outlay equivalent value for tax breaks where applicable in the high estimate.

(2) Values shown reflect half of authorized spending levels, as not all funding will end up being appropriated.

(3) Annualized values provide a more accurate estimate of the multi-year level of support, as shifts in particular programs are averaged over time. To look at just 2006, production was set to expected values for 2006; funding that has been authorized but not appropriated was set to zero; and the small producer tax credit and accelerated depreciation benefits were calculated excluding plants that won't enter production until after 2006.

(4) NA = Not Applicable; NQ = Not Quantified

5.3 Subsidy intensity

Estimates of total support provide only a crude measure of the potential market distortion. Large subsidies, spread across a very large market, can have less of an effect on market structure than much smaller subsidies focused on a small market segment. Subsidy intensity metrics normalize subsidies for the size of particular energy markets, and for differential heat rates of similar volumetric units (i.e., gallons). We also compare subsidy levels to the market price of the ethanol and biodiesel.

The values shown here reflect subsidies per gallon of biofuel, and per million Btus (MMBtus) of energy equivalent. As noted above, the denominator used for ethanol in the annualized value estimate is the average gallons per year required to meet the Renewable Fuels Standard; and projected 2006 production for the 2006 estimate. The denominator used for biodiesel is the expected production level once plants in-process come online. For the 2006 estimate, projected 2006 production is used.

In both markets, a higher than expected growth in supply could in theory bring down subsidy intensity values as supports are spread over a bigger production base. However, this shift is muted by the fact that the largest subsidy for both fuels, the excise tax credit, rises linearly with production levels. In addition, many of the state production and excise tax subsidies will also rise in a similar fashion.

Table 5.2 summarizes the subsidy intensity of ethanol and biodiesel. Results are presented for both an annualized cost basis, and for 2006 production levels and installed base.

Total support per gallon of ethanol produced is expected to range between $1.06 and $1.45 per gallon in the annualized reference volume case. Per MMBtu, the estimates range between $12 and $17 ($1.44-$1.96 on a gasoline gallon equivalent basis). Though much lower than the early to mid-1980s, a comparison with historical subsidy intensity figures in Chapter 3 suggests that total support for ethanol per MMBtu is likely to remain higher than for other energy resources.

Subsidy intensities for biodiesel production are somewhat larger than for ethanol, at $1.14–$1.55 per gallon. However, because biodiesel has a higher energy content per gallon of fuel, values on a heat-rate basis are lower than for ethanol—though still sizeable at roughly $10-$13 per MMBtu ($1.24-$1.70 gasoline gallon equivalent basis).

Subsidies per MMBtu as a share of the market value of that energy are quite high. Annualized subsidies were between 30 and 50 per cent of the market value of E85 and B100 in June 2006. The levels for our estimate holding 2006 production and infrastructure constant were even higher, ranging from 40 to 55 per cent of market value. It is also important to recognize that almost no support elements decline as prices of ethanol and biodiesel fuels fall. Thus, the recent sharp declines in the prices of petroleum fuels would have generated higher levels of support as a share of market prices, had more recent price data been available.

Table 5.2: Subsidy Intensity Values for Ethanol and Biodiesel

	Ethanol		Biodiesel	
	Low	High	Low	High
Subsidy/gallon ($/gallon)				
Annualized value	1.06	1.45	1.14	1.55
2006 production and infrastructure levels	1.05	1.38	1.54	1.96
Subsidy/gasoline gallon equivalent ($/gge)				
Annualized value	1.44	1.96	1.24	1.70
2006 production and infrastructure levels	1.42	1.87	1.69	2.15
Subsidy/MBtu ($/MMBtu)				
Annualized value	12.60	17.20	9.60	13.10
2006 production and infrastructure levels	12.40	16.40	13.00	16.60
Subsidy relative to market value of E85 and B100 (note 1)				
U.S. avg. prices, $/MMBtu, June 2006 (note 2)	29.74	29.74	32.10	32.10
Subsidy/market price – Annualized value (reference volume)	36%	49%	30%	35%
Subsidy/market price – 2006 estimate (current production base and levels)	42%	55%	40%	52%

Notes:

(1) Ethanol subsidies multiplied by 85% for comparison with E85 prices.

(2) Market pricing data from U.S. DOE, "Clean Cities Alternative Price Report," June 2006.

(3) Thermal conversion data for ethanol (0.843 MMBtu/gal) and biodiesel (0.1183 MMBtu/gal) are from the U.S. Energy Information Administration and the National Biodiesel Board, respectively. This translates to 11.9 gallons of ethanol per MMBtu, and 8.5 gallons of biodiesel per MMBtu. Additional data on gasoline gallon equivalents from the National Association of Fleet Administrators.

Although adjustments for 2006 production levels results in substantial changes in the estimate of total support for biofuels (see Table 5.1), the shifts in subsidy intensities are much smaller, with slightly lower levels for ethanol currently than expected in the coming years. This is primarily due to our 2006 benchmark scenario where we zero out all of the growing federal research and demonstration projects on ethanol, which have been authorized but not yet funded. Under the 2006 scenario, subsidy intensities for biodiesel are 25–35 per cent higher than under the annualized value. This is due to a much smaller production base over which to spread the biofuels supports that do not scale with production levels.

5.4 Subsidy per unit of petroleum or fossil fuel displaced

Public subsidies to biofuels are often proposed as a way to wean the country from its dependence on fossil fuels in general, and petroleum in particular. To estimate how efficiently biofuels subsidies help to reduce reliance on petroleum, or on fossil fuels in general, we need to avoid crediting the ethanol or biodiesel with the expenditure of petroleum (or fossil energy in general) used to create and deliver that gallon.

The degree to which use of biofuels displaces petroleum (and fossil) energy varies fairly widely across estimates by different researchers, even when system boundaries have been standardized. We have side-stepped this controversy by simply using the highest and lowest normalized values from Farrell *et al*. (2006b).[55] Our results indicate that even the highest displacement ratios do little to bring the cost of that displacement to an efficient level.

Mechanically, these values multiply the *gross energy content* of source fuels by the *net displacement* of fossil fuel and petroleum. The higher the net displacement, the more of the gross energy content remains as a base over which to spread the biofuel subsidy numbers. Table 5.3 provides a summary of this evaluation, and includes hypothetical calculations for cellulosic ethanol as well. The cellulosic calculations assumed the same thermal conversion as with starch-based ethanol, and the same level of production. Subsidies to corn and sorghum were zeroed out from the subsidy totals, assuming that feedstocks would no longer be subsidized in a cellulosic system. In reality, this is not likely to be the case, and there is already discussion of special exemptions to Conservation Reserve Program contracts to allow farmers to both produce energy crops and collect CRP payments.

Some argue that ethanol subsidies are a transitional policy toward cellulosic ethanol, since cellulosic ethanol displaces far more fossil fuels than does ethanol derived from starch-based processes. Measuring the cost of this displacement under the scenario of having already attained large-scale cellulosic production is a useful first-level test of whether the incremental benefits of cellulosic ethanol would be high enough to offset the very high financial costs seen with corn-based production.

Biofuels are not the only course of action to diversify away from fossil fuels. Estimating the subsidy cost per unit of displacement provides important information as to whether there might be alternative policies that could achieve similar ends at a lower cost.

Because no biofuels are able to displace all of the petroleum or other fossil energy consumed in transport, subsidy intensities in Table 5.3 are all higher than those in Table 5.2. All of the fuels provide fairly good petroleum displacement, though at a high cost. The lowest-cost corn-based ethanol scenario still costs roughly $16 per MMBtu of petroleum displaced. That is equivalent to about $1.80 per gallon of gasoline displaced. Even if the output were cellulosic ethanol rather than corn-based, costs would still be above $11 per MMBtu ($1.25 per gallon of gasoline) displaced. These costs are *in addition* to what the consumer pays for the fuel at the pump. Biodiesel cost efficiency is somewhat better using annualized values, but spikes sharply if subsidies are spread across today's much smaller production base.

Displacement factors for fossil fuels overall are much worse for corn-based ethanol and biodiesel than for cellulosic ethanol. This is due to a fossil-intensive fuel cycle, including feedstock production and high consumption of natural gas (and increasingly coal) within the plants themselves. In this area, potential returns for cellulosic ethanol appear much better than the other two fuels. Nonetheless, even our hypothetical cellulosic process

55 Farrell *et al.* (2006b) have posted more detailed supporting data to their *Science* article online. We have used their commensurate value data from "Table S3: EBAMM Results" from their 13 July 2006 supporting information update in our calculations. This material is not included within their published article.

requires between $11 and $15 in subsidies per MMBtu of fossil energy displaced. It is not clear that this would be competitive with alternative strategies, especially those that took into consideration the potential for demand-side measures.

Table 5.3: Subsidy per unit displacement of petroleum and fossil fuels

	Ethanol		Biodiesel		Cellulosic Ethanol (Hypothetical Case)	
	Low	High	Low	High	Low	High
Petroleum Displacement						
Displacement Factor (note 1)	78.2%	96.4%	84.6%	84.6%	92.7%	92.7%
Net gain in non-petroleum MMBtu/gal	0.0659	0.0812	0.1001	0.1001	0.0781	0.0781
Subsidy/net MMBtu petroleum displaced, annualized value, $/MMBtu (reference volume)	16.10	17.90	11.40	15.50	11.70	15.40
Subsidy/net MMBtu petroleum displaced 2006 estimate $/MMBtu (current production base and levels)	15.90	17.00	15.40	19.60	11.10	13.90
Fossil Fuel Displacement						
Displacement Factor (note 1)	40.1%	40.1%	47.9%	47.9%	96.0%	96.0%
Net gain in non-fossil MMBtu/gal	0.0338	0.0338	0.0567	0.0567	0.0809	0.0809
Subsidy/net MMBtu fossil fuel displaced, annualized value, $/MMBtu (reference volume)	31.40	42.90	20.10	27.40	11.30	14.90
Subsidy/net MMBtu fossil fuel displaced 2006 estimate, $/MMBtu (current production base and levels)	30.90	41.00	27.20	34.70	10.70	13.40

Notes and sources:

(1) Displacement factors represent the high and low values in the range, from Farrell *et al.* (2006) and U.S. EPA (2006a). These are lifecycle estimates that compare the level of fossil fuel or petroleum use in the baseline (gasoline or diesel) with use of the biofuel.

Subsidy Per Unit of CO_2-equivalent Displaced

A final issue worth examining is the subsidy per unit of CO_2-equivalent displaced through increased reliance on biofuels. As with the examination of petroleum and fossil fuel displacement, the key policy question is whether these investments are efficient with regards to GHG mitigation. We did not have sufficient data to examine this with respect to biodiesel, but did analyze both corn-based and cellulosic ethanol.

Were the markets to properly integrate the cost of GHG emissions into all energy supply chains, we would expect to see investment decisions begin to shift as a result. However, in the absence of carbon controls, the subsidy per unit of CO_2-equivalent reduced can at least provide a benchmark for comparing against the cost of purchasing carbon credits. As shown in Table 5.4, buying GHG reductions by subsidizing U.S. corn-based ethanol production is not very efficient, costing well over $500 per metric ton of CO_2-equivalent removed. Note that this high cost applies to the most advantageous study of corn-based ethanol examined by Farrell *et al.* (2006b). The lower-bound estimate shows GHG emissions actually rising from the ethanol production supply chain. Since there are no reductions, there is no cost of reductions to examine.[56]

Even in this best-case scenario for GHG reductions, one could have achieved far more reductions for the same amount of money by simply purchasing the reductions in the marketplace. The cost per metric ton of reductions through public support of corn-based ethanol could have purchased more than 140 metric tons of removal on the Chicago Climate Exchange, or more than 30 metric tons on the European Climate Exchange.[57]

56 The study showing the lowest carbon displacement in Table S3 of Farrell *et al.* (2006b) analysis was D. Pimentel and T. Patzek, Natural Resources Research 14, 65 (March 2005). The study showing the highest carbon displacement was H. Shapouri, J.A. Duffield, and A. Macloon, paper presented to the Corn Utilization and Technology Conference, Indianapolis, 7–9 June 2004.

57 The European market is much more tightly controlled than the U.S., which is why prices there are so much higher. Credits do not exchange freely between the two geographic regions at this time.

Even if all current production were cellulosic, with a much better GHG reduction coefficient, the subsidies would still be far higher than the market value of the GHG reductions achieved. Depending on the scenario, the cost of one metric ton of reduction via subsidies to cellulosic ethanol would buy between eight and almost 45 metric tons of reductions in the carbon markets.

Table 5.4: Subsidy Cost Per Unit CO_2-equivalent Displaced

	Ethanol		Cellulosic Ethanol (Hypothetical Case)	
	Low	High	Low	High
Greenhouse Gas Displacement				
% reduction from baseline (note 2)	-21%	32%	88%	88%
Net reduction, metric ton $C0_2$-eq./MMBtu	(0.0211)	0.0317	0.0876	0.0876
Net reduction, metric ton $C0_2$-eq./gallon of biofuel	(0.0018)	0.0027	0.0074	0.0074
Gallons biofuel/metric ton CO_2-eq. reduced	NA	376	136	136
Subsidy cost per ton displaced				
Subsidy/mtCO_2e reduced, $/mt – annualized value (reference volume)	NA	545	124	164
Subsidy/mtCO_2e reduced, $/mt – 2006 estimate (current production base and levels)	NA	520	118	147
Comparable market values, current prices, $/mt CO_2 (note 4)				
European Climate Exchange, January 2007 settlements	15.71	15.71	15.71	15.71
Chicago Climate Exchange, vintage 2007 settlements	3.85	3.85	3.85	3.85
mt CO_2-equivalents on markets that could be purchased for cost to remove one mt CO_2-equivalents via biofuel subsidies	NA	33–142	8–32	9–43

Notes and Sources:

(1) Lifecycle emissions and displacement values from Farrel *et al*. (2006b). Ethanol values are the lowest and highest reduction values in studies they evaluated. See also http://rael.berkeley.edu/EBAMM/EBAMM_1_1.xls

(2) Negative value means emissions from the ethanol process exceed the baseline in this particular evaluation.

(3) Farrell *et al*. (2006b) included only one estimate for cellulosic; and had no comparable data on biodiesel.

(4) CO_2 futures contract data from European and Chicago exchanges, priced as of October 16, 2006. Markets are not interchangeable; higher prices in Europe reflect tighter constraints.

(5) Range results from two subsidy values (annualization and 2006); and carbon trade value from two different exchanges. The U.S. prices (generating the high-end of the range for the tons that could be purchased) is more appropriate to compare to U.S. subsidy levels.

5.5 Conclusions

Despite a maturing industry and a rapidly growing production base since the 1980s, ethanol and biodiesel remain heavily subsidized. A handful of programs have comprised the bulk of the subsidies at the federal level. State support appears to be small in relation, though we were unable to properly characterize the many state and local credit subsidies frequently given to the industry.

While total government support for biofuels is not as high as total support for conventional fuels, the subsidy intensity metrics present a different picture. We expect that on a subsidy per unit of energy delivered basis that liquid biofuels would be close to the top for all energy sources, similar to the position ethanol held in the late 1980s. We did not find a material difference in the subsidy intensity values when we estimated them for 2006 production and infrastructure levels, rather than an annualized estimate that incorporates the rapid pace of industry growth and the many new federal programs benefiting the sector but not yet funded.

While biofuels do achieve some degree of petroleum and fossil fuel displacement, as well as GHG mitigation, achieving those gains through large, diverse, and poorly tracked government subsidies is not efficient or effective. This is evidenced by the high ratio of subsidy level to market value of the fuels; and by the comparison in carbon mitigation costs with simple market purchase of credits on an open exchange.

6
Conclusions and Recommendations

This report set out to provide a comprehensive survey to date of subsidies to liquid biofuels in the United States. Although data and resource limitations prevented us from identifying and quantifying all the subsidies now supporting these industries, we believe we have in large measure accomplished that goal. By constructing an integrated picture of subsidies to biofuels at all levels of government, and using a wide variety of policy instruments, we were able to assemble a more comprehensive assessment of the level of public support than has previously existed. We hope that other researchers will be able to build on this study, correct errors and continue the process of quantifying support to the industry. We hope, as well, that some of these researchers will be within state and local governments, and will endeavour to make their spending more visible to the public, and their non-cash subsidies more easily quantified.

The picture that emerges from our analysis on biofuels markets illustrates not only that subsidies to ethanol and biodiesel are pervasive and large, but that they are not a particularly efficient means to achieve many of the policy objectives for which they have been justified.

Key Findings

Current subsidies to biofuels in the United States are large, between $5.5 and $7.3 billion per year

The report finds that subsidies to biofuels have reached startling levels, already several billion dollars a year. The largest subsidies remain those provided under federal programs, but many state-level programs provide significant amounts of support to the industry. In total, subsidies provided for liquid biofuels currently fall somewhere within the range of $5.1–$6.8 billion for ethanol, and $0.4–$0.5 billion for biodiesel.

Biofuels subsidies lack transparency and coordination

These subsidies are the result of many independent decisions at different levels of government, resulting in policies that are often poorly coordinated and targeted. Hundreds of government programs have been created to support virtually every stage of production and consumption relating to ethanol and biodiesel, from growing the crops that are used for feedstock to the vehicles that consume the biofuels. In many locations, producers have been able to tap into multiple sources of subsidies.

Biofuels subsidies continue to grow rapidly in scope and scale, expected to soon reach $8–11 billion per year

Because the bulk of subsidies are tied to output and output is increasing at double-digit rates of growth, the cost of these programs will continue to climb. High levels of legislative activity, especially at the state level, compounds the problem with new exemptions, purchase mandates, and subsidies appearing every month. At an annual consumption level of 7.9 billion gallons a year (the most recent EIA forecast for 2010), the VEETC alone would cost the federal government over $4 billion (on a revenue loss basis). Incorporating just the capacity now in process and the purchase mandate targets for biofuels will generate subsidies substantially higher in future years. We estimate average annual values between 2006 and 2012 of $6.3–$8.7 billion per year for ethanol, and $1.7–$2.3 billion per year for biodiesel. Many state incentives that are only now beginning to take effect will add hundreds of millions of dollars more per year.

Subsidy growth is not well constrained under present law

By far the bulk of support is linked directly to output, either through tariffs, renewable fuel mandates, or per-gallon payments or tax credits. In addition to distorting product markets and trade more than any other form of support, production-linked support is also expensive and public expenditure rises with output. Although there are proposals before Congress to create variable-rate subsidies, which would decline as oil prices rise, the existing subsidies are still set at fixed rates. While some state programs limit total financial costs by statute, many other state and federal programs do not. The main current policy constraints are sunset dates for the import tariff and the VEETC; even these potential curbs on subsidy growth could very well be extended in response to industry pressure.

Subsidies lack coherence in achieving policy aims

The settings of current production-linked support—the per-gallon rates of subsidization—are highly arbitrary, and warrant re-examination. Overlapping programs may also carry a high cost for little benefit in terms of energy infrastructure. Production is subsidized at the federal level even though consumption of it is mandated through the RFS. Ethanol production is supported on the grounds that it helps wean the U.S. from imported petroleum, but special loopholes in vehicle efficiency standards for flexible fuel vehicles (including those that run on high ethanol blends) result in higher oil imports. The maintenance of a high tariff on imported ethanol (2.5 per cent plus 54¢/gallon), in particular, sits at odds with the professed policy of the U.S. government to encourage the substitution of gasoline by ethanol.

State and local credit subsidies for biofuels are not well characterized

Subsidies to value-adding factors, particularly for capital investments in new plants, are much smaller on a subsidy-equivalent basis than output-related subsidies, and many are provided under general programs. But because these government-intermediated loans and loan guarantees often shift the risk of default to the government body providing the assistance, a large number of communities have thereby committed a significant amount of public money to the future of biofuels production. Use of tax-free bond capacity, also commonly done to promote biofuels, does not put government finances at risk, but does preclude bond issues for other purposes. The amount of public capital used, the degree of risk being taken, and the implications in terms of future government dependence on the continuation of biofuels subsidies are all important issues to examine in greater depth.

The cost-effectiveness of subsidies to biofuels is low

The absolute value of the subsidies is not the only, and perhaps not the main, indicator of the market-distorting potential of a set of support policies. Per unit of energy produced, the subsidies generated by policies supporting liquid biofuels are higher than those going to most other fuels—on a thermal-equivalent basis (per MMBtu) with their petroleum-product equivalents, in the neighborhood of $1.05 to $1.38 per gallon for ethanol and $1.54 to $1.96 for biodiesel. Subsidies as a share of market price were above 40 per cent as of mid-2006, and will rise as gasoline and diesel prices fall. Such high rates of subsidization might be considered reasonable if the industry was new, and ethanol and biodiesel were being made on a small-scale, experimental basis using advanced technologies. But that is not the case: they are being produced using mature technologies that, notwithstanding progressive improvements, have been around for decades.

The arguments for maintaining subsidies to biofuels can and should be questioned

Government subsidies to liquid biofuels, particularly ethanol, started out as a way to increase the demand for surplus crops. But lately they have been promoted as a way to reduce oil imports, improve the quality of urban airsheds, reduce CO_2 emissions, raise farmer incomes and promote rural development. That is a tall order for a pair of commodities to live up to. It is highly unlikely that they can.

Evaluating the alternatives to subsidizing biofuels was beyond the scope of this study. However, the subsidy costs per unit of conventional energy and carbon displaced that we have estimated do suggest that there may be many quicker and cheaper ways to achieve these same goals.

Some argue that subsidies to biofuels are a good way to increase energy security, …

In the current rush to promote biofuels, the demand side of the equation has almost been forgotten. Even the most ardent proponents of biofuels concede that corn-based ethanol takes a considerable amount of energy to make, and that the net yield is modest. That is not surprising for any supply-side approach. By comparison, a gallon of gasoline or diesel conserved because a person walks, rides a bicycle, carpools or tunes up his or her vehicle's engine more often is a full gallon of gasoline or diesel saved, at a much lower cost to the economy.

Supporting policies are needed to achieve a more diversified response to energy-security needs. Simple tools such as properly integrating the security costs associated with energy imports from insecure areas into energy prices should be baseline conditions for energy security, allowing a variety of market responses rather than targeted subsidization of politically-chosen alternatives. Biofuels do offer a diversification benefit, inasmuch as they may be less vulnerable to the same kinds of disruptions that threaten supplies of petroleum from politically unstable regions of the world. However, the cost per unit of displacement is very high, and there are likely many more efficient means to achieve the same end. Moreover, the feedstocks from which biofuels are currently derived are also vulnerable to their own set of unmanageable and unpredictable risks, such as adverse weather and crop diseases.

The production of ethanol, at least for now, relies heavily on natural gas. Unfortunately, natural gas markets are developing many of the same supply insecurities as exist with imported oil. Shifts to coal would address the security problem, but worsen the environmental profile substantially.

Because most liquid biofuels will be consumed as blends with gasoline or petroleum diesel, biofuels will for some time to come be complements to petroleum-based transport fuels, not major competitors with them. The internal combustion engine as the dominant technology for motor transport will not be threatened with extinction any time soon.

… or to reduce greenhouse-gas emissions

Biofuels also have some greenhouse gas and local pollution benefits. But the cost of obtaining a unit of CO2-equivalent reduction through subsidies to biofuels is extremely high. We calculate that ethanol subsidies are well over $500 per metric ton of CO_2 equivalent removed for corn-based ethanol, even when assuming an efficient plant uses low-carbon fuels for processing. Yet even under such best-case scenario assumptions for GHG reductions from corn-based ethanol, one could have achieved far more reductions for the same amount of money by simply purchasing the reductions in the marketplace. The cost per metric ton of reductions achieved through public support of corn-based ethanol already programmed over the next several years could purchase more than 30 metric tons on the European Climate Exchange, or nearly 140 metric tons on the Chicago Climate Exchange.

When, as is happening now, some ethanol refineries are beginning to be built using coal to supply part of their energy requirements, there is even more reason to question how much net GHG reduction is actually being purchased for every dollar of subsidy spent.

Others argue that the subsidies are justified because biofuels are infant industries …

Corn-based ethanol is not an infant industry, and has been heavily subsidized for nearly 30 years. Even the U.S. Energy Information Administration characterizes it as “mature.” Biodiesel manufacturing may be at a smaller scale, but it is based on long-established chemical processes that are fairly well understood. Most of the existing subsidies are not targeted at the most technically-challenging cellulosic process.

... or because petroleum is subsidized also.

Petroleum and natural gas (as well as other energy sources) have been subsidized (see, for example, Koplow and Martin, 1998), and continue to be. However, historical data assembled in this study illustrate that the subsidy intensity of ethanol (biodiesel was not eligible for many of these subsidies until recently), whether on a per-gallon or an energy-equivalent basis, is actually substantially higher than subsidies received by other energy resources. In any case, two subsidies do not make for fiscal virtue. Together they add to the public deficit and they mask the true cost of driving. A more effective strategy is to remove subsidies to all transport fuels

But aren’t biofuel subsidies needed to provide a transition towards cellulosic ethanol?

The potential markets for ethanol and biodiesel are quite large even without modifying the vehicle fleet at all. The United States consumed 139 billion gallons of gasoline last year. Vehicles can handle 10 per cent ethanol on a volumetric basis, with no modifications, suggesting a current market capacity with no fleet modifications of 14 billion gallons a year. This is a level not expected to be reached until sometime next decade.

The feedstock that supplies ethanol should be the result of a combination of availability, environmental impact, and cost. If cellulosic ethanol can be cost-competitive, the market size is large enough to drive investment in that direction. If there are technological issues, there may be a role for government—but that role needs to be carefully constructed. The Energy Policy Act of 2005 (section 942) plans to implement a reverse auction for cellulosic production, where the bidder requiring the lowest amount of public money per gallon produced will get the subsidy. This is an example of an efficient program that keeps development risks with the private sector. Most of the other subsidies to biofuels are far less well structured.

If cellulosic ethanol were to become viable, there would be a phase-in period during which infrastructure would adjust without government subsidy at least up to the 10 per cent of domestic consumption threshold. If it were highly competitive, new vehicles would implement flexible fuel technology on their own.

Cellulosic ethanol is but one of many technologies and policy shifts that can address issues such as GHG emissions, supply security, and petroleum displacement. Despite being more efficient in these goals than is corn-based ethanol, cellulosic ethanol would still likely fail the market test with regards to a wider range of fuels and demand-side approaches. Precluding this competition by instituting wide-ranging subsidies through the political process is not in the best long-term interest of the country

Meanwhile, the potential for unintended consequences is huge

Subsidies to liquid biofuels are being injected into an already distorted agricultural economy—one through which billions of dollars in support are channelled each year. The wider energy market in which biofuels are sold is itself distorted by subsidies and special tax breaks, and subject to considerable volatility. Opportunities for unintended consequences are plentiful.

Environmental stresses associated with subsidized expansion of biofuel, and biofuel feedstock, production are already being seen

The linkage between biofuel production and government subsidization of the crops used as feedstocks is becoming increasingly important as a higher percentage of these crops is used in energy production.

The linkages between energy and agricultural policy are also having effects on the environment. Already, rapid growth in demand for biofuel feedstocks, particularly corn and soybeans, is changing cropping patterns in the Midwest, leading to more frequent planting of corn in crop rotations, an increase in corn acreage at the expense of wheat, and the ploughing up of grasslands.

Corn, according even to the U.S. Department of Agriculture, is one of the most chemical-intensive crops grown in the United States. Moreover, both corn and soybeans, like all row crops, typically experience higher rates of erosion than crops such as wheat. Corn is also a crop that requires lots of water, and the current trend in the expansion of corn-based ethanol is westward, into areas that are more dependent on fossil water sources, like the Ogallala Aquifer, than is corn produced in the central Midwest. The ethanol plants themselves also require significant volumes of water, and reports in the press of local concerns over their effects on water supplies are appearing with increased regularity.

Plant emissions are an increasing problem as well, with efforts now reportedly underway to relax requirements for ethanol plants under the Clean Air Act. By stimulating domestic biofuel production based on corn and soybeans, the country is, in effect, promoting "renewable" fuels that require lots of non-renewable inputs. As the market continues to rapidly scale up, it is important to continually weigh whether the biofuels supply cycle is itself becoming unsustainable.

Proponents of cellulosic ethanol argue that a broader mix of indigenous feedstocks would address many of these problems. However, once cellulosic acreage is scaled to provide meaningful displacement of gasoline, many similar issues regarding crop diversification, land conversion, and the need for additional inputs like water and fertilizers could arise.

Concerns over competition for crops between fuel and food should argue for caution

Farmers should be free to plant crops for biofuel production, and manufacturers to make biofuels, as long as they conform to prevailing environmental standards. There are many niche markets for which biofuels production—especially cellulosic ethanol—that can co-exist with food production. However, by mandating biofuel consumption and, worse, providing subsidies to ensure that the mandate is met, the federal and state governments have interfered with the workings of a market that previously was geared to the production of food, animal feed and a small volume of industrial products. While we have not examined the question of fuel-food competition, we would note that many economic assessments of feedstock outlet markets under increasing demand for biofuels are projecting declining crop exports to price-sensitive countries abroad. With demand growing so fast, it is likely that shifts in the food-fuel balance could also occur quickly, with important social implications.

Subsidies related to the supply and use of E85 seem of particularly dubious value

To the extent that there are any benefits for national security, regional economies, and greenhouse-gas emissions from consuming biofuels, it is the overall displacement rate of petroleum fuels rather than the specific blends in which it is consumed that matters.

The costly obsession of policymakers with E85—a blend of 85 per cent ethanol and 15 per cent gasoline—and the flex-fuel vehicles (FFVs) that can run on it, is based on circular logic. Originally, it was thought, building E85-capable vehicles would lead to an increase in the availability of the fuel. It didn't. FFVs got built in any case, because they helped automobile manufacturers obtain generous credits towards meeting their CAFE standards, with the perverse consequence of actually increasing gasoline consumption. When oil prices started to rise in 2005, policy-makers decided that, given there were now several million FFVs on the road, it would be a good idea to get infrastructure in place so that they could actually run on the alternative fuel these vehicles were designed to use. That has meant yet more subsidies to pay for the rapid expansion in the number of filling stations with E85 pumps. Yet even if one accepts that there are net benefits for the country of using ethanol in place of gasoline, E85 is not needed: the same benefits could be achieved through more widespread use of E10 (a blend of 10 per cent ethanol and 90 per cent gasoline), which any car built since 1980 can safely run on.

Meanwhile, most of the six million or so FFVs on the road continue to run mainly on gasoline. That, at least, should be of some relief to the U.S. taxpayer. As we show, keeping a typical 2007 model FFV (most of which have 5.3-liter engines) running exclusively on E85 for a year requires over 1,000 gallons of ethanol, which in turn costs the federal government some $520 a year in lost tax revenues, and taxpayers in ethanol-producing states even more. Keeping all six million FFVs running on E85 would cost taxpayers $3 billion at a minimum, and probably closer to $4 billion, each year. Meanwhile, U.S. automakers are planning to ramp up their rate of production of such vehicles, to perhaps a million new FFVs next year.

The current level of government subsidization, in short, appears to be unsustainable, and disproportionate to the benefits achieved.

Recommendations

Our list of recommendations at this stage in the analysis is straightforward and short: improve information on subsidies to energy, including biofuels; declare a moratorium on new subsidies; and develop a plan to sharply reduce or eliminate subsidies to all transport fuels.

Clearly, more research into the consequences—intended and not—from current support policies for liquid biofuels is needed

More research into the effects of continuing to subsidize and protect domestic production of liquid biofuels is sorely needed. But good research requires data, and that in turn necessitates that governments be much more transparent than they have been so far with information on subsidies to biofuels (and, indeed, to all forms of energy). More is needed than just descriptions of the programs, such as those normally provided by the U.S. Department of Energy. What is needed is amounts of expenditure associated with these programs, and suitable metrics that would allow evaluation of the cost-effectiveness of current and proposed policies.

Political support for subsidies to biofuels has been described as a perfect storm, combining the powerful interests of agriculture, the national security community, and a significant portion of the environmental community. Circumstances may lead to support for subsidies that is less critical than it should be. There is an urgent need to examine the claimed benefits from biofuel subsidies, and to compare them with the costs of meeting the same goals in other ways.

A moratorium on new subsidies for liquid transport fuels, and a plan for phasing them out, should be adopted

Some subsidies, most notably the VEETC (which is due to expire in 2010), have sunset clauses, i.e., they are scheduled to come to an end some day. However, the fact that the ethanol industry has been receiving subsidies for the past 28 years, and that the sentiment in Congress and many state capitals is to extend them (and those to biodiesel), increase them or even make them permanent, does not engender confidence in the prospect of subsidies subject to sunset clauses being allowed to expire.

With oil prices recently at record levels, one would expect that federal and state policymakers would be looking to reduce or eliminate subsidies to biofuels. They are not. Considering how much effort assembling subsidy data for this study took, it can be surmised that those proposing new incentives do not have a clear understanding of the full gamut of support *already* provided by the different levels of government, nor of the potential impact that government support for biofuels is having on the environment and the economy. Policy-makers need complete, not partial information.

Rather than proposing yet more one-off subsidies, pressure should focus on turning off the tap. Farm policy should be once again separated from energy policy. Far more efficient approaches should be used to achieve the often-stated underlying policy objectives of energy security and reduced greenhouse gas emissions. These include appropriate charges on emissions and recovery of energy security-related expenditures through user fees. Expanded use of reverse auctions in renewable fuels markets could also greatly improve the efficiency of these policies by forcing all potential solutions—including on the demand side—to compete for support based on the smallest required subsidy per unit of petroleum displaced.

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Annex

Table A1: Summary of Government Subsidy Programs to Ethanol and Biodiesel

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Producer production incentives (not capped)					
Alaska	E10 reduction supposedly limited in practice to Anchorage during the winter. As of 2004, there was also a 60 month tax credit for E10 produced from wood or wood waste (CEC, 23), or seafood waste.				
Arkansas	Supplier tax refund for biodiesel blends. Rate of $1/gal for B2 or higher; $0.50/gal for B1 (Biodiesel Mag., see source col.). Must have capacity of 1 million gallons within 12 month period (EERE, May 2006).	Biodiesel	Producer		Minimum capacity of 1 mmgy; max blend of B2.
California	40 cpg production incentive for liquid fuels fermented in this state from biomass and biomass-derived resources produced in this state. Eligible liquid fuels include, but are not limited to, ethanol, methanol, and vegetable oils. Eligible biomass resources include, but are not limited to, agricultural products and byproducts, forestry products and byproducts, and industrial wastes (CA Public Resources Code 25678).	Both	Producer	Never funded. (MacDonald, 13 June 2006).	From CA Clean Fuels Act.
Florida	County waste credits for diversion of yard wastes into a range of beneficial reuse, including ethanol production. Likely an indirect and minor effect on ethanol production within the state (EERE, May 2006).	Ethanol	Producer		
Indiana	Biodiesel Blending tax credit of 2 cpg of blended biodiesel (EERE, May 2006). If blend is B2, this is equivalent to $1/gallon of blending oil. This appears to be in addition to the biodiesel PTC.	B2 and higher, but excluding B100.	Producer	Lifetime limit of $3m per facility.	Both the biodiesel blend and the biodiesel used in the blend, must be produced at a facility located inside of Indiana. Advanced approval from the Indiana Economic Development Corporation is required (EERE, May 2006). [Are these types of restrictions constitutional?] Spending on all 3 IN producer subsidies capped at $50m for all taxable years after 31 December 2004.
Indiana	Biodiesel PTC of $1/gallon blended to at least B2. Incentive must be applied for with the Indiana Economic Development Corporation. (IN Code 6-3.1-27).	Biodiesel	Producer	Lifetime limit of $3m per facility, or $5m with special state approval.	Only biodiesel produced within Indiana is eligible. Total program cost for this, the IN ethanol PTC, and the IN biodiesel blending credit is capped at $50m.
Indiana	Biodiesel retailer tax credit of 1 cpg of blended biodiesel distributed by the taxpayer for retail purposes (EERE, May 2006). At B2, this would be equivalent to 50 cpg of blending oil.	Biodiesel	Producer	Lifetime limit of $1m for all retailers in the state.	This is not subject to the state-wide $50m cap.

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Iowa	PTC of 3 cpg to fuel distributors selling B2 so long as 50% or more of the distributors' sales are B2 or higher blends (Pearson, 30 May 2006).	B2 and higher		IA sold 75 million gallons of biodiesel in 2005 (Lincoln Energy, p. 4)	Signed into law 5/30/06. HF 2754 and HF 2759.
Iowa	Retail tax credit of 25 cpg for E85 (HF2754 and appropriation HF2759). Iowa sold 600,000 gallons of E85 in 2005; this provides a floor to calculate the E85 tax credit for 2006. Stats from Lincoln Energy (p. 3): http://www.lincolnway energy.com/newsletter/january_06.pdf	E85			Retroactive to 1 January 2006.
Iowa	Incremental tax credit of 2.5 cpg for retailers for whom >60% of total gallons sold contain some blended ethanol. Runs from 2002–2007 (ACE, 16). Gallons up to 60% do not get the credit. Estimate assumes equal sales per retailer, with 40% of total volume getting the credit.	Ethanol		State has poor tracking systems for tax credits. See Schuling, IA Dept. of Revenue, December 2005.	The Iowa corn growers association notes that 75% of gas sold in IA in 2005 was 10% ethanol or higher. Reasonable to assume that nearly all contained some blended ethanol, and received the tax credit. 1.211 billion gallons of ethanol-blended fuel were sold in Iowa in 2005 (IA Corn).
Maine	5 cpg PTC for ethanol and biodiesel, starting 1 January 2004. Substitution for any liquid fuel is eligible (EERE, May 2006).	Both	Producer	As of mid-2006, ME had no ethanol plants and one pending biodiesel plant at 300,000 gpy.	
Montana	Distributor tax rebate of 2 cpg of biodiesel sold (equivalent to $1/gal of B100) if biodiesel sourced entirely from MT feedstocks (EERE, May 2006; MT Code 15-70-369).	Biodiesel			
Nebraska	Floor Stocks Tax on Ethanol and Biodiesel. A floor stocks tax is an excise tax levied on inventoried fuel. In 2004, Nebraska shifted the point of tax levy from blending to when the fuel is received. As a result, there was an existing inventory of fuel that would have escaped all taxation without the floor stocks tax. This levy applies only to the transitional inventory, and does not represent any incremental tax burden on either fuel (NE DOR, 2004; NE Statute 66-4, 146.01).	Ethanol, biodiesel	Production	Not applicable.	
North Dakota	Biodiesel income tax credit, to blenders, of 5 cpg of diesel fuel B5 or higher. This translates to $1 per gallon of biologically-derived oil.	B5 or higher.			
Ohio	Producer payment up to 50% of invested capital; expires tax year 2013 (F.O. Licht).	Ethanol			
Government renewable-fuel vehicle purchase mandates					
Colorado	State fleet purchase mandate for B20 by 1 January 2007; when available, and at price premiums of less than 10% (NBB, 25 May 2006).	Biodiesel	Purchase preference		
Indiana	Biodiesel Price preference allows government entities to purchase B20 or above for fleet use even at a 10% price premium over standard gas and diesel (EERE, May 2006).	Biodiesel			

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Producer production incentives (capped)					
Federal	EPACT 942 production incentives for cellulosic biofuels, to deliver the first billion gallons by 2015. Annual auctions of 100 mmgy of capacity, with incentive going to lowest requested subsidy per gallon delivered. Winning bid gets subsidy for 6 years (EPACT 942).	Ethanol		Initial authorization: $250m.	Limits: No more than $100m/year; $1 billion for entire provision. Single project may not receive more than 25% of total annual subsidy paid out. Interesting policy design.
Arkansas	Production linked grants – at discretion of Ark. Alternative Fuels Commission (EERE, May 2006).	Biodiesel	Producer		Not guaranteed; rates of up to 10 cpg; max. of 5 mgpy per producer; max. duration of grants is 5 yrs.
Arkansas	50 cpg excise tax credit on B100 gallons used for blending (Pearson, 30 May 2006).	Biodiesel	Producer		Limited to the first 2 per cent of total gallons of biodiesel blended.
Hawaii	Producer tax credits of 30 cpg for facilities entering production prior to 01.01.2012 and with at least 75% capacity utilization. Facility size limits. Total credits per plant for maximum of 10 years or $4.5 million. Total annual credits for state capped at first 40 mmgy (or $12m/ year) (ACE, 12; HI Revised Statutes, 235-110.3).				Eligible for plants between 0.5 and 15 mmgy in capacity. Max. annual credit = 30% of nameplate capacity (EERE, May 2006). At minimum production of 75% of nameplate required for eligibility, the per gallon tax credit would be 40 cpg of ethanol. Once state capacity >40 mmgy, no new plants will be certified to receive credits (HI statutes).
Illinois	Renewable Fuels Development Program provides producer subsidies for new biofuels production facilities in IL. Rate is 10 cpg for new facilities or 5 cpg for modifying or retrofitting old ones, with a maximum grant of $6.5 million. IL Public Act 93-15 (IL DCEO, RFDP, 2006).	Both	Grant	$15m in 2004; $20m in 2007 (IL Farm Bureau, 2006).	Facility must have annual production capacity of at least 30 mmgy, and grant must be <10% of the total construction costs of the facility.
Indiana	Production tax credit of 12.5 cpg of ethanol for plants that built or increased capacity by 40 mmgy subsequent to 12.31.03. (IN Code 6-3.1-28)	Ethanol	Producer	Lifetime cap of $2m for plants 40-60 mmgy; $3m if >60 mmgy capacity.	3 plants now under construction: 2 @ 40 mmgy; 1 @ 100 mmgy. Lifetime caps mean these plants will max out PTC in their first year of production.
Kansas	Kansas Qualified Biodiesel Producer Incentive Fund provides production tax credit of 30 cpg to qualified biodiesel fuel producers. (NBB, 25 May 2006).	Biodiesel	Producer	3.5000	Effective for sales beginning 1 April 2007. Total funding for the incentive program appears to be $3.5m/year.

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Kansas	PTC of 5 cpg of ethanol produced from capacity predating 07.01.2001, running from 2002–05. New capacity >5 MGY can earn credits of 7.5 cpg on up to 10 MGY ($750k/plant). Capacity expansions of older plants of at least 5 MGY can also earn 7.5 cpg credit, up to 15 MGY new capacity ($1.125m/plant) (ACE, 17). Credits in 2001–2004 were 5 cpg (EERE, May 2006).				
Kentucky	Biodiesel income tax credit of $1 per gallon, available to producers or blenders. Program cap of $1.5 million per year (EERE, May 2006).	Biodiesel	Producer	1.5m/year.	
Maryland	Ethanol PTC of 20 cpg for ethanol produced from small grains; 5 cpg for other agricultural feedstocks such as corn. Maximum of 15 mmgy eligible for the tax credit, of which at least 10 mmgy must be from small grains. (EERE, May 2006).	Ethanol	Producer	Max. value of $0.20 x 10 mmgy + $0.05 x 5 mmgy, or 2.25m/year.	
Maryland	Biodiesel PTC of 20 cpg if from soybean oil produced at a facility built or expanded after 12.31.2004. PTC of 5 cpg if from another feedstock, or from soy in a plant built prior to 12.31.2004. Annual cap of 2 mmgy from new soy capacity and 3 mmgy from other capacity (EERE, May 2006).	Biodiesel	Producer	Max. value of $0.20 x 2 mmgy + $.05 x 3 mmgy, or 350k/year.	
Minnesota	Blender's Tax credit. Between 1980 and 1997, E10 or higher paid 4 cpg less than gasoline in excise taxes (Rankin, 2002).	E10 or higher	Producer	The MN Taxpayers League estimates total payments during this period at $208m (2006$). Heimdahl, June 2006).	
Minnesota	PTC of 20 cpy (13 cpg effective 2003), for a period of 10 years. Annual payments capped at $1.95m per producer (ACE, 24; EERE, May 2006). Multiple plants with a single controlling interest would count as a single producer; minority interests would not (MN Statutes 41A.09). New enrollments ceased in 2004.	Ethanol	Producer	See Text Box 4.1.	Capacity increases subsequent to the initial cut-off date are eligible for the PTC, and for its full 10 years (MN 41A.09, Subd. 3a (c)). Capacity above 15 mmgy does not earn PTCs.
Mississippi	20 cpg PTC for ethanol from production entering the market on or before 30 June 2005. Payments for up to 10 years from point production entered the market; limited to $6m/producer per year; and $37m statewide to all producers in a year (ACE, 25; MS statutes 69-51-5).	Ethanol	Producer		Capacity above 30 mmgy not eligible for PTC.
Missouri	PTC of 20 cpg on first 12.5 MGY of production; and 5 cpg on up to the next 12.5 MGY. Eligibility period applies to first five years of production, expiring 12.31.2005. Capped at $3.125 million over five years (ACE, 26).	Ethanol	Producer		Plants must be located in MO, and 51% of the ownership must be by agricultural producers engaged commercially in farming (MO Revised Statutes, 142.028, 142.029).

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Missouri	Qualified Biodiesel Producer Incentive Fund provides a monthly grant to producers of 30 cpg for the first 15 mmgy of B100, and 10 cpg for the next 15 mmgy of B100 produced in a fiscal year. 60 months of eligibility per producer.	Biodiesel	Producer		Feedstock for plants must be 51% sourced from inside Missouri and 100% from inside the United States (MO Revised Statutes, 142.031).
Montana	Biodiesel production tax credit for increases in annual production of 10 cpg increase over the previous year (MT code 15-70-601).	Biodiesel			
Montana	PTC of 20 cpg for all production sourced from MT feedstocks. Eligibility requirements ramp up from 20% MT content in year one to 65% MT content in year 6. Credit is pro-rated downwards based on share of feedstocks originating from outside of the state. Incentive available during first six years of production; may not exceed $6m/year for state or $2m/yr per producer. (MT statutes 15-70-522).	Ethanol	PTC		Payments capped at $6m/yr per producer and $2m/yr per distributor (MT Code 15-70-522)
Nebraska	PTC of 18.5 cpg on first 15.625 MGY of ethanol production. Credit caps of up to $2.8m per year per plant, for eight years (a total of $22.5m/ plant). Plants must be producing by 30 June 2004 to be eligible (ACE, 28).	Ethanol	Producer	NE Department of Revenue estimates the cost of these tax credits at $100m to $176m for 2006 through 2012 when eligibility ceases (NE DOR, 2005). Changes to the rules, especially given large increases in production capacity, would result in much larger outlays. Credits granted from 1990 through 2005 were nearly 230m (NE DOR, 2006; url in source column).	
North Dakota	PTC of up to 40 cpg for ethanol produced and sold in ND. Plants built pre-07/01/95, get avg. of $450k/yr from 2005-07 if capacity <15 MGY. Plants >15 MGY get avg. of $225k/yr during same period (EERE, May 2006).	Ethanol			
North Dakota	Agricultural products utilization commission can also make quarterly counter-cyclical payments to ethanol producers depending on corn and ethanol prices under ND Code 4-14.1-08. (ACE, 35). These payments support increased production at plants built prior to 1 July 1995; or after 31 July 2003 (per ND 4-14.1-01).	Ethanol		Rate rises as corn prices rise or ethanol prices fall. Benchmarks not indexed for inflation.	Capacity increases must be the less of 10 mmgy or 50% of existing capacity. Total annual disbursements under this provision seem to be capped at $1.6m/year; with the most any facility can cumulatively earn at $10m (ND 4.14-1.09).

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Oklahoma	Biodiesel PTC of 20 cpg for new plant construction or capacity increases completed during the period of eligibility. Credits allowed for 5 years, ending before Dec. 31, 2011. Eligibility determined based on maintaining capacity utilization of 25% or more during first six months of operation. Caps of 25 mmgy for capacity prior to 2012; 10 mmgy thereafter. Lifetime limits per facility of credits on 125 mmg.	Biodiesel	Producer	Max of $25m/plant prior to 2012; $6m/ plant subsequent to 2012. PV would be lower.	Capacity expansions eligible prior to 2012 if equal to 12x the average of the 3 highest month production levels; or after 2012 if at least 2 mmgy. No size requirements for new construction. Credits must be approved by the tax authority.
Oklahoma	Ethanol PTC of 20 cpg for new plant construction or capacity increases completed during the period of eligibility. Credits allowed for 5 years, ending before Dec. 31, 2011. Eligibility determined based on maintaining capacity utilization of 25% or more during first six months of operation. (OK Statutes 68-2357.66).	Ethanol	Producer	Eligibility caps: single plant (25 mmgy pre-2011 plants; 10 mmgy post-2011 plants; max. 125 mmg lifetime eligibility. For industry, caps of 75 mmgy pre-2011; 30 mmgy post-2011.	Capacity expansions eligible only after Jan. 1, 2011, and only for substantial increases (roughly quadrupling).
Pennsylvania	Grants to ethanol producers of 5 cpg on up to 12.5 MGY can be provided by the PA DEP Alternative Incentive Grant Program (ACE, 39).				
South Dakota	PTC of 20 cpg through 12/31/06 capped at $1 mln per year per plant; total of $10 mln lifetime per plant. Maximum payout on PTCs under this provision (SD Statutes 10-47 B-162) of $7 million a year (ACE, 42).				
Tennessee	PTC of up to $6 million (ACE, 43). Couldn't find this referenced elsewhere.				
Texas	PTC of 20 cpg on first 18 MGY from each or biodiesel or ethanol plant. Corresponding fee levied on producers of 3.2 cpg on this same production level generates a net gain to them of 16.8 cpg. Fees go back to the TX Dept. of Agriculture to fund part of the PTC; the remainder of funding comes from the general fund. Plants eligible for 10 years of tax credits. (TX Ag Code 16.001 - 16.005).	Ethanol and Biodiesel	Producer	18 mmgy x 16.8 cpg net x 10 years = $30.2m per plant maximum.	All forms of biodiesel eligible. No restrictions on where the crop/ animal products need to be sourced from. No limits on how many plants a single owner can be subsidized for.
Virginia	Biofuels Production fund issues grants to biofuels producers, especially ethanol and biodiesel. Grants are 10 cpg that are sold in Virginia between 1 January 2007 and 1January 2017. Minimum production size of 10 mmgy to be eligible, and can receive grants during 6 calendar years (VA Code 45.1.393 and 45.1-394). Pre-existing production eligible only if production in 2007 exceeds 2006 level by more than 10 mmgy, and stays at that level (or higher) in future years. This provision effectively allows all pre-existing production to receive the subsidy (EERE, May 2006).	Ethanol and Biodiesel	Producer		

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Wisconsin	PTC of 20 cpg on first 15 MGY of ethanol production; capped at $3 million over 5 years. Expired 1 July 2006. Eligibility period of 5 yrs; minimum production threshold of 10 MGY/year; and commodity inputs for the plant must come from within WI. Availability subject to legislative funding (ACE, 50).	Ethanol			
Wyoming	PTC of 40 cpg, up to a maximum of $4m/year for the entire state or $2m/yr for single plant. (Single plant max. is higher if certain expansion thresholds are met). Credits available through 30 June 2009. Plants built or expanded after 1 July 2003 get 15 years of credits. (ACE, 51; EERE, May 2006). WY 39-17-109.	Ethanol	Producer		At least 25% of the distillation feedstock purchases (excluding water) must originate from within WY to be eligible for the credit. Existing production prior to 1 July 2003 receive PTC only through 30 June 2009. Tax credits can be sold to anybody.
Grants, subsidized credit and tax concessions related to capital investment					
Federal	EPACT Sect. 251, Insular areas energy security. Funds decentralized energy sources. Includes coconut-based biofuels amongst eligible sources (EPACT 251).	Biodiesel, though lots of other fuels.		$6m/year authorized, for all fuels.	
Federal	Sec. 1510, Renewable Fuel Research and Production Grants, primarily to states generating potentially usable biomass but that don't have a large ethanol production base (EPACT 1510).	Ethanol		Authorized: $25m/ yr for 2006-2010 ($125m total)	
Federal	Sec. 1511, cellulosic biomass ethanol conversion assistance. Eligible facilities are non-profit sites such as universities (EPACT 1511).	Ethanol		Authorized: $250m in 2006; $400m in 2007.	According to EESI (July 06), the Senate clarified language for loan guarantees on Sec. 1511(b) to allow private financing of the risk premium normally covered by DOE, with the federal government insuring the entire project. If this makes DOE less of a gate-keeper in screening out projects, it could be a substantial taxpayer risk.
Federal	Sec. 1512, Grants to producers to help build cellulosic ethanol plants (EPACT 1512).	Ethanol	Producer	Authorized: $100m in 2006; $250m in 2007; $400m in 2008.	
Federal	USDA Sect. 9006 Renewable Energy Systems and Energy Efficiency Improvements Funding			Separate sheet.	
Delaware	Green Energy Fund, administered by the State Energy Office, to provide loans and grants for a variety of clean energy projects. Includes biodiesel manufacturing facilities.	Biodiesel	Producer		Grants capped at 25% of project cost; no single project can receive more than $300,000 (EERE, May 2006).
Illinois	Renewable fuel plant development funding of $20m passed the IL legislature in May 2006. To be run via DCEO, the money is slated to expedite the construction of biorefineries for ethanol and biodiesel.	Both	Grant	$20m	

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Iowa	General investment tax credit provides an ITC equal to the percentage of the new investment "directly related to new jobs created by the location or expansion of an eligible business under the program." This includes a wide range of plant, real estate, and machinery purchases. Most businesses must amortize the credit in five equal installments, with carryforwards of up to 7 years. Value-added agricultural processors and ethanol producers (specifically named) are allowed to request a refund for unused tax credits (IA Code, Title 1, Subtitle 5, 15.333).	Ethanol, appears biodiesel as well.	Producer		ITC refunds require issuance of a tax credit certificate from the state. The state caps issuance of such certificates at $4m per year. Unclear how this provision interacts with the other production subsidies in the state. Rules on the program changed in 2005. New rules not that different in terms of rates or caps (See IA Admin. Code, 701-52.28(15)).
Iowa	Value-Added Agricultural Products and Processes Financial Assistance Program, started in 1994, has provided nearly $45 million in public subsidies to a variety of projects that "encourage the increased utilization of agricultural commodities produced in the State of Iowa." This has included renewable energy since its inception. Ethanol facilities have been regular recipients of this support (IA DED, 2005; IA Code Title 1, Subtitle 5, 15E.111).	Ethanol, Biodiesel, other biomass fuels		Don't know total funding to these sectors from the overall grants of $45m.	
Kentucky	KY Agriculture Development Fund offers grants to new projects, including ethanol production plants (Kotrba, Feb. 2006)	Ethanol	Producer		
Louisiana	Property and equipment used to manufacture, produce or extract B100 is exempt from from state sales and use taxes (EERE, May 2006).	Biodiesel	Producer		
Minnesota	Economic recovery grants via the MN Department of Trade and Economic Development were also given to ethanol plants.	Ethanol	Producer	Through FY96, grants of $150k each went to Morris Ag Energy, Corn Plus (Winnebago) and Heartland Corn Products (Winthrop). A grant of $100k went to Al-Corn (Claremont). (MN OLA, p. 7).	
Montana	Tax credit of 15%, up to $500,000, for investments into oil seed crushing facilities. (MT code 15-32-701).	Biodiesel		No operating ethanol or biodiesel plants currently in state.	Facility must be operating prior to 1 January 2010.
Montana	All manufacturing machinery, fixtures, equipment, and tools used for the production of ethanol from grain during the course of the construction of an ethanol manufacturing facility and for 10 years after initial production of ethanol from the facility are exempt from property taxes (MT Code 15-6-20).	Ethanol	Production		
New Mexico	Compensating tax exemption for equipment related to ethanol or biofuels production. The compensating tax acts as a use or excise tax on real property, and is 5% in NM (DSIRE database; NM HB 995).	Ethanol, biodiesel	Production	5% x cost of equipment.	

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
New York	Grants for biodiesel refining facilities. Total funding of $500k through the NY State Energy Research and Development Authority, with maximum grants of $100k/recipient. A wide variety of planning, development and operational costs are eligible. (Pataki, 20 November 2005).	Biodiesel	Grant	$500k	
New York	Grant subsidy for 50 mmgy dry mill ethanol plant in New York state. Total cost of $87m.	Ethanol	Grant	$3.1m for rail access; $2.5m in economic development funding. $25m in additional federal support through USDA; and $0.4m through the NY DOT have been requested (Pataki, 8 May 2006).	
New York	Funding grant for development of Cellulosic Ethanol Facility in New York. Program to be administered by the state Department of Agriculture and Markets (Pataki, 8 May 2006).	Ethanol	Grant	$20m	
North Carolina	A tax credit equal of 35% is available to taxpayers who construct, purchase, or lease renewable energy property. This includes equipment that uses renewable biomass to produce ethanol or biodiesel, as well as equipment for converting, conditioning, and storing the resultant fuels. Credit taken in 5 installments, being year property begins active service. Non-residential investments may earn no more than $2.5m in tax credits per installation.(NC statutes 105-129.15 and 105-129.16A) (EERE, May 2006).	Both	Production, infrastructure		Can offset a maximum of 50% of state tax liability under either the state franchise tax or the state income taxes. Firm must stipulate which tax to offset in first year of tax claimed; selection is binding. Tax credit carryforward of up to five years.
North Carolina	State grants to ethanol plant owned by the NC Grain Growers Cooperative from Golden LEAF, the state fund to reinvest proceeds from tobacco settlements. Additional grants to a biodiesel plant were also announced in 2002, but not funded thus far. Grants to the ethanol plant are mired in conflicts of interest amongst the principals, and an attempt to transfer the assets to a related private owner. (Carrington, 2003).	Ethanol, biodiesel		$1.1m in grants to the coop through 2003. $10m commitment to biodiesel plant hadn't been funded as of 2003.	
North Dakota	Biodiesel equipment used to facilitate sale of biodiesel (B2 or higher) in the state is exempt from state sales tax (EERE, May 2006; ND Code 57-39.2-04(51))	B2 or higher.		Normal sales tax is 5%.	
North Dakota	Biodiesel equipment tax credit of 10% per year for five years (total credit of 50%) of the cost of enabling a facility to sell B2 or higher.	Biodiesel		Capped at 50k per facility.	
North Dakota	Income tax credits of 25% (up to a maximum of 250k) for investing in a qualified ND venture capital corporation (ND Code 10-30.1). Venture capital is now a significant source of funding for ethanol and biodiesel plants.	Ethanol, biodiesel			

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
North Dakota	Subsidies to agricultural commodity processing facilities. These are any plants that apply knowledge and/or labor to boost the value of agricultural products produced in ND. Would include ethanol and biodiesel. Investment tax credit of 30% of investment, up to $50k per year per taxpayer, $250k total for a project. (ND Code 57-38.6). Sales tax exemption for coal if used in an ag processing facility or sugar beet refining facility (ND Code 57-39.2-02.1(g). Construction materials used to construct an agricultural processing facility are exempt from sales and use taxes (of 5%) (ND Code 57-39.2-04.4).	Ethanol, probably biodiesel as well.			Pass-through entities defined at the taxpayer for the purposes of the ITC limits.
Oklahoma	Agricultural producer tax credit of 30% for investments, by farmers, in value-added agricultural processing. Generally capped at $2m/year per facility (OK Statutes 68-2357.25).	Appears to include ethanol and biodiesel.	Producer		
Oregon	Property tax exemption for ethanol facilities equal to 50% of the assessed value. Subsidy lasts 5 years (ORS 307.701; OR DEP 2006).	Ethanol	Producer		
Oregon	Business energy tax credits equal to 35% of the eligible project costs. Includes a range of alternative energy investments, including ethanol and biodiesel. Max. credit per project of $10m. Includes most investment costs (including loan fees), other than maintenance costs (Sources in last column).	Ethanol, Biodiesel	Producer		
Pennsylvania	Grant for biodiesel injection blending facility in Middletown, PA, via the PA Energy Harvest Grant Program (Rendell, October 2005).	Biodiesel	Grant	220k	
South Dakota	Biodiesel production facility tax refund for excise, sales, or use taxes paid by contractors for products used to build a new agricultural processing facility. While the project must include an expansion to an existing soybean processing facility that will be used to produce biodiesel to get the refund, it appears that taxes on the entire project (not just the biodiesel part) will be refunded. Project costs must be $4.5m or greater (EERE, May 2006).	Biodiesel	Producer		
Utah	Corporate tax credit of 10% of eligible investments, up to a maximum of 50k. Includes biomass, but only if converted into electrical energy.				
Washington	Tax exemption for alternative fuels distribution and sale infrastructure. All equipment, services, and vehicles associated with the sale or distribution of ethanol (E85 and above) and biodiesel (B20 and above) are exempt from state retail fuel sales and use taxes. (EERE, May 2006; Washington Revised Code 82.08.955). State taxes in effect for 2006 are 6.5% on most items; and 6.8% on retail motor vehicles.	B20, E85	Infrastructure	6.5 to 6.8% of the cost of investments in biofuels infrastructure and delivery.	

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Washington	Tax deferral of state and local sales and use taxes through 1 July 2009 for investments in biofuels production capacity. Includes buildings, equipment, labor to make biodiesel, biodiesel feedstock, and alcohol fuel. Qualifying buildings and equipment are also exempt from state and local property and leasehold taxes for six years. A reduced Business and Occupation tax rate of 0.138% applies to the people involved with these activities.			Standard business and occupation rate is 0.484 (WA statute 82.04.240). Standard sales and use tax rate is 6.5%.	
Arkansas	Income tax credit for biodiesel supply chain, up to 5% of the cost of facilities and equipment.	Biodiesel	Infrastructure		
Arkansas	State income tax credit for investment in production of advanced biofuels (as of 2001). State rebate for incremental cost of alternative fuel vehicles, also as of 2001 (CEC, 23).	Ethanol, Biodiesel			
Indiana	Government support for Indiana Bio-Energy LLC plant in Bluffton, IN. $800,000 in annual support guarantees in case of project default, funded by local governments through County Economic Development Income Tax Funds. State cash and training grants of ~$1.6m. Planned state funding for infrastructure improvements near the site (Frank, 2006).	Ethanol	Producer		
Iowa	Iowa Renewable Fuel Fund provides low cost financing for renewable energy projects, often ethanol or biodiesel. 20% of commitment is a soft-loan (i.e., grant); 80% is a low-interest (below prime rate) loan. Maximum loan per recipient is 520k (EERE, May 2006; Iowa Energy Center). Run through the Value-Added Agricultural Products and Processes Financial Assistance Program.	Ethanol (and others)		$44m in funding between 1995–2005. Ethanol share of total awards not known (IA DED, 2005).	
Iowa	Alternate Energy Revolving Loan Program is accessible to any individual or organization who wants to build renewable energy production facilities in Iowa. Recipients get a combination of AERLP funds and private lender funds (IA Energy Center, 2006).			Public funding may comprise up to 50% of the loan, but no more than 250k per project. Interest rates can be as low as 0%. No information on whether the privately-funded portion of the loan is also state guaranteed.	
Kentucky	$300,000 loan to Commonwealth Agri-Energy, LLC for construction of ethanol plant in Hopkinsville, KY. Funded by the Christian County Fiscal Court, not by the state (Alt. Fuels Today, 2 February 2004).	Ethanol	Producer		

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Minnesota	Ethanol Production Facility Loan Program, begun in 1993, provided up to 500k/facility to help finance construction and start-up. Loans had supported seven facilities in the state through 2002 (Rankin, 2002). MN issues municipal revenue bonds for this purpose (MN statutes 41B.044). Stock loan program. Seven facilities also made use of low interest state loans to farmers from the Rural Finance Authority to pay for up to 45% of the costs of shares of stock in a value-added agricultural product processing facility (Rankin, 2002). The interest rate subsidy on these was about 4% (MN OLA, p. 7).	Ethanol	Producer	As of 1997, the four dry mills in the state had each received a low-interest MN loan for $500k, as well as up to $1m in tax increment financing per plant (MN OLA, p. xi). Through the end of FY97, at total of $466k in loans had been made, "most of these to purchase stock in ethanol plants." (MN OLA, p. 7).	
Missouri	Authorized up to $250m in non-taxable revenue bonds to assist Renewable Power build a 40 mmgy ethanol plant in Cape Girardeau County (Alt. Transport Fuels Today, 4 December 2003). Not clear why so much capacity has been released since the projected cost of the plant was only $58 million.	Ethanol	Producer	Large intermediation value.	
Nebraska	Skip zoning, allowed smaller cities to collect property taxes from nearby plants, then use these dollars to help with project financing. (Werner, 20).				Not clear if applied to biodiesel and ethanol plants, or just biomass-fired electricity.
North Dakota	Biodiesel loan program via the Partnership in Assisting Community Expansion buys down interest rate on loans for biodiesel production facilities. Eligible purposes include purchase of real property and equipment, expansion of facilities, working capital, and inventory. Size of program noted at $1.2 million.	Biodiesel			
Oregon	Energy Loan Program (SELP) provides low-interest loans for a variety of alternative energy programs including biofuels (OR DEP, 2006).	Ethanol, Biodiesel			
Federal	Sect. 1510 Cellulosic biomass loan guarantee program. Loan guarantees for up to 20 years to finance plants that convert municipal solid waste or cellulosic biomass into ethanol. May support up to three plants (EPACT 1510).	Ethanol	Producer	Authorizes "such sums as may be necessary." Up to 80% of cost, not exceeding $250m/ project.	Performance bond of at least 20% of amount borrowed is required. Guarantee fee also charged to cover administrative costs. Max. value, excluding defaults = $250m per project x 80% max guarantee x 4 projects max x 2.5% avg. int. rate spread btwn Corp Baa and treasury debt (2000–2005), or $20m/year. CBO estimated cost of this program assuming 3 loans at $110m over 5 yrs, or $22m/yr.

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Federal	EPACT 1516, Sugar-based ethanol loan guarantee program. Offers guarantee on up to 80% of the project cost (max. of $50m per project). Supplemental guarantees for cost increases boost total coverage to as high as 95% of the original cost estimate (EPACT 1516). Estimates here assume four projects nationwide.			$4m	Guarantee enables risky borrowers to obtain debt at the Treasury rate. New industry debt rate would be Baa or worse. We assume Baa, 80% of $50m project. Guarantee cuts borrowing costs by ~2.5%. Subsidy shown is per per year for 4 projects. Rises linearly if more are done.
Federal	EPACT Title XVII. Loan guarantees for advanced energy projects, including biomass. Most of energy must be converted to electricity. However, 1703(a)(2) allows industrial gasification projects in which 65% of biomass is converted into electricity, and up to 35% can go to gas products used as a fuel of feedstock. This may open the provision to benefit biodiesel or ethanol production (EPACT, 1701-1703). Biofuels are eligible per p. 2 of DOE solicitation.	Biodiesel and ethanol (and others)	Producer	Fees under wide discretion of the secretary of DOE.	Max. term of 30 years or 90% of the useful project life, whichever is less. Guarantee capped at 80% of the project cost. Total guarantees under this traunche capped at $2 billion. For the purposes of estimating the subsidy value, we assume 15% will go to cellulosic ethanol.
California	Agricultural Industries Energy Program. Subsidized loan program for a variety of uses including ethanol production facilities (CA Public Resources Code 25650).			At least 2% below rate earned in CA Pooled Money Investment Account.	Max. duration of 7 years.
Hawaii	Authorized $50m in special-purpose revenue bonds to fund a baggasse-fed ethanol plant in Kauai, run by the World Wide Energy Group. Bonds were authorized in 2000, with a sales deadline recently extended to 2008 (Sommer, 2004).	Ethanol	Producer	Rev. loss estimate per year = face value x muni bond rate x marg. tax rate.	Revenue bonds not guaranteed by the state, but are tax exempt and greatly reduce the plant's cost of borrowing.
Nebraska	Authorizes public power districts to finance and/or build ethanol production and distribution capacity. Authorizes use of tax exempt municipal bonds for the construction of such plants (NE Statutes 70-143).	Ethanol	Production		
New Jersey	Tax-exempt bond financing for ethanol production plants via the New Jersey Economic Development Authority. $84 million financing approved in late 2005 for a 52 mmgy plant owned by Future Fuels, Inc. in Toms River, NJ. No information on other NJEDA loan or financing commitments (Nuclear Solutions, 2005).	Ethanol	Production	$84m in tax-exempt financing. Rev. loss estimate per year = face value x muni bond rate x marg. tax rate.	

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Montana	New or expanded industry tax credit. Businesses engaged in the production of energy by means of an alternative renewable energy source are eligible for the new or expanded industry tax credit against corporate income tax (MT Code 15-31-124 et. seq.)				To be considered an expanding industry, total full-time jobs must increase by 30 per cent or more. The credit is equal to 1 per cent of new wages paid in state during the first three years of operation. No carry back or carryover is allowed for this credit.
Oregon	Enterprise zone tax exemptions from property taxes for site improvements for 3 or 5 years. (OR Code 285C.055; OR DEP, 2006).				
Federal	USDA Sec. 6401 Value-Added producer grants			Separate sheet; fairly small.	
Iowa	Consultant support for bioenergy business plans through the Rural Economic Value-Added Mentoring Program. Low cap to subsidy suggests this program will primarily support very small on-farm conversion programs rather than large plants (IA DNR, 2006).	Ethanol, biodiesel		Max. of $10k grant per approved project in consulting support.	
Subsidies to intermediate inputs (goods or services)					
Arkansas	Rice Straw Income Tax Credit (Ark Code Ann 26-51- 512). Tax credit of $15/ton of rice straw, in excess of 500 tons, purchased by an Arkansas end user for use in processing, manufacturing, generating energy, or producing ethanol. (AR DFA, 2005). Estimated cost for 2006–07 is 2.5m (AR DFAb, 2005).	Ethanol	Producer	~1.2m/year. Will rise steeply if rice-to-ethanol plant now being researched is built.	Credit limited to 50% of the income tax due for the tax year. Unused credits can be carried forward for 10 years (AR DFA, 2005).
Government-funded research, development, demonstration and market promotion					
Federal	Sec. 971(d), Integrated bioenergy research centers. Funding via DOE's Office of Science.	Various biofuels		$49m/yr authorized for 2005 2009.	Split 50% cellulosic, 25% starch, 25% biodiesel (guess).
Illinois	Ethanol research on corn-to-ethanol conversion efficiency at Western Illinois University.	Ethanol	Grant	$1 million	
New York	Funding through the NY Dept. of Agriculture and Markets Food and Agricultural Industry Development Grants for biodiesel projects at Sidor Farms and Northern Biodiesel of 60k each in 2006 (Pataki, 8 May 2006).	Biodiesel	Grant	120k	
New York	Funding through the NY Dept. of Agriculture and Markets Food and Agricultural Industry Development Grants for cellulosic ethanol crop research at SUNYESF and Cornell (Pataki, 8 May 2006).	Ethanol	Grant	82k	
Federal	EPACT Sec. 208 Sugar cane ethanol program, to be run out of EPA. Demonstration projects on sugar-based ethanol production, with funds split equally between the states of HI, LA, FL, and TX (EPACT section 208).	Ethanol	Producer	Authorized: $36m over 3 years.	
Federal	EPACT Sect. 757, Biodiesel Engine Testing program. Public/private partnership to test engine and fuel injection systems to better handle bio-diesel blends (EPACT 757).	Biodiesel		Authorized: $5m/yr, 2006–2010; $25m total.	
Federal	EPACT 941, amendments to the Biomass Research and Development Act of 2000 modify language to include biofuels in many of the provisions of the original law (EPACT 941).	Both		Unknown.	

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Federal	EPACT Section 946 Pre-Processing and Harvesting Demonstration Grants. Funds research into harvesting and processing of biomass that is subsequently used to make ethanol or other energy (EPACT 05, Sect. 946).	Ethanol, probably biodiesel as well.	Producer	Authorized $5m per year, 2006–2010.	Split between ethanol and biodiesel.
Federal	EPACT Sect. 1505. Mandated study of health effects of fuel additives, many of which are related to ethanol (EPACT 1505).	Ethanol	Producer	No data	
Federal	Sect. 1511 cellulosic biomass research facilities at Mississippi State University and Oklahoma State University (EPACT 1511).	Ethanol		$4m/yr., 2005–07.	
Federal	EPACT 1514, Advanced biofuels technologies program. Funding demonstration projects with at least 4 different cellulosic to ethanol Conversion technologies; and not less than 5 approaches to develop marketable byproducts. (EPACT 1514).	Ethanol		Authorized: $110m for 2005–09 ($550m total)	
Federal	EPACT 932(d) integrated biorefinery demonstration projects. Though fuels are a key output of the biorefineries, the model is a petrochemical refinery that produces a range of outputs to supply multiple industries. Up to 3 demonstration projects to be funded, with a 60% cost-share funded by the industrial partner (Stevens, 2/22/2006; EERE, 2005, "Integrated biorefineries")			160m over 3 years as announced. Funding in statute restricted to no more than $100m per demonstration facility. Funding announcement Summer 2006 estimated $57m in funding for 2007.	Requires use of ligno-cellulosic feedstocks. Not only for energy; integrated production of other chemicals as well. We assume 50% of funding will support energy production; 50% for other productions.
Federal	EPACT 932(f), University Biodiesel Program. Studies the performance of biodiesel blends up to B100, containing high cellulosic content. (EPACT 932(f)). Focus on use of biodiesel in university-owned electric power generating stations.	Biodiesel		No amounts specified.	
Federal	2002 Farm Bill, Section 9008. USDA/DOE biomass research and development grants support a variety of rural energy options including biofuels (EESI, 2004).	Ethanol, biodiesel	Producer	~$3m awarded for ethanol research in 2004.	Biodiesel eligible, but no awards visible in the year for which we reviewed data.
Federal	R&D via standard DOE budget; and via the Biomass R&D Act of 2000.				
Illinois	Illinois Renewable Fuels Research, Development, and Demonstration Program, run through the IL Department of Commerce and Economic Opportunity (EERE, May 2006). Promotes and expands the use of ethanol in transportation.	Ethanol	Grant	Funding in 2003 of $750k; in 2004 of $400k.	Grant maximums are 25k for planning/ development; 350k for demonstration and research/development projects. Demonstration projects by for-profit entities require 50% cost share; all others have no required cost-share (IL OAG, 2006).
Illinois	Corn-to-ethanol research pilot plant, managed by the IL Ethanol Research Advisory Board. Funded jointly by the Federal and State of IL governments.	Ethanol	Grant	Initial funding, 2004: $15m fed, $6m state. 2004 additional: 0.6m state 2005: 1.0m state, 2m fed 2006: 4m state. Total known: $28.6m	

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
New York	$20m grant available to finance construction of pilot cellulosic ethanol plants. Funds can go to 1–4 projects, depending on responses (EESI, July 2006, p. 16).	Ethanol	Grant	$20m	
Federal	Sect. 1506, Analysis of Motor Vehicle Fuel Changes to study emissions profile of new fuel blends, primarily with ethanol.	Ethanol		No data	
Oklahoma	Biodiesel Development Advisory Committee, 11 member group from various backgrounds to study and promote increased use and production of biodiesel within Oklahoma. (OK Statutes, Title 2, 37B-1950.11)	Biodiesel	Producer		
Oklahoma	Ethanol Development Advisory Committee, 15 member group from various backgrounds to study and promote increased use and production of ethanol within Oklahoma. (OK Statutes,Title 2, 37A-1950.2)	Ethanol	Producer		
Federal	EPACT945 Regional Bioeconomy Development Grants to support bioeconomy development associations, farm or energy trade associations or Land Grant institutions in study and support bioeconomy development.			$1m year.	
Federal	EPACT 947 Education and Outreach to producers and consumers, regarding both biofuels and bioproducts.	Both		Authorized $1m/year.	
Delaware	Funding from DE Soybean Board for rebates and marketing, promotion and education assistance (EERE, May 2006).	Biodiesel	Producer		
Minnesota	Minnesota E85 Team – public/private partnership to pilot large scale promotion of E85 (EERE, May 2006).	E85	Consumer		
Minnesota	Ethanol education to public, via MN Department of Agriculture. Funded from 1987 through 1998.	Ethanol		$100k/year, or roughly $1.1m over the life of the program. (Rankin, 2002).	
Nebraska	National Ethanol Board appointed and funded by the state to promote ethanol. State also authorized to fund memberships in national ethanol promotion organizations (NE Statutes, 66-1335).	Ethanol			
Washington	Biofuels Education fund establish a biofuels consumer education and outreach program at Washington State University extension energy program.	Biodiesel		0.1m	Funding data for one year; subsequent funding unknown.
Consumption subsidies					
Iowa	Biodiesel purchase grants funded by the sale of Energy Policy Act credits, will be used to fund the purchase of biodiesel for the IA Dept. of Transportation vehicles (EERE, May 2006)	Biodiesel	Consumer		
Louisiana	B100 used as fuel by a registered manufacturer in the state is exempt from state sales and use tax (EERE, May 2006).	Biodiesel	Producer		
Maryland	Biodiesel rebate to consumers for up to 50% of the incremental cost to purchase the biodiesel blend. Minimum rebate of $100; maximum of $1,000. Each consumer is eligible for only one year of rebate (EERE, May 2006).	Biodiesel	Consumer	Funded by farmers, not government, so program does not constitute a public subsidy (See www.mdsoy.org).	

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Missouri	Biodiesel purchase subsidies for school districts purchasing B20 or higher from non-profit generation cooperatives. Subsidies given to schools, but effectively supporting producers.	Biodiesel	Producer		
Montana	Retailer tax rebate of 1 cpg of biodiesel (50 cpg B100) purchased from a licensed distributor and if sourced entirely within MT (EERE, May 2006; MT Code 15 70-369).	Biodiesel	1 cpg		
New Jersey	Biodiesel fuel use rebate compensates state and . local government entitites for the incremental cost of using biodiesel over regular diesel.	Biodiesel	Consumer		
New York	Residential bioheat income tax credit. Provides 1 cent state income tax credit for each percentage of biodiesel blended into heating oil, not to exceed 20 cpg (Pearson, 30 May 2006).	Biodiesel	Consumer		Took effect July 2006.
North Carolina	Purchase subsidies to state agencies to offset the incremental cost of alternative fuels for their fleets (EERE, May 2006). NC Statutes 143-58.4, 143-58.5, 136-28.13, 143-341(8)i.	B20 or higher; E85 or higher; plus others.	Consumer		
Wisconsin	Funding to cover incremental cost of biodiesel usage in school buses is available through the Wisconsin Department of Public Instruction. (EERE, May 2006).	Biodiesel	Consumer		Shortfalls in funding vs. need for biodiesel subsidy would be allocated across recipient districts by the number of pupils.
Subsidies for infra-structure related to biofuel distribution					
Federal	EPACT Section 1342, Credit for Installation of Alternative Refueling Stations. Covers 30% of eligible cost of depreciable property, up to a 30k maximum (EPACT 1342).	E85 or higher; B20 or higher	Infrastructure	Estimated on Fed Tax page.	
Colorado	State income tax credits for installing E85 fueling equipment (NECV), and for alternative fueled vehicles (as of 2001) (CEC, 23).				
Illinois	State income tax credits for installing E85 fueling equipment (NECV).	Ethanol			
Illinois	E85 refueling infrastructure grants disbursed through the IL Dept. of Commerce and Economic Opportunity (EERE, May 2006).	Ethanol	Grant	$500k	Up to 50% of the cost to convert an existing site (up to 2k/site) or for construction of a new refueling facility (up to 40k/site).
Indiana	Biofuels Grants Program promotes increased use of biofuels in Indiana. Supports grants to install E85 and B20 infrastructure, or for school districts or large fleet operators to boost usage (EERE, May 2006).	Both	Infrastructure		Requires 50% matching funds. Maximum grants of 25k for single fuel infrastructure; 50k is both E85 and B20 being installed.
Iowa	Biodiesel Terminal Infrastructure Installation Grant provides cost share via the IA Department of Economic Development to install on-site and off-site terminals for biodiesel (IA Code 15.401; IA DNR 2006). State has appropriated $13m over next three years (2006-08) for this program. See: http://www.iowarfa.org/NR060705.php	Biodiesel	Infrastructure	Max of $30k for retailer per project; $50k for blender per project (EERE, May 2006).	

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Iowa	E85 cost-sharing with state government, to a maximum outlay of 325k/yr (EERE, May 2006). Has recently been used to fund new E85 pumps. (EPM, May 2006).	Ethanol	Infrastructure	325k/yr., though legislature "appears poised to increase the funding amount by between $2 million and $5 million" for FY2007 (EPM, May 2006).	
Kansas	State income tax credits for installing E85 fueling equipment (NECV). These equal 50% of total cost (max. of $200k per station) for in-service dates of 1 January 1996-1 January 2005. Credit caps after Jan. 1, 2005 are 40% of total cost (max. of $160k/station) (KS statutes 79-32, 201).	Ethanol (E70 or higher); probably biodiesel as well.	Infrastructure		
Kentucky	Grants for E85 stations (Kotrba, Feb. 2006).	Ethanol			
Maine	Tax credit for installation or upgrading of clean fuel or recharging stations for the public. Credit is equal to 25% of qualifying expenditures, through 31 December 2008 (EERE, May 2006).	Both	Infrastructure		
Minnesota	If the biodiesel mandate is repealed within eight years of enactment, distributors are eligible for partial reimbursement from the state for capital investments they made in blending infrastructure. Reimbursement rate is 80% in first two years, declining by 10% each successive year (MN Statutes, 239.771).	Biodiesel	Infrastructure		
Minnesota	Loans for installing ethanol pumps and infrastructure. No information on amounts, but considered an important element of the expansion in EERE's 2001 write-up (URL in source column).				
Montana	Tax credit to businesses and individuals for 15% of the cost of biodiesel storage and blending equipment. Credit limited to $52.5k for a distributor, and $7.5k for the owner of an outlet. (EERE, May 2006). MT 15-32-702.	Biodiesel			Credit must be taken in first year biodiesel is blended, and can't be carried forward.
Montana	Ethanol distributor credit.				
New Jersey	Local Government Alternative Fuel Infrastructure Program can reimburse the cost of installing alternative energy refueling infrastructure (including E85) up to 50k/applicant. 50% cost share required (EERE, MAy 2006).	E85	Infrastructure		
North Carolina	Tax credit for alternative fuel refueling infrastructure. 15% tax credit, taken in three equal installments. Includes pumps, tanks, other dispensing infrastructure. Does not seem to include trucks. 25% tax credit for renewable fuel processing facility, taken in seven equal installments (NC Statutes 105-129.16D).	E70 or above; Biodiesel of any blend ratio (per NC 105-449.60).	Infrastructure		
Ohio	Alternative Fuel Transportation Grant Program, funded by at least $1 million to increase biofuel infrastructure and availability within the state (EESI, July 2006, p. 9).	Both	Infrastructure	$1m minimum.	House Bill 245.
Ohio	Infrastructure grants to retail fuel station owners to install and promote E85 and/or B20 at their stations. Grants of up to $5k/recipient for E85; and $15k/recipient for B20. Funding through the Ohio Biofuels Retail Incentive Program (EERE, May 2006).	E85 and B20	Infrastructure	Maximum available funding of $135k through July 2006.	

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Oregon	State income tax credits for installing E85 fueling equipment (NECV).				
Tennessee	Grants through the TN Department of Transportation to install refueling network, including storage tanks and fuel pumps, dedicated to dispensing biofuels. Can fund capital costs of this equipment for private stations. Minimum private cost-share of 20%. (EERE, May 2006; TN DOT, 2006).	E85 or B20			
Subsidies to biofuel-consuming capital					
Federal	EPACT Sec. 741 Clean School Bus Program. Grants for up to 100% of retrofits and 50% of replacements for older, high-polluting school buses. E85- and biodiesel-fueled buses are eligible, among other propulsion systems (EPACT 05, Section 741).	E85, biodiesel	Infrastructure	Authorized: $55m in '06; $55m in '07; "such sums as necessary" for 2008–10.	Roughly 20% of past awards seem to have involved biodiesel. Virtually no ethanol.
Federal	EPACT Sec. 702. Diesel truck retrofit and fleet modernization program.	Biodiesel, other fuels as well		Authorized: $20m in 2006; $35m in 2007; $45m in 2008.	As with school bus program, we ascribe 20% of funding to biodiesel.
Federal	EPACT Sec. 791-97 Diesel Emissions Reduction. Cost share for improving emissions profile of existing diesel equipment.	Potentially biodiesel		$200m/yr for 2007–10.	Past funded projects focus on installation of pollution controls, not fuel substitution. Assume no benefit to biodiesel.
Colorado	Alternative fuel income tax credit for most of the incremental cost of purchasing an alternative-fueled vehicle. E85 eligibility specified; biodiesel eligibility via more general statute language. CO guidance suggests that in practice flex-fueled or dual-fueled vehicles have no incremental cost, so would not generate a tax credit (CO DOR, 2006).	Both	Infrastructure		
Georgia	Mandated purchase of alternative fueled vehicles for state agencies and departments; and for stocking ethanol and biodiesel at state refueling facilities. Mandates subject to economic tests and other language that suggest their effect in driving market behavior will be fairly weak (EERE, May 2006).	Both	Mandate		
Georgia	Tax credit for purchase of AFVs, including E85 or higher; or biodiesel. Credit equal to 10% of cost of new vehicle, conversion, or $2,500, whichever is less. Caps would be double for electric vehicles (EERE, May 2006; Georgia code 48-7-40.16).	E85 or higher; biodiesel			Definitions include "fuels other than alcohol derived from biological materials." This appears to include biodiesel, though not clear how mixtures of biological oils and standard diesel would be treated.
Hawaii	Allows each mandated purchase of an alternative fueled vehicle to be offset by use of equivalent to 450 gallons of B100 in existing state fleet (NBB, 25 May 2006).	Biodiesel	Purchase preference		

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Illinois	Purchase mandates, biodiesel. Any diesel powered vehicle, refueling at a bulk central refueling facility, that is owned or operated by any sub-national government entity (including schools and colleges) must use B2 when available. The only exceptions are if the vehicle can use a higher biodiesel blend or ultra low sulfur fuel. 625 IL Compiled Statutes 5/12-705.1). (EERE, May 2006).	Biodiesel	Mandate		
Kansas	State income tax credits for certain alternative fueled vehicles, including E85 and probably bio diesel. Credit ranges from 40% of cost/ incremental cost (max. $2.4k to $40k depending on vehicle weight) if placed in service after 1 January 2005. In-service from 1996-2004 was 50% (max 3k–50k, depending on vehicle weight) (EERE, May 2006; KS statutes 79-32, 201).	Ethanol (E70 or higher); probably biodiesel as well.	Infrastructure		
West Virginia	Alternative vehicle tax credits, including for E85 vehicles, of $3,750. Credit taken over three years, and was slated to expire in June 2006. (EERE, May 2006).	Ethanol			
Support for production of feedstocks					
Federal	2002 Farm Bill, section 2101. Allows Conservation Reserve Program land to be used to produce biomass for energy production, while still earning its CRP rental payment. (Schnepf, 18 May 2006, p. 13).	Ethanol and Biodiesel	Producer	Unknown	
Minnesota	Tax increment financing has been granted to most of the ethanol plants in the state as of 1996; (MN OLA, 7).				
Minnesota	Ethanol combustion efficiency grants provide $100k per year on ways to improve the efficiency of ethanol within vehicle systems. (MN Statutes 41A.09)	Ethanol	Producer	100k/yr.	Requires $2 of non-state money for each $3 of state money.
Federal	USDA sec. 9002 federal procurement of biobased products			Quite small.	
Arizona	State fleets must use or give preference to biodiesel blends when available (Pearson, 30 May 2006).	Biodiesel	Purchase preference		
Iowa	Biodiesel purchase mandates for state agencies at bulk fuel outlets. 5% renewable content by 2007, 10% by 2008, 20% by 2010 (EERE, May 2006).	Biodiesel	Mandate		
Iowa	Purchase mandates for state-funded refueling. Credit cards issued for refueling vehicles not allowed to be used for any fuel with less than E10 (IA Code Title VIII, Subtitle 1, 455A.6).	E10	Consumer		
Kansas	Biodiesel purchase preference for state-owned vehicles, so long as less than 10 cpg price premium.	Biodiesel (B2 or higher)	Mandate		
Minnesota	Executive order to expand availability and usage of E85 throughout the state; and to use E85 in state fleets whenever practical (Pawlenty, 2006).				

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Nebraska	Purchase mandates for state fleets of flex fuel or diesel vehicles, to buy E85 or biodiesel whenever "reasonably" available. Executive order 05-03 (EERE, May 2006).	E85, biodiesel	Consumer		
New Mexico	Purchase mandate for state agencies, universities and public schools. Must take action towards using ethanol and biodiesel to meet 15% of their total transportation fuel requirements (Executive order 2005-049, 2005) (EERE, May 2006)	Both	Mandate		
New York	Purchase mandates, through Executive Orders, mandate 5% of heating fuel used in state buildings be 2012 be biodiesel; and at least 2% of the fuels used in the state fleet be biodiesel, increasing to 10% by 2012 (Pataki, 20 November 2005).	Biodiesel	Mandate		
New York	Purchase mandate to use E85 in flex fuel state-fleets whenever feasible to do so. (EERE May 2006; Exec. order 142, 2005).	E85	Mandate		
North Carolina	State-owned fleets with >10 vehicles must achieve 20% reduction or displacement of current petroleum products consumed by 1 January 2010. Displacement by ethanol or biodiesel is eligible (EERE, May 2006).	Biodiesel, ethanol	Mandate		
Ohio	Purchase mandates for biofuels (1 million gpy of biodiesel and 30k gallons of ethanol) in state fleet; new Ohio light duty truck purchases must be able to drive on E85. Executive Order 2005-18T) (EERE, May 2006).	Both	Mandate		
Oregon	Purchase mandate for the city of Portland. City stations required to sell B5 and E10. (EESI, July 2006, p. 10).	Both	Mandate		
South Dakota	Purchase preference to stock and use B2 or higher for state employees and fleets. Executive order 2006-01 (EERE, May 2006).				
Virginia	Biodiesel purchase preference encourages state fleets to use biodiesel fuels. Fairly weak language though (EERE, May 2006).				
Wisconsin	Executive Order for state fleets to reduce the use of petroleum-based gasoline 20% by 2010, and 50% by 2015; and petroleum-based diesel 10% by 2010, and 25% by 2015. Also encourages increased education and usage of these fuels by state fleet operators (Doyle, 2006).	Ethanol and Biodiesel			
Colorado	Purchase mandate: by 10 July 2010, at least 10% of all state-owned bifuel vehicles to be fueled exclusively with alternative fuel. (EERE, May 2006).	Both	Mandate		
Iowa	Vehicle purchase mandates for state educational institutions. At least 10% of new car and light truck purchases must have alternative fueled propulsion (IA Code, Title VII, Sub. 2, 260C.19A).	E85 and higher; B20 and higher			

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Nevada	90% of the vehicles purchased by the state government or larger counties must be alternative fueled vehicles or ultra low emissions vehicles, starting in 2000. Targets can be met by converting existing fleet as well. Once purchased, the vehicle must operate solely on this alt fuel whenever it is available. Includes bus and heavy-duty vehicle fleets (EERE, 05/06, Nev. Statutes 486A.010 through 486A.180).	B5 or higher; probably E85 or higher (per NRS 590.020)	Infrastructure		Fleets containing less than 10 vehicles are exempt, but any fleet owned, leased, or operated by the government entity would be covered by this mandate. Other fuels also count; thus, entire incentive will not flow to biodiesel and ethanol.
New Jersey	Purchase mandate for NJ Transit Corp. All buses purchased after 1 July 2007 must run on alternatives to conventional diesel. Biodiesel buses (among other options) comply. (EERE, May 2006).	Biodiesel	Mandate		
North Carolina	State goal that 75% or more of new or replacement light duty cars and trucks purchased by the state after Jan. 1, 2004 must be AFVs or low emission vehicles. AFVs include E85 or "fuels, other than alcohol, derived from biological materials." (NC 143-215.107C).	E85, probably biodiesel	Purchase goal		
Ohio	State vehicles must all be flex-fuel cars. (EESI, July 2006, p. 9).	Both	Mandate		House Bill 245.
Federal	Rural Utility Services Plant financing (may be primarily electricity).			Unknown	
Montana	Oilseed crushing facility tax credit. Equals 15% of the cost of depreciable property used to crush oilseeds, up to a maximum of 500k (MT 15-32-701; Schumacher, 2006). Regulatory relaxation favoring biofuels.				
Illinois	Expedited permitting for ethanol and biodiesel plants.	Both	Grant	$100k	
Minnesota	Exemption from environmental impact assessment requirements for any plants with a production capacity of less than 125 mmgy, and located outside of the seven-county metropolitan area (MN Statutes, 116D.04, Subd. 2a).	Ethanol only	Production		
Minnesota	Construction of large energy facilities within the state of MN are not allowed to proceed without receiving a certificate of need from the state. Ethanol plants are exempt from this requirement (MN Statutes 216B.243).	Ethanol only	Producer		
Nebraska	Ethanol plants included among list of facilities that are included as "internal improvements." This inclusion makes them eligible to use state powers of eminent domain if they are not privately owned. May also have some additional rights even if privately owned. (NE Statutes, 70-667).	Ethanol	Production		
New Mexico	Added B20 or greater to state definition of "alternative fuel," making it eligible for other existing state programs. [need to figure out which] (EERE, May 2006).	B20			
Washington	Underground storage tanks holding B100 are exempt from regulations governing underground diesel tanks (EERE, May 2006).	Biodiesel			

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Renewable fuels mandate					
Federal	EPACT Section 1501, Renewable Content of Gasoline. Mandates minimum usage of ethanol in fuels at 4b gallons/yr in 2006, rising to 7.5 b gallons in 2012 (EPACT 1501).	Ethanol	Producer	Analyzed in Market Price Support	
California	Executive order setting targets for biofuels in the state. These targets are for 20% of the state's biofuels to be produced in-state by 2010, 40% by 2020, and 75% by 2050. Does not appear particularly binding, and percentages apply to shares of total biofuels usage, not to shares of total transportation fuel usage (CA Exec. Order, 2006).	Ethanol, biodiesel	Mandate	Probably small direct impact since terms do not appear to be particularly binding.	
Hawaii	10% ethanol content mandate for gasoline fuel. Some exemptions (HI Statutes, 486J-10).	Ethanol			
Iowa	Purchase mandate stipulating that 25% of a retailers fuel sales must be ethanol or biodiesel by 2020 (Pearson, 30 May 2006). Failure to reach target will reduce eligibility for tax credits.	Ethanol, biodiesel			Signed into law 30 May 2006. HF 2754 and HF 2759.
Maryland	Requires that, beginning FY08, at least 50% of the vehicles in the state fleet using diesel fuel use B5 or higher (NBB, 25 May 2006).	B5 or higher	Mandate		
Minnesota	State mandates that all diesel fuel sold in MN, used in internal combustion engines, must contain at least 2% biodiesel by value.	Biodiesel	Mandate	Incremental cost to consumers est. at $24m/yr for B2 mandate; $56m/yr for B5, and $56m/yr for B20. This was 2001$ and markets (Runge, 2002, v.) % increases from then (low) prices were: 4.5% for B2 mandate; 10.6% for B5; and 45% for B20 (Runge, 2002, 9). Runge notes that there would also be fairly large infrastructure investment costs.	
Minnesota	Ethanol mandated to comprise 10% of all gasoline sold in the state. This was increased to 20% in 2005, with a compliance date of 2013.	Ethanol	Mandate	In 1997, the state of MN estimated the ethanol mandate would cost consumers $33–50m/year, or 2–3 cpg (MN OLA, p. 14). However, they note that other estimates were as high as 5 cpg, and that adjusting for the lower energy content of ethanol blends generates an additional $24–$36 m/yr (1997$), p. xiv).	Higher mandate of 20% won't take effect if state reaches this level anyway by 2013. The rule would expire at the end of 2010 if Minnesota is not granted federal approval to use E-20 gasoline blends.
Missouri	Purchase preference for B20 or higher fuels in state vehicle fleet and heavy equipment, so long as B20 is within 25 cpg of straight diesel (EERE, May 2006).	Biodiesel			

	Subsidy Description	Fuel	Cat	Subsidy Rate ($mils)	Comments/ Other Eligibility Criteria
Missouri	Renewable Fuel purchase mandates for E10. Exclusions apply if more expensive than gasoline, and for premium gasoline blends. (EESI, July 2006, p. 10).	Ethanol	Mandate		
Montana	10% ethanol blending mandate once in-state production capacity hits 40 mmgy (ACE, 27; MT Code 82-15-121).	Ethanol	Mandate	No immediate impact,since in-state capacity below threshold.	Consumption of gasoline in MT (2001) was about 465mmgy, so the mandate could not be met by in-state supply.
Washington	2% purchase mandate for ethanol composition of gasoline beginning December 1, 2008. This could be increased to 10% if deemed not to affect air quality in the state. Mandate for 2% of diesel sold in Washington to be biodiesel beginning November 30, 2008, or when the state certifies in-state feedstock can support this mandate. Mandate rises to 5% once in-state production can meet 3% (EERE, May 2006).	Ethanol and Biodiesel	Mandate		
Iowa	Mandated all cars sold in the state needed to be able to operate on E10 or lower by 1993. (IA Code 331.908).	Ethanol			
Federal	USDA Sec. 2301 Environmental quality incentives program.			Unknown	

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About the Author

Doug Koplow founded Earth Track in 1999 to more effectively integrate information on energy subsidies. For nearly 20 years, Mr. Koplow has written extensively on natural resource subsidies for organizations such as the National Commission on Energy Policy, the Organisation for Economic Co-operation and Development, the United Nations Environment Programme (UNEP), Greenpeace, the Alliance to Save Energy and the U.S. Environmental Protection Agency. He has analyzed scores of government programs and made important developments in subsidy valuation techniques.

His work outside of the subsidy area has included water conservation, wastewater treatment, hazardous waste tracking, recycling and brownfields redevelopment. Working collaboratively with other organizations, Earth Track focuses on ways to more effectively align the incentives of key stakeholder groups and to leverage market forces to help address complex environmental challenges. Mr. Koplow holds an MBA from the Harvard Graduate School of Business Administration, and a BA in economics from Wesleyan University

The Global Subsidies Initiative (GSI) of the International Institute for Sustainable Development (IISD)

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While subsidies can play a legitimate role in securing public goods that would otherwise remain beyond reach, they can also be easily subverted. Special interest lobbies and electoral ambitions can hijack public policy. When subsidies result in a fundamentally unfair trading system, and lie at the root of serious environmental degradation, the question has to be asked: Is this how taxpayers want their money spent?

The GSI starts from the premise that full transparency and public accountability for the stated aims of public expenditure must be the cornerstones of any subsidy program. In cooperation with a growing international network of research and media partners, the GSI is endeavouring to lay bare just what good or harm public subsidies are doing; to encourage public debate and awareness of the options that are available; and to help provide policymakers with the tools they need to secure sustainable outcomes for our societies and our planet.

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